BEFORE THE
TENNESSEE PUBLIC UTILITY COMMISSION

PETITION OF KINGSPORT POWER COMPANY D/B/A AEP APPALACHIAN POWER
GENERAL RATE CASE

DOCKET NO. 21-00107

DIRECT TESTIMONY
OF
AARON L. ROTHSCHILD

COST OF CAPITAL

ON BEHALF OF
OFFICE OF THE TENNESSEE ATTORNEY GENERAL

March 30, 2022

Contents

I. STATEMENT OF QUALIFICATIONS

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

A. My name is Aaron L. Rothschild. My title is President, and my business address is 15 Lake Road, Ridgefield, CT.

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

A. I am President of Rothschild Financial Consulting ("RFC").

Q. PLEASE STATE YOUR EDUCATIONAL ACHIEVEMENTS AND PROFESSIONAL DESIGNATIONS.

A. I have a B.A. degree in mathematics from Clark University (1994) and an M.B.A. from Vanderbilt University (1996).

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE.

A. I performed financial analysis in the telecom industry in the United States and Asia Pacific from 1996 to 2001, investment banking consulting in New York, complex systems science research regarding the power sector at an independent research institute, and I have prepared rate of return testimonies since 2002. See Appendix A for my resume.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE TENNESSEE PUBLIC UTILITY COMMISSION, OR OTHER STATE COMMISSIONS? IF SO, WHICH COMMISSIONS?

A. My expert witness experience also includes testifying in over 50 cost of capital proceedings before the following state commissions: California, Colorado, Connecticut, Delaware, Florida, New Jersey, Maryland, North Dakota, Pennsylvania, and Vermont. See Appendix B for the list of dockets for each of my testimonies.

Q. ON WHOSE BEHALF ARE YOU PROVIDING THIS TESTIMONY?

A. I am testifying on behalf of the Office of the Tennessee Attorney General ("Attorney General").

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

A. The purpose of my testimony is to address the cost of capital for Kingsport Power Company ("KgPCo" or the "Company") which includes the following three components:

1. The cost of equity ("COE")
2. Cost of Debt
3. Capital Structure

Based on my analysis of these cost of capital components, I recommend an allowed rate of return for ratemaking purposes, including an appropriate authorized return on equity ("ROE"), authorized cost of debt, and authorized capital structure.

Q. PLEASE DEFINE THE COE, COST OF DEBT, AND CAPITAL STRUCTURE.

A.

1. **COE:** My COE recommendation is my opinion of the return investors require to provide equity capital to KgPCo based on current capital markets. My recommendation is consistent with the following legal standards set by the United States Supreme Court for a fair rate of return:

> The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[1]

And

> …sufficient to…support its credit and…raise the money necessary for the proper discharge of its public duties.[2]

2. **Cost of Debt:** My cost of debt recommendation is based on the actual cost of debt paid by the utility to its sources of debt. For example, if a utility has issued a bond with a 3% interest rate three years ago, its authorized cost of debt should be 3% even if interest rates are currently higher or lower than 3%.

3. **Capital Structure:** Capital structure is the percentage of equity and debt that makes up the finances of a utility. For example, if a utility raises $1 million of equity capital and $1 million of debt capital, we say it has a capital structure containing 50% equity and 50% debt.

Q. WHAT IS THE DIFFERENCE BETWEEN KGPCO'S COST OF EQUITY AND ITS AUTHORIZED ROE?

A. The COE is the market-based return investors expect to earn on the market value of any given stock. As it applies to this proceeding, it is the return investors require to provide equity capital to KgPCo. The appropriate authorized ROE is based on the Commission's determination of the COE at the time of the proceeding, after reviewing the evidentiary record, which incorporates investor expectations. Once the Commission issues an authorized ROE, the market-based cost of equity will continue to fluctuate as capital

[1] *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944).
[2] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of the State of W. Va.* 262 U.S. 679, 692-693 (1923).

markets inevitably continue to change. The authorized ROE is based on a snapshot of the COE, which is constantly changing.

Q. PLEASE DEFINE THE APPROPRIATE RATE OF RETURN.

A. The appropriate Rate of Return (ROR) is based upon the weighted overall cost of capital (WACC) of the current cost of debt and equity at the time of this proceeding. The weighted cost rate is calculated by multiplying the capital structure ratios of the sources of capital (debt, preferred equity, and equity) times respective cost rates.

WACC = Cost of Debt X Debt Ratio + COE X Common Equity Ratio.

Q. CALCULATING THE COST OF EQUITY IS A HIGHLY TECHNICAL TOPIC. HOW CAN A DECISION MAKER WHO IS NOT SPECIALIZED IN FINANCE BEST USE THE CONTENT OF THIS TESTIMONY?

A. My testimony provides the information required so one can use common sense to evaluate my model results. For example, Table 2 on page 9 shows the long-term equity return expectations of pension funds and leading financial institutions for comparative purposes. These return expectations, among other widely understood financial facts discussed below, can assist the financial specialist as well as people whose only exposure to finance is reading the news and watching their retirement funds ebb and flow with financial markets.

My testimony includes a thorough technical analysis, including the use of specialized mathematical models. Models are required to determine the cost of equity like a map is required to plan a road trip. Maps and models are useful because they simplify the complexity and vastness of reality into a form that is understandable and useful. A map of Tennessee that left out no details would be the same size as the state and thus unusable. A model that included every detail of financial markets (e.g., the trading activity of every single stock investor on earth) would be unusable as well. It is critical to remember that models are simplifications of reality. Sometimes what is left out of a model can cause its results to be significantly inaccurate and lead us to make poor decisions, including setting electric utility rates that are too low or too high. I would argue that the hedge fund Long Term Capital Management lost billions of dollars and was eventually liquidated in early 2000 because it had too much faith in its fancy models. I do my best to provide a comprehensive analysis so the Commission can make an informed decision without having to feel forced to blindly trust my financial model results. I do not want the decision-makers to feel forced to throwing their hands in the air and just take an average of my results and KgPCo's requested rate of return.

If my cost of equity recommendation is too low, KgPCo will not be able to raise the funds it needs to provide safe and reliable service, and if it is too high, consumers will be overcharged and Tennessee's economy would be negatively impacted. Therefore, coming back to cost of equity models, it is critical to use common sense as a check on model results. For example, if cost of equity-model results are completely out of line with returns expected by pension funds and the published equity return expectations of leading financial institutions, one should carefully examine the way the model works to make sure it is accurately reflecting the impact of current events on financial markets (e.g., pandemic, Russia's invasion of Ukraine).

Q. HAVE YOU REVIEWED KGPCO'S APPLICATION AND DIRECT TESTIMONY?

A. Yes.

II. INTRODUCTION AND SUMMARY OF CONCLUSIONS

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I provide a summary of my recommendations, an overview of cost of equity concepts, and how current capital markets relate to my cost of equity calculations. Second, I provide a more detailed discussion of current capital markets. Third, I provide a detailed explanation of the various models I use in my cost of equity calculations. Lastly, I provide an evaluation of KgPCo's rate of return testimony.

Q. PLEASE PROVIDE A SUMMARY OF YOUR RECOMMENDATIONS.

A. I recommend the following cost of capital for KgPCo's retail electric service operations:

- An overall cost of capital of 4.97% (4.21% - 5.22%)
- An ROE of 7.35% (5.81% - 7.86%)
- A capital structure containing 48.90% common equity and 42.49% debt
- A debt cost rate of 3.14%

A summary of my cost of capital recommendations for KgPCo's retail electric service operations is presented in Table 1 below.

TABLE 1: ALR COST OF CAPITAL RECOMMENDATIONS - KINGSPORT POWER COMPANY
Docket No. 21-00107

	Capital Structure Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	42.49%	3.14%	1.33%
Short-Term Debt	8.61%	0.45%	0.04%
Preferred Equity	0.00%	0.00%	0.00%
Common Equity	48.90%	7.35%	3.59%
Rate of Return			4.97%

Exhibit ALR-1

Q. ARE YOU RECOMMENDING A SPECFIC ROE OF 7.35% OR AN ROE RANGE OF 5.81% TO 7.86%?

A. I recommend both a range of appropriate ROEs and a specific point within that range that I feel would be the most appropriate. Applying the various COE models results in a range for the true COE and not a precise number. The range of 5.81% to 7.86% that I recommend already eliminates the extreme ends of the results of my models and reflects the range of ROEs I feel confident will allow KgPCo to raise the capital it needs to provide safe and reliable service. However, I also recommend a specific point of 7.35% within that range because commissions have often requested this specifically.

Q. WHY ARE YOU RECOMMENDING AN ROE OF 7.35% INSTEAD OF 6.98%, WHICH IS THE MIDPOINT OF YOUR COE MODEL RESULTS?

A. The model results presented in Table 4 on page 19 represent the average cost of equity for the RFC Electric Proxy Group. A risk adjustment must then be applied to take into account the difference between the average capital structure ratio of the companies in this group and the capital structure of KgPCo. A higher common equity ratio means less debt, a lower chance of financial stress (financial risk), and therefore a lower COE. On the other hand, a lower common equity ratio means more debt, a higher chance of financial stress (financial risk), and therefore a higher COE. Based on a regression analysis of dozens of utility companies, I found a 0.04% reduction in the DCF cost of equity results for every 1% increase in the common equity ratio. Based on my recommended capital structure of 48.90% common equity, the required risk adjustment is -0.15%, which results in a risk-adjusted COE range for KgPCo of 5.81% to 7.86%. If the Commission authorizes a different capital structure with a higher or lower common equity ratio for KgPCo, then the authorized ROE for KgPCo should be reduced or increased by 0.04% for every 1% its authorized common equity ratio is higher or lower that of the proxy group.

As discussed below, numerous recent authorized ROEs for water and electric utilities have been between 7.36% and 7.90%, including an ROE of 7.46% for Blue Granite Water Company.[3] Even though it is encouraging for consumers and the general public that commissions are authorizing ROEs that are more in line with the market-based COE, I am recommending a 7.35% ROE for KgPCo instead of the midpoint of my recommended range because I believe it is prudent to not be overly abrupt while bringing ROEs in line with the true market-based COE. However, as discussed above, I provide a recommended ROE range of 5.81% to 7.86% so that the Commission can ultimately decide what ROE they believe is appropriate given the evidence presented in the record.

Q. PLEASE PROVIDE A SUMMARY OF HOW YOUR COST OF EQUITY RECOMMENDATION COMPARES TO RETURN EXPECTATIONS OF MAJOR FINANCIAL INSTITUTIONS.

A. My cost of equity recommendation of 7.35% (5.81% to 7.86%) for KgPCo is in the middle of the range of the expectations published by major banks and brokerage houses (5.5 to 8.5%) shown in Table 2 on page 9. My recommendation is consistent with the cost of equity demanded by investors and enables KgPCo to raise the capital needed to provide safe and reliable service.

[3] *Order Ruling on Application for Adjustments in Rates*, pp. 3, 37-43 and 126-128, S.C. Pub. Serv. Comm'n, Docket No. 2019-290-WS (April 9, 20220). A copy of this opinion is attached as Exhibit ALR-A

TABLE 2: U.S. EQUITY RETURN EXPECTATIONS AMONG MAJOR FINANCIAL INSTITUTIONS	
Duff & Phelps (December 2021) [1]	**8.0%**
Horizon Actuarial Services, LLC Survey - 20 Year Horizon (August 2021) [2]	**4.6 - 8.9%**
50% Percentile: 6.9%	
J.P. Morgan Asset Management - Equity Long-Term Returns (Sep 2021) [3]	**4.1%**
Charles Schwab - 10-year U.S. Large Cap Returns (May 2021) [4]	**6.6%**

Dates above indicate latest market-data used in analysis.

Sources:

[1] Duff & Phelps, Cost of Capital in the Current Environment, COVID-19 Update - December 2021.

[2] Horizon Actuarial Services, LLC, Survey of Capital Market Assumptions Survey, August 2021, page 17. Survey participants Include: Bank of New York Mellon, BlackRock, Goldman Sachs Asset Management, J.P. Morgan Asset Management, Merrill, Morgan Stanley Wealth Management, Royal Bank of Canada, UBS.

[3] J.P. Morgan Asset Management - 2022 Long-Term Capital Market Assumptions September 30, 2021, page 15.

[4] Charles Schwab - Why Market Returns May Be Lower and Global Diversification More Important in the Future May 3, 2021.

The data presented in Table 2 above shows that major financial institutions are informing their clients to expect returns on their investments similar to the cost of equity I propose in this testimony. The return expectations published by all these financial institutions are based on their own financial models. These expectations are for the overall stock market (e.g., US Large Cap, S&P 500). My cost of equity recommendation is based on government-regulated electric utility companies only. Given the relatively lower risk associated with monopoly utilities, it is unlikely that investors would expect to earn a higher return for a utility company than for the overall stock market.

Q. PLEASE COMPARE YOUR ROE RECOMMENDATION TO THE ROE REQUESTED BY KGPCO.

A. I recommend a different ROE[4] for KgPCo than its witness Mr. Castle for many reasons.

First, we have different analytical approaches. I focus primarily on using market data (e.g., stock prices, bond yields, stock option prices) to measure investors' expectations as much as possible. On the other hand, Mr. Castle relies considerably on historical data

[4] My ROE recommendation is based on KgPCo's current market-based COE. As stated previously, the authorized ROE is based on a snapshot of the COE which is constantly changing. In the context of this case my recommended COE and ROE are synonymous.

(e.g., betas in his CAPM are based on data from the past 5 years) and non-market data, including historical accounting returns, to inflate his results.

The ROE recommended by Mr. Castle and requested by KgPCo is 10.20%. As shown in Table 2 on page 9, his requested ROE is considerably higher than return expectations published by major consulting firms, brokerage houses, and market data publications (4.1% to 8.9%).

Determining the appropriate cost of capital is a delicate balance. If the COE and overall cost of capital is set too low, KgPCo will not be able to access the capital needed to provide safe and reliable service. However, charging consumers above the current market rate for capital is not appropriate or necessary to assure capital is available and will result in an unjustified windfall to KgPCo. Mr. Castle's 10.20% cost of equity recommendation is well above the equity return expectations of the financial industry. His cost of equity recommendation is also considerably above allowed returns in the following recent electric and water rate cases:

- **8.00%** - On December 21, 2021, the Public Service Commission of South Carolina authorized an ROE of 8.00% for Palmetto Wastewater Reclamation, Inc. (Docket No.2021-153-S – Order No. 2021-814).
- **7.90%** - On September 14, 2021, the Connecticut Public Utilities Regulatory Authority Public determined that effective November 1, 2021, Eversource's authorized ROE will be 7.90%.[5]

[5] *Proposed Interim Order*, p. 27, Connecticut Public Utilities Regulatory Authority, Docket No. 17-10-46RE03 (September 14, 2021). A copy of this opinion is attached as Exhibit ALR-B.

- **7.46%** - On April 9, 2020, this Commission authorized a ROE of 7.46% for Blue Granite Water Company (Docket No. 2019-290-WS).[6] This decision was upheld by the South Carolina Supreme Court.[7]
- **7.36%** - In Illinois Commerce Commission Docket No. 21-0365 Ameren Illinois proposed a 7.36% ROE in its formula rate update.[8] Note- Formula rates set in Illinois are based on a formulaic ROE calculation (current yield on 30-year U.S. Treasury plus 580 basis points).
- **7.36%** - In Illinois Commerce Commission Docket No. 21-0367 ComEd proposed a 7.36% ROE in its formula rate update.[9] Note- Formula rates set in Illinois are based on a formulaic ROE calculation (current yield on 30-year U.S. Treasury plus 580 basis points).

My market-based analysis indicates that the ROE I recommend for KgPCo is sufficient to attract capital. As shown in Table 3 on page 12, Mr. Castle and I have different cost of debt, capital structure and cost of equity recommendations. My 7.35% cost of equity recommendation results in a 4.97% overall rate of return. Mr. Castle's 10.2% cost of equity recommendation results in an overall rate of return of 6.36%.

[6] Exhibit ALR-A at p. 38..
[7] *Blue Granite Water Co. v. S.C. Pub. Servs. Comm'n,* Case No. 2020-001283, 862 S.E.2d 887, 891-894 (S.C 2021). A copy of this opinion is attached as Exhibit ALR-C.
[8] *Order, In re Ameren Illinois Co.*, p. 63, Docket No. 21-0365 (December 31, 2021). A copy of the order is attached as Exhibit ALR-D. *See also* "Lowest equity return on record to be used in Ameren Illinois' newest rate case", RRA Regulatory Focus, S&P Capital IQ (April 16, 2021). A copy of the article is attached as CONFIDENTIAL Exhibit ALR-E
[9] "Fitch Rates Commonwealth Edison's First Mortgage Bonds 'A'", Fitch Ratings, (August 5, 2021) available at www.fitchratings.com/research/corporate-finance/fitch-rates-commonwealth-edison-first-mortgage-bonds-a-05-08-2021.

TABLE 3: RECOMMENDATION COMPARISON - ROTHSCHILD AND CASTLE

	Cost of Equity	Cost of Debt	Common Equity %	Debt %	Rate of Return
Rothschild [1]	7.35%	3.14%	48.90%	51.10%	5.20%
Castle [2]	10.20%	3.14%	48.90%	51.10%	6.59%

[1] Exhibit ALR-1
[2] Mr. Messner's Direct Testimony, KgPCo Exhibit No. 1

Q. IS IT APPROPRIATE TO ALLOW KGPCO AN AUTHORIZED ROE BASED ON THOSE ALLOWED IN OTHER JURISDICTIONS?

A. As explained below, KgPCo's authorized ROE should be market-based. In other words, it should be based on investors' return expectations as indicated by current market data. Even if it were assumed that all historical authorized ROEs of electric utility companies in other jurisdictions are based on accurate market-based cost of equity calculations, they are from the past. The cost of equity should be based on current market conditions. Setting rates based on historical data is like driving a car by looking out the rear-view mirror. Calculating the cost of equity while looking backward is particularly ineffective now because the pandemic and the Russian invasion of Ukraine are impacting capital markets in real time. Unless authorized ROEs are set based on investors' current expectations as indicated by market data at the time of the proceeding, the resulting rates could be either too low to permit a utility to raise capital on reasonable terms or too high so that ratepayers would be overcharged. For these reasons, I strongly recommend using the results of my market-based methods as confirmed by the equity return expectations of leading financial institutions shown in Table 2 on page 9.

Q. YOU MENTIONED ABOVE THAT SOME RECENT AUTHORIZED ROES HAVE BEEN BETWEEN 7.36% AND 8.0%. SHOULD THESE AUTHORIZED ROES

GIVE THE COMMISSION COMFORT THAT YOUR RECOMMENDED 7.35% ROE WILL ALLOW KGPCO TO RAISE THE CAPITAL REQUIRED TO PROVIDE SAFE AND RELIABLE SERVICE?

A. Yes. As discussed above, it is encouraging for consumers and the general public that commissions are authorizing ROEs that are more in line with the market-based COE. Understandably, I have seen intense pushback from utility companies regarding the relevance of these lower ROEs because it is their job to grow earnings as much as possible. However, I believe comparisons to recent commission-authorized ROEs are relevant to other proceedings to some degree, including this one, because there is evidence that the companies listed above have maintained their capacity to raise capital. ComEd raised $750 million of first mortgage bonds ($300 million maturing in 10-years and $450 million maturing in 30-years) in March 2022 with an authorized ROE of 7.36% and a capital structure with a 48.7% common equity ratio.[10] Fitch assigned an A rating to these bonds, stating that "ComEd's stable regulated electric transmission and distribution operations have a low business risk profile." For the $300 million that matures in 10-year the interest rate was 3.17%.[11] For the $450 million that matures in 30-years the interest rate was 3.86%.[12] The fact that ComEd was recently able to raise considerable capital with an authorized ROE nearly identical to the one I am recommending in this proceeding is additional evidence that supports the accuracy of my cost of equity models and that my

[10] Fitch Rates Commonwealth Edison's First Mortgage Bonds 'A', Fitch Ratings (March 8, 2022) available at https://www.fitchratings.com/research/corporate-finance/fitch-rates-commonwealth-edison-first-mortgage-bonds-a-08-03-2022.

[11] Finra, Bond Detail, https://finra-markets.morningstar.com/BondCenter/BondDetail.jsp?ticker=C1024734&symbol=EXC5376106 (last visited March 29, 2022).

[12] Finra, Bond Detail, https://finra-markets.morningstar.com/BondCenter/BondDetail.jsp?ticker=C1024738&symbol=EXC5376107 (last visited March 29, 2022).

recommended 7.35% ROE will allow KgPCo to raise the capital required to provide safe and reliable service.

Should authorized ROEs continue to become more in line with the market-based COE, it is critical that we continue to analyze the data (e.g., stock prices, credit ratings) to ensure that utility companies have access to capital to provide safe and reliable service.

Q. HOW DOES YOUR COST OF EQUITY RECOMMENDATION OF 7.35% (5.81% TO 7.86%) FOR KGPCO COMPARE TO PRIOR RATE OF RETURN TESTIMONIES FILED ON BEHALF OF THE TENNESSEE ATTORNEY GENERAL?

A. Dr. Christopher C. Klein recommended a 9.0% ROE for Chattanooga Gas Company in his testimony filed on July 3, 2018.[13] However, the result of one of his cost of equity models (7.51%)[14] is nearly identical to my 7.35% cost of equity recommendation. It is understandable that he recommended a 9.0% ROE in 2018 because this was before we had evidence that utility companies with authorized ROEs under 8.0% have maintained investment grade credit ratings and access to capital markets.

Q. YOU RECOMMEND THAT KGPCO SHOULD BE AUTHORIZED TO EARN AN ROE EQUAL TO ITS MARKET-BASED COST OF EQUITY OF 7.35% (5.81% TO 7.86%). PLEASE EXPLAIN MORE REGARDING THE IMPORTANCE OF DETERMINING THE MARKET-BASED COE AS ACCURATELY AS POSSIBLE.

A. As discussed above, KgPCo's authorized ROE should be in line with its market-based COE. In other words, the cost of equity is the return investors expect to earn when they

[13] Direct Testimony of Christopher C. Klein at 6:1-2, TPUC Docket No. 18-00017 (July 3, 2018).
[14] *Id.* at 16:14.

purchase the equity (or stock) of a company. The return investors expect can come in the form of capital gains (stock price appreciation) or dividend payments. As investors buy and sell stock in the market, they convey information about their return expectations and therefore the underlying cost of equity (companies with different risk profiles will have different costs of equity). It is impossible to determine the cost of equity based on accounting information alone (e.g., revenue, net income, equity book value, or return on book equity) as it can only be established by capital market prices (e.g., stocks, stock options).

It is important that the cost of equity used to set rates for KgPCo in this proceeding be market-based. This makes sense because investor-owned utility companies ("IOUs") raise money from investors. It is thus critical that the authorized ROE be consistent with the market return expectations of investors. If the authorized ROE is below investors' market return expectations, KgPCo will not be able to raise the capital required to provide safe and reliable service. On the other hand, if the allowed return is above investors' market return requirements, KgPCo's consumers will be paying more than necessary for their service.

Q. DO ANY ROE WITNESSES USE A DIFFERENT DEFINITION FOR THE COST OF EQUITY?

A. Yes. All ROE witnesses I have encountered over my more than 20 years in the industry, including Mr. Castle, define the cost of equity as market-based somewhere in their testimony. Mr. Castle correctly states that the ROE should be consistent with investors' return expectations "given current market conditions."[15] However, Mr. Castle's so called

[15] Direct Testimony of William K. Castle at 15:11-14.

Peer Group Analysis method is based exclusively on historical accounting returns and therefore may have no relation to investors' return expectations in current capital markets. His Peer Group Analysis method is like a traditional scale without a counterweight – without market data as a counterweight to the accounting data, we cannot measure investors' return expectations and we certainly cannot determine the cost of equity.

Q. IS YOUR MARKET-BASED COST OF EQUITY RECOMMENDATION BASED ON YOUR OPINION OF FUTURE STOCK PRICE RETURNS?

A. No. I do not pretend to be able to predict the future. Capital markets are unpredictable and, as explained above, it is investors' expectations that matter since they are the ones providing the capital. Therefore, I provide an expert evaluation of investors' return expectations as indicated by the current market prices of stocks, bonds, and stock options, without attempting to predict future prices. This is an important topic that I will revisit throughout my testimony.

I do use Value Line and Zacks forecasts to estimate the market-based cost of equity in my Discounted Cash Flow (DCF) analyses. However, I do not use them mechanically and I go to great lengths to distill the sustainable growth component to ensure it is in line with investors' long-term expectations. My Capital Asset Pricing Model (CAPM) is based on a direct measurement of investors' expectations as indicated by market prices instead of analyst forecasts.

Q. PLEASE SUMMARIZE HOW YOU DETERMINED YOUR COST OF EQUITY RECOMMENDATION OF 7.35% (5.81% TO 7.86%) FOR KGPCO'S RETAIL ELECTRIC SERVICE OPERATIONS.

A. To arrive at my recommendation, I applied the Constant Growth and Non-Constant Growth versions of the DCF and 8 variations of the CAPM methodologies to a proxy group of 36 publicly traded electric utility companies ("RFC Electric Proxy Group") using data available through February 28, 2022. As discussed below, I review capital market data in general and the model results of leading financial institutions as an additional check on the reasonableness of my model results. Additionally, I consider potential cost of equity impacts from the war in Ukraine that have materialized after February 28, 2022.

Q. ARE YOUR COST OF EQUITY MODELS BASED ON ESTABLISHED METHODOLOGIES?

A. Yes. The purpose of my testimony is to provide the Commission with an independent analysis. However, I do not reinvent the wheel. It is mostly a question of which established methodologies and theories are best to use. There are countless established methodologies and theories used by investors, scholars, and rate of return witnesses. Further, finance does not stand still and can be affected by numerous factors. For example, Wall Street traders have been increasingly using machine learning to make investment decisions, and the use of quantum computing is likely the next new tool.

The Constant Growth DCF model I use is the same one chosen by major financial institutions. For example, J.P. Morgan Chase uses the same sustainable growth form of the DCF method in its 2019 Long-Term Capital Market Assumptions publication.[16] *Principles of Corporate Finance*, a leading financial textbook used in business schools and investment banks around the world, recommends using the very same method I use to calculate the cost of equity for regulated utility companies.[17] As discussed in Section V.F. Capital Asset Pricing Model on page 64, my CAPM is based on methodologies used by Value Line, the Chicago Board of Options Exchange (CBOE), and published in peer-reviewed academic journals (e.g., *The Review of Financial Studies*).

My market-based methodology has also been recognized by this and other state commissions. On September 14, 2021, the Connecticut Public Regulatory Authority stated the following:

> The Authority finds Rothschild's market-based approach for determining a reasonable ROE to be credible and persuasive. Specifically, the Authority finds that the incorporation of investor market return expectations into the historically applied DCF and CAPM methodologies enables the Authority, and all docket participants, to better consider a just and reasonable rate of return based on the same prospective basis that base distribution rates are set. As such, the Authority determines that this added layer of analysis provides appropriate protection to the relevant public interests, both existing and foreseeable, pursuant to Conn. Gen. Stat. § 16-19e(a). Therefore, the Authority considered Rothschild's DCF and CAPM calculations, as outlined below, in this Decision; moreover, on a going forward basis, the Authority shall consider a similar approach to incorporating investor expectations into the historically applied DCF and CAPM methodologies in all future rate proceedings.[18]

In California's 2017 Water Cost of Capital proceedings, a company witness acknowledged the validity of RFC's method. California ALJ Bemesderfer stated the following:

---

[16] 23rd Annual Edition, Long-Term Capital Market Assumptions - Time-tested projections to build stronger portfolios, pp. 62-63.
[17] BREALEY, MYERS, AND ALLEN, Principles of Corporate Finance, pp. 86-87 (McGraw-Hill Irwin, New York, 12th ed. 2017).
[18] Exhibit ALR-B at p. 21.

> . . .on cross-examination Vilbert [California Water Service Company witness] admitted that Rothschild's use of the method [b x r method] was "reasonable" and that Rothschild had "implemented the methodology correctly" in arriving at his Water Proxy Group ROE of 8.25%.[19]

On April 9, 2020, The Public Service Commission of South Carolina stated the following:

> Amongst the three witnesses, Consumer Affairs Rothschild's approach was unique in that he included the use of both historical and forward-looking, market-based data in his analysis. Based on the testimony and facts presented, the Commission therefore adopts the recommended ROE of 7.46% proposed by witness Rothschild.[20]

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR COST OF EQUITY MODELS.

A. I have determined the cost of equity for the average company in my RFC Electric Proxy Group to be between 5.95% and 8.01%.[21] As shown in Table 4 below, the high-end results of my cost of equity models, including eight variations of the CAPM, range between 7.05% and 8.31%, with an upper quartile at 8.01%. The low-end results of my cost of equity models range between 5.80% and 8.21%, with a lower quartile at 5.95%.

TABLE 4: COST OF EQUITY MODEL RESULTS		
DCF	**Low**	**High**
Constant Growth	7.89%	7.91%
Non-Constant Growth	8.21%	8.31%
CAPM		
Spot (Feb. 28, 2022)		
Risk Free Rate - 3-Month T Bill	5.80%	7.09%
Risk Free Rate - 30-Yr T Bond	6.67%	7.74%
3-Mo. Weighted Average (Dec. 2021 to Feb. 2022)		
Risk Free Rate - 3-Month T Bill	6.00%	7.05%
Risk Free Rate - 30-Yr T Bond	6.80%	7.66%
Outer Quartile Range	**5.95%**	**8.01%**
Midpoint of Range	**6.98%**	

Exhibit ALR-2

[19] Proposed Decision of ALJ Bemesderfer, p.19, Public Utility Commission of California, Application No. 17-04-001 (February 6, 2018). A copy is attached as Exhibit ALR-F.
[20] Exhibit ALR-A at p. 43.
[21] Exhibit ALR-2.

Q. PLEASE EXPLAIN WHAT MARKET DATA SHOW REGARDING HOW INVESTORS' PERCEPTION OF ELECTRIC UTILITY EQUITY RISK WAS IMPACTED BY THE COVID PANDEMIC.

A. As shown in Chart 1 below, investors' forward beta expectations of electric utility companies were about 0.8 in pre-pandemic market conditions in the winter of 2019-2020, spiked to over 1.0 during the spring 2020 initial phase of the pandemic, and since the early February 2021 electric utility betas have ranged between 0.53 and 0.62. These lower electric utility betas indicate that the cost of equity for electric utility stocks has decreased since the initial outbreak of the pandemic and points to a lower cost of equity than before the pandemic. During the first month of the war in Ukraine, the option-implied betas for electric utility companies has ranged between 0.47 and 0.57 which supports the general understanding that investors perceive electric utility company stocks to have a cost of equity significantly lower than the overall market.

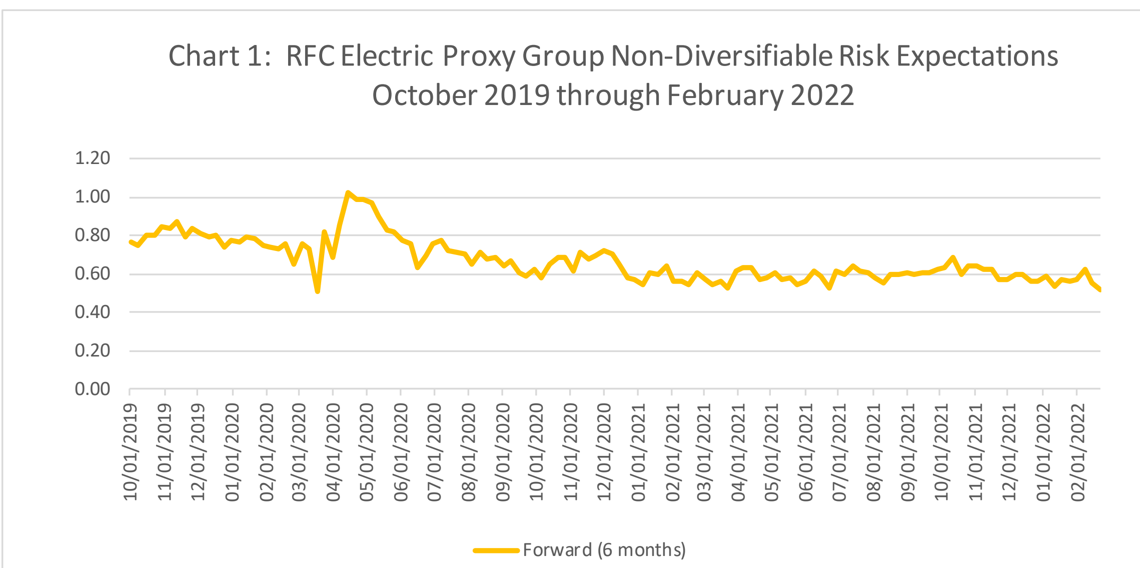


Table 5 on page 22 shows a summary of how COVID-19 has impacted financial markets between December 31, 2019 and February 28, 2022. Line 1 of Table 5 shows how the overall stock market (S&P 500) sharply declined during the initial spread of COVID-19, but has fully recovered and is regularly reaching new highs. Line 2 shows that interest rates initially declined sharply (30-year U.S. Treasury yields fell from 2.39% to a low of 1.17% on April 24, 2020), bounced back by March 2021, and have since once again gone down considerably below (2.17%) pre-pandemic levels. As shown on line 3, in March through December 2020, investors were demanding an increased credit spread to invest in riskier corporate bonds (151 basis point increase from December 2019 to March 2020), but credit spreads have since come down to below pre-pandemic levels. Line 4 shows that investors' volatility expectations as measured by the Market Volatility Index (VIX) increased significantly from 13.78 on December 31, 2019 to 75.91 in March 2020 but have since come back down considerably to 30.15 as of February 28, 2022. Line 5 shows that stock option prices indicate that the equity risk premium, which also peaked in March and April 2020, has since come down but remains somewhat elevated when compared to pre-pandemic levels. Lastly, as shown on line 6 of Table 5 and Chart 13 on page 72, option-implied betas for my RFC Electric Proxy Group, which peaked in February 2020, have since decreased to levels below those before the pandemic (0.52 on February 28, 2022 vs. 0.77 on December 31, 2019), indicating that investors expect electric utility stock price movements to be less correlated with the overall market than before the pandemic and therefore to be less risky relative to the market.

TABLE 5: COST OF EQUITY IN TODAY'S FINANCIAL MARKET - SUMMARY
MEASURING COVID-19'S IMPACT ON THE COST OF EQUITY

	31-Dec-19	19-Feb-20	17-Mar-20	30-Jun-20	31-Dec-20	30-Jun-21	31-Dec-21	28-Feb-22	
	Pre-Crisis	COVID-19 Crisis							Dec '19 - Feb '22 Delta
		Mkt Peak	Trough	"Recovery"					
1. Stock Prices (S&P 500)	$3,230.78	$3,386.15	$2,529.19	$3,100.29	$3,756.07	$4,297.50	$4,766.18	$4,373.94	**$1,143.16**
Growth Since 12/31/19		*4.8%*	*-21.7%*	*-4.0%*	*16.3%*	*33.0%*	*47.5%*	*35.4%*	
2. Interest Rates (30-Yr) [1]	2.39%	2.01%	1.63%	1.41%	1.65%	2.06%	1.90%	2.17%	**-0.22%**
3. Credit Spreads (Baa vs. 10-Yr) [2]	1.98%	2.05%	3.49%	2.93%	2.18%	1.87%	1.85%	2.34%	**0.36%**
4. Volatility Expectations (30-Day) [3]	13.78	14.38	75.91	30.43	22.75	15.83	17.22	30.15	**16.37**
5. Market Risk Premium [4]	4.59%	4.95%	10.07%	9.03%	8.48%	6.87%	8.55%	8.54%	**3.95%**
6. RFC Electric Proxy Group - Fwd. Beta (6-Mo.) [5]	0.77	0.76	0.51	0.76	0.58	0.62	0.57	0.52	**-0.25**

[1] 30-year U.S. Treasury Yield
www.treasury.gov
[2] Baa rated corporate bond yield - 10-year U.S. Treasury Yield
https://fred.stlouisfed.org/series/BAA
https://fred.stlouisfed.org/series/GS10
[3] VIX Index - 30 days
[4] Annualized option-implied market risk premium vs. 30-year Treasury RFR - weighted across all traded expirations as of last Tuesday before date, assuming 50.0% cumulative probability (median)
[5] Option-implied beta - 6-month, as of last Tuesday before date
Exhibit ALR-4

Q. HOW DID YOU CONSIDER THE IMPACT OF THE WAR IN UKRAINE ON THE COST OF EQUITY IN YOUR TESTIMONY?

A. As mentioned above, the cost of equity models I use to make my recommendations in this proceeding are based on data that mostly precedes the war in Ukraine. Russia invaded Ukraine on February 24, 2022 and the data I use in my cost of equity models only includes data through February 28, 2022. The concern is that my cost of equity models could be out of date if they do not reflect the impact of the war. However, a preliminary analysis based on capital market data from the first month of the War in Ukraine indicates that the cost of equity for electric utility companies has likely not been significantly impacted by the ongoing war. During the first month of the war (February 24 – March 24), electric utility stocks have outperformed the overall market (the RFC Electric Proxy Group was up 8.21%, the S&P 500 was up 5.40%), the option-implied betas of electric utility stocks have remained stable, and the spread between the option-implied skewness of the overall market as compared to electric utility stocks has increased. As explained further below, these developments support the common sense understanding that utilities are attractive to investors during times of geopolitical uncertainty, including during the outbreak of a war in Europe. The War in Ukraine has likely increased uncertainty regarding inflation and interest rates among other economic factors. It makes sense that investors have bid up the price of electric utility stocks recently because if inflation remains high, electric utility stocks are relatively safe since it is difficult for consumers to cut back on necessary services like electricity.

III. COST OF EQUITY IN TODAY'S FINANCIAL MARKETS

Q. HOW DO RECENT FINANCIAL MARKET DEVELOPMENTS AFFECT THE COST OF EQUITY?

A. The spread of COVID-19 significantly impacted the global economy and has tragically taken millions of lives, but its impact on capital markets was positive for most equity investors. Morningstar's US Market Index was up 20.9% in 2020 and 25.78% in 2021.[22] As discussed above, option data indicates that the cost of equity for electric utility companies has likely decreased relative to the overall market since the onset of the pandemic. The onset of the war in Ukraine has increased market volatility and possibly even increased the cost of equity for the market overall, but market data indicates that the cost of equity for companies providing essential services like utilities has likely been

[22] Morningstar, 2022 U.S. Stock Market Outlook, p. 5 (January 2022). A copy is attached as Exhibit ALR-G.

decreasing during the initial phases of the war. As mentioned above, during the first month of the war in Ukraine the RFC Electric Proxy Group has increased by 8.21%, while the S&P 500 Index is up only about 5.40%. As discussed above, it makes sense if investors are bidding up the price of electric utility stocks – and driving down the cost of equity – because they believe they are relatively safe investments during the uncertainties of war. KgPCo's authorized ROE should reflect current capital market conditions, including the market data that indicates the COE for electric utility companies is declining as investors place a higher relative value on safe investments. In this section, I provide additional capital market data that supports the results of my stock option and other analyses.

Q. PLEASE DISCUSS MARKET DEVELOPMENTS THAT IMPACT THE COST OF EQUITY.

A. Market developments since the onset of the Covid pandemic in March 2020 that have impacted the cost of equity include:

1. **Stock prices crashed and have more than recovered.** The S&P 500, Dow Jones Industrial Average, and other stock indices fell faster in the second half of March 2020 than during the 2007-2008 financial crisis, the crash of 1987, and the Great Depression. As of March 23, 2020, the S&P 500 had fallen approximately 34% from its high reached on February 19, 2020.[23] On August 18, 2020, the S&P 500 set a new high, which represents the fastest recovery (126 trading days) from a bear market. As shown in Chart 2 on page 28, electric utility stocks initially fell slightly more than the overall market (about 36% off their peak versus 34% for the S&P

[23] The S&P reached a new high of $3,386 on February 19, 2020 and fell to a low of $2,237 on March 23, 2020. ($3,386 - $2,237)/$3,386 = 33.9%.

500) and have lagged the market's recovery, but Chart 3 on page 28 shows the RFC Electric Proxy Group has slightly outperformed the market in the last six months as of the end of February 28, 2022, with a change of -0.08% vs. -3.32% for the S&P 500 Index.[24] As discussed above, electric utility stocks have continued to outperform the overall market during the first month of the war in Ukraine.

2. **Interest rates reached record lows during the pandemic and remain historically low.** The yield on 30-year U.S Treasury bonds recently increased slightly higher than they were before the pandemic – the average yield was 2.30% between March 1 and March 16, 2022, compared to an average yield of 2.22% in January 2020, before the pandemic started to significantly impact capital markets.[25] It is possible that interest rates will continue to increase, and this should be monitored. However, capital markets are unpredictable and the current yield on long-term treasury is still our best indication of investors' current interest rate expectations and our best guide to the current cost of equity for electric utility companies. There is a lot of speculation in the news regarding the possibility that recent spikes in inflation will remain and how this will impact capital markets, including interest rates. Inflation may or may not be high in the future, but for the purposes of this proceeding, what matters most is investors' expectations, not the speculations of journalists and economists. Since the onset of the war in Ukraine, investors' inflation expectations started to increase, but investors' inflation expectations have stabilized in the second half of March 2022. As shown on Chart 6 on page 34, the relative market price of inflation-protected bonds as compared to

[24] Chart 2, p. 28.
[25] Chart 4, p. 30.

regular Treasury bonds as of February 28, 2022 indicates that investors expect inflation to be 3.11% over the next 5 years and about 2.28% over the next 30-years. As of March 24, 2022, investors' inflation expectations are 3.57% for 5-years and 2.53% over the next 30-years.

3. **Credit spreads increased sharply during the initial phase of the pandemic, but quickly declined and are now below pre-pandemic levels.** The spread between the yield investors demand to purchase U.S. corporate bonds and U.S. Treasury bonds (see Chart 7 on page 35) increased significantly in the initial phases of the COVID-19 pandemic, but never got as high as it did during the financial crisis of 2007-2008. As of February 28, 2022, the yield spread for Baa credit-rated corporate bonds is 2.34%, below pre-pandemic levels of 1.98% on December 31, 2019, after reaching a high of over 4.00% in March 2020.[26] Credit spreads can be used as a gauge of the cost of equity because, all else equal, when investors demand a lower spread to take on the risk of corporate bonds versus U.S. Treasury bonds they will demand a lower spread to invest in the equity of corporations. Therefore, credit spread data shows additional evidence that the cost of equity has not been materially impacted by the pandemic and is likely a little bit lower. Yield spreads indicate that the war in Ukraine has not increased the cost of equity as of March 25, 2022.[27]

4. Investors' stock price volatility expectations have fallen from highs reached during initial phases of the pandemic. In March 2020, the VIX Index reached

[26] Chart 7, p. 35.
[27] According to the Federal Reserve Bank of St. Louis, the Baa Corporate bond yield relative to Treasures is nearly identical to what it was before the pandemic. On March 25, 2022, it was 1.96%. On December 31, 2019, it was 1.98%. Available at https://fred.stlouisfed.org/series/BAA10Y

levels not seen since the financial crisis of 2007-2008, and even set all-time records.[28] Volatility expectations remain higher than before COVID-19 but have declined significantly since peaks reached in March 2020. As discussed below, the first month of the war in Ukraine surprisingly has had a relatively limited impact on investors' volatility expectations.

I elaborate on each of the points above in the following sections.

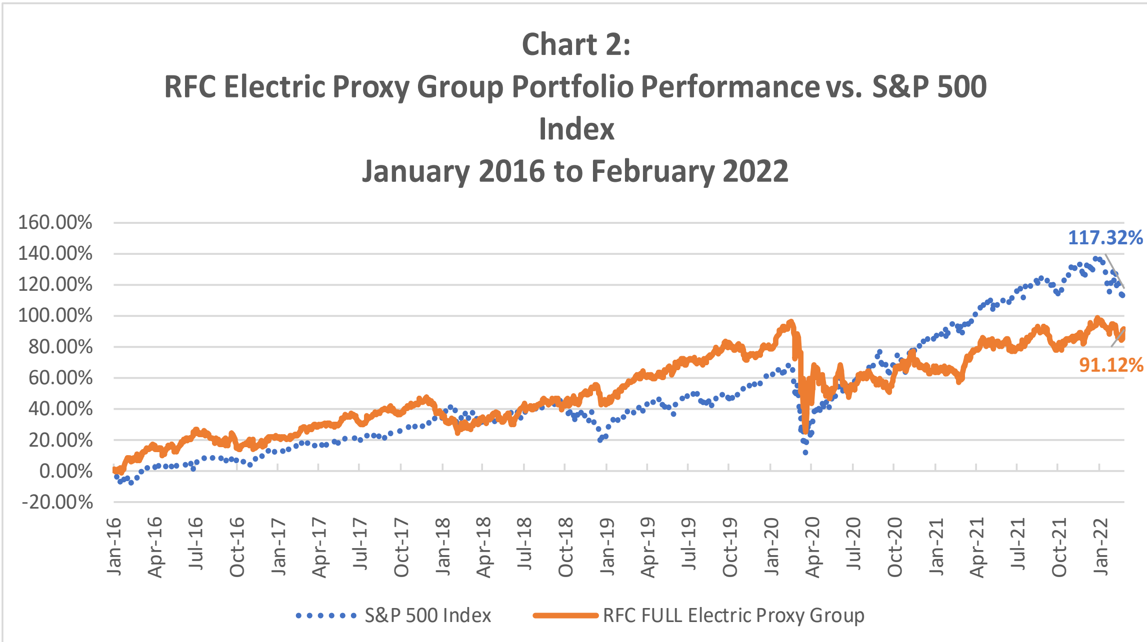
A. Stock Price Trends and Perceived Risk

Q. WHAT, IF ANYTHING, DOES STOCK MARKET DATA INDICATE WITH REGARD TO THE COST OF EQUITY?

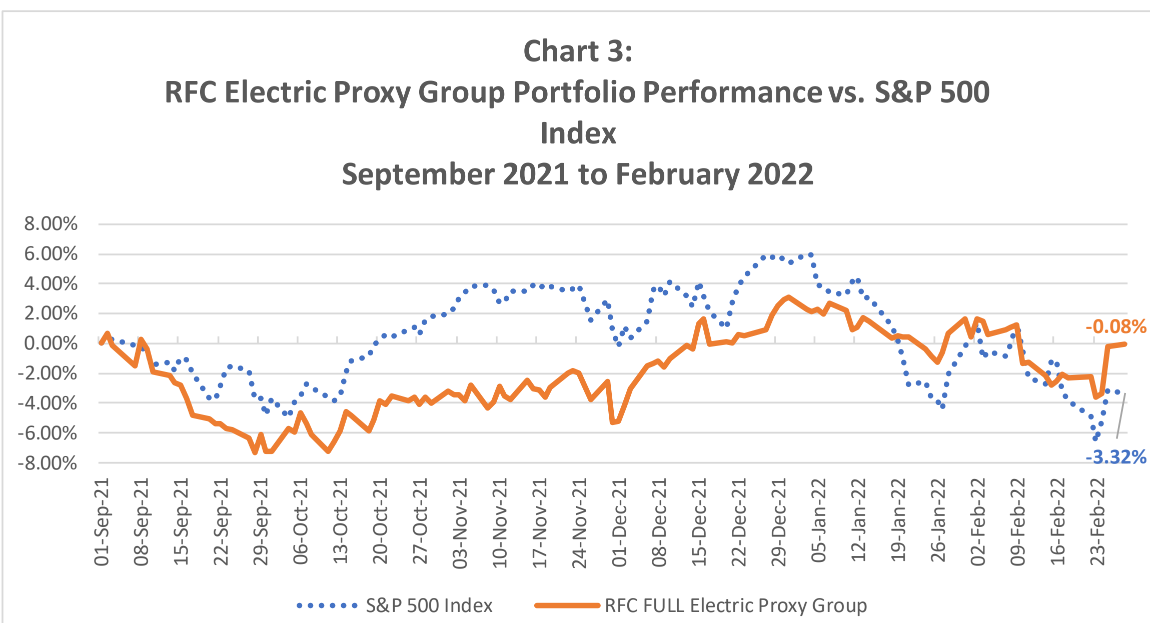
A. As stock prices have shown an overall increase between 1926 and 2020, price-to-earnings (P/E) ratios have increased significantly as well.[29] This indicates that the cost of equity may be decreasing along with the higher stock prices because investors are paying a higher price for the same earnings. For example, an investor paying $100 for a share of a stock with $10 per year of earnings will earn a 10% annual return, assuming no growth. If this stock goes up to $200 per share, the annual earnings decrease to 5%. As shown in Chart 2 on page 28, until the COVID-19-related crash, stock prices for the S&P 500 and the RFC Electric Proxy Group increased significantly in the nearly 6.2 years since KgPCo filed testimonies in its last rate case on January 4, 2016.[30] After the significant losses due to COVID-19 in March 2020, the S&P 500 Index and the stock prices for the RFC Electric

[28] Chart 9, p. 38.
[29] ROGER G. IBBOTSON, JAMES P. HARRINGTON, *2021 The Stocks, Bonds, Bills, and Inflation (SBBI) Yearbook*, pp. 10-28, available at www.cfainstitute.org/-/media/documents/book/rf-publication/2021/sbbi-summary-edition-2021.pdf .
[30] *Petition of Kingsport Power Company d/b/a AEP Appalachian Power General Rate Case and Motion for Protective Order*, TPUC Docket No. 16-00001 (January 4, 2016).

Proxy Group have fully recovered and are up nearly 117.32% and 91.12% as of February 28, 2022, respectively.



As shown in Chart 3 below, the RFC Electric Proxy Group has slightly outperformed the market in the last six months as of the end of February 28, 2022, with a change of -0.08% vs. -3.32% for the S&P 500 Index.



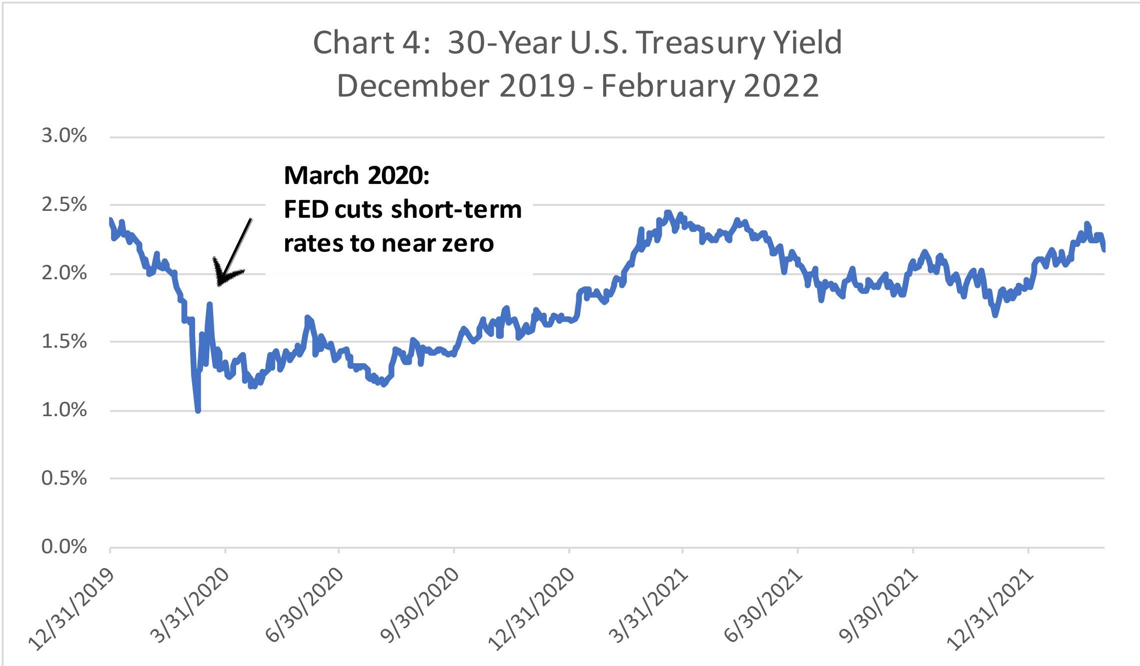
Q. WHAT DOES THE RELATIVE UNDERPERFORMANCE OF ELECTRIC UTILITY STOCKS DURING THE PANDEMIC INDICATE?

A. The relative stock price performance of electric utility stocks is just one piece of a multi-dimensional puzzle that we must construct to measure the cost of equity. As discussed throughout this testimony, betas, credit spreads, option-implied skewness, and other measures of risk and investors' expectations indicate that the cost of equity for electric utility companies has not been materially impacted as a result of the pandemic.

B. Interest Rates and Inflation

Q. PLEASE DISCUSS THE CURRENT INTEREST RATE ENVIRONMENT AND WHAT IT INDICATES REGARDING THE COST OF EQUITY.

A. Two significant interest rate developments occurred in response to COVID-19. First, interest rates have fallen significantly since the beginning of the COVID-19 pandemic. Short-term interest rates are now near 0%. As shown on Chart 4 on page 30, yields on 30-year U.S. Treasuries have fallen from 2.39% as of December 31, 2019 to 2.17% as of February 28, 2022. As expected by investors, Federal Reserve voted on March 16, 2022 to raise the benchmark federal-funds rate by a quarter percentage point to between 0.25% and 0.5%. The market yields on long-term U.S. Treasury have increased 35 basis points between March 1, 2022 and March 16, 2022. However, long-term interest rates remain at historical lows. And lower interest rates, all else equal, indicate a lower cost of equity for electric utility companies because many bond investors sell bonds and purchase utility stocks as interest rates decline.



Q. HOW DO YOU RESPOND TO PEOPLE WHO CLAIM THAT INTEREST RATES ARE ABOUT TO INCREASE?

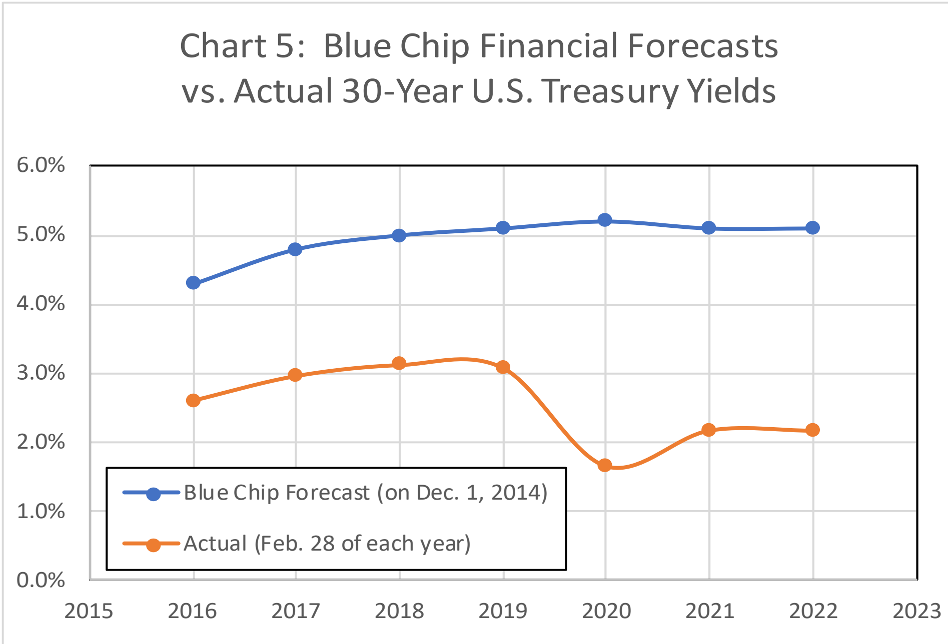
A. It is important to recognize that current long-term Treasury bond yields represent a direct observation of investor expectations and there is no need to use "experts" to determine market-based cost of equity.

Many economists and forecasters will continue to be quoted in the press prognosticating on possible developments that are truly unpredictable. The Nobel Laureate Economist Daniel Kahneman stated the following regarding forecasting:

> It is wise to take admissions of uncertainty seriously, but declarations of high confidence mainly tell you that an individual has constructed a coherent story in his mind, not necessarily that the story is true.[31]

As Chart 5 below shows, Blue Chip Financial forecasted in 2014 that 30-Year U.S. Treasury bonds would be over 5% by 2018 while in fact they turned out to be under 2%.

[31] DANIEL KAHNEMAN, *Thinking Fast and Slow*, p. 212 (2011).



The time covered in Chart 5 above was chosen to provide a concrete example. Blue Chip's interest rate forecasts have been persistently inaccurate. A paper published by the Congressional Budget Office determined Blue Chip consensus forecasts exhibited "significant positive bias" between 1984 and 2012 and "have become more biased and less accurate over time."[32] Interest rates may or may not remain at historically low levels, but it is safe to say interest rates are unpredictable and consumers should not pay higher rates because an economist believes they will increase.

Q. PLEASE DISCUSS THE CURRENT INFLATION ENVIRONMENT AND WHAT IT INDICATES REGARDING THE COST OF EQUITY.

A. The stated reason the Federal Reserve increased short-term interest rates on March 16, 2022 was to fight potential increases in inflation. Fed Chairman Jerome Powell stated that

[32] Congressional Budget Office, Edward N. Gamber, *Did Treasury Debt Markets Anticipate the Persistent Decline in Long-Term Interest Rates?*, p. 2, (September 2017) available at: https://www.cbo.gov/system/files/115th-congress-2017-2018/workingpaper/53153-interestrateswp.pdf.

the Committee is "acutely aware of the need to return economy to price stability."[33] Therefore, higher inflation could possibly impact the cost of equity because it can impact interest rates. Inflation has increased substantially recently and there is a lot in the news regarding the economic consequences of persistently high inflation, including how it could impact capital markets and the cost of equity. As stated throughout this testimony, the cost of equity should be based on investors' return expectations because they are the ones providing the capital.

Q. IS THERE A WAY TO MEASURE INVESTORS' INFLATION EXPECTATIONS DIRECTLY?

A. Yes. It is possible to measure investors' inflation expectations directly simply by subtracting the interest rate of nominal Treasuries and TIPS (Treasury Inflation -Protected Securities) of comparable matures. This difference is referred to as the "breakeven inflation rate" because it represents what inflation would have to be for an investor to "break even" or make the same return on both nominal Treasuries and TIPS. For example, if the yield on a nominal 10-year Treasury is 2.5% and TIPS of the same duration are 1.5%, an investor would make the same real return on both bonds if the inflation rate is 1% over the next 10 years.

Nominal yield – real yield = breakeven inflation rate

In this case, investors breakeven inflation rate is 1% (2.5% - 1.5%) = 1%

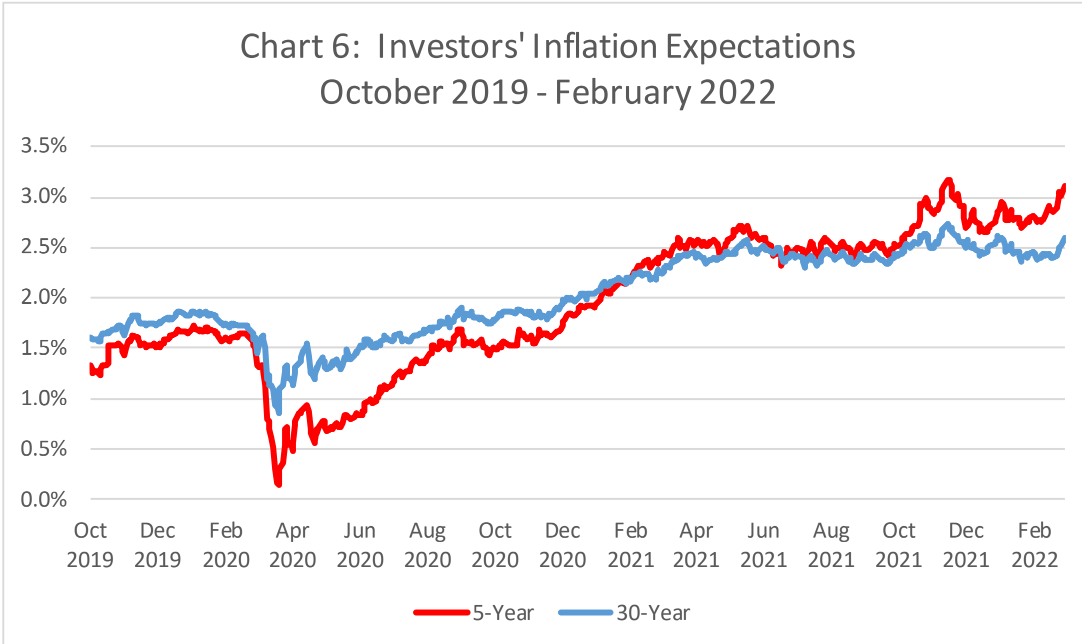
It makes sense that investors' inflation expectation is equal to the breakeven inflation rate because if investors, on average, believed that inflation was going to be lower

[33] Transcript of Chair Powell's Press Conference, Board of Governors of the Federal Reserve System (March 16, 2022) available at https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20220316.pdf.

than 10%, in the example above, they would purchase TIPS and expect to make exceptional profits. The investor who purchases TIPS would earn 1.5% + 10% inflation = 11.5%. The investor who purchased the nominal Treasury would only earn a 2.5% return. With such large relative returns to be made buying TIPS in this hypothetical example, investors would bid up the price of TIPS and drive down the yield until investors expect the same real return on nominal Treasures and TIPS.

Q. WHAT DOES MARKET DATA INDICATE REGARDING INVESTORS CURRENT INFLATION EXPECTATIONS?

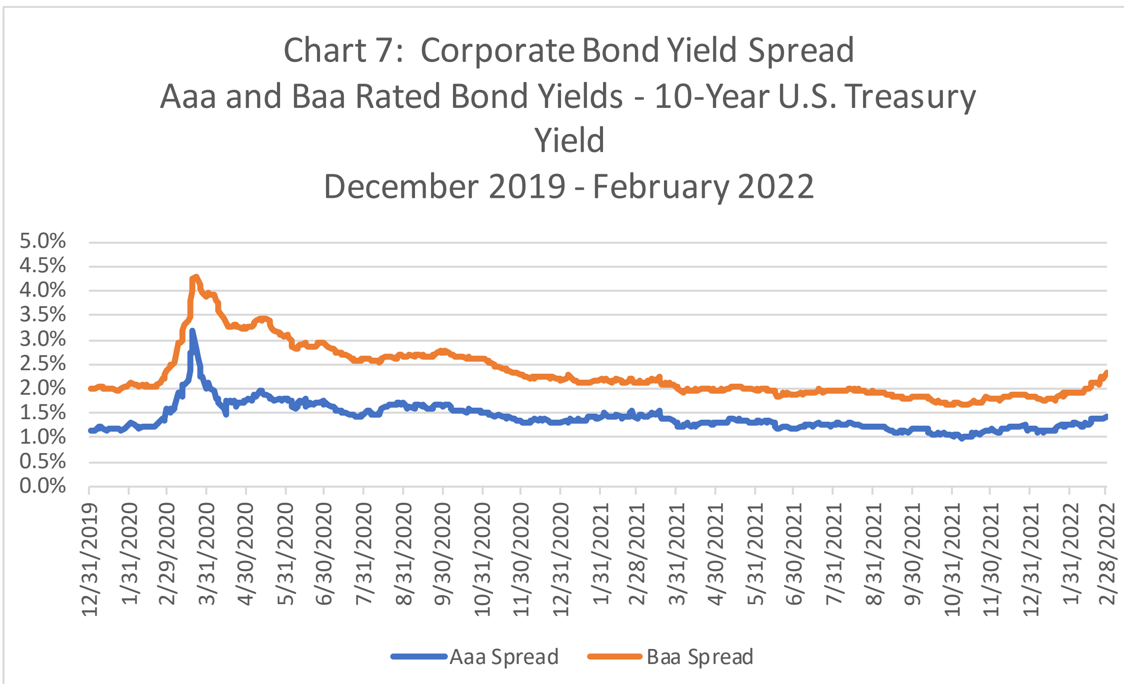
A. As indicated by the difference between nominal-treasures and TIPS, investors inflation expectations decreased substantially during the height of COVID's impact on capital markets. See Chart 6 on page 34. In March 2020, investors expected the inflation rate over the next 5-years to be as low as 0.1% and approximately 1% over the 30-year timeframe. On December 31, 2021, investors expected the inflation rate over the next 5-years to be 2.9% and 2.3% over the 30-year timeframe. Investors' inflation expectations started to increase on February 24, 2021 as Russian troops started to drive their tanks into Ukraine. As of March 24, 2022, investors expected the inflation rate over the next 5-years to be 3.57% and 2.53% over the 30-year timeframe. Inflation may or may not increase more than expected by investors, but if it does, KgPCo can apply for a rate increase at that time. Consumers should not be asked to pay a premium now for the possibility that inflation will remain elevated because the financial data used in my market-based cost of equity models already reflects investors' most recent expectations regarding inflation.



C. Credit Spreads

Q. WHAT DOES AN INCREASING CREDIT SPREAD MEAN FOR THE COST OF EQUITY?

A. The yield spread between corporate bonds and U.S. Treasuries can be used as general gauge of investors' risk tolerance and how much extra return they require to take on more risk. A higher credit spread, all else equal, can indicate a higher cost of equity because if investors are demanding a higher return to take on the risk of buying corpore bonds they are likely also demanding a higher return to take on the risk of investing in stocks. As shown in Chart 7 on page 35, the yield spread between Corporate bonds and Treasury bonds increased significantly during the initial phase of the pandemic in March and April 2020. The interest rate spread between Baa Corp bonds and 10-year U.S. Treasuries peaked at over 4% in mid-March 2020. This chart clearly shows, however, that yield spreads have declined since their peak to pre-pandemic levels and are currently about the same as before the pandemic. As of February 28, 2022, the yield spread between Baa Corp bonds and 10-year U.S. Treasuries is 2.34%, about 200 basis points lower than the peak reached in March 2020 and about 35 basis points higher than before the pandemic. Surprisingly, the spread between Baa Corp bonds and 10-year U.S. Treasures has decreased during the war in Ukraine to about 2.0% as of March 24, 2022.[34] The movement of the yield spread indicates that the cost of equity for the overall market is significantly lower than during the peak of the pandemic in 2020, but slightly higher than before the pandemic.



[34] FRED Economic Data, Moody's Seasoned Baa Corporate Bond Yield Relative to Yield on 10-Year Treasury Constant Maturity, https://fred.stlouisfed.org/series/BAA10Y (last visited March 29, 2022).

D. Volatility Expectations

Q. PLEASE DISCUSS CURRENT STOCK PRICE VOLATILITY EXPECTATIONS AND WHAT THEY INDICATE REGARDING THE COST OF EQUITY.

A. Volatility, uncertainty, and risk are synonymous. There are two primary types of volatility: "realized volatility" and "implied volatility." The former is based on historical returns, which may or may not represent future volatility. On the other hand, implied volatility is calculated from options data, which indicates investors' future expectations for volatility. As discussed below, the "term structure" of volatility indicates investors' volatility expectations over different forward-looking time periods (i.e., 1 month, 1 year, etc.).

Q. PLEASE EXPLAIN THE "TERM STRUCTURE OF VOLATILITY."

A. Investors can expect volatility to increase or decrease over time. In general (i.e., in "normal" financial markets), investors expect higher volatility for longer time horizons. For example, investors generally expect the chance stock prices will increase or decrease by 10% (on an annual basis) in 1 year to be greater than the chance of a 10% (annualized) move over the next 30 days. This makes sense because there is more uncertainty regarding economic and stock market changes the further in the future you look out.

However, during the height of a crisis, when volatility generally tends to rise in the short-term, investors often expect volatility to decrease in coming months or years. In other words, investors expect the current capital market hurricane to pass and the winds to die down. During the peak of implied volatility in mid-March 2020, shortly after the World Health Organization declared COVID-19 a pandemic, the data indicated that investors expected stock price volatility to decrease over time. This implies that investors expected the riskiness of equity investments to decrease over time. As shown in Chart 8 on page 37, before the COVID-19 outbreak, investors expected volatility to increase from less than 15% annually at the 1-month time frame to about 20% annually at the 24-month time frame. Investors' volatility expectations peaked in March 2020. At that time, investors expected stock price volatility would decrease from over 70% at the 1-month time frame to about 38% at the 24-month time frame.

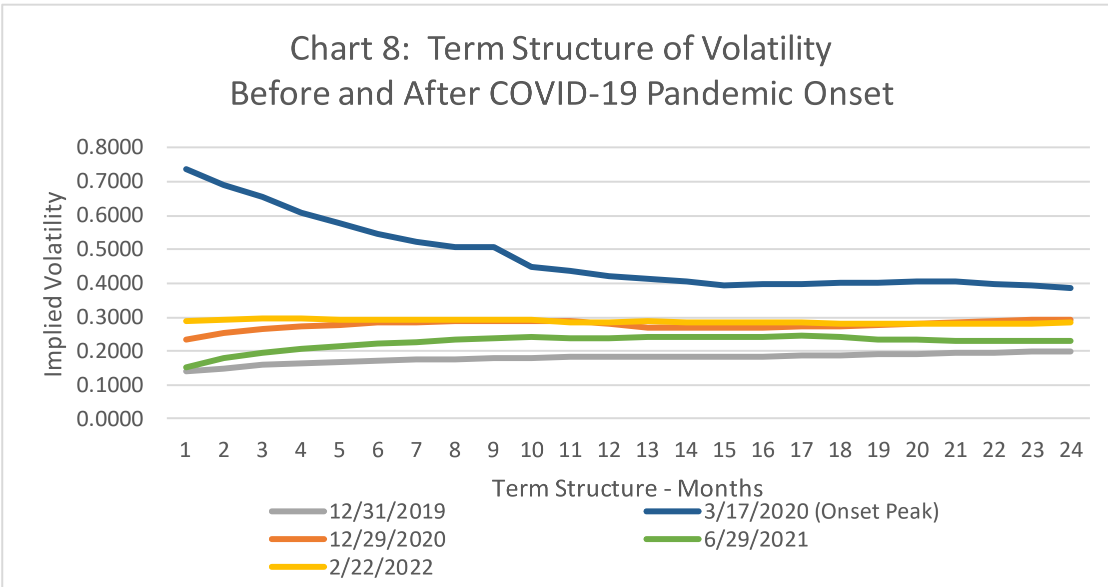
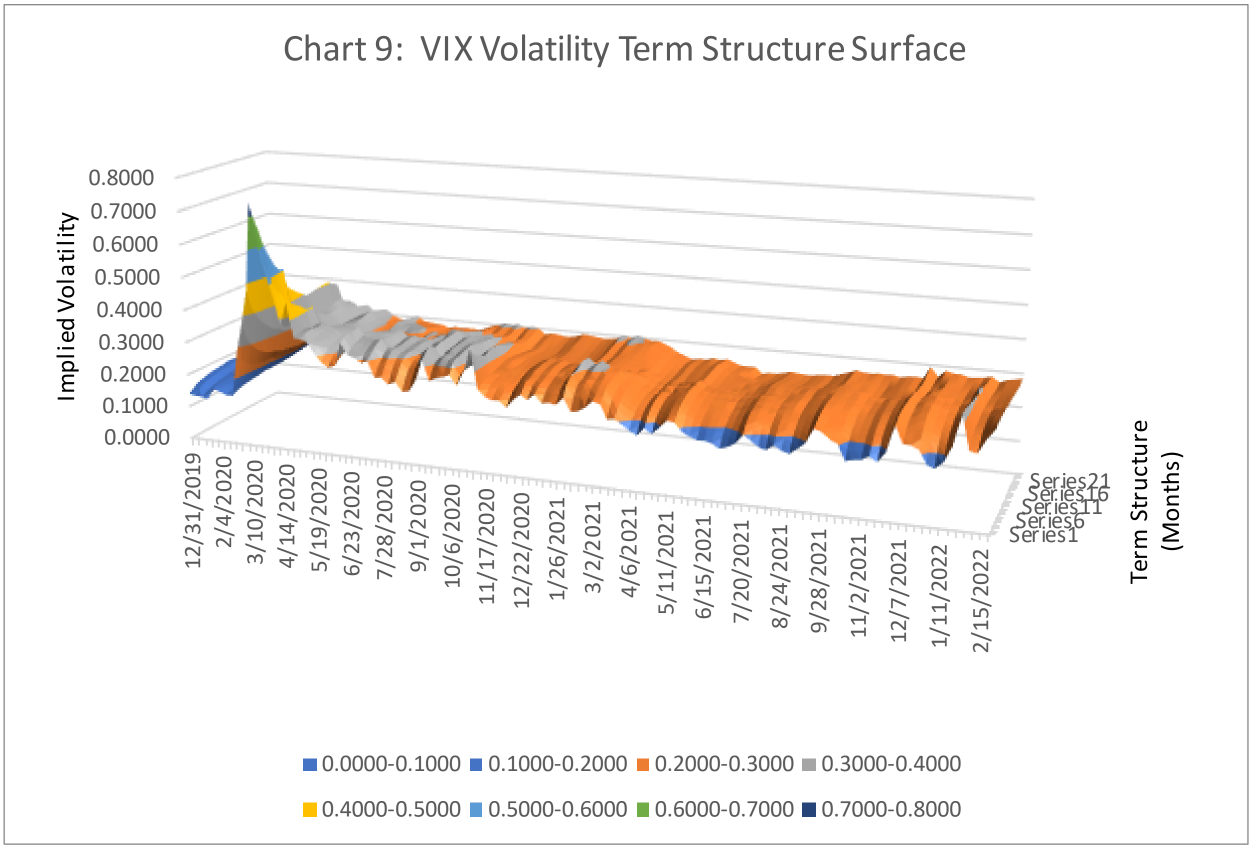


Chart 9 on page 38 provides a 3-dimensional surface[35] to show how the term-structure of volatility has evolved since before the COVID-19 outbreak and how it has changed during and since the outbreak. Chart 8 above is simply five selected cross sections of the same data in the surface in Chart 9. In the surface, one can see that on December 31, 2019, the term structure of volatility is almost flat, increasing slightly from the 1-month to the 24-month time frame. In mid-March 2020, the implied volatility increased over every time period in comparison to December 31, 2019, but one can see that investors expected a declining term structure of volatility. By the end of July 2020, the implied

[35] The X axis shows the implied volatility. The Y axis shows the data. The Z axis shows market expectation of future implied volatility of different time frames. Series1 = 1 month and Series24 = 24 months.

volatility for all time periods had decreased, and the declining term structure moved to a more typical structure in which investors expected higher volatility over longer time periods, as it remains as of February 22, 2022. In late November 2021, implied volatility increased as the Covid Omicron variant rapidly spread throughout the world, but by the end of December 2021, implied volatility returned to pre-Omicron levels.



A declining term structure of volatility is important data to consider in determining the appropriate cost of equity for KgPCo because it shows that even during the peak of the pandemic's impact on financial markets, investors expected risk to decline in coming months. Lower risk means a lower cost of equity. Investors' market volatility expectations turned out to be correct. In March 2020, investors expected implied volatility to decline considerably over the next 12 to 24 months, and it has.

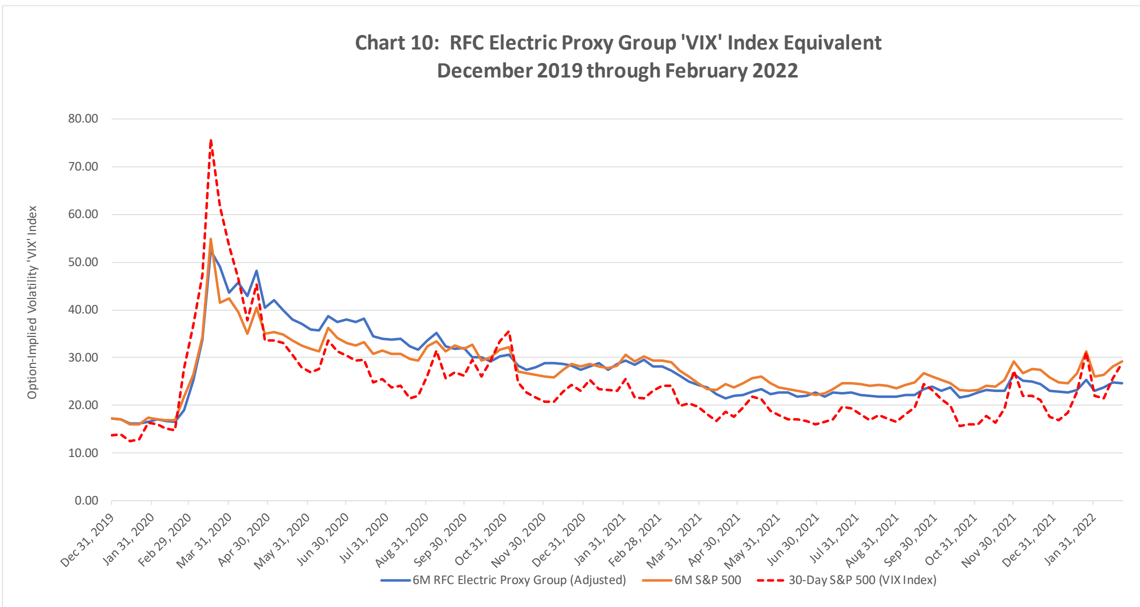
Q. HOW HAS THE WAR IN UKRAINE IMPACTED INVESTORS' VOLATILITY EXPECTATIONS?

A. Investors' volatility expectations increased during the onset of the War in Ukraine. The VIX Index rose from about 28 before War and reached a high of 36.45 on March 7, 2022. However, even at this peak, the term structure of volatility indicated that investors expected volatility to decrease in the future, exactly as explained above during the volatility peak due to the onset of Covid in March 2020. As expected, the VIX Index has since decreased steadily with a value of 21.67 as of March 24, 2022. Volatility expectations for electric utility stocks have followed a nearly identical pattern to those for the overall market.

Q. HOW HAVE VOLATILITY EXPECTATIONS FOR ELECTRIC UTILITY COMPANIES COMPARED TO VOLATILITY EXPECTATIONS FOR THE S&P 500?

A. The dashed red line and the solid orange line in Chart 10 on page 40 show investors' stock price volatility expectations for the overall market (S&P 500) increased significantly as COVID-19 infections spread to the U.S. and continued to grow exponentially around the world. The dashed red line and solid orange line show volatility expectations over the next 30 days and 6 months, respectively. In December 31, 2019, investors expected an annualized change of 13.78% over the next 30 days. In mid-March 2020, investors' volatility expectations peaked at over 80% (on March 16, 2020, a point not actually shown on the chart, which has weekly data on Tuesdays). As of February 22, 2022, investors expect an annualized change of 28.81%.

The blue line in Chart 10 shows that investors' adjusted[36] 6-month volatility expectations for my RFC Electric Proxy Group, as indicated by their stock option prices, increased along with the market in mid-March 2020, but to a significantly lesser degree. Investors' 6-month adjusted volatility expectations for electric utility companies were higher than for the S&P 500 for the most part from May through August 2020, remained very comparable through mid-July 2021, and have mostly remained below expectations for the market since then through February 22, 2022.



As discussed above, changes in implied volatility do not paint the full cost of equity picture. We must consider implied covariance, or how much investors expect the volatility of returns for electric utility companies to correlate with the overall market (e.g., S&P 500 Index).

[36] The implied volatility for individual stocks and small groups of stocks is almost always higher than the overall market because of the effects of diversification, even when the underlying stocks in the smaller portfolio are less risky, as is the case with electric utility companies. As a result, Chart 10 adjusts the 6-month expected volatility for the RFC Electric Proxy Group by the difference with the 6-month expected volatility for the S&P 500 Index on 12/31/2019 to facilitate the comparison throughout the chart.

Q. HOW IS COVID-19 AND THE WAR IN UKRAINE IMPACTING FINANCIAL MARKETS AND THE COST OF EQUITY FOR ELECTRIC UTILITY COMPANIES?

A. As discussed above, financial data indicate that the capital market upheaval the COVID-19 pandemic generated was not long-lasting and did not significantly impact the cost of equity for electric utility companies. A preliminary analysis of the option-implied betas of electric utility stocks indicates that the war in Ukraine has not significantly impacted KgPCo's cost of equity. Investors know that electric utility companies provide an essential service that will be used and paid for even during a war in Europe.

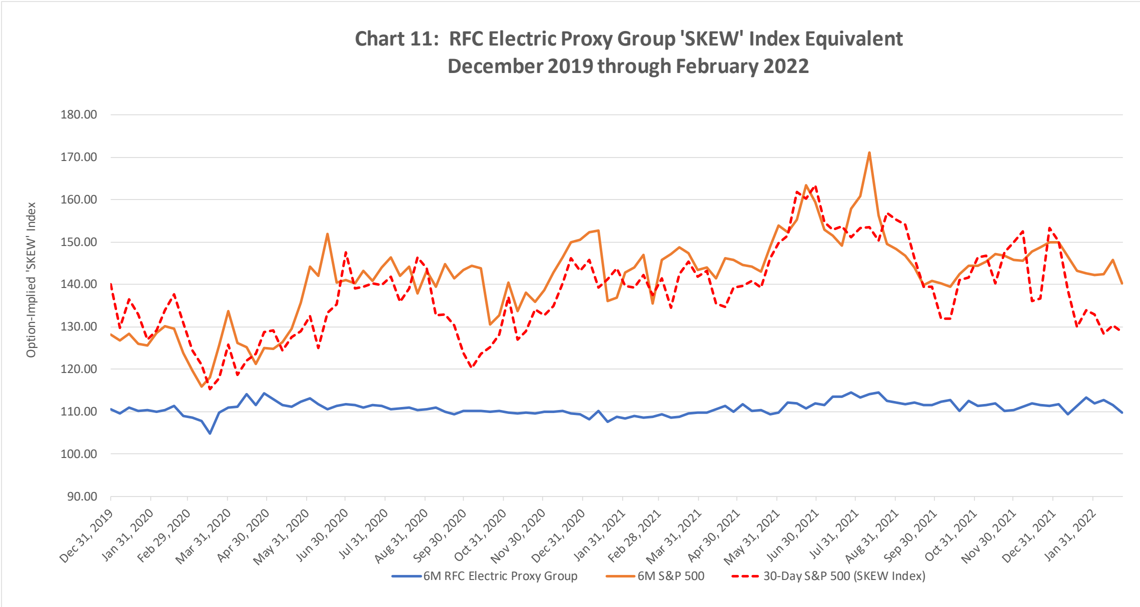
E. Option-Implied Skewness (Investor-Perceived Downside Risk)

Q. YOU EXPLAINED EARLIER THAT STOCK OPTION PRICES REVEALED THAT INVESTORS FOUND THAT THE SYSTEMATIC RISK (AS MEASURED BY OPTION-IMPLIED BETAS) FOR ELECTRIC UTILITY COMPANIES IS LOWER THAN BEFORE THE PANDEMIC AND THAT THIS RELATIONSHIP HAS REMAINED STABLE DURING THE FIRST MONTH OF THE WAR IN UKRAINE. DO STOCK OPTION PRICES PROVIDE ADDITIONAL EVIDENCE THAT THE COST OF EQUITY FOR ELECTRIC UTILITY COMPANIES CONTINUES TO BE CONSIDERABLY LOWER THAN THE OVERALL MARKET?

A. Yes. Stock option prices provide considerable information regarding investors' expectations. The most well-known measure of investors' expectations as measured by stock option prices is the VIX Index. The VIX Index is a measure of investors' volatility expectations and is referred to as the "fear index" because, all else equal, higher volatility expectations indicate higher uncertainty and risk. However, volatility expectations are only one piece of a multi-dimensional puzzle that reveals the market-based cost of equity. After volatility expectations, the next dimension to explore is skewness (referred to as the second moment in statistics). Option-implied skewness reflects investors' expectations regarding the asymmetry of the probability distribution. For example, option-implied probability distributions are almost always negatively skewed for stock market indexes (e.g., S&P 500) and individual stocks, which means that investors almost always think there is a greater chance of a large decrease in stock prices than a large increase. The CBOE also publishes an index based on option-implied skewness referred to as the SKEW Index.

Q. WHAT DOES THE SKEW INDEX REVEAL REGARDING THE IMPACT OF THE COVID PANDEMIC AND THE WAR IN UKRAINE ON KGPCO'S COST OF EQUITY?

As shown in Chart 11 on page 43, comparing the SKEW Index to an equivalent metric based on electric utility company stock options indicates that the cost of equity for electric utility companies continues to be considerably lower than the overall market, and if anything, the difference has only become more pronounced since the onset of the COVID pandemic.



I updated the SKEW Index analysis above to include the first month of the war in Ukraine (February 24, 2022 – March 24, 2022) and can confirm that the SKEW Index equivalent for electric utility companies has remained relatively flat while the SKEW Index for the S&P 500 has increased once again since the start of the war.

IV. CAPITAL STRUCTURE AND COST OF DEBT

Q. MR. CASTLE PROPOSES USING A CAPITAL STRUCTURE OF 48.90% COMMON EQUITY AND 42.49% DEBT. DO YOU AGREE WITH HIS RECOMMENDATION?

A. I disagree with the use of this capital structure because the common equity ratio of KgPCo's requested capital structure is significantly above the average of the 36 regulated electric utility companies in my proxy group (47.0%). As a result, I recommend using a capital structure consisting of 48.90% equity and 42.49% debt, based on the average common equity ratios of the companies in my proxy group. As per Exhibit ALR-5, the common equity ratios of the 36 companies in my proxy group are between 42.5% and 38.0%.

Q. WHAT COST OF DEBT DO YOU RECOMMEND?

A. I recommend adopting KgPCo's requested cost of debt of 3.14%.

V. COST OF EQUITY CALCULATION

A. Overview

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR PERSPECTIVE REGARDING HOW CAPITAL MARKETS RELATE TO THE COE AND THE OVERALL COST OF CAPITAL

A. The cost of capital is the return investors require to provide capital to KgPCo based on current capital markets. The spread of COVID-19 has made it more challenging to determine the current cost of capital because it has drastically increased the speed and intensity of capital market change. To measure the cost of equity accurately during rapid change, it is critical to use current market data. Because of the current financial crisis, it is particularly important to consider model results in the context of extreme financial turbulence. To do this, it is crucial to consider how capital markets and model results have changed over time as this crisis has evolved since its onset in March 2020.

As discussed above, my COE recommendation is my opinion of the return investors require to provide equity capital to KgPCo based on current capital markets. My recommendation is consistent with the following legal standards set by the United States Supreme Court for a fair rate of return: "[t]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks”[37] and “sufficient to… support its credit and… raise the money necessary for the proper discharge of its public duties.”[38]

Because the cost of equity is not a published figure like a bond yield, some interpretation is required to determine the appropriate market price. My cost of equity recommendation is based on my computation of what the market indicates investors require (return on investment) to provide capital to companies with comparable risk to KgPCo.

As explained below, I use current market prices (e.g., stocks, bonds, options), which measure investors’ expectations directly, instead of relying solely on historical data and analyst forecasts.

A COE based on market prices (market-based) is superior to a COE based on historical data (non-market-based) for two reasons:

1. The COE that KgPCo has to pay investors is based on capital markets. Interest rates remain at historical low levels after a persistent downtrend since the early 1980s. It is possible interest rates will increase, but if the marketplace expected interest rates to change, then that would already be part of current prices.
2. Capital markets are unpredictable. Regarding capital markets’ unpredictability, investment guru Warren Buffet recently gave the following advice to investors: “[t]hey should not listen to a lot of the

[37] *Fed. Power Comm’n v. Hope Nat. Gas Co.* v. Hope Nat. Gas Co., 320 U.S. 591, 603 (1944).
[38] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm’n of the State of W. Va*, 262 U.S. 679, 692-693 (1923).

> jabbering about what the market is going to do tomorrow, or next week or next month because nobody knows."[39]

Current capital markets are our best source of investors' expectations regarding future capital markets. Current market prices of stocks and bonds reflect investors' forecasts for long-term interest rates and capital markets in general. If, indeed, investors in the aggregate should be expecting an increase in interest rates, adding a separate factor for this on top of what is already indicated in market prices would amount to a double count. As I will discuss below, KgPCo's witness, Mr. Castle inflates his CAPM results by using interest rate forecasts as a proxy for the risk free rate component of this model. There is no reason to add this separate factor to current interest rates that already reflect investors' expectations.

Q. HOW DID YOU ARRIVE AT YOUR COE RECOMMENDATION?

A. To arrive at my recommendation, I applied the DCF, including a Constant Growth and a Non-Constant Growth method and a CAPM analysis to a group of similar companies ("RFC Electric Proxy Group") using data available through February 28, 2022, as discussed below. In all of my models, I use both historical averages and the most recently available spot data for the inputs wherever it is possible and applicable.

[39] PBS News Hour, June 26, 2017, Part 1 – America should stand for more than just wealth, says Warren Buffett available at www.pbs.org/newshour/show/pbs-newshour-full-episode-june-26-2017.

Q. CONSIDERING THAT STOCK AND OPTION PRICES AND BOND YIELDS CHANGE DAILY, WOULD IT NOT BE BETTER TO USE HISTORICAL AVERAGES EXCLUSIVELY FOR THE INPUTS IN YOUR MODELS?

A. Not necessarily. Most people would agree that the use of spot market data, the value of a particular input on a particular day, can lead to COE results that can vary over short periods of time. It may therefore be tempting to find a more stable value based on historical averages that are not overly influenced by short-term fluctuations in capital markets. When doing a forward-looking analysis, however, it is equally important to look at the most recent market data as an indication of trends and where a given value is more likely to be in the future. This is a broad and generally accepted principle, as made clear in the following example.

As a simple example using historical stock prices to make the point clear, if Company A's stock price were to go up linearly over the course of one year from $50 to $100, its average stock price over that year would be $75. If Company B's stock price declined linearly from $100 to $50 over the same year, it would have the same exact average stock price of $75. But most people would agree that predicting both stock prices at $75 over the near future would be overly simplistic and leave readily accessible forecasting data unused. Without relying on any additional data, at the very least, it would stand to reason that in the near future, Company A's stock price is more likely to be between $75 and $100 than Company B's stock price, and that Company B's stock price is more likely to be between $50 and $75 than Company A's stock price. These observations cannot be made by looking at the yearly averages alone and must take the most recent data into consideration.

The point above does not eliminate concerns regarding the effect of daily fluctuations in market data, especially during periods of volatility. As a result, it is important to consider both averages and recent spot values when using market data for forward-looking analyses. That is precisely my approach when using market data that are expected to continue to fluctuate, such as stock prices, dividend yields, betas, and market risk premia.

Q. CAN A DIFFERENCE OF ONE DAY IN THE SELECTION OF SPOT DATA HAVE A SIGNIFICANT POSITIVE OR NEGATIVE EFFECT ON ROE RESULTS? IF SO, HOW DO YOU GO ABOUT CHOOSING WHICH DAY TO USE FOR MARKET-BASED SPOT DATA?

A. Daily fluctuations in stock prices, resulting dividend yields, betas, etc., all have an impact on resulting ROE calculations, especially when using recent spot values for market data. Such is the nature of market data, which change from day to day. This is rightfully noted as a potential risk of using spot data, but given the stated benefits of using recent spot data for forward-looking analyses, there are ways to address such potential pitfalls.

For this reason, it is very important to establish consistent methodologies that eliminate the possibility of personal bias, especially when using spot market data. I consistently use the last trading day of the last full calendar month before my schedule preparations for all market-based spot data and as the last day for all historical market-data averages.

It is important to keep in mind that even averages fluctuate over time, and all responsible data analysts must find a consistent and reproducible way to “freeze time” to work with such fluctuations while eliminating bias.

It is also important to point out once again that I use recent spot market-data to establish one benchmark for market-based inputs, which are balanced by the use of historical averages, as stated previously.

B. Proxy Group Selection

Q. PLEASE EXPLAIN HOW YOU SELECTED THE COMPANIES IN YOUR COMPARABLE PROXY GROUP?

A. My comparable proxy group, shown in Table 6 on page 50 and referred to as the RFC Electric Proxy Group, consists of the following 36 publicly traded electric utility companies covered by Value Line:

TABLE 6: RFC ELECTRIC PROXY GROUP COMPOSITION

	Company Name	Ticker
1	AMEREN	AEE
2	AMERICAN ELEC. PWR.	AEP
3	AVANGRID, INC.	AGR
4	ALLETE	ALE
5	AVISTA CORP.	AVA
6	BLACK HILLS CORP.	BKH
7	CMS ENERGY CORP.	CMS
8	CENTER POINT EN’RGY	CNP
9	DOMINION ENERGY, INC.	D
10	DTE ENERGY CO.	DTE
11	DUKE ENERGY	DUK
12	CON. EDISON	ED
13	EDISON INTERNAT’L	EIX
14	EVERSOURCE ENERGY	ES
15	ENTERGY CORP.	ETR
16	EVERGY, INC.	EVRG
17	EXELON CORP.	EXC
18	FIRST ENERGY	FE
19	FORTIS, INC.	FTS.TO
20	HAWAIIAN ELECTRIC	HE
21	IDACORP, INC.	IDA
22	ALLIANT ENERGY	LNT
23	MGE ENERGY INC.	MGEE
24	NEXTERA ENERGY	NEE
25	NORTHWESTERN	NWE
26	OGE ENERGY CORP.	OGE
27	OTTERTAIL CORP.	OTTR
28	P.S. ENTERPRISE GP.	PEG
29	PNM RESOURCES	PNM
30	PINNACLE WEST	PNW
31	PORTLAND GENERAL	POR
32	PPL CORPORATION	PPL
33	SOUTHERN COMPANY	SO
34	SEMPRA ENERGY	SRE
35	WEC ENERGY GROUP	WEC
36	XCEL ENERGY	XEL

C. Discounted Cash Flow

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR DCF MODELS.

A. I used both the constant growth form of the DCF method, which determines growth based on the sustainable retention growth procedure, and a non-constant growth DCF method. My constant growth form DCF analysis indicates a COE range of between 7.89% and 7.91% for the RFC Electric Proxy Group.[40] The results of my non-constant growth DCF method indicate a COE of between 8.21% and 8.31% for the RFC Electric Proxy Group.[41]

Q. WHAT IS THE DISCOUNTED CASH FLOW METHOD?

A. The DCF method, is an approach to determining the COE. The method recognizes that investors purchase common stock to receive future cash payments. These payments come from: (a) current and future dividends, and (b) proceeds from selling stock. A rational investor will buy stock to receive dividends and to ultimately sell the stock to another investor at a gain. The price the new owner is willing to pay for stock is related to that buyer's expectation of future flow of dividends and the future expected selling price. The value of the stock is the discounted value of all future dividends until the stock is sold plus the value of proceeds from the sale of the stock.

Q. HAVE INVESTORS ALWAYS USED THE DCF METHOD?

A. While investors who buy stock have always done so for future cash flow, the DCF approach first appeared in the 1937 Harvard Ph.D. thesis of John Burr Williams titled *The Theory of Investment Value*. Author Peter L. Bernstein once stated that "Williams' model for valuing

[40] Exhibit ALR-3 at p. 1.
[41] Exhibit ALR-3 at p. 2 and Exhibit ALR-3 at p. 3.

a security calls for the investor to make a long-run projection of a company's future dividend payments…"[42] The Williams DCF model separately discounts each and every future expected cash flow. Dividends and proceeds from the sale of stock are the expected cash flows. Its accuracy is therefore unaffected by non-constant growth rates. Myron Gordon and Eli Shapiro, who helped to make this method widely used, referred to Williams' work in their paper published in 1956 "*Equipment Analysis: The Required Rate of Profit*."

D. Constant Growth Form of the DCF Model

Q. YOU STATE YOU USED THE CONSTANT GROWTH FORM OF THE DCF MODEL. WHAT IS THE CONSTANT GROWTH FORM OF THE DCF MODEL?

A. The constant growth form of the DCF model is a form of the DCF method that can be used in determining the COE when investors can reasonably expect that the growth of retained earnings and dividends will be constant.

Retained earnings are funds that a company keeps in its treasury, so that they are available for future needs, such as operating expenses, capital expenditures, debt payments, and new investments. These retained earnings show investors whether the company is growing, which, in turn, is a measure of the future indicator of dividends and the value of a company's stock.

Q. DESCRIBE HOW THE CONSTANT GROWTH MODEL WORKS.

A. The constant growth model is described by this equation $k = D/P + g$, where: [43]

[42] P. BERNSTEIN, *Capital Ideas: The Improbable Origins of Modern Wall Street* (The Free Press, © 1992).
[43] M. GORDON, *Cost of Capital to a Public Utility*, p. 32-33 (MSU Public Utility Studies 1974).

k= cost of equity (COE);
D=Dividend; and
P=Market price of stock at time of the analysis

and where:

g=the growth rate, where g= br + sv;
b=the earnings retention rate;
r=return on common equity investment (referred to below as "book equity");
v=the fraction of funds raised by the sale of stock that increases the book value of the existing shareholders' common equity; and
s=the rate of continuous new stock financing

The constant growth model is therefore correctly recognized to be:

k=D/P + (br +sv)

The COE demanded by investors is the sum of two factors. The first factor is the dividend yield. The second factor is growth (dividends and stock price). The logical relationship among these factors is as follows: the dividend yield is calculated based on current dividend payments while growth indicates what dividends and stock price will be in the future.

Q. WHAT OTHER FACTORS IMPACT HOW ONE USES THE CONSTANT GROWTH FORM OF THE DCF MODEL?

A. Sufficient care must be taken to be sure that the growth rate "g" is representative of the constant sustainable growth. To obtain an accurate constant growth DCF result, the mathematical relationship between earnings, dividends, book value and stock price must be respected.

The basic difference between the use of an analysts' earnings per share growth rate in the constant growth DCF formula and using the "br" (**b** (the earnings retention rate) X **r** (rate of return on common equity investment)) approach is that the "br" form, if properly applied, eliminates the mathematical error caused by an inconsistency between the expectations for earnings per share growth and dividends per share growth. Because it eliminates that error, the results of a properly applied "br" approach will be superior to the answer obtained from other approaches to the constant growth form of the DCF model. This is not to say that even a properly applied "br" approach will be perfect. The self-correcting nature of a properly applied "br" to forecasted differences in earnings per share and dividends per share growth rates help mitigate the resultant error but should not be viewed as the perfect way to quantify the impact of expected non-constant growth rates.

Q. ARE YOU AWARE OF CLAIMS ALLEGING THAT THE "BR" APPROACH TO THE CONSTANT GROWTH DCF MODEL IS FLAWED BECAUSE IT RELIES ON THE VALUE OF THE FUTURE EXPECTED RETURN ON BOOK EQUITY "R" TO ESTIMATE WHAT THE EARNED RETURN ON EQUITY SHOULD BE?

A. Yes. One common criticism is that it is not reasonable for the DCF to indicate a COE (market return) that is different (lower or higher) than the expected return on book equity (accounting). There are multiple reasons why this concern is unfounded:

1. The constant growth form of the equation using "br" is:

   $$k= D/P + (br + sv)$$

   In this equation, "k" is the variable for the COE, and "r" is the future expected return on equity. The COE, "k," is not the same variable as the future expected earned return on equity, "r." In fact, there often is a large difference between the two.

2. The correct value to use for "r" is the return on book equity expected by investors as of the time the stock price and dividend data are used to quantify the D/P term in the equation. Therefore, even if future events occur

that may change what investors expect for "r," the computation of the COE "k" remains correct as of the time the computation was made.

3. The ability of a commission's ROE decision to influence future cash flow expectations is not unique to the retention growth DCF approach. The five-year analysts' earnings per share growth rate is a computation that is directly influenced by what earnings per share will be in 5 years. Allowed ROEs impact earning – higher allowed returns lead to higher earnings growth because the higher allowed returns the more earnings are available for reinvestment.

Q. CAN CHANGES IN THE ACTUAL EARNED RETURNS IMPACT GROWTH ABOVE AND BEYOND WHATEVER GROWTH RESULTS FROM EARNINGS RETENTION?

A. Yes, but large short-term changes in earnings per share caused by a perceived change in the future expected earned returns are unsustainable. The new perceived earned return on book equity should be part of the computation, but the one-time growth spurt to get there is no more indicative of the sustainable growth required in the constant growth DCF formula than the temporary negative growth that occurs when a company has a bad year.

Q. HOW HAVE YOU IMPLEMENTED THE CONSTANT GROWTH FORM OF THE DCF MODEL IN THIS CASE?

A. I have applied the constant growth form of the DCF model by staying true to the mathematically derived "k=D/P + (br + sv)" form of the DCF model. I have also taken care to fully allocate all future expected earnings to either future cash flow in the form of dividends ("D") or to retained earnings (the retention rate, "b"). This extra accuracy is obtained only when the retention rate "b" is derived from the values used for "D" and "r," rather than independently.

Q. PLEASE EXPLAIN HOW YOU OBTAINED THE VALUES YOU USED IN THE CONSTANT GROWTH FORM OF THE DCF METHOD.

A. The DCF model generally calls for the use of the dividend expected over the next year. A reasonable way to estimate next year's dividend rate is to increase the quarterly dividend rate by half of the current actual quarterly dividend rate. This is a good approximation of the rate that would be obtained if the full prior year's dividend were escalated by the entire growth rate.[44]

I obtained the stock price—"P"—used in my DCF analysis from the closing prices of the stocks on February 28, 2022. I also obtained an average stock price for the 12 months ending February 28, 2022 by averaging the high and low stock prices for the year.

I based the value of the future expected return on equity— "r" —on the average return on book equity expected by Value Line, adjusted in consideration of recent returns. I also made a computation that was based on a review of both the earned return on equity consistent with analysts' consensus earnings growth rate expectations and on the actual earned returns on equity. For a stable industry such as utility companies, investors will

[44] For example, assume a company paid a dividend of $0.50 in the first quarter a year ago, and has a dividend growth rate of 4 % per year. This dividend growth rate equals (1.04)^4-1=0.00985 % per quarter. Thus, the dividend is $0.5049 in the second quarter, $0.5099 in the third quarter, and $0.5149 in the fourth quarter. If that 4 % per annum growth continues into the following year, then the dividend would be $0.5199 in the 1st quarter, $0.5251 in the 2nd quarter, $0.5303 in the 3rd quarter, and $0.5355 in the 4th quarter. Thus, the total dividends for the following year equal $2.111 (0.5199 + 0.5251 + 0.5303 + 0.5355). I computed the dividend yield by taking the current quarter (the $0.5149 in the 4th quarter in this example) and multiplying it by 4 to get an annual rate of $2.06. I then escalated this $2.06 by half the 4 % growth rate, which means it is increased by 2 %. $2.06 x 1.02= $2.101, which is within one cent of the $2.111 obtained in the example.

typically look at actual earned returns on equity as one meaningful input into what can be expected for future earned returns on book equity. See Exhibit ALR-3, page 1.

This return on book equity expectation used in the DCF method to compute growth must *not* be confused with the COE. Since the stock prices for the comparative companies are substantially higher than their book value, the return investors expect to receive on their market price investment is considerably less than the anticipated return on book value. If the market price is low relative to book value, the COE will be higher than the future expected return on book equity, and if the market price is high, then the return on book equity will be less than the COE.

In addition to growing through the retention of earnings, utility companies also grow by selling new common stock. Selling new common stock increases a company's growth. I quantified this growth caused by the sale of new common stock by multiplying the amount that the actual market-to-book ratio exceeds 1.0, by the compound annual growth rate of stock that Value Line forecasts. The results of that computation are shown on line 4 of Exhibit ALR-3, page 1.

Pure financial theory prefers concentrating on the results from the most current price because investors cannot purchase stock at historical prices. There is a legitimate concern, however, about the potential distortion of using just a single price. I present DCF results based on the most recent stock pricing data (February 28, 2022) as well as the average of the high and low stock price over the past 12 months to obtain a range of reasonable values. As shown in Exhibit ALR-3, page 1, the DCF result based on the average of the high and low stock price for the year ending February 28, 2022 is 7.89%. The DCF result based on the stock price as of February 28, 2022 is 7.91%. Exhibit ALR-

3, page 1, shows more of the specifics of how I implemented the constant growth form of the DCF model for the RFC Electric Proxy Group.

Q. PLEASE EXPLAIN HOW YOU DETERMINED WHAT VALUE TO USE FOR "R" WHEN COMPUTING GROWTH IN YOUR CONSTANT GROWTH FORM OF THE DCF MODEL.

A. The inputs I considered are shown in Footnote [C] of Exhibit ALR-3, page 1. The value of "r" that is appropriate to use in the DCF formula is the value anticipated by investors to be maintained on average in the future. This Exhibit shows that the average future return on equity forecasted by Value Line for the RFC Electric Proxy Group between 2021 and 2024-26 is 10.35%. The same footnote also shows that the future expected return on equity derived from the Zacks consensus forecast is 9.96%, and that the actual returns on equity earned by the RFC Electric Proxy Group on average were 10.26% in 2019, 9.47% in 2020, and 9.51% in 2021. Based on the combination of the forecasted return on equity derived from the Zacks consensus, the recent historical actual earned returns, and Value Line's forecast, I made the DCF growth computation using a 10.00%[45] value of "r".

Q. WHAT COE IS INDICATED BY THE CONSTANT GROWTH FORM OF THE DCF METHOD THAT YOU RELY ON FOR YOUR RECOMMENDATION?

A. The result of my DCF analysis using the Constant Growth form of the DCF indicates a COE range of between 7.89% and 7.91% for the RFC Electric Proxy Group.[46] Since these DCF findings use analysts' forecasts to derive sustainable growth (in part) and on analysts'

[45] I used 10.00% in consideration of historical returns, Zacks's projections, and Value Line projected returns for the RFC Electric Proxy Group.
[46] Exhibit ALR-3 at p. 1.

forecasts of dividend growth and book value growth in the non-constant form of the DCF method, the results should be considered as conservatively high. This is because, as previously mentioned above, analysts' forecasts of such growth have been notoriously overstated.

My results are not as influenced by overly-optimistic analysts' forecasts as would have been the case had I merely used analysts' five-year earnings growth rate forecasts as a proxy for long-term growth. This is because the DCF methods I use compute sustainable growth rates, rather than growth rates that can exaggerate the growth rate due to assuming that a relatively short-term forecast (5 years) will remain indefinitely.

E. <u>Non-Constant Growth Form of the DCF Model</u>

Q. PLEASE EXPLAIN HOW YOU IMPLEMENTED THE NON-CONSTANT GROWTH FORM OF THE DCF MODEL.

A. The non-constant growth form of the DCF model determines the return on investment expected by investors based on an estimate of each separate annual cash flow the investor expects to receive. For the purpose of this computation, I have incorporated Value Line's detailed annual forecasts to arrive at the specific non-constant growth expectations that an investor who trusts Value Line would expect. This implementation is shown on Exhibit ALR-3, page 2 and Exhibit ALR-3, page 3. In the first stage, cash flow entry is the cash outflow an investor would experience when buying a share of stock at the market price. The subsequent years of cash flow are equal to the dividends per share that Value Line forecasts. For the intermediate years of the forecast period in which Value Line does not provide a specific dividend, the annual dividends were obtained by estimating that dividend growth would persist at a compound annual rate. The cash flow at the end of the forecast period consists of both the last year's dividend forecast by Value Line, and the proceeds from the sale of the stock. The stock price used to determine the proceeds from selling the stock was obtained by estimating that the stock price would grow at the same rate at which Value Line forecasts book value to grow.

Q. WHY DID YOU USE BOOK VALUE GROWTH TO PROVIDE THE ESTIMATE OF THE FUTURE STOCK PRICE?

A. For any given earned return on book equity, earnings are directly proportional to the book value. Furthermore, book value growth is the net result after the company produces earnings, pays a dividend and also, perhaps, either sells new common stock at market price or repurchases its own common stock at market price.

Once these cash flows are entered into an Excel spreadsheet, the compound annual return an investor would achieve as a result of making this investment was obtained by using the Internal Rate of Return (IRR) function built into the spreadsheet. As shown on Exhibit ALR-3, page 2 and Exhibit ALR-3, page 3, this multi-stage DCF model produced an average indicated COE of 8.21% based on the year-end stock price, and 8.31% based on average prices for the year ending February 28, 2022 for the RFC Electric Proxy Group.

Q. YOUR NON-CONSTANT GROWTH DCF MODEL USES ANNUAL EXPECTED CASH FLOWS. SINCE DIVIDENDS ARE PAID QUARTERLY RATHER THAN ANNUALLY, HOW DOES THIS SIMPLIFICATION IMPACT YOUR RESULTS?

A. I used the annual model because it is easier for observers to visualize what is happening. By modeling cash flows to be annual rather than when they are actually expected to occur causes a small overstatement of the COE.

Q. WHY IS IT A SMALL OVERSTATEMENT OF THE COE IF YOU HAVE MODELED DIVIDENDS TO BE RECEIVED SOME MONTHS AFTER INVESTORS ACTUALLY EXPECT TO RECEIVE THEM?

A. The process of changing from an annual model to a quarterly model would require two changes, not just one. A quarterly model would show dividends being paid sooner and would also show earnings being available sooner. A company that receives its earnings sooner, rather than at the end of the year, has the opportunity to compound them. Since revenues, and therefore earnings, are essentially received every day, a company that is supposed to earn an annual rate of 9.00% on equity would have to earn only 8.62% if the return were compounded daily.[47] This reduction from 9.00% to 8.62% would then be partially offset by the impact of the quarterly dividend payment to bring the result of switching from the simplifying annual model closer to, but still a bit below 9.00%.

Q. BY USING CASH FLOW EXPECTATIONS AS THE VALUATION PARAMETER, DOES THE NON-CONSTANT DCF MODEL STILL RELY ON EARNINGS?

A. Yes. It relies on an expectation of future cash flows. Future cash flows come from dividends during the time the stock is owned and capital gains from the sale of the stock once it is sold. Since earnings impact both dividends and stock price, the non-constant DCF model still relies on earnings.

Every dollar of earnings is used for the benefit of stockholders, either in the form of a dividend payment, or earnings reinvested for future growth in earnings and/or dividends. Earnings paid out as a dividend have a different value to investors than earnings retained in the business. Recognizing this difference and properly considering it in the

[47] (1+.0862/365)^365=1.09=9.00 %.

quantification process is a major strength of the DCF model and is why the non-constant DCF model as I have set forth is an improvement over either the price-to-earnings ratio (P/E ratio) or dividend/price (D/P) methods. Comparing the P/E ratios and the dividend yield (D/P) are helpful as a rule of thumb, but they must be used with caution because, among other reasons, two companies with the same dividend yield can have a different COE if they have different retention rates. A DCF model is more reliable than these rules of thumb because it can account for different retention rates, among other factors.

Q. WHY IS THERE A DIFFERENCE TO INVESTORS IN THE VALUE OF EARNINGS PAID OUT AS A DIVIDEND COMPARED TO THE VALUE OF EARNINGS RETAINED IN THE BUSINESS?

A. The return on earnings retained in the business depends upon the opportunities available to that company. If a regulated utility reinvests earnings in needed “used and useful” utility assets, then those reinvested earnings have the potential to earn at whatever return is consistent with ratemaking procedures allowed and the skill of management in prudently operating the system.

When an investor receives a dividend, he can either reinvest it in the same or another company or use it for other things, such as paying down debt or paying living expenses. Although an investor could theoretically use the proceeds from any dividend payments to simply buy more stock in the same company, when an investor increases her investment in a company by purchasing more stock, the transaction occurs at market price. However, when the same investor sees her investment in a company increase because earnings are retained rather than paid as a dividend, the reinvestment occurs at book value. Stated within the context of the DCF terminology: earnings retained in the business earn at the future expected return on book equity "r," and dividends used to purchase new stock earn at the rate "k." When the market price exceeds book value (that is, the market-to-book ratio exceeds 1.0), retained earnings are worth more than earnings paid out as a dividend because "r" will be higher than "k." Conversely, when the market price is below book value, "k" will be higher than "r," meaning that earnings paid out as a dividend earn a higher rate than retained earnings.

Q. IF RETAINED EARNINGS WERE MORE VALUABLE WHEN THE MARKET-TO-BOOK RATIO IS ABOVE 1.0, WHY WOULD A COMPANY WITH A MARKET-TO-BOOK RATIO ABOVE 1.0 PAY A DIVIDEND RATHER THAN RETAIN ALL OF THE EARNINGS?

A. Retained earnings are more valuable than dividends only if there are sufficient opportunities to profitably reinvest those earnings. Regulated utility companies are allowed to earn the cost of capital only on assets that are used and useful in providing utility service. Investing in assets that are not needed may not produce any return at all. For unregulated companies, opportunities to reinvest funds are limited by the demands of the business. For example, how many new computer chips can Intel profitably develop at the same time?

Q. UNDER THE NON-CONSTANT DCF MODEL, IS IT NECESSARY FOR EARNINGS AND DIVIDENDS TO GROW AT A CONSTANT RATE FOR THE MODEL TO BE ABLE TO ACCURATELY DETERMINE THE COST OF EQUITY?

A. No. Because the non-constant form of the DCF model separately discounts each and every future expected cash flow, it does *not* rely on any assumptions of constant growth. The dividend yield can be different from period to period, and growth can bounce around in any imaginable pattern without harming the accuracy of the answer obtained from quantifying those expectations. When the non-constant DCF model is correctly used, the answer obtained is as accurate as the estimates of future cash flow.

Q. WHAT COST OF EQUITY DOES YOUR NON-CONSTANT GROWTH DCF METHOD INDICATE?

A. My non-constant growth DCF method indicates a cost of equity of between 8.21% and 8.31%.[48]

F. Capital Asset Pricing Model

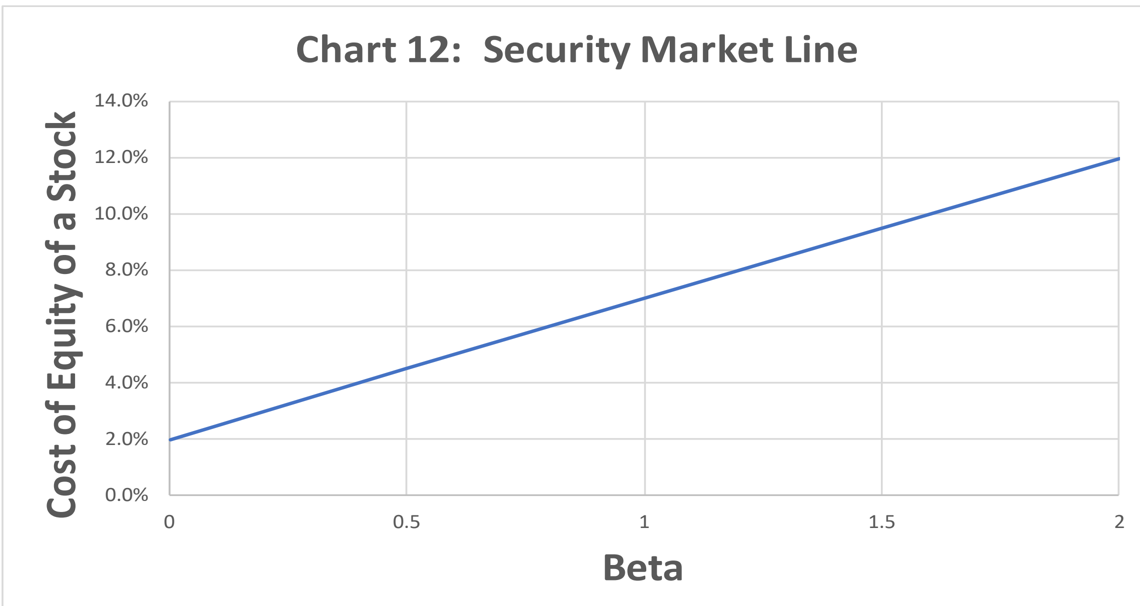
Q. PLEASE DESCRIBE THE CAPM.

A. CAPM stands for "Capital Asset Pricing Model." The CAPM relates return to risk; specifically, it relates the expected return on an investment in a security to the risk of investing in that security. The riskier the investment, the greater the expected return (i.e., the cost of equity) investors require to make that investment.

Investors in a firm's equity face two types of risks: (1) firm-specific risk and (2) market risk (financial analysts refer to this market risk as systematic risk). Firm-specific risk refers to risks unique to the firm, such as management performance and losing market share to a new competitor. Investors can reduce firm-specific risk by purchasing stocks as part of a diverse portfolio of companies if they construct the portfolio to cause the firm-specific risk of individual companies to balance out. Market-related risk refers to potential

[48] Exhibit ALR-3 at p. 2 and Exhibit ALR-3 at p. 3.

impacts from the overall market, such as a recession or interest rate changes. This risk cannot be removed by diversification, so the investor must bear it no matter what. Because the investor has no option but to bear market risk, the investor's cost of equity will reflect that risk. The CAPM predicts that for a given equity security, the cost of equity has a positive linear relationship to how sensitive the stock's returns are to movements in the overall market (e.g., S&P 500). A security's market sensitivity is measured by its beta.[49] As shown in Chart 12 below, the higher the beta of a stock, the higher the company's cost of equity—the return required by the investor to invest in the stock.



Here is the standard CAPM formula:

K = Rf + βí * (Rm – Rf)

Where:

K is the cost of equity;
Rf is the risk-free interest rate;
Rm is the expected return on the overall market (e.g., S&P 500);

[49] The covariation of the return on an individual security with the return on the market portfolio.

[Rm – Rf] is the premium investors expect to earn above the risk-free rate for investing in the overall market ("equity risk premium" or "market risk premium"); and

βí (Beta) is a measure of non-diversifiable, or systematic, risk.

Q. PLEASE EXPLAIN HOW YOU IMPLEMENTED THE CAPM.

A. First, I determined appropriate values or ranges for each of the three model inputs: (a) Risk-Free Rate, (b) Beta, and (c) Equity Risk Premium. Second, I used the equation above to calculate the cost of equity implied by the model. Below I will explain how I calculated the three model inputs and summarize the CAPM cost of equity numbers resulting from those inputs. Table 7 and Table 8 on page 93 show the results of my CAPM.

Risk-Free Rate

Q. WHAT RISK-FREE RATE DID YOU USE IN YOUR CAPM?

A. It is generally preferable to use the market yield on short-term U.S. Treasury yields as the risk-free rate because these bonds have a beta close to zero. *Principles of Corporate Finance* states "The CAPM… calls for a short-term interest rate."[50] I chose to use a risk-free rate based on both long- and short-term Treasury yields, however, because, as indicated by the steepness of the yield curve,[51] investors with a longer investment horizon would likely use a higher risk-free rate as an opportunity cost for their investment decisions. My short-term risk-free rate is based on the yield of 3-month U.S. Treasury bills and my long-term risk-free rate is based on the yield of 30-year U.S. Treasury bonds. In line with my Spot and Weighted Average CAPM approaches, I use both spot values as

[50] BREALEY, MYERS, AND ALLEN, *Principles of Corporate Finance*, p. 228, (McGraw-Hill Irwin, New York, 12th ed. 2017).

[51] The yield curve on U.S. Treasury bonds relates the yield to its time to maturity. We say the current yield curve is steep because the difference in yield between short-term (near 0%) and long-term (over 1%) bonds is large in percentage terms.

of February 28, 2022 and weighted averages over the 3 months ending on that date for these two yields.

As outlined in Exhibit ALR-4, page 2, my spot and weighted average short-term risk-free rates are 0.35% and 0.23%, respectively. My spot and weighted average long-term risk-free rates are 2.17% and 2.08%, respectively.

U.S. government bonds are reasonable to use as a risk-free rate because they have a negligible risk of default. The value of short-term U.S. Treasury bills has a relatively low exposure to swings in the overall market. The value of long-term U.S. Treasury bonds is relatively more exposed to the market and therefore must be used with caution. I considered using a risk-free rate based on subtracting the historical spread between long-term and short-term U.S. Treasury bills from current long-term yields, as recommended by some financial textbooks.[52] I did not use this method because in the current capital markets, this method results in an unreasonably low risk-free rate (under 0%).

Regarding my weighted average risk-free rates, it is worth noting that any form of averaging or weighting approach applied to the last 12 months of historical yield data would not have any significant effect on my CAPM results.

Q. WHAT IS YOUR RESPONSE TO ANALYSTS WHO CLAIM THAT THE CAPM MUST BE IMPLEMENTED WITH A LONG-TERM INTEREST RATE (E.G.,

[52] BREALEY, MYERS, AND ALLEN, *Principles of Corporate Finance*, p. 228 (McGraw-Hill Irwin, New York, 12th ed. 2017).

YIELD ON 30-YEAR TREASURY BOND) AS AN ESTIMATE OF THE RISK-FREE RATE COMPONENT OF THE CAPM?

A. When looking for a security to calculate an estimate of the risk-free rate, it could be argued that it is appropriate to find one with a term or maturity that best matches the life of the asset being financed. In that sense, the 30-year Treasury bond yield can be argued to be ideal for this specific application. However, it is equally important to find a security that has a beta coefficient with the overall market as close to zero as possible, because by the very definition of the risk-free rate in the CAPM model, its movements should have no correlation to the movements of the market. And this is where the problem with the 30-year Treasury bond yield arises, as it has an established non-zero beta. The 3-month Treasury bill yield has a considerably lower beta, and therefore is superior in that respect to the 30-year Treasury bond yield. Neither one is a perfect fit on both fronts, which is why I have chosen to consider both as proxies for the risk-free rate to establish a range for my CAPM results.

Q. HOW DO YOU RESPOND TO ANALYSTS WHO CLAIM THAT THE RISK-FREE RATE SHOULD BE BASED ON INTEREST RATE FORECASTS FROM FIRMS SUCH AS BLUE CHIP FINANCIAL?

A. It is important to recognize that current long-term Treasury bond yields represent a direct observation of investor expectations and there is no need to use “expert” forecasts such as Blue Chip to determine the appropriate risk-free rate to use in a CAPM analysis or any other cost of equity calculations.

Many economists and forecasters will continue to be quoted in the press prognosticating on possible developments that are truly unpredictable. The Nobel Laureate Economist Daniel Kahneman stated the following regarding forecasting:

> It is wise to take admissions of uncertainty seriously, but declarations of high confidence mainly tell you that an individual has constructed a coherent story in his mind, not necessarily that the story is true.[53]

As Chart 5 on page 31 shows, Blue Chip Financial forecasted in 2014 that 30-Year U.S. Treasury bonds would be over 5% by 2018 while in fact they turned out to be under 2%.

The time covered in Chart 5 on page 31 was chosen to provide a concrete example. Blue Chip's interest rate forecasts have been persistently inaccurate. A recent paper published by the Congressional Budget Office determined Blue Chip consensus forecasts exhibited "significant positive bias" between 1984 and 2012 and "have become more biased and less accurate over time."[54]

Beta

Q. WHAT BETA DID YOU USE IN YOUR CAPM?

A. Since the cost of equity should be based on investor expectations, I chose to use two betas. My "forward beta" is based on forward-looking investor expectations of non-diversifiable risk. My "hybrid beta" is based on both forward-looking investor expectations and historical return data.

[53] DANIEL KAHNEMAN, *Thinking Fast and Slow*, p. 212(New York: Farrar, Straus, and Giroux, 2011).
[54] Congressional Budget Office, Edward N. Gamber, *Did Treasury Debt Markets Anticipate the Persistent Decline in Long-Term Interest Rates?*, p. 2 (September 2017) available at https://www.cbo.gov/system/files/115th-congress-2017-2018/workingpaper/53153-interestrateswp.pdf.

Most published betas are based exclusively on historical return data. For example, Value Line publishes a 5-year historical beta for each of the companies it covers. However, it is also possible to calculate betas based on investors' expectations of the probability distribution of future returns. This probability distribution of future returns expected by investors can be calculated based on the market prices of stock options.

Q. WHAT IS A STOCK OPTION?

A. A stock option is the right to buy or sell a stock at a specific price for a specified amount of time. A call option is the right to buy a stock at a specified exercise or strike price on or before a maturity date. A put option is the right to sell a stock at a specified exercise or strike price on or before a maturity date. For example, a call option to purchase Apple Computer stock for $230 on January 17, 2020 allows the owner the option (not the obligation) to buy Apple stock for $230 on that date. At the end of July 2019, Apple stock was trading at about $215 per share. Why would anyone pay for the right to buy a stock higher than the current price? Investors who purchased those call options thought there was a chance Apple stock would be trading higher than $230 on January 17, 2020, and those options gave those investors the right to buy Apple stock for $230 and profit by selling it at the market price on that date, if it was higher. The price of Apple's stock was $317.98 at the close of trading on January 17, 2020. Therefore, the investor who purchased this call option for $635 on July 31, 2019 earned a profit of $8,163[55] at expiry on January 17, 2020. On the other hand, the investor who purchased an Apple put option with the same expiration date and strike price on July 31, 2019 would have lost the price of the

[55] $8,163 profit from exercising call option ($31,798 from selling at $317.98 market price - $23,000 cost to purchase at $230) - $635 ($6.35 X 100) option purchase price. Note: Each call option is the right to purchase 100 shares.

option ($2,248) and gained nothing on the expiration date because the right to sell Apple stock for $230 when the price is over $300 is worthless.

The market prices of put options and call options provide information regarding the probability distribution of future stock prices expected by investors. Using established techniques, I am able to use price data for stock options of my RFC Electric Proxy Group companies and the S&P 500 Index to determine investors' return expectations, including the relationship (covariance) between the return expectations for individual RFC Electric Proxy Group companies and those for the overall market (S&P 500). This covariance between the expected returns for my RFC Electric Proxy Group and for the S&P 500 indicates what investors expect betas will be in the future. I refer to betas based on option price calculations as "option-implied betas."

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE BETAS USED IN YOUR CAPM.

A. Traditionally, the betas used in CAPM calculations are calculated from historical returns. This approach has strengths and weaknesses. An alternative way to calculate betas is to incorporate investors' return expectations by calculating option-implied betas as explained in the previous paragraph. As discussed below, I have chosen to use both historical and option-implied betas in my CAPM analysis. I chose to use option-implied betas in my CAPM analysis because, among other reasons, studies have found that betas calculated based on investor expectations (option-implied) provide information regarding future perceived risks and expectations.[56]

[56] Bo-Young Chang & Peter Christoffersen & Kris Jacobs & Gregory Vainberg. Option-Implied Measures of Equity Risk, *Review of Finance*, Vol. 16, Issue 2, pp. 385-428 (April 2012) available at https://academic.oup.com/rof/article/16/2/385/1584560.

As shown in Chart 13 below, stock option prices indicate that investors likely expect lower betas for the RFC Electric Proxy Group in the future.

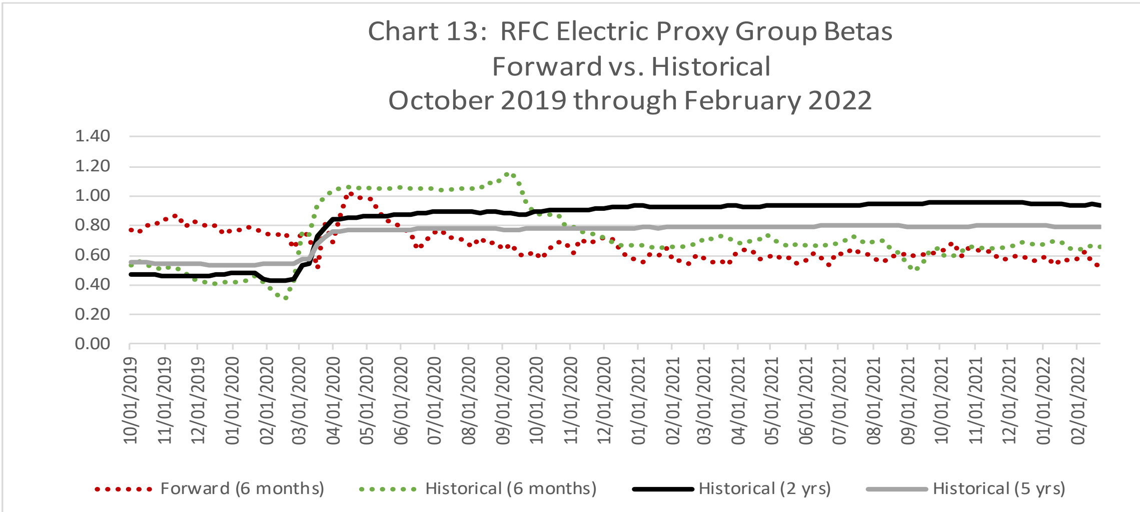


Exhibit ALR-4, page 3 contains the last three months of data used in creating Chart 13 above, which is what I use in my CAPM analysis. Specifically, I use the following two betas in my CAPM analysis:

1. **Hybrid Beta:** 50% Option-Implied Beta (6 months) + 25% Historical Beta (6 months) + 15% Historical Beta (2 years) + 10% Historical Beta (5 years).
2. **Forward Beta:** 100% Option-Implied Beta (6 months).

Q. PLEASE EXPLAIN HOW YOU CALCULATE HISTORICAL BETAS.

A. I calculate historical betas following the methodology used by Value Line, with some modifications. Specifically, Value Line adheres to the following guidelines:

1. Returns for each security are regressed against returns for the overall market in the following form:

$$\text{Ln}\,(p^{I}_{t} / p^{I}_{t-1}) = a_{I} + B_{I} * \text{Ln}\,(p^{m}_{t} / p^{m}_{t-1})$$

Where:

- p^{I}_{t} is the price of the security I at time t
- p^{I}_{t-1} is the price of the security I one week before time t
- p^{m}_{t} and p^{m}_{t-1} are the corresponding values of the market index
- B_I is the regression estimate of Beta for the security against the market index

2. The natural log of the price ratio is used as an approximation of each return and no adjustment is made for dividends paid during the week.
3. Weekly returns are calculated on one day of the week, with a stated preference for Tuesdays to minimize the effect of holidays as much as possible.
4. Betas calculated using the regression method above are adjusted as per Blume (1971)[57] using the following formula:

$$\text{Adjusted } B_I = 0.35 + 0.67 * \text{Calculated } B_I$$

There are four differences between my historical beta calculations and Value Line's calculations:

1. The first significant difference is that whereas Value Line uses the New York Stock Exchange Composite Index as the market index, I use the S&P 500 Index.
2. Another important difference is that whereas Value Line calculates weekly returns on one day of the week, with a stated preference for Tuesdays, I calculate weekly returns on all days of the week.

[57] M. Blume, On the Assessment of Risk, *The Journal of Finance*, Vol. XXVI (March 1971) available at www.stat.ucla.edu/~nchristo/Fiatlux/blume2.pdf..

3. Value Line only calculates betas every 3 months in their quarterly company reports, whereas I use the same consistent methodology to calculate betas every week during the most recent 3 complete months (November 2021 through February 2022).

4. Value Line always uses a 5-year period for the return regression,[58] whereas I calculate historical betas for periods of 6 months, 2 years, and 5 years, as shown in Chart 13 on page 72.

In the following pages, I explain my rationale for making the four modifications above to Value Line's beta calculation methodology.

Q. WHY DO YOU CALCULATE YOUR HISTORICAL BETAS VS. THE S&P 500 INDEX INSTEAD OF THE NYSE COMPOSITE INDEX, AS VALUE LINE DOES?

A. A critical factor in the calculation of a beta coefficient is the choice of index to represent the overall market. Using exactly the same beta calculation methodology with a different market index will result in different values of beta for a given company or portfolio -- sometimes drastically different values. It is easy to jump to the conclusion that this points to a flaw in CAPM theory, as different values of beta would result in a different implied cost of equity. However, another key component of the CAPM, the market risk premium, also depends on the choice of the market index, which in theory would have an offsetting effect on the cost of equity calculation. This points to the most important aspect of selecting a market index for a CAPM analysis, which is to be consistent and use the same index for the calculation of beta as for the calculation of the market risk premium. This is

[58] They offer betas calculated over different time periods on their website, including 3 years and 10 years.

a fundamental concept of the CAPM and using betas based on one index with a market risk premium based on a different index yields invalid results.

As stated above, Value Line calculates its published betas based on the NYSE Composite Index. Most methodologies used to calculate the market risk premium, including those I rely on, are based on the S&P 500 Index, so using them in the CAPM together with Value Line betas exactly as published would yield invalid results.

For this reason, I calculate my historical betas versus the S&P 500 Index, making my CAPM approach entirely consistent. This is in contrast to Mr. Castle's approach, which mixes betas based on a different index (NYSC) than his equity risk premium component (S&P 500), rendering his CAPM results inconsistent and unreliable.

As an aside related to my option-implied betas, using the S&P 500 Index consistently throughout my CAPM has the added benefit that this index has a much larger number of options traded, which makes the calculation of option-implied betas more reliable.

Q. WHY DO YOU CALCULATE YOUR HISTORICAL BETAS USING WEEKLY RETURNS ON EVERY DAY OF THE WEEK AS OPPOSED TO USING ONLY ONE DAY OF THE WEEK, AS VALUE LINE DOES?

A. Using one day of the week to calculate weekly returns for use in the regression analysis used to calculate historical betas has the unintended effect of generating different values of betas depending on the day of the week that is used. To clarify, if one were to use Value Line's precise methodology for calculating a 5-year historical beta for a given company using weekly returns calculated on Tuesdays, the resulting beta value would be different than the resulting value if one were to use the same exact methodology, but using weekly returns calculated on Wednesdays, or any other day of the week. Even though 5-year historical betas should in theory be quite stable and should not change very much from one day to the next, calculating returns on only one day of the week results in differences that can be significant and make no sense conceptually.

I only became aware of this side-effect recently, but it is easy to understand why it happens. Even though there is some correlation due to some overlap, the set of weekly returns calculated on Mondays is a completely different set of numbers than the set of weekly returns calculated on Tuesdays. As a result, there are five 5-year betas that can result from Value Line's methodology, and even though the Monday beta for a given company will change slowly from week to week, the change between the Monday beta and the Tuesday beta, calculated just one trading day apart, can be quite significant.

Since I became aware of this undesirable effect, I began calculating my historical betas based on an all-encompassing set of weekly returns calculated on every trading day in the beta calculation period. This methodology has the effect of averaging out the five possible betas that could result from using only one day of the week for the return calculations,[59] as Value Line does. In this way, a 5-year beta calculated on any two consecutive trading days would only change minimally, as it should.

Using a daily calculation of weekly returns could be criticized for the resulting overlap in a weekly return from Monday to Monday with that from Tuesday to Tuesday. However, given that the overlap is consistent and equal for the net effect of every trading day, no trading day is given undue weight in the regression. Even though the effect of each trading day appears 5 times in the weekly return data, there are also 5 times the total number

[59] The resulting beta is not a direct arithmetic or geometric average of the other five betas, but rather a regression based on the union of all five possible sets of weekly returns.

of weekly returns in the overall set used in the regression, so any individual trading day has the same relative weight than in Value Line's methodology. The fact that the resulting beta value of this aggregate approach turns out to be a sort of average of the five possible values that would result from Value Line's methodology on different days of the week is the final confirmation that this is the superior approach for calculating a historical beta based on weekly returns.

Using a daily calculation of weekly returns has the added marginal benefit of providing more data pairs to be used in historical beta calculations for shorter periods, such as for 6-month historical betas, where instead of 25 return pairs, the regression is performed on 117 return pairs.

Q. ARE THERE ADDITIONAL BENEFITS TO DOING YOUR OWN HISTORICAL BETA CALCULATIONS?

A. Doing my own historical beta calculations using Value Line's established methodology allows me to see how beta values change from week to week and to use the most up-to-date beta calculations instead of relying on stale beta values that can be more than 3 months old.

Q. WHY DO YOU USE PERIODS OF 6 MONTHS, 2 YEARS, AND 5 YEARS FOR YOUR HISTORICAL BETA CALCULATIONS, AS OPPOSED TO RELYING EXCLUSIVELY ON THE 5-YEAR PERIOD USED BY VALUE LINE?

A. Using shorter periods for the return regression analysis portion of the historical beta calculation allows me to see if the correlation between the returns of each of the companies in my RFC Electric Proxy Group and those of the S&P 500 Index has changed in the last

2 years or 6 months. Using a 5-year period exclusively tends to make recent changes in the correlation more difficult to identify because of the weight of 5 years of data.

Q. WOULD YOU AGREE THAT CHANGES IN MARKET DYNAMICS WILL HAVE A LARGER EFFECT ON 6-MONTH HISTORICAL BETAS THAN THEY WILL ON 2-YEAR OR 5-YEAR HISTORICAL BETAS?

A. Yes. As with other historical metrics based on a given time period, say, average stock prices, the longer the time horizon under consideration, the more data points are considered, and the smaller the effect of any one given change in the data set.

Q. IS THIS LARGER EFFECT ON 6-MONTH HISTORICAL BETAS FROM CHANGES IN MARKET DYNAMICS A GOOD OR A BAD THING?

A. The answer depends on what the beta will be used for. I would argue that in any attempt to forecast the beta coefficient of a company for any forward-looking analysis such as the cost of capital calculations in this proceeding, more recent historical data should be given more relevance than data from 5 or 10 years ago. The weight of 10 years of data makes a beta coefficient react extremely slowly to market developments. Even pronounced permanent market changes can take more than 6 months to have a detectable effect on a 10-year beta.

As with using spot values and averages of historical market data, I believe the right answer is not to use *either* 6-month historical betas or historical betas with longer horizons, but to consider *both*. For this reason, I have created my hybrid betas, which take into consideration 6-month, 2-year, and 5-year historical betas along with forward-looking, option-implied betas.

Q. DO YOU THINK IT IS A GOOD IDEA TO RELY ON 6-MONTH HISTORICAL BETAS DESPITE MARKET DEVELOPMENTS IN THE PAST YEAR THAT SOME WOULD CALL "MARKET DISLOCATIONS?"

A. Financial markets are constantly in flux due to the influence of countless factors. What some people may refer to as "market dislocations," though arguably more significant, I would say are just some of the numerous factors that are constantly affecting markets. To attempt to separate any one specific factor from "real" underlying market dynamics would be an exercise in futility.

Furthermore, it is very difficult if not impossible for anyone to predict how long any one influencing factor will be present or how long its effects will be felt by financial markets. When interest rates came down to historical lows in 2008, many analysts referred to it as an aberration that would be short-lived. Twelve years later, rates have not only remained low, but have come down even further due to yet another unexpected event. COVID-19 affected markets tumultuously, and though the initial wall of the tsunami has passed, no one can say for sure if its direct fallout and the effects of its reverberations or a resurgence will continue to affect financial markets for months or years to come.

So, in response, yes, I think it is a good idea to use 6-month historical betas to measure recent and current market dynamics regardless of recent developments. I use them as part of my hybrid betas in conjunction with longer-term historical betas and forward-looking, option-implied betas to achieve the most reasonable result.

Speaking specifically about the most significant initial impact caused of the onset of the COVID-19 pandemic in March 2020, it should be pointed out that 6-month betas calculated in the past 3 months no longer cover that period of time.

Q. GIVEN THE SHORTER PERIOD COVERED BY 6-MONTH HISTORICAL BETAS, CAN THEY STILL BE CONSIDERED STATISTICALLY SIGNIFICANT? HOW MANY DATA POINT PAIRS ARE USED IN THE CALCULATION OF YOUR 6-MONTH HISTORICAL BETA COEFFICIENTS?

A. A 6-month historical beta based on weekly returns calculated weekly is calculated using 26 closing price points for a company and for its corresponding market index, in this case the S&P 500 Index. This translates into 25 pairs of return data that are then used in the regression analysis. This is most certainly enough data to achieve statistical significance as addressed further below.

Furthermore, as stated above, the recent improvement in my calculation of historical betas of using weekly returns on every day of the week as opposed to using only one day of the week, as Value Line does, has the added benefit of providing significantly more data pairs to be used in the regression analysis used to calculate beta. For 6-month historical betas, instead of relying on 25 return pairs, the regression is performed on 117 return pairs.

Q. HOW MANY DATA POINT PAIRS ARE NECESSARY TO ESTABLISH A STATISTICALLY SIGNIFICANT CORRELATION BETWEEN TWO VARIABLES IN A REGRESSION ANALYSIS, SUCH AS THE ONE USED TO ESTABLISH BETA COEFFICIENTS?

A. Establishing a minimum number is somewhat subjective, though various authorities on statistics argue the number is between 3 and 8 data pairs. While one can broadly correctly generalize that the more data point pairs one uses, the more certain one can be about the significance of the results of any correlation analysis, this is very different from stating that one cannot achieve statistical significance with a relatively low number of data pairs. In fact, it is important to realize that one can achieve statistical significance with less than 10 data pairs, and that even hundreds of data pairs do not guarantee statistical significance. For precisely this reason, statisticians have developed a tool that helps determine statistical significance based on the number of data pairs in a regression analysis.

A "table of critical values" of Pearson's correlation, which can be readily found online[60] or in most statistics books, tells a statistician that for 25 data point pairs (implying N-2=23 "degrees of freedom"), a correlation, or beta, coefficient of 0.505 or higher will occur *by chance* with a probability of only 0.01.[61] As explained in more detail in the text regarding how to use the table of critical values,[62] any beta coefficient above this level, and certainly above the 0.664 3-month average for the recent 6-month betas for my RFC Electric Proxy Group, by definition are considered statistically significant. The threshold for statistical significance for 117 data point pairs (implying 115 "degrees of freedom"), is so low that it is not even included in the table of critical values. The maximum "degrees of freedom" listed is 100, with an already very low threshold of 0.254.

Q. PLEASE EXPLAIN HOW YOU CALCULATED OPTION-IMPLIED BETAS.

A. Calculating option-implied betas of a company requires (1) obtaining stock option data for that company and a market index, (2) filtering the stock option data, (3) calculating the option-implied volatility for the company and for the index, (4) calculating the option-implied skewness for the company and for the index, and (5) calculating option-implied

[60] University of Connecticut, *r Critical Value Table*, available at https://researchbasics.education.uconn.edu/r_critical_value_table/#

[61] In fact, many researchers use a more lenient "alpha level" of 0.05 for determinations of statistical significance.

[62] University of Connecticut, *Statistical Significance: Is there a relationship (difference) or isn't there a relationship (difference)?* available at https://researchbasics.education.uconn.edu/statistical_significance

betas for the company based on implied volatility and skewness for the company and for the index. There are various ways one could choose to perform the steps above, but I chose to filter stock option data and calculate option-implied volatility[63] and skewness[64] following exactly the same methodology used by the Chicago Board of Options Exchange (CBOE) in the calculation of their widely-used VIX (or Volatility Index) and SKEW Index, respectively.

I start my process with publicly available trading information for all the options for a given security (company or index) for a complete trading day. I then filter the option data as described by the CBOE using the following guidelines:

1. Use the mid-quote or mark (average of bid and ask) as the option price.
2. Use only out-of-the-money call and put options.
    - Determine the "moneyness" threshold where absolute difference between call and put prices is smallest (using CBOE "Forward Index Price" formula).
    - Include "at-the-money" call and put options and use average of call and put prices as price for "blended" option.
3. Exclude all zero bids.
4. Exclude remaining (more out-of-the-money) options when two sequential zero bids are found.

[63] CBOE Volatility Index White Paper (2018) available at https://cdn.cboe.com/resources/indices/srvix-white-paper.pdf. Please note that the cover page says, "proprietary information." However, this document has been in the public domain for over 3 years.
[64] The CBOE SKEW Index (2010) available at https://cdn.cboe.com/resources/indices/documents/SKEWwhitepaperjan2011.pdf. Please note that the cover page says, "proprietary information." However, this document has been in the public domain for over 3 years.

I then apply the series of formulas clearly described in both of the CBOE's white papers to the remaining options to calculate Option-Implied Volatility and Option-Implied Skewness. In the words of the CBOE, each of its two indices is "an amalgam of the information reflected in the prices of all of the selected options." To be clear, Implied Volatility is not exactly the same as the VIX Index, and Implied Skewness is not exactly the same as the SKEW Index, but both indices are directly based on their corresponding statistical value.

Option-Implied Volatility reflects investors' expectations regarding future stock price movements. Option-Implied Skewness reflects investors' expectations regarding how implied volatility changes for strike prices that are closer and further to the current value of the underlying stock price.

The CBOE calculates Times to Expiration by the minute—as do I. The Time to Expiration of traded options cannot be changed and varies from day to day. For the sake of consistency, the CBOE calculates the VIX and SKEW indices on a "30-day" basis by interpolating for two sets of options with Times to Expiration closest to the 30-day mark. I prefer to focus on as long of a time horizon as possible for forecasting purposes. Option Times to Expiration vary significantly for various stocks but can relatively consistently be found to go out to 6 months (180 days) for utility companies. Therefore, for the sake of consistency, I have chosen to calculate 6-month volatility and skewness where possible. Occasionally, Times to Expiration for a given stock do not go out to 180 days. If the greatest Time to Expiration available is 171 days (95%) or greater, I use the volatility and skewness for that group of options as a proxy for the 180-day volatility and skewness, respectively.

Finally, once I have calculated the option-implied volatility and skewness for each company and index using the methodology described above, I calculate option-implied betas using the following formula developed by Christoffersen, Chang, Jacobs and Vainberg (2011): [65]

$$\beta_i = \left(\frac{SKEW_i}{SKEW_m}\right)^{1/3} \left(\frac{VAR_i}{VAR_m}\right)^{1/2}$$

Where:

β_i: $option - implied\ beta\ of\ security\ (e.g. stock, fund)$;
$SKEW_i$: $skewness\ of\ security$;
$SKEW_m$: $skewness\ of\ overall\ market\ (S\&P\ 500)$;
VAR_i: $variance\ of\ company$;
VAR_m: $variance\ of\ overall\ market\ (S\&P\ 500)$.

Q. YOU CALCULATE YOUR OPTION-IMPLIED BETAS BASED ON A 6-MONTH HORIZON. WOULD IT NOT BE BETTER TO USE A LONGER FORECASTING HORIZON?

A. The methodology I use to calculate my option-implied betas "allows for the computation of a complete term structure of beta for each company so long as the options data are available,"[66] so there is nothing inherent in the methodology that limits it to a certain time horizon.

For many applications, including cost of capital, one could argue that the longer the time horizon for the option-implied betas, the better. However, the limitation on the forecasting horizon is always set by the longest expiration period of the options currently

[65] Bo-Young Chang & Peter Christoffersen & Kris Jacobs & Gregory Vainberg, Option-Implied Measures of Equity Risk, *Review of Finance* Volume 16, Issue 2, pp. 385-428 (April 2012) available at https://academic.oup.com/rof/article/16/2/385/1584560.
[66] Peter Christoffersen, Kris Jacobs, and Gregory Vainberg, *Forward-Looking Betas*, p. 24 (April 25, 2008) available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=891467.

traded in the market. Some companies trade options with expiration periods up to 2 or 3 years into the future. As evidenced by the exhaustive option data in my working papers, the maximum expiration period for the options of the companies in my RFC Electric Proxy Group is approximately 8 months. None of the 36 companies ever trade options with expiration periods of more than 8 months. New options are issued roughly every 3 months for all of these companies, so the maximum expiration period on any given trading day is somewhere between 5 and 8 months. For consistency across companies in my proxy group and across dates within the 3-month period on which my analysis is focused (November 2021 through February 2022), I chose to use 6 months for the time horizon of my option-implied betas. If the maximum expiration period for the options of a given company on a given day is less than 6 months, I use the maximum expiration period as an approximation for the target 6-month horizon.

Simply because some may argue that it may be preferable to use longer time horizons in place of or in addition to a 6-month horizon, it does not mean that a 6-month option-implied beta is of no relevance or cannot be used. That would be tantamount to saying you cannot use a 1-year Value Line Earnings Per Share estimate, or that the minimum relevant forecast is 2 or 3 years. In fact, for purposes of option-implied betas, it would be difficult to say if a time horizon of 1 year, for instance, is necessarily always better than a time horizon of 6 months. An option-implied forward-looking beta, even with a time horizon of less than 6 months, is still a useful tool in interpreting the current expectations of investors at any given time.

A final strong argument in support of using 6-month option-implied betas in a cost of capital calculation looking years into the future is that, as expanded upon on page 87, the authors of the paper on which I based my option-implied betas concluded that their predictive powers are not limited to 6 months into the future. In fact, they conclude that 6-month option-implied betas have stronger predictive power than 6-month, 1-year, or 5-year historical betas when attempting to forecast betas 1 or 2 years into the future.

Q. WHY DIDN'T YOU USE LONG-TERM EQUITY ANTICIPATION SECURITIES, WHICH ARE OPTIONS CONTRACTS WITH AN EXPIRATION DATE OF TYPICALLY MORE THAN 1 YEAR?

A. It is not possible to use Long-Term Equity Anticipation Securities (LEAPS) to calculate option-implied betas for all utility companies because these contracts are not traded for many of them. As stated above, the maximum expiration period for the options of the 36 companies in my RFC Electric Proxy Group is approximately 8 months, and so for consistency across companies and dates, I chose to use 6 months for the time horizon of my option-implied betas. As explained above, option-implied betas calculated from options contracts with expiration periods less than 1 year, in my case 6 months, are still a useful tool in interpreting investors' current expectations and are superior to the historical betas. As a further note, I use LEAPS in my CAPM when the data is available. The risk premium portion of my CAPM is based on options contracts with expiration periods exceeding 1 year, and as far out as 36 Months.

Q. HOW DID YOU DECIDE ON THE RELATIVE WEIGHTS YOU ALLOCATE TO EACH COMPONENT OF YOUR HYBRID BETAS? IS THERE ANY ACADEMIC SUPPORT FOR YOUR APPROACH?

A. I am not aware of any academic study specifically focused on the optimal relative weight of historical betas to predict future betas. However, the authors of the paper I relied upon for guidance on the calculation of my option-implied betas did attempt to quantify the predictive power of 6-month option-implied ("forward-looking") betas as well as that of 6-month ("180-day"), 1-year, and 5-year historical betas by back-testing historical predictions with actual *expost* results, or "realized" betas, for the 30 companies in the Dow Jones Index. In addition to using each of the betas above independently, they also measured the predictive power of a "mixed" beta consisting of a simple average of the six-month option-implied beta and the 6-month historical beta.

Their conclusions for predicting 6-month future betas are as follows:

> The forward-looking beta outperforms the other methods ten times, and the same is true for the 180-day historical beta. The mixed beta is the best performer in seven cases, and the 1-year historical beta in three cases. The 5-year historical beta is always outperformed by at least one other method, and it often ranks last. The 180-day historical beta clearly dominates the two other historical methods.[67]

Their conclusions for predicting 1-year and 2-year future betas are as follows:

> Somewhat unexpectedly, the performance of the forward-looking beta compared to that of the 180-day historical beta is much better [for the one-year prediction] than [for the six-month prediction], and this conclusion carries over to [the two-year prediction]. The mixed beta also perform [sic] well. It is perhaps not surprising that the performance of the 180-day historical beta [for the one- and two-year predictions] is poorer than [for the six-month prediction], because the horizons used in the construction of realized betas are no longer equal to 180 days. What is harder to explain is why the correlation between realized beta and forward-looking beta is in many cases higher [for the one- and two-year predictions] than [for the six-month prediction]. Finally, it is also interesting that the 1-year and 5-year historical betas do not perform well [for the one-and two-year predictions]. In summary, [for the one-year prediction] either the forward-looking beta or the mixed beta is the best performer in nineteen out of thirty cases. [For the two-year prediction], this the case twenty-two times out of thirty.[68]

---

[67] Peter Christoffersen, Kris Jacobs, and Gregory Vainberg, *Forward-Looking Betas*, p. 16 (April 25, 2008) available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=891467.
[68] *Id. at 17.*

Their conclusions strongly support the use of 6-month historical betas, 6-month option-implied betas, and/or an average of the two as predictors of future betas 6 months, 1 year, or 2 years into the future. They also seem to indicate that historical betas lose predictive power the longer the period that is used.

I decided on the composition of my hybrid betas primarily based on the conclusions of the authors above. A mixed or hybrid beta made up of 50% historical betas and 50% forward-looking option-implied betas seemed to be the best way to go. Though the predictive power of longer-term historical betas seems to be quite reduced, it is not zero, so in an effort to preserve the effect of longer-term market trends in my hybrid betas, I chose to further subdivide the historical component into 50% (25% of the hybrid) for the stronger predicting 6-month historical betas, 30% (15% of the hybrid) for the 2-year historical betas, and 20% (10% of the hybrid) for the 5-year historical betas.

Market Risk Premium

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE EQUITY RISK PREMIUM USED IN YOUR CAPM.

A. Traditionally, the risk premium used in CAPM calculations is derived from historical returns and/or equity analyst projections. The former approach is historically accurate but does not take into account investors' expectations for future market risks and returns. The latter approach is based on analyst projections, which are not market-based and do not reflect current investor expectations. A superior market-based way to calculate the equity risk premium is to use option-implied return expectations, which is the approach I have used.

My equity risk premium is the expected return on the S&P 500 minus the risk-free rate. I calculate an expected return on the S&P 500 by using stock options traded on this index. To begin with, I use exactly the same methodology used by the Chicago Board of Options Exchange to filter stock option data and calculate option-implied volatility and skewness,[69] as described in detail in the Beta section on page 81. The volatility and skewness calculated in this way describe a probability function representing the possible trajectories for the S&P 500 implied by the options market. The resulting skewed probability function can be closely approximated by a log-normal function using established statistical formulas, which then make it straightforward to calculate the expected growth for the S&P 500 for any given cumulative probability. A cumulative probability of 50% represents the median of the probability distribution, or the option-implied market consensus, which is how I arrive at my calculation of expected market growth.

Once the option-implied growth rate of the S&P 500 has been estimated as described above, I add the dividend yield and subtract the risk-free rate to arrive at the market risk premium, as laid out in Exhibit ALR-4, page 4 and Exhibit ALR-4, page 6. In line with my Spot and Weighted Average CAPM approaches, I use both spot values as of February 28, 2022 and weighted averages over the 3 months ending on that date for option-implied growth, dividend yields, and short- and long-term risk-free rates in these calculations to arrive at a total of 4 estimated values for the market risk premium. The market risk premium I use in my Weighted Average CAPM analysis with short- and long-term risk-free rates is 10.15% and 8.31%, respectively. The market risk premium I use in

[69] As used in the calculation of their widely-used VIX (or Volatility Index) and SKEW Index, respectively.

my Spot CAPM analysis with short- and long-term risk-free rates is 10.43% and 8.61%, respectively.

Q. DID YOU TAKE INTO CONSIDERATION THE DIFFERENCE IN VOLATILITIES ACROSS EXPIRATION PERIODS IN THE OPTIONS TRADED ON THE S&P 500?

A. Yes. The volatility implied by the options market changes over time as investors' perception of risk changes. For example, during a crisis, implied volatility generally increases as investors expect that stock market prices have a greater chance of large swings compared to times when there is no crisis. As discussed earlier, investors also often have different volatility expectations over different time periods. For example, on any given day, investors might expect volatility to be relatively high over the next 30 days and to decrease over the next year or longer. The same holds true for skewness, even though it is less intuitive to understand changes in skewness than in volatility. Because of these changes across option expiration periods, I take a weighted average of the entire term structure of the option-implied volatility and skewness, which for the S&P 500 typically goes out to 24 to 36 months, interpolating where necessary, and giving the most weight to the option expiration period of 12 months.

Q. WHICH CUMULATIVE PROBABILITY DID YOU USE TO ESTIMATE THE OPTION-IMPLIED GROWTH OF THE S&P 500 IN THE CALCULATION OF YOUR MARKET RISK PREMIUM AND WHY?

A. I used a cumulative probability of 50.0% in the calculation of my option-implied growth for the S&P 500, which results in a value of 9.45% as of February 28, 2022 and a value of 9.08% for the weighted average of the 3 months ending on that date. As stated above, a cumulative probability of 50% represents the median of the probability distribution, or in this case the option-implied market consensus, which is why I have chosen to use this level.

As a matter of fact, using the same probability distribution derived from the options market described above, one can also calculate the cumulative probability implied by a given cost of capital. For instance, using the same risk-free rates and betas in my CAPM analysis, KgPCo's requested rate of return on equity of 10.20% implies an average market risk premium of 15.1%, an average overall market return of 16.2%, average growth for the S&P 500 of 14.9%, and a cumulative probability of 64.4%. In other words, to achieve the required market growth of 14.9%, reality would have to exceed 64.4% of the scenarios investors currently see as plausible for the market in aggregate, considerably more than the median market consensus at 50%. To put this into perspective, it is important to note that values on the tails of the probability function get increasingly separated, requiring an ever-increasing growth rate for every additional percentage in the cumulative probability, and making it impossible to ever arrive at 100%.

Using exactly the same methodology, my 7.35% recommended cost of equity for KgPCo implies an average market risk premium of 10.3%, an average overall market return of 11.5%, average growth for the S&P 500 of 10.2%, and a cumulative probability of 52.5%.

Q. ARE THE CUMULATIVE PROBABILITIES YOU REFER TO IN THIS CASE DIRECTLY COMPARABLE TO THE CUMULATIVE PROBABILITIES YOU HAVE USED OR REFERRED TO IN PRIOR TESTIMONIES YOU HAVE FILED?

A. In late 2020, after significant efforts related to the complexities in processing extremely large volumes of option data, I was finally able to use option-implied volatility and option-implied skewness to come up with a log-normal function that approximates the probability distribution of the possible trajectories for the S&P 500 implied by the options market as of any given day, as explained above. All of the testimonies I have filed since then, starting in 2021, have used this complete and superior approach along with a cumulative probability of 50%, representing the median of the probability distribution, or the option-implied market consensus, to estimate expected market growth. Any references to cumulative probability in these testimonies are directly comparable.

Prior to incorporating skewness into the approximation, I used a normal function to estimate the same probability distribution referred to above. Using a normal distribution as an approximation is a simplification used commonly in economics, including in the Black-Scholes formula for a single option. However, unlike a skewed log-normal function, a normal function has the same median and mean, meaning that when applied in this case, the option-implied market consensus of this simplified approximation implies market growth of 0%. As a result, before using log-normal functions, I had to resort to finding an adequate level of cumulative probability above 50% to estimate market growth, which is admittedly somewhat subjective. To be conservative, I often used a cumulative probability of 68.3%, which is the probability found within one standard deviation of the mean of a normal distribution, which I understood would lead to a conservatively high estimate for market growth. It is important to point out that the cumulative probabilities of the simplified normal function approximation I used in cases before 2021 cannot be directly compared to the cumulative probabilities of the superior log-normal function approximation, which takes skewness into account. The considerably improved approximation based on a log-normal function eliminates all subjectivity in arriving at the implied market consensus and allows a much better measure of implied cumulative probabilities of deviations from that market consensus.

CAPM Results

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR CAPM.

A. Table 7 and Table 8 below show the results of my Weighted Average CAPM and Spot CAPM Analyses, respectively.

Weighted Average CAPM

TABLE 7: CAPITAL ASSET PRICING MODEL (CAPM) - INDICATED COST OF EQUITY
WEIGHTED - All Inputs Weighted From December 2021 to February 2022

	3-Month Treasury Bill		30-Year Treasury Bond	
	Hybrid Beta	Forward Beta	Hybrid Beta	Forward Beta
Risk-Free Rate	0.23%	0.23%	2.08%	2.08%
Beta	0.67	0.57	0.67	0.57
Risk Premium	10.15%	10.15%	8.31%	8.31%
CAPM	7.05%	6.00%	7.66%	6.80%

Source: Exhibit ALR-4, page 1

Spot CAPM

TABLE 8: CAPITAL ASSET PRICING MODEL (CAPM) - INDICATED COST OF EQUITY (SPOT)
SPOT - All Inputs Based on Last Available Data as of February 28, 2022

	3-Month Treasury Bill		30-Year Treasury Bond	
	Hybrid Beta	Forward Beta	Hybrid Beta	Forward Beta
Risk-Free Rate	0.35%	0.35%	2.17%	2.17%
Beta	0.65	0.52	0.65	0.52
Risk Premium	10.43%	10.43%	8.61%	8.61%
CAPM	7.09%	5.80%	7.74%	6.67%

Source: Exhibit ALR-4, page 5

VI. EVALUATION OF KGPCO'S RATE OF RETURN TESTIMONY

Q. PLEASE SUMMARIZE THE TESTIMONY OF MR. CASTLE.

A. Mr. Castle has recommended that the Company be allowed a return on equity of 10.20%. [70]Witness Messer recommends a cost of debt of 3.14% and an overall cost of capital of 6.36%.[71] Mr. Castle arrived at his recommendation based upon his own versions of the Discounted Cash Flow ("DCF") model, Capital Asset Pricing Model ("CAPM") and what he calls a peer group analysis of actual returns. Mr. Castle testified that, "The cost of equity should reflect the return investors require based on the risks of the subject company and the returns available for comparable investments."[72] Mr. Castle explains that KgPCo's cost of equity is not directly observable and therefore in order to estimate its cost of equity it is necessary to develop a proxy group of companies with that investors would consider comparable in risk to KgPCo.[73] The results of Mr. Castle's three cost of equity methods applied to his "Peer Group" of 24 electric utility companies are shown on Table 9 below.

TABLE 9: MR. CASTLE'S COST OF EQUITY RESULTS

METHOD	Weighted Average	Median	Average
DCF [1]	9.7%	9.1%	9.4%
CAPM Average [1]	10.9%	11.0%	11.0%
Peer Group Earned ROE [2]	N/A	9.7%	9.70%

[1] Mr. Castle's Direct Testimony, KgPCo Exhibit No. 10

[2] Mr. Castle's Direct Testimony, KgPCo Exhbit No. 11

[70] Direct Testimony of William K. Castle at 9:17 and 14:3.

[71] *Id.* at 9:17-19.

[72] *Id.* at 14:7-8.

[73] *Id.* at 15:15-21.

Q. DO THE RESULTS OF MR. CASTLE'S COST OF EQUITY MODELS PROVIDE A RELIABLE INDICATION OF KGPCO'S COST OF EQUITY?

A. No. Each of his cost of equity models has specific issues that contribute to his unreasonably high results. First, I will address how his constant growth DCF method is unreliable because it mechanically uses analyst 5-year EPS growth rates as a proxy for growth without considering the mathematical relationship between retention rates, dividend payments, and growth. A company cannot invest and grow with money it has paid out to investors as a dividend. Second, I will explain how his CAPM model overstates the cost of equity primarily because it is based on historical data that is no longer relevant to KgPCo's current cost of equity. Finally, I will discuss why the results of his peer group analysis of actual returns should be disregarded because it is not a market-based method.

A. DCF Method

Q. WHAT FORMULA DOES MR. CASTLE USE IN HIS DCF ANALYSIS?

A. Cost of equity (Ke) = Dividend Yield (D1/P0) + Growth Rate (g).

and where:

P0 = the current price of the stock
D1 = the expected dividend in the subsequent period
Ke = cost of equity
g = long-term growth expectation[74]

[74] *Id.* at 21:4-9.

Q. DOES MR. CASTLE PROPERLY APPLY THE SIMPLIFIED OR CONSTANT DCF METHOD?

A. No. Mr. Castle's DCF model overstates KgPCo's cost of equity because the growth rate component analysis is not based on sustainable growth rates. The correct application of the DCF method requires that the dividend yield be computed properly, and that the growth rate used be derived from a careful study of the future *sustainable* growth in cash flow anticipated by investors. As discussed in Section II above, major financial institutions like J.P. Morgan Chase do not use a growth rate based on analyst 5-year EPS growth rates, as Mr. Castle has done.

Q. HOW DID MR. CASTLE CALCULATE HIS GROWTH RATE FOR HIS DCF METHOD?

A. Mr. Castle explains that his "projected growth rate approach" is based on examining 5-year projected EPS growth rates published by Value Line, Yahoo, and Zack's for the companies in his Peer Group.[75] Regarding these 5-year projected EPS growth rates, Mr. Castle states, "Value Line uses a smoothing technique to minimize the impacts of potential anomalies in earnings…but the compiled analyst estimates do not, which can potentially lead to high or low growth estimates for an individual stock which is not necessarily indicative of the industry as a whole."[76] Below are the weighted average of the five-year projected earnings per share rates by the three investment research firms he chose:

Value Line: 7.60%

Zacks: 5.9%

[75] *Id.* at 21:17 – 22:1.
[76] *Id.* at 22:1-5.

Yahoo: 6.0%[77]

As discussed below, Mr. Castle's constant growth DCF results of between 9.0% and 10.8%[78] is above investors' returns expectations because he does not account for the difference between the growth rate forecasts of earnings per share and book value per share.

Q. IS MR. CASTLE'S METHODOLOGY TO DETERMINE THE GROWTH RATE FOR USE IN HIS DCF MODEL APPROPRIATE?

A. No. Mr. Castle mentions the "b x r" method on pages 17-18 of his direct testimony but he does not use it. As stated above, Mr. Castle uses analyst five-year earnings per share growth without attempting to reconcile the retention rate used for computing growth with the retention rate he used to compute the dividend yield. This is analogous to failing to reconcile the money you are taking out of your checking account with your future balance, i.e., the basic balancing of a checkbook.

Q. CAN YOU PLEASE SUMMARIZE WHY A FUTURE ORIENTED "B X R" METHOD IS SUPERIOR TO A FIVE-YEAR EARNINGS PER SHARE GROWTH RATE FORECAST IN PROVIDING A LONG-TERM SUSTAINABLE GROWTH RATE?

A. Yes. The primary cause of sustainable earnings growth is the retention of earnings. A company can create higher future earnings by retaining a portion of the prior year's earnings in the business and purchasing new business assets with those retained earnings. There are many factors that can cause short-term swings in earnings growth rates, but the long-term sustainable growth is caused by retaining earnings and reinvesting those

[77] *Id.* at KgPCo Exhibit No. 7, p. 1 of 1.
[78] *Id.* at KgPCo Exhibit No. 9, p. 1 of 1.

earnings. Factors that cause short-term swings include anything that causes a company to earn a return on book equity at a rate different from the long-term sustainable rate. Assume, for example, that a particular utility company is regulated so that it is provided with a reasonable opportunity to earn 9.0% on its equity. If the company should experience an event such as the loss of several key customers, or unfavorable weather conditions which cause it to earn only 6.0% on equity in a given year, the drop of 9% earned return on equity to a 6% earned return on equity would be concurrent with a very large drop in earnings per share. In fact, if a company did not issue any new shares of stock during the year, a drop from a 9% earned return on book equity to a 6% earned return on book equity would result in a 33.3% decline in earnings per share over the period.[79] However, such a drop in earnings would not be any indication of what is a long-term sustainable earnings per share growth rate. If the drop were caused by weather conditions, the drop in earnings would be immediately offset once normal weather conditions return. If the drop were from the loss of some key customers, the company would replace the lost earnings by filing for a rate increase to bring revenues up to the level required for the company to be given a reasonable opportunity to recover its cost of equity.

For the above reasons, changes in earnings per share growth rates that are caused by non-recurring changes in the earned return on book equity are inconsistent with long term sustainable growth, but changes in earnings per share because of the reinvestment of additional assets is a cause of sustainable earnings growth. The “b x r” term in the DCF equation computes sustainable growth because it measures only the growth which a

[79] By definition, earned return on equity is earnings divided by book value. Therefore, whatever level of earnings is required to produce earnings of 6% of book would have to be 33.3% lower than the level of earnings required to produce a return on book equity of 9%.

company can expect to achieve when its earned return on book equity "r" remains in equilibrium. If analysts have sufficient data to be able to forecast varying values of "r" in future years, then a complex, or multi-stage DCF method must be used to accurately quantify the effect. Averaging growth rates over sub-periods, such as averaging growth over the first five years with a growth rate expected over the subsequent period, will not provide an appropriate representation of the cash flows expected by investors in the future and, therefore, will not provide an acceptable method of quantifying the cost of equity using the DCF method. The choices are either a constant growth DCF, in which one "b x r" derived growth rate should be used, or a complex DCF method in which the cash flow anticipated in each future year is separately estimated. Mr. Castle has done neither.

Q. WHY ARE ANALYSTS FIVE-YEAR CONSENSUS GROWTH RATES NOT INDICATIVE OF LONG-TERM SUSTAINABLE GROWTH RATES?

A. Analysts' five-year earnings per share growth rates are earnings per share growth rates that measure earnings growth from the most currently completed fiscal year to projected earnings five years into the future. These growth rates are not indicative of future sustainable growth rates in part because the sources of cash flow to an investor are dividends and stock price appreciation. While both stock price and dividends are impacted in the long-run by the level of earnings a company is capable of achieving, earnings growth over a period as short as five years is rarely in synchronization with the cash flow growth from increases in dividends and stock prices. For example, if a company experiences a year in which investors perceive that earnings temporarily dipped below normal trend levels, stock prices generally do not decline at the same percentage that earnings decline, and dividends are usually not cut just because of a temporary decline in a company's earnings. Unless both the stock price and dividends mirror every down swing in earnings, they cannot be expected to recover at the same growth rate that earnings recover. Therefore, growth rates such as five-year projected growth in earnings per share are not indicative of long-term sustainable growth rates in cash flow. As a result, they are inapplicable for direct use in the simplified DCF method.

Q. IS THE USE OF FIVE-YEAR EARNINGS PER SHARE GROWTH RATES IN THE DCF MODEL ALSO IMPROPER?

A. A raw, unadjusted, five-year earnings per share growth rate is usually a poor proxy for either short-term or long-term cash flow that an investor expects to receive. When implementing the DCF method, the time value of money is considered by equating the current stock price of a company to present value of the future cash flows that an investor expects to receive over the entire time that he or she owns the stock. The discount rate required to make the future cash flow stream, on a net present value basis, equal to the current stock price is the cost of equity. The only two sources of cash flow to an investor are dividends and the net proceeds from the sale of stock at whatever time in the future the investor finally sells. Therefore, the DCF method is discounting future cash follows that investors expect to receive from dividends and from the eventual sale of the stock. Five-year earnings growth rate forecasts are especially poor indicators of cash flow growth even over the five years being measured by the five-year earnings per share growth rate number.

Q. WHY IS A FIVE-YEAR EARNINGS PER SHARE GROWTH RATE A POOR INDICATOR OF THE FIVE-YEAR CASH FLOW EXPECTATIONS FROM DIVIDENDS?

A. The board of directors changes dividend rates based upon long-term earnings expectations combined with the capital needs of a company. Most companies do not cut the dividend simply because a company has a year in which earnings were below sustainable trends, and similarly they do not increase dividends simply because earnings for one year happened to be above long-term sustainable trends. Therefore, over any given five-year period, earnings growth is frequently very different from dividend growth. In order for earnings growth to equal dividend growth, at a minimum, earnings per share in the first year of the five-year earnings growth rate period would have to be exactly on the long-term earnings trend line expected by investors. Since earnings in most years are above or below the trend line, the earnings per share growth rate over most five-year periods is different from what is expected for earnings growth.

Q. WHY IS THE FIVE-YEAR EARNINGS PER SHARE GROWTH RATE A POOR INDICATION OF FUTURE STOCK PRICE GROWTH?

A. If a company happens to experience a year in which earnings decline below what investors believe are consistent with the long-term trend, then the stock price does not drop anywhere near as much as earnings drop. Similarly, if a company happens to experience a year in which earnings are higher than the investor-perceived long-term sustainable trend, then the stock price will not increase as much as earnings. In other words, the P/E (price/earnings) ratio of a company will increase after a year in which investors believe earnings are below sustainable levels, and the P/E ratio will decline in a year in which investors believe earnings are higher than expected. Since it is stock price that is one of the important cash flow sources to an investor, a five-year earnings growth rate is a poor indicator of cash flow both because it is a poor indicator of stock price growth over the five years being examined and is equally a poor predictor of dividend growth over the period.

Q. ARE YOU SAYING THAT ANALYSTS' CONSENSUS EARNINGS PER SHARE GROWTH RATES ARE USELESS AS AN AID TO PROJECTING THE FUTURE?

A. No. Analysts' EPS growth rates are, however, very dangerous if used in a simplified DCF without proper interpretation. While they are not useful if used mechanically as Mr. Castle does, they can be useful in computing estimates of what earned return on equity investors expect will be sustained in the future, and as such, are useful in developing long-term sustainable growth rates, as I have done.

B. <u>CAPM Method.</u>

Q. PLEASE SUMMARIZE MR. CASTLE'S CAPM METHOD.

A. Mr. Castle explains that "The CAPM is a construct that seeks to determine an 'expected return' of an asset on the basis of risk relative to the market."[80] Risker assets should expect higher returns.[81] He states that "β (beta) is the measure of an asset's risk relative to the market."[82] He states that the CAPM consists of three components: the risk-free rate, the market risk premium, and 'beta'…"[83]

[80] Direct Testimony of William K. Castle at 17:14-15.
[81] *Id.* at 17:15-16.
[82] *Id.* at 18:1.
[83] *Id.* at 17:16-17.

Q. WHAT RISK-FREE RATE DOES MR. CASTLE USE IN HIS CAPM

A. Mr. Castle states that risk-free rate is almost always a U.S. Treasury bill or bond, but the appropriate tenor is debatable - ranging from three-month T-Bill rate, 30-year U.S. Treasury Bond.[84] He states it is appropriate to use projected treasury rates because "the ROE is being set for prospective periods".[85] He uses the following four risk free rates in his CAPM analysis:

30-day T-Bill Yield: 0.04%

Projected 30-day T-Bill Yield: .013%

Current 30-Year T-Bond Yield: 1.93%

Projected 30-Year T-Bond Yield: 2.37%[86]

Q. DOES MR. CASTLE USE AN APPROPRIATE RISK-FREE RATE IN CAPM?

A. Yes. Mr. Castle appropriately uses the current yield on U.S. T-Bills and U.S. Treasury bonds for two of his four risk-free rates in his CAPM analysis. In principles I do not agree with Mr. Castle that is appropriate to use treasury rates projected by economists because, as explained above, the yields on 30-year U.S. Treasury bonds reflect investors' expectations. In this case, I would agree the risk free rates Mr. Castle uses in his CAPM are reasonable values.

Q. WHAT BETA COEFFICIENT DOES MR. CASTLE USE IN CAPM?

A. Mr. Castle uses the weighted average (0.89) and median (0.90) of the company-specific 5-year historical betas published by Value Line.[87]

---

[84] *Id.* at 18:12-15.
[85] *Id.* at 18:19-20.
[86] *Id.* at KgPCo Exhibit No. 6, pp. 1-5.
[87] *Id.* at 19:1-11.

Q. DO MR. CASTLE'S BETA COEFFICIENTS OVERSTATE THE COST OF EQUITY?

A. Yes. The historical beta coefficients used by Mr. Castle are higher than a broader measure of recent historical and forward-looking beta coefficients indicate and therefore overstate the cost of equity. Mr. Castle's CAPM results likely overstate the cost of equity because he uses 5-year historical betas (peer group weighted-average of 0.89 and a median of 0.90[88]) instead of betas based on current investor expectations. Option-implied betas for my RFC Electric Proxy Group have averaged 0.568 over the past three months and has a value of 0.52 as of the end of February 2022, indicating that investors expect electric utility stock price movements to be less risky than indicated by Mr. Castle's betas and therefore his CAPM overstates the cost of equity.

Another flaw with Mr. Castle's CAPM analyses is that he uses a different market index for his beta calculations than he uses for his market risk premium. He uses 5-year historical betas published by Value Line which are based on the 2,800 companies on the NYSE Composite Index, but, as discussed below, his market risk premium is based on only 825 stocks. As discussed above, the most important aspect of selecting a market index for a CAPM analysis, is to be consistent and use the same index for the calculation of beta as for the calculation of the market risk premium. Using exactly the same beta calculation methodology with a different market index will result in different values of beta for a given company or portfolio -- sometimes significantly different values (10 basis points or more).

[88] *Id.* at 19:10-11.

Q. WHAT RISK PREMIUM DOES MR. CASTLE USE IN CAPM?

A. Mr. Castle explains that the market risk premium is the excess return of the market over the risk-free rate.[89] In other words, the market risk premium is the difference between the expected market return and the risk-free rate. He calculates the expected market return (11.3% to 12.9%) by applying a DCF model to the 825 dividend-paying stocks covered by Value Line that have 3-5 year earnings growth rates under 20%. His analysis produces 8 different risk premium results ranging from 8.94% to 12.78%.[90]

Q. DO YOU AGREE WITH THE RESULTS OF MR. CASTLE'S CAPM ANALYSIS?

A. No, I do not agree with the results (10.1% to 11.85% with an average of 10.97%) of Mr. Castle's CAPM analysis primarily because they are not based on investors' expectations regarding electric utility beta coefficients. He uses historical betas that are still being impacted by the transitory events of March-April 2020 during the onset of the pandemic. I believe it significantly and inaccurately overstates the Company's cost of equity.

C. <u>Peer Group Analysis</u>

Q. PLEASE EXPLAIN THE PEER GROUP ANALYSIS PRESENTED BY MR. CASTLE.

A. Mr. Castle's peer group analysis consists of determining the average return on book equity of the 24 electric utility companies in his peer group for the trailing twelve months ending October 4, 2021. The companies in his peer group earned a return on book equity of between 5.5% and 14.7%, averaging 9.7%.

---

[89] *Id.* at 19:14.
[90] *Id.* at 20:1-3.

Q. IS THIS METHOD VALID?

A. No. Mr. Castle has attempted to determine the cost of equity that would be demanded by investors on the market price of a company comparable to KgPCo by comparing it to accounting returns. Mr. Castle's peer group analysis did not address the cost of equity at all. It simply considered the returns on book equity that were achieved according to Yahoo Finance. The earned return on book equity is an entirely different concept from the cost of equity.

For this reason, a method based on return on book equity has recently been discredited and eliminated from consideration in Federal Energy Regulatory Commission (FERC) ROE proceedings. FERC determined it is not appropriate to use the Expected Earnings model because "the record does not support departing from our traditional use of market-based approaches to determine base ROE."[91] FERC goes on to say:

> In Hope, the Supreme Court explained that 'the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.' In order to determine this, we must analyze the returns that are earned on 'investments in other enterprises having corresponding risks,' but investors cannot invest in an enterprise at book value and must instead pay the prevailing market price for an enterprise's equity. As a result, the expected return on a utility's book value does not reflect 'returns on investments in other enterprises' because book value does not reflect the value of any investment that is available to an investor in the market, outside of the unlikely situation in which market value and book value are exactly equal. Accordingly, we find that relying on the Expected Earnings model would not satisfy the requirements of Hope.[92]

[91] *Order on Briefs, Rehearing, and Initial Decision*, FERC Opinion No. 569. Par 201 (November 21, 2019).
[92] *Id.*

As explained clearly by FERC, models based on return on book equity should be excluded from consideration in this proceeding because it violates regulatory principles that require the cost of equity to be market-based.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF MR. CASTLE'S TESTIMONY.

A. Mr. Castle's 10.20% ROE recommendation is significantly higher than KgPCo's market-based cost of equity. If his recommendations are used to set rates, consumers will be significantly overcharged. Mr. Castle's 10.20% ROE recommendation overstates the cost of equity because (1) his COE calculations are based on out of date beta coefficients in his CAPM analysis that are still being impacted by the capital market turmoil during the onset of the COVID pandemic in March-April 2020, (2) his DCF is based on an unsustainably high growth rate, and (3) Mr. Castle's Peer group analysis is not really an equity costing method at all, as no consideration was given to investor's reactions to the earned returns on book equity.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.

A. Based on the evidence presented in my testimony, I conclude that the cost of equity allowed for the Company should be between 5.81% to 7.86% (recommended at 7.35%). Based on my recommended common equity ratio of 48.90%, that results in an overall cost of capital of between 4.21% and 5.22% (recommended at 4.97%).

My recommendations satisfy the requirements of *Hope* and *Bluefield* that regulated utility companies should have the opportunity to earn a return commensurate with returns on investments in other enterprises having corresponding risks. My recommendations are consistent with legal standards set by the United States Supreme Court and market data and will allow KgPCo to raise capital on reasonable terms while fulfilling its obligation to provide safe and reliable service.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APPENDIX A: RESUME OF AARON L. ROTHSCHILD

SUMMARY

Financial professional providing U.S. public utility commissions financial tools and expert testimony to assist in rate setting for regulated utility companies (e.g., regulated electric distribution providers, natural gas pipelines). Relevant experience includes developing and applying methodologies that directly measure investors' equity return expectations based on stock option prices, applied mathematics research for utility industry as an affiliate of the New England Complex Systems Institute, and serving as Head of Business Analysis for a major U.S. telecom firm in Asia Pacific.

EXPERIENCE

Rothschild Financial Consulting, Ridgefield, CT November 2001- present
Independent consulting firm specializing in utility sector
President

- Provide financial expert testimony (e.g., rate of return and M&A) to regulators, policy makers, foundations, and consumer groups in utility rate case proceedings, including representing the California Public Advocates Office and the Wild Tree Foundation in the ongoing California water and energy cost of capital proceedings
- Developed cost of equity models that have been adopted by the Public Service Commission of South Carolina in 2020 (decision upheld by the South Carolina Supreme Court in September 2021) and the Connecticut Public Regulatory Authority in September 2021
- Developing market-based cost of equity methodology in ongoing regulated natural gas pipeline case before the Federal Energy Regulatory Commission (FERC), including proposing replacing equity analyst earnings per-share forecasts (IBES, Value Line) with options-implied growth expectations to determine authorized return on equity (ROE)
- Present at utility regulation conferences (NARUC/NASUCA and MARC) regarding rate of return, power purchase agreements, complex systems science, and subsidy auctions

360 Networks, Hong Kong January 2001 - October 2001
Pioneer of the fiber optic telecommunications industry
Senior Manager

- Business development and investment evaluation
- Negotiated landing rights and formed local partnerships in Korea, Japan, Singapore, and Hong Kong for $1 billion undersea cable project
- Structured fiber optic bandwidth swapping agreement with Enron and Global Crossing
- Established relationships with Hong Kong based Investment Bankers to communicate Asia Pacific objectives and accomplishments to Wall Street

Dantis, Chicago, IL July 2000- December 2000
Start-up managed data-hosting services provider
Director

- Built capital raise valuation models and negotiated with potential investors
- Team raised $100M from venture capital firm through valuation negotiations and internal strategic analysis

MFS, MCI-WorldCom, Chicago, Hong Kong, Tokyo September 1996- July 2000
American Telecommunications Company
Head of Business Analysis for Japan operations

- Managed staff of 5 business development analysts
- Raised $80M internally for Japanese national fiber network expansion plan by conducting an investment evaluation and presenting findings to CEO of international operations in London, UK
- Built financial model for local fiber optic investment evaluation that was used by business development offices in Oak Brook, IL and Sydney, Australia

EDUCATION

Vanderbilt University, Nashville, TN 1994-1996
MBA, Finance

- Completed business plan for Nextlink Communications in support of their national fiber optic network expansion, including identifying opportunities from passage of Telecom Act of 1996
- Developed analytical framework to evaluate predictability of rare events
- Provided financial and accounting analysis to Chicago's consumer advocate, the Citizens Utility Board (CUB) as a summer intern

Clark University, Worchester, MA 1990 - 1994
BA, Mathematics

APPENDIX B: TESTIFYING EXPERIENCE OF AARON L. ROTHSCHILD

Filed Rate of Return Testimonies:

California

- California American Water Company, Application 21-05-001, Rate of Return, January 2022
- California Water Service Company, Application 21-05-002, Rate of Return, January 2022
- Golden State Water Company, Application 21-05-003, Rate of Return, January 2022
- San Jose Water Company, Application 21-05-004, Rate of Return, January 2022
- Southern California Edison, Application 21-08-013, Rate of Return/Cost of Capital Mechanism, January 2022
- San Diego Gas & Electric Company, Application 21-08-014, Rate of Return/Cost of Capital Mechanism, January 2022
- Pacific Gas and Electric Company, Application 21-08-015, Rate of Return/Cost of Capital Mechanism, January 2022
- Pacific Gas and Electric Company, Application 21-01-004, Securitization, February 2021
- Pacific Gas and Electric Company, Application 20-04-023, Securitization, October 2020
- Southern California Edison, Application 20-07-008, Securitization, September 2020
- San Diego Gas & Electric Company, Application 19-04-017, Rate of Return, August 2019
- Southern California Gas Company, Application 19-04-016, Rate of Return, August 2019
- Pacific Gas and Electric Company, Application 19-04-015, Rate of Return, August 2019
- Southern California Edison, Application 19-04-014, Rate of Return, August 2019
- Liberty Utilities, Application A.18-05-006, Rate of Return, August 2018
- San Gabriel Water Company, Application 18-05-005, Rate of Return, August 2018
- Suburban Water Company, Application 18-05-004, Rate of Return, August 2018
- Great Oaks Water Company, Application 18-05-001, Rate of Return, August 2018
- California Water Service Company, Application 17-04-006, Rate of Return, August 2017
- California American Water Company, Application 17-04-003, Rate of Return, August 2017
- Golden State Water Company, Application 17-04-002, Rate of Return, August 2017
- San Jose Water Company, Application 17-04-001, Rate of Return, August 2017

Colorado

- Public Service Company of Colorado, Docket No. 11AL-947E, Rate of Return, March 2012

Connecticut

- Eversource and United Illuminating, Docket No. 17-12-03RE11, Rate of Return / Interim Rate Reduction, April 2021
- United Water Connecticut, Docket No. 07-05-44, Rate of Return, November 2008
- Valley Water Systems, Docket No. 06-10-07, Rate of Return, May 2007

Delaware

- Tidewater Utilities, Inc., PSC Docket No. 11-397, Rate of Return, April 2012

Florida
- Florida Power & Light (FPL), Docket No. 070001-EI, October 2007
- Florida Power Corp., Docket No. 060001 Fuel Clause, September 2007

New Jersey
- Aqua New Jersey, Inc., BPU Docket No. WR11120859, Rate of Return, April 2012

Maryland
- Delmarva Power & Light, Case No. 9317, Rate of Return, June 2013
- Columbia Gas of Maryland, Case No. 9316, Rate of Return, May 2013
- Potomac Electric Power Company, Case No. 9286, Rate of Return, March 2012
- Delmarva Power & Light, Case No. 9285, Rate of Return, March 2012

North Dakota
- Montana-Dakota Utilities Co., Case No. PU-20-379, Rate of Return, January 2021
- Otter Tail Power Company, Case No. PU-17-398, Rate of Return, May 2018
- Montana-Dakota Utilities Co., Case No. PU-15-90, Rate of Return, August 2015
- Northern States Power, Case No. PU-400-04-578, Rate of Return, March 2005

Pennsylvania
- UGI Utilities, Inc. – Electric Division, Docket No. R-2021-3023618, Rate of Return, May 2021
- Pennsylvania American Water Company, Docket No. P-2021-3022426, Rate of Return, February 2021
- Audubon Water Company, Docket No. R-2020-3020919, Rate of Return, November 2020
- Pennsylvania American Water Company, Docket No. R-2020-3019369 and R-2020-3019371, Rate of Return, September 2020
- Twin Lakes Utilities, Inc., Docket No. R-2019-3010958, Rate of Return, October 2019
- City of Lancaster Sewer Fund, Docket No. R-2019-3010955, Rate of Return, October 2019
- Community Utilities of Pennsylvania Inc. Wastewater Division, Docket No. R-2019-3008948, Rate of Return, July 2019
- Community Utilities of Pennsylvania Inc. Water Division, Docket No. R-2019-3008947, Rate of Return, July 2019
- Newtown Artesian Water Company, Docket No. R-20019-3006904, Rate of Return, May 2019
- Hidden Valley Utility Services, L.P. – Wastewater Division, Docket No. R-2018-3001307, Rate of Return, September 2018
- Hidden Valley Utility Services, L.P. – Water Division, Docket No. R-2018-3001306, Rate of Return, September 2018
- The York Water Company, Docket No. R-2018-3000019, Rate of Return, August 2018
- SUEZ PA Pennsylvania, Inc., Docket No. R-2018-000834, Rate of Return, July 2018
- UGI Utilities, Inc. – Electric Division, Docket No. R-2017-2640058, Rate of Return, April 2018
- Wellsboro Electric Company, Docket No. R-2016-2531551, Rate of Return, December 2016
- Citizens' Electric Company of Lewisburg, PA, Docket No. R-2016-2531550, Rate of Return, December 2016
- Columbia Gas of Pennsylvania, Inc., Docket No. R-2016-2529660, Rate of Return, June 2016
- Columbia Gas of Pennsylvania, Inc., Docket No. R-2015-2468056, Rate of Return, June 2015
- Pike County Light & Power Company, Docket No. R-2013-2397353 (gas), Rate of Return, April 2014

- Pike County Light & Power Company, Docket No. R-2013-2397237 (electric), Rate of Return, April 2014
- Columbia Water Company, Docket No. R-2013-2360798, Rate of Return, August 2013
- Peoples TWP LLC, Docket No. R-2013-2355886, Rate of Return, July 2013
- City of Dubois – Bureau of Water, Docket No. R-2013-2350509, Rate of Return, July 2013
- City of Lancaster – Sewer Fund, Docket No. R-2012-2310366, Rate of Return, December 2012
- Wellsboro Electric Company, Docket No. R-2010-2172665, Rate of Return, September 2010
- Citizens' Electric Company of Lewisburg, PA, Docket No. R-2010-2172662, Rate of Return, September 2010
- T.W. Phillips Gas and Oil Company, Docket No. R-2010-2167797, Rate of Return, August 2010
- York Water Company, Docket No. R-2010-2157140, Rate of Return, August 2010
- Joint Application of The Peoples Natural Gas Company, Dominion Resources, Inc. and Peoples Hope Gas Company LLC, Docket No. A-2008-2063737, Financial Analysis, December 2008
- York Water Company, Docket No. R-2008-2023067, Rate of Return, August 2008

South Carolina

- Kiawah Island Utility, Inc., Docket No. 2021-324-WS, Rate of Return, February 2022
- Palmetto Wastewater Reclamation, Inc., Docket No. 2021-153-S, Rate of Return, September 2021
- Dominion Energy South Carolina, Inc., Docket No. 2020-125-E, Rate of Return, November 2020
- Palmetto Utilities, Inc., Docket No. 2019-281-S, Rate of Return, May 2020
- Palmetto Utilities, Inc., Docket No. 2019-281-S, Accounting, May 2020
- Blue Granite Water Company, Docket No. 2019-290-WS, Rate of Return, January 2020

Vermont

- Central Vermont Public Service Corp., Docket No. 7321, Rate of Return, September 2007

Wisconsin

- American Transmission Company, LLC, ITC, Midwest, LLC, Case No. 19-CV-3418, financial and regulatory analysis regarding requested temporary injunction to halt the construction in Wisconsin of the proposed Cardinal-Hickory Creek transmission line, October 2021

IN THE TENNESSEE PUBLIC UTILITY COMMISSION
AT NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF KINGSPORT POWER COMPANY d/b/a AEP APPALACHIAN POWER GENERAL RATE CASE	)	
	)	**DOCKET NO. 21-00107**
	)	
	)	

AFFIDAVIT

I, Aaron L. Rothschild, on behalf of the Consumer Advocate Unit of the Attorney General's Office, hereby certify that the attached Direct Testimony represents my opinion in the above-referenced case and the opinion of the Consumer Advocate Unit.

Aaron L. Rothschild

AARON L. ROTHSCHILD

Sworn to and subscribed before me this 30th day of March, 2022.

Terra Allen

NOTARY PUBLIC

TERRA ALLEN STATE OF TENNESSEE NOTARY PUBLIC HICKMAN COUNTY

My commission expires: September 28, 2022.

OVERALL COST OF CAPITAL
Kingsport Power Company

	Ratios		Cost Rate		Weighted Cost Rate
					[C]
Long-Term Debt	42.49%	[A]	3.14%	[A]	1.33%
Short-Term Debt	8.61%	[A]	0.45%	[A]	0.04%
Preferred Equity	0.00%	[A]	0.00%	[A]	0.00%
Common Equity	48.90%	[A]	7.35%	[B]	3.59%
	100.00%				**4.97%**

RECOMMENDED RANGES

		Low		High
Proxy Group Cost of Equity Range		5.95%		8.01%
Proxy Group Cost of Equity			6.98%	
Based on RFC Capital Structure Recommendation				
Capital Structure Risk Adjustment	[D]		-0.15%	
Adjusted Recommended Cost of Equity Range		**5.81%**		**7.86%**
Gradual Implementation Adjustment			0.51%	
Company Specific Cost of Equity Recommendation			**7.35%**	
Cost of Capital Range		4.21%		5.22%
Based on Mr. Castle's Capital Structure Recommendation				
Capital Structure Risk Adjustment	[D]		-0.15%	
Adjusted Recommended Cost of Equity Range		**5.81%**		**7.86%**
Company Specific Cost of Equity Recommendation			**6.83%**	
Cost of Capital Range		4.21%		5.22%
Comprehensive Cost of Capital Range				
Cost of Debt Range		3.14%		3.14%
Common Equity Ratio Range		45.22%		48.90%
Comprehensive Cost of Capital Range		4.11%		5.22%

Sources:
[A] Mr. Messner's Direct Testimony, KgPCo Exhibit No. 1
[B] Company Specific Cost of Equity Recommendation based on RFC Capital Structure Recommendation
[C] Ratios times Cost Rate
[D] Based on estimate of 0.04% change in Cost of Equity for each 1% difference in Common Equity Ratio compared to the Proxy Group (Exhibit ALR-1 vs. Exhibit ALR-5, page 4).

COST OF EQUITY SUMMARY

RFC Electric Proxy Group (36 Companies)

		Low		High
DCF				
Constant Growth	[A]	7.89%		7.91%
Non-Constant Growth	[B]	8.21%		8.31%
CAPM				
3-Mo. Weighted Average (Dec. 2021 to Feb. 2022)				
3-Month Treasury Bill Risk-Free Rate	[C]	6.00%		7.05%
30-Year Treasury Bond Risk-Free Rate	[C]	6.80%		7.66%
Spot (Feb. 28, 2022)				
3-Month Treasury Bill Risk-Free Rate	[D]	5.80%		7.09%
30-Year Treasury Bond Risk-Free Rate	[D]	6.67%		7.74%
Average		**6.90%**		**7.63%**
Outer Quartile Range		**5.95%**		**8.01%**
Proxy Group Cost of Equity			**6.98%**	

Sources:
[A] Exhibit ALR-3, page 1
[B] Exhibit ALR-3, page 2 and Exhibit ALR-3, page 3
[C] Exhibit ALR-4, page 1
[D] Exhibit ALR-4, page 5

CONSTANT GROWTH DISCOUNTED CASH FLOW (DCF) - INDICATED COST OF EQUITY
RFC Electric Proxy Group (36 Companies)

		Based on Average Market Price For Year Ending 2/28/2022	Based On Market Price As Of 2/28/2022
1 Dividend Yield On Market Price	[A]	3.52%	3.43%
2 Retention Rate:			
a) Market-to-Book Ratio	[A]	1.98	2.01
b) Dividend Yield on Book	[B]	6.97%	6.91%
c) Expected Return on Equity	[C]	10.00%	10.00%
d) Retention Rate	[D]	30.32%	30.87%
3 Reinvestment Growth	[E]	3.03%	3.09%
4 New Financing Growth	[F]	1.27%	1.31%
5 Total Estimate of Investor Anticipated Growth	[G]	4.30%	4.40%
6 Increment to Dividend Yield for Growth to Next Year	[H]	0.08%	0.08%
7 Indicated Cost of Equity	**[I]**	**7.89%**	**7.91%**

Sources:

[A] Exhibit ALR-5, page 1

[B] Line 1 x Line 2a

[C] Some of the considerations for determining Future Expected Return on Equity:

	Median	Mean	From
Value Line Expectation	**10.00%**	**10.35%**	Exhibit ALR-5, page 2
Return on Equity to Achieve Zacks Growth	9.66%	9.96%	Exhibit ALR-5, page 3
Average Historical Growth	9.99%	9.75%	
Earned Return on Equity in 2021	9.60%	9.51%	Exhibit ALR-5, page 2
Earned Return on Equity in 2020	9.91%	9.47%	Exhibit ALR-5, page 2
Earned Return on Equity in 2019	10.45%	10.26%	Exhibit ALR-5, page 2

[D] 1 - Line 2b / Line 2c

[E] Line 2c x Line 2d

			From
[F] S x V = (Ext. Fin Rate) x (Line 2a - 1)	Ext. Fin. Rate =	1.29%	Exhibit ALR-3, page 4

S = rate of continuous new stock financing

V = fraction of funds raised by sale of stock that increases the book value of existing shareholders' common equity

[G] Line 3 + Line 4

[H] Line 1 x one-half of Line 5

[I] Line 1 + Line 5 + Line 6

NON-CONSTANT GROWTH DISCOUNTED CASH FLOW (DCF) - INDICATED COST OF EQUITY
(BASED ON VALUE LINE FORECASTS AND CLOSING STOCK PRICE)
RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
		Forecasted Dividends per Share					Growth	Book Value		Closing Stock Price		Cash Flow From Buying and Selling Stock (At Closing Price)					
		2022	2023	2023	2024	2025	2022-25	2/28/22	2/28/25	2/28/2022	2/28/2025		2022	2023	2024	2025	IRR / DCF
		[A]	[A]	[B]	[B]	[A]	[B]	[C]	[C]	[D]	[E]	[F]	[F]	[F]	[F]	[F]	[G]
AMEREN	AEE	$2.34	NA	$2.51	$2.70	$2.90	7.41%	$37.94	$45.53	$85.95	$103.14		($83.61)	$2.51	$2.70	$103.14	9.27%
AMERICAN ELEC. PWR.	AEP	$3.17	NA	$3.35	$3.55	$3.75	5.76%	$44.40	$52.06	$90.65	$106.28		($87.48)	$3.35	$3.55	$106.28	9.28%
AVANGRID, INC.	AGR	$1.76	NA	$1.79	$1.82	$1.85	1.74%	$49.98	$51.29	$44.87	$46.05		($43.11)	$1.79	$1.82	$46.05	5.02%
ALLETE	ALE	$2.64	NA	$2.75	$2.87	$3.00	4.35%	$44.90	$50.08	$62.94	$70.20		($60.30)	$2.75	$2.87	$70.20	8.27%
AVISTA CORP.	AVA	$1.76	NA	$1.84	$1.92	$2.00	4.35%	$30.12	$33.06	$44.63	$48.98		($42.87)	$1.84	$1.92	$48.98	7.44%
BLACK HILLS CORP.	BKH	$2.41	NA	$2.53	$2.66	$2.80	5.13%	$43.42	$50.26	$69.99	$81.02		($67.58)	$2.53	$2.66	$81.02	8.75%
CMS ENERGY CORP.	CMS	$1.80	NA	$1.89	$1.99	$2.10	5.27%	$22.23	$26.64	$64.01	$76.73		($62.21)	$1.89	$1.99	$76.73	9.27%
CENTER POINT EN'RGY	CNP	$0.71	NA	$0.77	$0.83	$0.90	8.23%	$12.90	$14.68	$27.35	$31.13		($26.64)	$0.77	$0.83	$31.13	7.29%
DOMINION ENERGY, INC.	D	$2.67	NA	$2.84	$3.02	$3.21	6.33%	$30.86	$36.50	$78.87	$93.27		($76.20)	$2.84	$3.02	$93.27	9.48%
DTE ENERGY CO.	DTE	$3.60	NA	$3.83	$4.08	$4.35	6.51%	$64.68	$71.73	$121.59	$134.85		($117.99)	$3.83	$4.08	$134.85	6.76%
DUKE ENERGY	DUK	$3.98	NA	$4.07	$4.16	$4.25	2.24%	$61.14	$67.33	$100.41	$110.57		($96.43)	$4.07	$4.16	$110.57	7.49%
CON. EDISON	ED	$3.16	NA	$3.24	$3.33	$3.41	2.60%	$56.81	$61.94	$85.77	$93.51		($82.61)	$3.24	$3.33	$93.51	6.85%
EDISON INTERNAT'L	EIX	$2.84	NA	$3.00	$3.17	$3.35	5.66%	$36.73	$41.79	$63.42	$72.16		($60.58)	$3.00	$3.17	$72.16	9.35%
EVERSOURCE ENERGY	ES	$2.56	NA	$2.71	$2.87	$3.04	5.90%	$42.50	$48.40	$81.15	$92.42		($78.59)	$2.71	$2.87	$92.42	7.88%
ENTERGY CORP.	ETR	$4.08	NA	$4.31	$4.55	$4.80	5.57%	$57.04	$64.91	$105.21	$119.72		($101.13)	$4.31	$4.55	$119.72	8.66%
EVERGY, INC.	EVRG	$2.33	NA	$2.49	$2.66	$2.85	6.95%	$40.35	$44.59	$62.41	$68.97		($60.08)	$2.49	$2.66	$68.97	7.54%
EXELON CORP.	EXC	$1.35	NA	$1.44	$1.54	$1.65	6.92%	$32.42	$37.13	$42.56	$48.75		($41.21)	$1.44	$1.54	$48.75	8.13%
FIRST ENERGY	FE	$1.56	NA	$1.66	$1.77	$1.88	6.42%	$15.25	$18.74	$41.85	$51.41		($40.29)	$1.66	$1.77	$51.41	11.22%
FORTIS, INC.	FTS.TO	$2.21	NA	$2.35	$2.49	$2.65	6.24%	$38.36	$42.99	$58.08	$65.10		($55.87)	$2.35	$2.49	$65.10	8.08%
HAWAIIAN ELECTRIC	HE	$1.40	NA	$1.45	$1.50	$1.55	3.45%	$22.26	$24.60	$40.98	$45.28		($39.58)	$1.45	$1.50	$45.28	7.04%
IDACORP, INC.	IDA	$3.05	NA	$3.25	$3.47	$3.70	6.65%	$53.13	$59.33	$103.95	$116.08		($100.90)	$3.25	$3.47	$116.08	6.97%
ALLIANT ENERGY	LNT	$1.71	NA	$1.82	$1.93	$2.05	6.23%	$24.03	$27.44	$58.40	$66.71		($56.69)	$1.82	$1.93	$66.71	7.74%
MGE ENERGY INC.	MGEE	$1.59	NA	$1.67	$1.76	$1.85	5.18%	$28.67	$33.14	$72.02	$83.24		($70.43)	$1.67	$1.76	$83.24	7.32%
NEXTERA ENERGY	NEE	$1.70	NA	$1.87	$2.05	$2.26	9.90%	$19.22	$24.37	$78.27	$99.24		($76.57)	$1.87	$2.05	$99.24	10.68%
NORTHWESTERN	NWE	$2.52	NA	$2.56	$2.61	$2.65	1.69%	$43.25	$46.34	$60.48	$64.80		($57.96)	$2.56	$2.61	$64.80	6.75%
OGE ENERGY CORP.	OGE	$1.66	NA	$1.71	$1.75	$1.80	2.74%	$18.91	$21.58	$37.55	$42.85		($35.89)	$1.71	$1.75	$42.85	9.25%
OTTERTAIL CORP.	OTTR	$1.68	NA	$1.81	$1.95	$2.10	7.72%	$23.90	$27.46	$61.86	$71.10		($60.18)	$1.81	$1.95	$71.10	7.76%
P.S. ENTERPRISE GP.	PEG	$2.16	NA	$2.28	$2.40	$2.53	5.37%	$27.98	$32.87	$64.83	$76.14		($62.67)	$2.28	$2.40	$76.14	9.14%
PNM RESOURCES	PNM	$1.64	NA	$1.66	$1.68	$1.70	1.20%	$25.47	$29.44	$45.17	$52.22		($43.53)	$1.66	$1.68	$52.22	8.76%
PINNACLE WEST	PNW	$3.44	NA	$3.52	$3.61	$3.70	2.46%	$52.02	$55.10	$70.83	$75.02		($67.39)	$3.52	$3.61	$75.02	7.16%
PORTLAND GENERAL	POR	$1.80	NA	$1.89	$1.99	$2.10	5.27%	$30.37	$33.77	$50.77	$56.46		($48.97)	$1.89	$1.99	$56.46	7.47%
PPL CORPORATION	PPL	$1.00	NA	$1.02	$1.04	$1.07	2.17%	$10.79	$12.72	$26.17	$30.86		($25.17)	$1.02	$1.04	$30.86	9.71%
SOUTHERN COMPANY	SO	$2.70	NA	$2.78	$2.86	$2.94	2.88%	$26.89	$30.54	$64.77	$73.55		($62.07)	$2.78	$2.86	$73.55	8.81%
SEMPRA ENERGY	SRE	$4.62	NA	$4.90	$5.19	$5.50	5.98%	$75.90	$89.77	$144.22	$170.58		($139.60)	$4.90	$5.19	$170.58	9.26%
WEC ENERGY GROUP	WEC	$2.89	NA	$3.07	$3.25	$3.45	6.08%	$34.62	$38.97	$90.88	$102.32		($87.99)	$3.07	$3.25	$102.32	7.52%
XCEL ENERGY	XEL	$1.94	NA	$2.05	$2.17	$2.30	5.84%	$28.67	$33.14	$67.33	$77.82		($65.39)	$2.05	$2.17	$77.82	8.08%
Maximum		$4.62	$0.00	$4.90	$5.19	$5.50	9.90%	$75.90	$89.77	$144.22	$170.58	$0.00	($25.17)	$4.90	$5.19	$170.58	11.22%
Minimum		$0.71	$0.00	$0.77	$0.83	$0.90	1.20%	$10.79	$12.72	$26.17	$30.86	$0.00	($139.60)	$0.77	$0.83	$30.86	5.02%
Median		$2.27	#NUM!	$2.42	$2.55	$2.65	5.61%	$33.52	$38.05	$64.39	$74.29	#NUM!	($62.14)	$2.42	$2.55	$74.29	8.08%
Average		$2.35	#DIV/0!	$2.46	$2.59	$2.72	5.12%	$36.34	$41.12	$68.62	$78.29	#DIV/0!	($66.27)	$2.46	$2.59	$78.29	**8.21%**

Sources:

[A] Value Line: Most current data available at time of schedule preparation. 2025 data is VL forecast for 2024-26.

[B] Straight line interpolation based on Value Line data, assuming constant dividend growth for 2022-25.

[C] Straight line interpolation based on Value Line data, assuming constant book value growth for 2022-25.

[D] EOD Data: Market Data as of February 28, 2022.

[E] Stock Price projected assuming constant Market to Book Ratio (Exhibit ALR-5, page 1) and using VL projected Book Value.

[F] Cash Flow from purchasing stock on March 1, 2022, receiving dividends through 2025, and selling on February 28, 2025.
Negative number in 2022 reflects cash outflow required to purchase stock.
Cash flow sources are 1) dividends and 2) proceeds of stock sale.
4 of 4 dividends assumed received in 2022 and 0 of 4 in 2025 based on purchase and sale date.

[G] Total return on equity to investor who purchased, held, and sold stock as described above,
assuming Value Line projections of Dividends and Book Value are correct and
assuming Stock Price grows at same rate as Book Value.
DCF result is an Internal Rate of Return computation made using the "IRR" function built into Microsoft Excel
based on projected cash flows from 2022 to 2025.

NON-CONSTANT GROWTH DISCOUNTED CASH FLOW (DCF) - INDICATED COST OF EQUITY
(BASED ON VALUE LINE FORECASTS AND LTM AVERAGE STOCK PRICE)
RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
		Forecasted Dividends per Share					Growth	LTM Avg. Book Value		LTM Avg. Stock Price		Cash Flow From Buying and Selling Stock (At LTM Average Price)					
		2022	2023	2023	2024	2025	2022-25	2022	2025	2/28/22	2/28/25		2022	2023	2024	2025	IRR / DCF
		[A]	[A]	[B]	[B]	[A]	[B]	[C]	[C]	[D]	[E]	[F]	[F]	[F]	[F]	[F]	[G]
AMEREN	AEE	$2.34	NA	$2.51	$2.70	$2.90	7.41%	$36.80	$44.16	$80.60	$96.72		($78.26)	$2.51	$2.70	$96.72	9.48%
AMERICAN ELEC. PWR.	AEP	$3.17	NA	$3.35	$3.55	$3.75	5.76%	$43.08	$50.51	$83.31	$97.68		($80.14)	$3.35	$3.55	$97.68	9.63%
AVANGRID, INC.	AGR	$1.76	NA	$1.79	$1.82	$1.85	1.74%	$49.66	$50.96	$48.89	$50.17		($47.13)	$1.79	$1.82	$50.17	4.67%
ALLETE	ALE	$2.64	NA	$2.75	$2.87	$3.00	4.35%	$44.52	$49.66	$64.97	$72.46		($62.33)	$2.75	$2.87	$72.46	8.13%
AVISTA CORP.	AVA	$1.76	NA	$1.84	$1.92	$2.00	4.35%	$29.77	$32.67	$43.44	$47.67		($41.68)	$1.84	$1.92	$47.67	7.56%
BLACK HILLS CORP.	BKH	$2.41	NA	$2.53	$2.66	$2.80	5.13%	$42.28	$48.95	$65.65	$76.00		($63.24)	$2.53	$2.66	$76.00	9.01%
CMS ENERGY CORP.	CMS	$1.80	NA	$1.89	$1.99	$2.10	5.27%	$20.87	$25.01	$59.49	$71.31		($57.69)	$1.89	$1.99	$71.31	9.51%
CENTER POINT EN'RGY	CNP	$0.71	NA	$0.77	$0.83	$0.90	8.23%	$12.00	$13.66	$23.95	$27.26		($23.24)	$0.77	$0.83	$27.26	7.71%
DOMINION ENERGY, INC.	D	$2.67	NA	$2.84	$3.02	$3.21	6.33%	$30.23	$35.75	$74.76	$88.42		($72.09)	$2.84	$3.02	$88.42	9.69%
DTE ENERGY CO.	DTE	$3.60	NA	$3.83	$4.08	$4.35	6.51%	$64.38	$71.40	$126.83	$140.66		($123.23)	$3.83	$4.08	$140.66	6.63%
DUKE ENERGY	DUK	$3.98	NA	$4.07	$4.16	$4.25	2.24%	$60.57	$66.70	$97.09	$106.92		($93.11)	$4.07	$4.16	$106.92	7.64%
CON. EDISON	ED	$3.16	NA	$3.24	$3.33	$3.41	2.60%	$56.06	$61.11	$76.87	$83.80		($73.71)	$3.24	$3.33	$83.80	7.32%
EDISON INTERNAT'L	EIX	$2.84	NA	$3.00	$3.17	$3.35	5.66%	$36.85	$41.93	$61.38	$69.84		($58.54)	$3.00	$3.17	$69.84	9.53%
EVERSOURCE ENERGY	ES	$2.56	NA	$2.71	$2.87	$3.04	5.90%	$41.85	$47.66	$84.65	$96.40		($82.09)	$2.71	$2.87	$96.40	7.73%
ENTERGY CORP.	ETR	$4.08	NA	$4.31	$4.55	$4.80	5.57%	$55.97	$63.69	$100.40	$114.24		($96.32)	$4.31	$4.55	$114.24	8.87%
EVERGY, INC.	EVRG	$2.33	NA	$2.49	$2.66	$2.85	6.95%	$39.56	$43.71	$61.16	$67.59		($58.83)	$2.49	$2.66	$67.59	7.63%
EXELON CORP.	EXC	$1.35	NA	$1.44	$1.54	$1.65	6.92%	$32.96	$37.75	$48.53	$55.58		($47.18)	$1.44	$1.54	$55.58	7.69%
FIRST ENERGY	FE	$1.56	NA	$1.66	$1.77	$1.88	6.42%	$14.43	$17.73	$37.48	$46.04		($35.92)	$1.66	$1.77	$46.04	11.72%
FORTIS, INC.	FTS.TO	$2.21	NA	$2.35	$2.49	$2.65	6.24%	$37.59	$42.13	$55.38	$62.08		($53.17)	$2.35	$2.49	$62.08	8.30%
HAWAIIAN ELECTRIC	HE	$1.40	NA	$1.45	$1.50	$1.55	3.45%	$21.90	$24.19	$40.39	$44.63		($38.99)	$1.45	$1.50	$44.63	7.10%
IDACORP, INC.	IDA	$3.05	NA	$3.25	$3.47	$3.70	6.65%	$52.09	$58.17	$99.74	$111.38		($96.69)	$3.25	$3.47	$111.38	7.11%
ALLIANT ENERGY	LNT	$1.71	NA	$1.82	$1.93	$2.05	6.23%	$23.48	$26.82	$54.21	$61.92		($52.50)	$1.82	$1.93	$61.92	8.00%
MGE ENERGY INC.	MGEE	$1.59	NA	$1.67	$1.76	$1.85	5.18%	$28.27	$32.68	$73.15	$84.54		($71.56)	$1.67	$1.76	$84.54	7.28%
NEXTERA ENERGY	NEE	$1.70	NA	$1.87	$2.05	$2.26	9.90%	$18.95	$24.03	$81.03	$102.74		($79.33)	$1.87	$2.05	$102.74	10.59%
NORTHWESTERN	NWE	$2.52	NA	$2.56	$2.61	$2.65	1.69%	$42.32	$45.34	$62.23	$66.68		($59.71)	$2.56	$2.61	$66.68	6.62%
OGE ENERGY CORP.	OGE	$1.66	NA	$1.71	$1.75	$1.80	2.74%	$18.58	$21.20	$33.96	$38.74		($32.30)	$1.71	$1.75	$38.74	9.78%
OTTERTAIL CORP.	OTTR	$1.68	NA	$1.81	$1.95	$2.10	7.72%	$22.66	$26.04	$56.25	$64.65		($54.57)	$1.81	$1.95	$64.65	8.07%
P.S. ENTERPRISE GP.	PEG	$2.16	NA	$2.28	$2.40	$2.53	5.37%	$29.53	$34.69	$60.92	$71.54		($58.76)	$2.28	$2.40	$71.54	9.38%
PNM RESOURCES	PNM	$1.64	NA	$1.66	$1.68	$1.70	1.20%	$24.78	$28.65	$46.98	$54.30		($45.34)	$1.66	$1.68	$54.30	8.61%
PINNACLE WEST	PNW	$3.44	NA	$3.52	$3.61	$3.70	2.46%	$51.15	$54.18	$75.66	$80.14		($72.22)	$3.52	$3.61	$80.14	6.82%
PORTLAND GENERAL	POR	$1.80	NA	$1.89	$1.99	$2.10	5.27%	$29.86	$33.20	$47.43	$52.74		($45.63)	$1.89	$1.99	$52.74	7.76%
PPL CORPORATION	PPL	$1.00	NA	$1.02	$1.04	$1.07	2.17%	$13.55	$15.98	$28.13	$33.18		($27.13)	$1.02	$1.04	$33.18	9.42%
SOUTHERN COMPANY	SO	$2.70	NA	$2.78	$2.86	$2.94	2.88%	$26.71	$30.33	$63.39	$71.99		($60.69)	$2.78	$2.86	$71.99	8.91%
SEMPRA ENERGY	SRE	$4.62	NA	$4.90	$5.19	$5.50	5.98%	$73.42	$86.84	$130.18	$153.98		($125.56)	$4.90	$5.19	$153.98	9.66%
WEC ENERGY GROUP	WEC	$2.89	NA	$3.07	$3.25	$3.45	6.08%	$34.00	$38.28	$90.30	$101.66		($87.41)	$3.07	$3.25	$101.66	7.54%
XCEL ENERGY	XEL	$1.94	NA	$2.05	$2.17	$2.30	5.84%	$28.00	$32.37	$65.09	$75.22		($63.15)	$2.05	$2.17	$75.22	8.20%
Maximum		$4.62	$0.00	$4.90	$5.19	$5.50	9.90%	$73.42	$86.84	$130.18	$153.98	$0.00	($23.24)	$4.90	$5.19	$153.98	11.72%
Minimum		$0.71	$0.00	$0.77	$0.83	$0.90	1.20%	$12.00	$13.66	$23.95	$27.26	$0.00	($125.56)	$0.77	$0.83	$27.26	4.67%
Median		$2.27	#NUM!	$2.42	$2.55	$2.65	5.61%	$33.48	$38.01	$62.81	$71.77	#NUM!	($60.20)	$2.42	$2.55	$71.77	8.10%
Average		$2.35	#DIV/0!	$2.46	$2.59	$2.72	5.12%	$35.80	$40.50	$66.77	$76.14	#DIV/0!	($64.43)	$2.46	$2.59	$76.14	**8.31%**

Sources:

[A] Value Line: Most current data available at time of schedule preparation. 2025 data is VL forecast for 2024-26.

[B] Straight line interpolation based on Value Line data, assuming constant dividend growth for 2022-25.

[C] Straight line interpolation based on Value Line data, assuming constant book value growth for 2022-25.

[D] EOD Data: Market Data as of February 28, 2022.

[E] Stock Price projected assuming constant Market to Book Ratio (Exhibit ALR-5, page 1) and using VL projected Book Value.

[F] Cash Flow from purchasing stock on March 1, 2022, receiving dividends through 2025, and selling on February 28, 2025.
Negative number in 2022 reflects cash outflow required to purchase stock.
Cash flow sources are 1) dividends and 2) proceeds of stock sale.
4 of 4 dividends assumed received in 2022 and 0 of 4 in 2025 based on purchase and sale date.

[G] Total return on equity to investor who purchased, held, and sold stock as described above,
assuming Value Line projections of Dividends and Book Value are correct and
assuming Stock Price grows at same rate as Book Value.
DCF result is an Internal Rate of Return computation made using the "IRR" function built into Microsoft Excel
based on projected cash flows from 2022 to 2025.

COMMON SHARES OUTSTANDING AND EXTERNAL FINANCING RATE
RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		Common Stock Outstanding (Millions of Shares)								Annual Growth Rate		
		2016	2017	2018	2019	2020	2021	2022	2025	2016-20	2020-25	2016-25
		[A]	[A]	[A]	[A]	[A]	[A]	[A]	[A]	[B]	[B]	[B]
AMEREN	AEE	242.6	242.6	244.5	246.2	253.3	259.0	265.0	280.0	1.08%	2.02%	1.60%
AMERICAN ELEC. PWR.	AEP	491.7	492.0	493.3	494.2	496.6	504.0	530.0	550.0	0.25%	2.06%	1.25%
AVANGRID, INC.	AGR	309.0	309.0	309.0	309.0	309.1	387.2	387.2	387.2	0.01%	4.61%	2.54%
ALLETE	ALE	49.6	51.1	51.5	51.7	52.1	52.5	52.8	54.0	1.24%	0.72%	0.95%
AVISTA CORP.	AVA	64.2	65.5	65.7	67.2	69.2	71.5	73.5	79.5	1.91%	2.80%	2.41%
BLACK HILLS CORP.	BKH	53.4	53.5	60.0	61.5	62.8	64.8	66.5	70.0	4.14%	2.20%	3.06%
CMS ENERGY CORP.	CMS	279.2	281.7	283.4	283.9	288.9	289.7	289.7	295.0	0.86%	0.42%	0.61%
CENTER POINT EN'RGY	CNP	430.7	431.0	501.2	502.2	551.4	629.0	630.0	633.0	6.37%	2.80%	4.37%
DOMINION ENERGY, INC.	D	627.8	644.6	680.9	838.0	806.0	810.0	835.0	860.7	6.45%	1.32%	3.57%
DTE ENERGY CO.	DTE	179.4	179.4	181.9	192.2	193.8	193.8	205.0	206.0	1.94%	1.23%	1.55%
DUKE ENERGY	DUK	700.0	700.0	727.0	733.0	769.0	770.0	770.0	770.0	2.38%	0.03%	1.06%
CON. EDISON	ED	305.0	310.0	321.0	332.6	342.3	354.0	360.0	370.0	2.93%	1.57%	2.17%
EDISON INTERNAT'L	EIX	325.8	325.8	325.8	362.0	378.9	385.0	390.0	390.0	3.85%	0.58%	2.02%
EVERSOURCE ENERGY	ES	316.9	316.9	316.9	329.9	343.0	344.3	347.0	357.0	2.00%	0.81%	1.33%
ENTERGY CORP.	ETR	179.1	180.5	189.1	199.2	200.2	204.0	205.0	208.0	2.82%	0.76%	1.67%
EVERGY, INC.	EVRG	--	--	255.3	226.6	226.8	230.0	230.0	230.0	NA	0.28%	NA
EXELON CORP.	EXC	924.0	963.3	968.2	973.0	976.0	980.0	984.0	996.0	1.38%	0.41%	0.84%
FIRST ENERGY	FE	442.3	445.3	511.9	540.7	543.1	570.0	572.5	579.7	5.27%	1.31%	3.05%
FORTIS, INC.	FTS.TO	401.5	421.1	428.5	463.3	466.8	473.0	479.0	500.0	3.84%	1.38%	2.47%
HAWAIIAN ELECTRIC	HE	108.6	108.8	108.9	109.0	109.2	109.5	110.0	113.0	0.14%	0.69%	0.44%
IDACORP, INC.	IDA	50.4	50.4	50.4	50.4	50.5	50.5	50.5	50.5	0.03%	0.00%	0.01%
ALLIANT ENERGY	LNT	227.7	231.4	236.1	245.0	249.9	250.5	251.0	252.5	2.35%	0.21%	1.16%
MGE ENERGY INC.	MGEE	34.7	34.7	34.7	34.7	36.2	36.2	36.2	36.2	1.06%	0.00%	0.47%
NEXTERA ENERGY	NEE	1,872.0	1,884.0	1,912.0	1,956.0	1,960.0	1,963.0	1,980.0	2,025.0	1.16%	0.65%	0.88%
NORTHWESTERN	NWE	48.3	49.4	50.3	50.5	50.6	54.5	60.0	62.0	1.15%	4.15%	2.81%
OGE ENERGY CORP.	OGE	199.7	199.7	199.7	200.1	200.1	200.2	200.2	200.2	0.05%	0.01%	0.03%
OTTERTAIL CORP.	OTTR	39.4	39.6	39.7	40.2	41.5	41.6	41.7	42.0	1.32%	0.25%	0.73%
P.S. ENTERPRISE GP.	PEG	504.9	505.0	504.0	504.0	504.0	502.0	498.0	498.0	-0.04%	-0.24%	-0.15%
PNM RESOURCES	PNM	79.7	79.7	79.7	79.7	85.8	85.8	88.0	90.0	1.89%	0.95%	1.37%
PINNACLE WEST	PNW	111.3	111.8	112.1	112.4	112.8	113.0	113.0	120.0	0.32%	1.25%	0.84%
PORTLAND GENERAL	POR	89.0	89.1	89.3	89.4	89.5	89.7	89.8	90.0	0.17%	0.10%	0.13%
PPL CORPORATION	PPL	679.7	693.4	720.3	767.2	768.9	735.0	737.0	743.0	3.13%	-0.68%	0.99%
SOUTHERN COMPANY	SO	990.4	1,007.6	1,033.8	1,053.3	1,056.5	1,070.0	1,070.0	1,070.0	1.63%	0.25%	0.86%
SEMPRA ENERGY	SRE	250.2	251.4	273.8	291.7	288.5	317.0	315.0	315.0	3.63%	1.78%	2.59%
WEC ENERGY GROUP	WEC	315.6	315.6	315.5	315.4	315.4	315.4	315.4	315.4	-0.02%	0.00%	-0.01%
XCEL ENERGY	XEL	507.2	507.8	514.0	524.5	537.4	540.0	544.0	553.0	1.46%	0.57%	0.96%
Maximum		1,872.0	1,884.0	1,912.0	1,956.0	1,960.0	1,963.0	1,980.0	2,025.0	6.45%	4.61%	4.37%
Minimum		34.7	34.7	34.7	34.7	36.2	36.2	36.2	36.2	-0.04%	-0.68%	-0.15%
Median		279.2	281.7	278.6	287.8	288.7	302.6	302.4	305.0	1.46%	0.70%	1.16%
Average		355.2	359.2	366.4	378.6	382.9	390.2	393.7	399.8	1.95%	1.04%	1.45%
									Sustainable Growth [C]			1.29%

Sources:

[A] Value Line: Most current data available at time of schedule preparation.

[B] Annualized Growth Rate calculation.

[C] Estimated Sustainable Growth in Common Stock based on analysis of historical and projected growth rates.

CAPITAL ASSET PRICING MODEL (CAPM) - INDICATED COST OF EQUITY

WEIGHTED - All Inputs Weighted From December 2021 to February 2022

RFC Electric Proxy Group

	3-Month Treasury Bill		30-Year Treasury Bond	
	Hybrid Beta	Forward Beta	Hybrid Beta	Forward Beta
Risk-Free Rate	0.23%	0.23%	2.08%	2.08%
Beta	0.67	0.57	0.67	0.57
Risk Premium	10.15%	10.15%	8.31%	8.31%
CAPM (Weighted)	7.05%	6.00%	7.66%	6.80%

CAPITAL ASSET PRICING MODEL (CAPM) - RISK-FREE RATE

Spot (Feb. 28, 2022)	
3-Month Treasury Bill	0.35%
30-Year Treasury Bond	2.17%
3-Mo. Weighted Average (Dec. 2021 to Feb. 2022)	
3-Month Treasury Bill	0.23%
30-Year Treasury Bond	2.08%

Source: www.treasury.gov

CAPITAL ASSET PRICING MODEL (CAPM) - BETAS
(BASED ON HISTORICAL AND OPTION-IMPLIED RETURNS)
RFC Electric Proxy Group

Betas	11/23/2021	11/30/2021	12/07/2021	12/14/2021	12/21/2021	12/28/2021	01/04/2022	01/11/2022	01/18/2022	01/25/2022	02/01/2022	02/08/2022	02/15/2022	02/22/2022	Average	Time Avg.
Forward (6 months)	0.57	0.58	0.60	0.60	0.57	0.57	0.59	0.54	0.57	0.56	0.57	0.63	0.55	0.52	0.573	0.568
Historical (6 months)	0.64	0.66	0.67	0.69	0.68	0.67	0.68	0.69	0.69	0.64	0.64	0.64	0.67	0.66	0.666	0.664
Historical (2 yrs)	0.96	0.96	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.94	0.94	0.94	0.95	0.94	0.948	0.945
Historical (5 yrs)	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.79	0.79	0.79	0.79	0.79	0.796	0.794
Weighting																
Forward (6 months)	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%		
Historical (6 months)	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%		
Historical (2 yrs)	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%		
Historical (5 yrs)	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%		
Hybrid Beta (Forward & Historical)	**0.67**	**0.68**	**0.69**	**0.69**	**0.68**	**0.67**	**0.69**	**0.66**	**0.68**	**0.66**	**0.67**	**0.70**	**0.66**	**0.65**	0.675	0.671006
Slope	15%															
Points	0.00	0.00	1.00	1.15	1.32	1.52	1.75	2.01	2.31	2.66	3.06	3.52	4.05	4.65		
Time Weight	0.0%	0.0%	3.4%	4.0%	4.6%	5.2%	6.0%	6.9%	8.0%	9.2%	10.5%	12.1%	13.9%	16.0%		

CAPM Betas	Spot (Feb 22, 2022)	Weighted (Nov 2021 - Feb 2022)
Forward	0.52	0.57
Hybrid	0.65	0.67

Note: Historical betas are calculated on Tuesdays, following Value Line's methodology. Forward (option-implied) betas are also calculated on Tuesdays for the sake of compatibility.

CAPITAL ASSET PRICING MODEL (CAPM) - MARKET RISK PREMIUM

WEIGHTED - All Inputs Weighted From December 2021 to February 2022

Cumulative Probability	50.00%	
S&P 500 Option-Implied Growth Rate	9.08%	
S&P 500 Dividend Yield	1.31%	
S&P 500 Market Return	10.39%	
	3-Month Treasury Bill	**30-Year Treasury Bond**
Risk-Free Rate	0.23%	2.08%
Option-Implied Market Risk Premium (Weighted)	10.15%	8.31%

CAPITAL ASSET PRICING MODEL (CAPM) - INDICATED COST OF EQUITY

SPOT - All Inputs Based on Last Available Data as of February 28, 2022

RFC Electric Proxy Group

	3-Month Treasury Bill		30-Year Treasury Bond	
	Hybrid Beta	Forward Beta	Hybrid Beta	Forward Beta
Risk-Free Rate	0.35%	0.35%	2.17%	2.17%
Beta	0.65	0.52	0.65	0.52
Risk Premium	10.43%	10.43%	8.61%	8.61%
CAPM (Spot)	7.09%	5.80%	7.74%	6.67%

CAPITAL ASSET PRICING MODEL (CAPM) - MARKET RISK PREMIUM

SPOT - All Inputs Based on Last Available Data as of February 28, 2022

Cumulative Probability	50.00%	
S&P 500 Option-Implied Growth Rate	9.45%	
S&P 500 Dividend Yield	1.33%	
S&P 500 Market Return	10.78%	
	3-Month Treasury Bill	**30-Year Treasury Bond**
Risk-Free Rate	0.35%	2.17%
Option-Implied Market Risk Premium (Spot)	10.43%	8.61%

MARKET TO BOOK RATIO AND DIVIDEND YIELD

RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
		Book Value per Share															
		Actual				**Estimated**			**Market Price**			**Mkt. to Book Ratio**		**Dividend Rate**		**Dividend Yield**	
		12/31/18	**12/31/19**	**12/31/20**	**12/31/21**	**2/28/21**	**2/28/22**	**12/31/22**	**2/28/22**	**LTM High**	**LTM Low**	**2/28/22**	**LTM Avg.**	**MRQ**	**Annual**	**2/28/22**	**LTM Avg.**
		[A]	[A]	[A]	[A]	[B]	[B]	[A]	[C]	[C]	[C]	[D]	[D]	[A]	[E]	[F]	[F]
AMEREN	AEE	$31.21	$32.73	$35.29	$37.55	$35.65	$37.94	$40.00	$85.95	$90.77	$70.43	2.27	2.19	$0.550	$2.200	2.56%	2.73%
AMERICAN ELEC. PWR.	AEP	$38.58	$39.73	$41.38	$43.80	$41.77	$44.40	$47.55	$90.65	$91.66	$74.96	2.04	1.93	$0.780	$3.120	3.44%	3.75%
AVANGRID, INC.	AGR	$48.88	$49.31	$49.21	$49.95	$49.33	$49.98	$50.15	$44.87	$55.57	$42.20	0.90	0.98	$0.440	$1.760	3.92%	3.60%
ALLETE	ALE	$41.86	$43.17	$44.04	$44.70	$44.15	$44.90	$45.95	$62.94	$73.10	$56.84	1.40	1.46	$0.630	$2.520	4.00%	3.88%
AVISTA CORP.	AVA	$26.99	$28.87	$29.31	$30.00	$29.42	$30.12	$30.75	$44.63	$49.14	$37.73	1.48	1.46	$0.423	$1.690	3.79%	3.89%
BLACK HILLS CORP.	BKH	$36.36	$38.42	$40.79	$43.05	$41.15	$43.42	$45.35	$69.99	$72.78	$58.53	1.61	1.55	$0.595	$2.380	3.40%	3.63%
CMS ENERGY CORP.	CMS	$16.78	$17.68	$19.02	$22.05	$19.50	$22.23	$23.15	$64.01	$65.79	$53.19	2.88	2.85	$0.435	$1.740	2.72%	2.92%
CENTER POINT EN'RGY	CNP	$12.53	$13.10	$10.78	$12.80	$11.10	$12.90	$13.40	$27.35	$28.52	$19.38	2.12	2.00	$0.170	$0.680	2.49%	2.84%
DOMINION ENERGY, INC.	D	$29.53	$35.33	$29.44	$30.40	$29.59	$30.86	$33.30	$78.87	$81.67	$67.85	2.56	2.47	$0.668	$2.670	3.39%	3.57%
DTE ENERGY CO.	DTE	$56.27	$60.73	$64.12	$63.90	$64.08	$64.68	$68.75	$121.59	$145.43	$108.22	1.88	1.97	$0.885	$3.540	2.91%	2.79%
DUKE ENERGY	DUK	$60.27	$61.20	$59.82	$60.90	$59.99	$61.14	$62.40	$100.41	$108.38	$85.80	1.64	1.60	$0.985	$3.940	3.92%	4.06%
CON. EDISON	ED	$52.11	$54.18	$55.06	$56.55	$55.30	$56.81	$58.20	$85.77	$87.67	$66.06	1.51	1.37	$0.790	$3.160	3.68%	4.11%
EDISON INTERNAT'L	EIX	$32.10	$36.75	$37.08	$36.40	$36.97	$36.73	$38.45	$63.42	$68.62	$54.14	1.73	1.67	$0.700	$2.800	4.42%	4.56%
EVERSOURCE ENERGY	ES	$36.25	$38.29	$41.01	$42.20	$41.20	$42.50	$44.05	$81.15	$92.66	$76.64	1.91	2.02	$0.603	$2.410	2.97%	2.85%
ENTERGY CORP.	ETR	$46.78	$51.34	$54.56	$56.65	$54.89	$57.04	$59.10	$105.21	$115.02	$85.78	1.84	1.79	$1.010	$4.040	3.84%	4.02%
EVERGY, INC.	EVRG	$39.28	$37.82	$38.50	$40.15	$38.76	$40.35	$41.40	$62.41	$69.45	$52.87	1.55	1.55	$0.568	$2.270	3.64%	3.71%
EXELON CORP.	EXC	$31.77	$33.12	$33.39	$34.05	$33.50	$32.42	$23.85	$42.56	$58.21	$38.85	1.31	1.47	$0.383	$1.530	3.59%	3.15%
FIRST ENERGY	FE	$13.17	$12.90	$13.33	$15.10	$13.61	$15.25	$16.05	$41.85	$42.69	$32.27	2.74	2.60	$0.390	$1.560	3.73%	4.16%
FORTIS, INC.	FTS.TO	$34.80	$36.49	$36.58	$38.10	$36.82	$38.36	$39.70	$58.08	$61.54	$49.23	1.51	1.47	$0.535	$2.140	3.68%	3.86%
HAWAIIAN ELECTRIC	HE	$19.86	$20.93	$21.41	$22.15	$21.53	$22.26	$22.85	$40.98	$45.97	$34.80	1.84	1.84	$0.340	$1.360	3.32%	3.37%
IDACORP, INC.	IDA	$47.01	$48.88	$50.73	$52.80	$51.06	$53.13	$54.85	$103.95	$114.19	$85.30	1.96	1.91	$0.750	$3.000	2.89%	3.01%
ALLIANT ENERGY	LNT	$19.43	$21.24	$22.76	$23.85	$22.93	$24.03	$24.95	$58.40	$62.35	$46.06	2.43	2.31	$0.403	$1.610	2.76%	2.97%
MGE ENERGY INC.	MGEE	$23.56	$24.68	$27.76	$28.45	$27.87	$28.67	$29.85	$72.02	$82.95	$63.34	2.51	2.59	$0.388	$1.550	2.15%	2.12%
NEXTERA ENERGY	NEE	$17.86	$18.92	$18.63	$18.95	$18.68	$19.22	$20.65	$78.27	$93.73	$68.33	4.07	4.28	$0.385	$1.540	1.97%	1.90%
NORTHWESTERN	NWE	$38.60	$40.42	$41.10	$42.95	$41.40	$43.25	$44.80	$60.48	$70.80	$53.66	1.40	1.47	$0.620	$2.480	4.10%	3.99%
OGE ENERGY CORP.	OGE	$20.06	$20.69	$18.15	$18.80	$18.25	$18.91	$19.50	$37.55	$38.57	$29.34	1.99	1.83	$0.410	$1.640	4.37%	4.83%
OTTERTAIL CORP.	OTTR	$18.38	$19.46	$21.00	$23.60	$21.42	$23.90	$25.45	$61.86	$71.89	$40.62	2.59	2.48	$0.390	$1.560	2.52%	2.77%
P.S. ENTERPRISE GP.	PEG	$28.53	$29.94	$31.71	$27.80	$31.08	$27.98	$28.95	$64.83	$68.06	$53.77	2.32	2.06	$0.510	$2.040	3.15%	3.35%
PNM RESOURCES	PNM	$21.20	$21.08	$23.88	$25.25	$24.10	$25.47	$26.60	$45.17	$50.11	$43.84	1.77	1.90	$0.328	$1.310	2.90%	2.79%
PINNACLE WEST	PNW	$46.59	$48.30	$49.96	$51.95	$50.28	$52.02	$52.40	$70.83	$88.54	$62.78	1.36	1.48	$0.850	$3.400	4.80%	4.49%
PORTLAND GENERAL	POR	$28.07	$28.99	$29.18	$30.20	$29.34	$30.37	$31.25	$50.77	$53.84	$41.01	1.67	1.59	$0.430	$1.720	3.39%	3.63%
PPL CORPORATION	PPL	$16.18	$16.93	$17.39	$10.70	$16.32	$10.79	$11.25	$26.17	$30.72	$25.55	2.43	2.08	$0.415	$1.660	6.34%	5.90%
SOUTHERN COMPANY	SO	$23.92	$26.11	$26.48	$26.75	$26.52	$26.89	$27.65	$64.77	$69.77	$57.02	2.41	2.37	$0.660	$2.640	4.08%	4.16%
SEMPRA ENERGY	SRE	$54.35	$60.58	$70.11	$75.30	$70.94	$75.90	$79.05	$144.22	$145.70	$114.66	1.90	1.77	$1.100	$4.400	3.05%	3.38%
WEC ENERGY GROUP	WEC	$31.02	$32.06	$33.19	$34.40	$33.38	$34.62	$35.75	$90.88	$99.86	$80.73	2.63	2.66	$0.678	$2.710	2.98%	3.00%
XCEL ENERGY	XEL	$23.78	$25.24	$27.12	$28.45	$27.33	$28.67	$29.85	$67.33	$72.94	$57.23	2.35	2.32	$0.458	$1.830	2.72%	2.81%
Maximum		$60.27	$61.20	$70.11	$75.30	$70.94	$75.90	$79.05	$144.22	$145.70	$114.66	4.07	4.28	$1.100	$4.400	6.34%	5.90%
Minimum		$12.53	$12.90	$10.78	$10.70	$11.10	$10.79	$11.25	$26.17	$28.52	$19.38	0.90	0.98	$0.170	$0.680	1.97%	1.90%
Median		$31.12	$32.93	$33.29	$34.23	$33.44	$33.52	$34.53	$64.39	$71.34	$55.49	1.90	1.91	$0.543	$2.170	3.39%	3.59%
Average		$32.33	$34.04	$35.09	$36.13	$35.26	$36.34	$37.42	$68.62	$75.52	$58.03	2.01	1.98	$0.574	$2.294	3.43%	3.52%

Sources:
[A] Value Line: Most current data available at time of schedule preparation.
[B] Straight-line interpolation of Actual and Estimated VL year-end values.
[C] EOD Data: Market Data as of February 28, 2022.
[D] Market Price divided by Book Value per Share.
[E] Most Recent Quarterly Dividend multiplied by 4.
[F] Dividend Rate divided by Market Price.

EARNINGS PER SHARE AND RETURN ON EQUITY
RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
		Earnings per Share				Return on Equity			
		2018	2019	2020	2021	2019	2020	2021	VL Future Exp.
		[A]	[A]	[A]	[A]	[B]	[B]	[B]	[A]
AMEREN	AEE	$3.32	$3.35	$3.50	$3.85	10.48%	10.29%	10.57%	10.50%
AMERICAN ELEC. PWR.	AEP	$3.90	$4.08	$4.42	$4.85	10.42%	10.90%	11.39%	10.50%
AVANGRID, INC.	AGR	$1.92	$2.26	$1.88	$2.05	4.60%	3.82%	4.13%	4.67%
ALLETE	ALE	$3.38	$3.33	$3.35	$3.15	7.83%	7.68%	7.10%	9.00%
AVISTA CORP.	AVA	$2.07	$2.97	$1.90	$2.05	10.63%	6.53%	6.91%	8.00%
BLACK HILLS CORP.	BKH	$3.47	$3.53	$3.73	$3.95	9.44%	9.42%	9.42%	9.00%
CMS ENERGY CORP.	CMS	$2.32	$2.39	$2.64	$2.65	13.87%	14.39%	12.90%	12.50%
CENTER POINT EN'RGY	CNP	$0.74	$1.49	$1.29	$1.15	11.63%	10.80%	9.75%	10.00%
DOMINION ENERGY, INC.	D	$3.25	$2.19	$1.82	$3.10	6.75%	5.62%	10.36%	11.83%
DTE ENERGY CO.	DTE	$6.17	$6.31	$7.08	$3.40	10.79%	11.34%	5.31%	9.00%
DUKE ENERGY	DUK	$4.13	$5.07	$3.92	$4.95	8.35%	6.48%	8.20%	9.33%
CON. EDISON	ED	$4.55	$4.08	$3.94	$4.45	7.68%	7.21%	7.97%	8.00%
EDISON INTERNAT'L	EIX	($1.26)	$3.98	$1.72	$1.60	11.56%	4.66%	4.35%	10.50%
EVERSOURCE ENERGY	ES	$3.25	$3.45	$3.55	$3.45	9.26%	8.95%	8.29%	9.33%
ENTERGY CORP.	ETR	$5.88	$6.30	$6.90	$6.30	12.84%	13.03%	11.33%	11.00%
EVERGY, INC.	EVRG	$2.50	$2.79	$2.72	$3.85	7.24%	7.13%	9.79%	9.50%
EXELON CORP.	EXC	$2.07	$3.01	$2.60	$2.60	9.28%	7.82%	7.71%	9.83%
FIRST ENERGY	FE	$1.33	$1.84	$1.85	$2.40	14.12%	14.11%	16.88%	15.50%
FORTIS, INC.	FTS.TO	$2.52	$2.68	$2.60	$2.65	7.52%	7.12%	7.10%	7.00%
HAWAIIAN ELECTRIC	HE	$1.85	$1.99	$1.81	$2.15	9.76%	8.55%	9.87%	9.00%
IDACORP, INC.	IDA	$4.49	$4.61	$4.69	$4.90	9.62%	9.42%	9.47%	9.50%
ALLIANT ENERGY	LNT	$2.19	$2.33	$2.47	$2.65	11.46%	11.23%	11.37%	11.50%
MGE ENERGY INC.	MGEE	$2.43	$2.51	$2.60	$2.95	10.41%	9.92%	10.50%	10.00%
NEXTERA ENERGY	NEE	$1.67	$1.94	$2.10	$1.81	10.55%	11.19%	9.63%	12.83%
NORTHWESTERN	NWE	$3.40	$3.53	$3.06	$3.65	8.93%	7.51%	8.69%	7.50%
OGE ENERGY CORP.	OGE	$2.12	$2.24	$2.08	$2.35	10.99%	10.71%	12.72%	12.50%
OTTERTAIL CORP.	OTTR	$2.06	$2.17	$2.34	$4.20	11.47%	11.57%	18.83%	12.00%
P.S. ENTERPRISE GP.	PEG	$2.76	$3.90	$3.61	$2.30	13.34%	11.71%	7.73%	12.50%
PNM RESOURCES	PNM	$1.66	$2.28	$2.15	$2.35	10.79%	9.56%	9.57%	10.00%
PINNACLE WEST	PNW	$4.54	$4.77	$4.87	$5.45	10.05%	9.91%	10.70%	8.50%
PORTLAND GENERAL	POR	$2.37	$2.39	$1.72	$2.75	8.38%	5.91%	9.26%	9.50%
PPL CORPORATION	PPL	$2.58	$2.37	$2.04	$0.60	14.32%	11.89%	4.27%	13.00%
SOUTHERN COMPANY	SO	$3.00	$3.17	$3.25	$3.50	12.67%	12.36%	13.15%	13.83%
SEMPRA ENERGY	SRE	$5.48	$5.97	$6.58	$3.25	10.39%	10.07%	4.47%	11.50%
WEC ENERGY GROUP	WEC	$3.34	$3.58	$3.79	$4.10	11.35%	11.62%	12.13%	13.00%
XCEL ENERGY	XEL	$2.47	$2.64	$2.79	$2.95	10.77%	10.66%	10.62%	11.00%
Maximum		$6.17	$6.31	$7.08	$6.30	14.32%	14.39%	18.83%	15.50%
Minimum		($1.26)	$1.49	$1.29	$0.60	4.60%	3.82%	4.13%	4.67%
Median		$2.55	$2.99	$2.68	$3.03	10.45%	9.91%	9.60%	10.00%
Average		$2.89	$3.26	$3.15	$3.18	10.26%	9.47%	9.51%	10.35%

Sources:
[A] Value Line: Most current data available at time of schedule preparation.
[B] Earnings per Share divded by average Book Value. Book Values shown on Exhibit ALR-5, page 1.

RETURN ON EQUITY IMPLIED BY ZACKS GROWTH RATES

RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
				Annual	Analyst	Analyst-Implied		Analyst-Implied		Implied	Analyst-
		Book Value	EPS	Dividend	5 Year	Book Value before SV		Book Value Incl. SV		EPS	Implied
		12/31/21	2021	Rate	Growth Rate	12/31/2025	12/31/2026	12/31/2025	12/31/2026	2026	ROE
		[A]	[A]	[A]	[B]	[C]	[C]	[C]	[C]	[C]	[C]
AMEREN	AEE	$37.55	$3.85	$2.200	7.50%	$45.48	$47.85	$53.61	$58.77	$5.53	9.84%
AMERICAN ELEC. PWR.	AEP	$43.80	$4.85	$3.120	5.60%	$51.74	$54.02	$57.20	$61.22	$6.37	10.76%
AVANGRID, INC.	AGR	$49.95	$2.05	$1.760	7.60%	$51.35	$51.77	$51.35	$51.77	$2.96	5.73%
ALLETE	ALE	$44.70	$3.15	$2.520	NA	NA	NA	NA	NA	NA	NA
AVISTA CORP.	AVA	$30.00	$2.05	$1.690	6.60%	$31.69	$32.19	$36.97	$39.03	$2.82	7.43%
BLACK HILLS CORP.	BKH	$43.05	$3.95	$2.380	6.30%	$50.38	$52.51	$56.22	$60.23	$5.36	9.21%
CMS ENERGY CORP.	CMS	$22.05	$2.65	$1.740	8.10%	$26.49	$27.83	$28.39	$30.35	$3.91	13.32%
CENTER POINT EN'RGY	CNP	$12.80	$1.15	$0.680	5.20%	$14.94	$15.54	$15.14	$15.81	$1.48	9.58%
DOMINION ENERGY, INC.	D	$30.40	$3.10	$2.670	6.60%	$32.42	$33.02	$35.92	$37.52	$4.27	11.62%
DTE ENERGY CO.	DTE	$63.90	$3.40	$3.540	6.00%	$63.25	$63.06	$64.03	$64.03	$4.55	7.11%
DUKE ENERGY	DUK	$60.90	$4.95	$3.940	6.00%	$65.58	$66.94	$65.58	$66.94	$6.62	10.00%
CON. EDISON	ED	$56.55	$4.45	$3.160	2.00%	$61.97	$63.40	$65.48	$67.91	$4.91	7.37%
EDISON INTERNAT'L	EIX	$36.40	$1.60	$2.800	3.50%	$31.17	$29.74	$31.17	$29.74	$1.90	6.24%
EVERSOURCE ENERGY	ES	$42.20	$3.45	$2.410	6.20%	$47.05	$48.45	$50.56	$53.02	$4.66	9.00%
ENTERGY CORP.	ETR	$56.65	$6.30	$4.040	1.00%	$65.92	$68.29	$68.31	$71.41	$6.62	9.48%
EVERGY, INC.	EVRG	$40.15	$3.85	$2.270	6.10%	$47.49	$49.62	$47.49	$49.62	$5.18	10.66%
EXELON CORP.	EXC	$34.05	$2.60	$1.530	6.20%	$39.04	$40.48	$39.87	$41.57	$3.51	8.63%
FIRST ENERGY	FE	$15.10	$2.40	$1.560	7.30%	$19.12	$20.31	$20.01	$21.50	$3.41	16.45%
FORTIS, INC.	FTS.TO	$38.10	$2.65	$2.140	NA	NA	NA	NA	NA	NA	NA
HAWAIIAN ELECTRIC	HE	$22.15	$2.15	$1.360	3.20%	$25.57	$26.50	$27.31	$28.77	$2.52	8.98%
IDACORP, INC.	IDA	$52.80	$4.90	$3.000	4.30%	$61.25	$63.60	$61.25	$63.60	$6.05	9.69%
ALLIANT ENERGY	LNT	$23.85	$2.65	$1.610	6.10%	$28.68	$30.08	$29.24	$30.82	$3.56	11.87%
MGE ENERGY INC.	MGEE	$28.45	$2.95	$1.550	6.50%	$35.02	$36.94	$35.02	$36.94	$4.04	11.23%
NEXTERA ENERGY	NEE	$18.95	$1.81	$1.540	8.80%	$20.29	$20.70	$22.89	$24.07	$2.76	11.75%
NORTHWESTERN	NWE	$42.95	$3.65	$2.480	3.10%	$48.00	$49.37	$51.02	$53.28	$4.25	8.15%
OGE ENERGY CORP.	OGE	$18.80	$2.35	$1.640	3.50%	$21.90	$22.74	$21.90	$22.74	$2.79	12.51%
OTTERTAIL CORP.	OTTR	$23.60	$4.20	$1.560	NA	NA	NA	NA	NA	NA	NA
P.S. ENTERPRISE GP.	PEG	$27.80	$2.30	$2.040	3.60%	$28.94	$29.25	$28.94	$29.25	$2.74	9.44%
PNM RESOURCES	PNM	$25.25	$2.35	$1.310	5.00%	$29.96	$31.28	$31.59	$33.43	$3.00	9.23%
PINNACLE WEST	PNW	$51.95	$5.45	$3.400	NA	NA	NA	NA	NA	NA	NA
PORTLAND GENERAL	POR	$30.20	$2.75	$1.720	4.60%	$34.82	$36.11	$34.99	$36.33	$3.44	9.66%
PPL CORPORATION	PPL	$10.70	$0.60	$1.660	NA	NA	NA	NA	NA	NA	NA
SOUTHERN COMPANY	SO	$26.75	$3.50	$2.640	4.00%	$30.55	$31.59	$30.55	$31.59	$4.26	13.70%
SEMPRA ENERGY	SRE	$75.30	$3.25	$4.400	5.30%	$70.06	$68.57	$70.06	$68.57	$4.21	6.07%
WEC ENERGY GROUP	WEC	$34.40	$4.10	$2.710	6.00%	$40.85	$42.71	$40.85	$42.71	$5.49	13.13%
XCEL ENERGY	XEL	$28.45	$2.95	$1.830	6.40%	$33.69	$35.22	$35.46	$37.55	$4.02	11.02%
Maximum		$75.30	$6.30	$4.400	8.80%	$70.06	$68.57	$70.06	$71.41	$6.62	16.45%
Minimum		$10.70	$0.60	$0.680	1.00%	$14.94	$15.54	$15.14	$15.81	$1.48	5.73%
Median		$34.23	$3.03	$2.170	6.00%	$35.02	$36.94	$36.97	$39.03	$4.04	9.66%
Average		$36.13	$3.18	$2.294	5.43%	$40.47	$41.60	$42.21	$43.87	$4.10	9.96%

Sources:

[A] Value Line: Most current data available at time of schedule preparation.

[B] Zacks: Data as of March 07, 2022.

[C] Analyst-Implied Book Value and Return on Equity is obtained by escalating both Dividends and Earnings per Share by the stated Analyst Growth Rate and adding Earnings and subtracting Dividends for each projected year.

"SV" = S X V, where S = rate of continuous new stock financing and V = rate of return on common equity investment.

CAPITAL STRUCTURE WITH SHORT TERM DEBT
RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
		% Common Equity					($ millions)						Percentage			
		2017	2018	2019	2020	2021	Total Debt	LT Debt	ST Debt	Pfd Stock	Equity	Total Capital	LT Debt	ST Debt	Pfd Stock	Equity Ratio
		[A]	[A]	[A]	[A]	[A]	[A]	[A]	[A]	[A]	[A]	[A]	[B]	[B]	[B]	[B]
AMEREN	AEE	49.8%	48.8%	47.1%	44.3%	43.5%	$ 13,054.0	$ 12,444.0	$ 610.0	$ 129.0	$ 9,680.1	$ 22,863.1	54.4%	2.7%	0.6%	42.3%
AMERICAN ELEC. PWR.	AEP	48.5%	46.8%	43.9%	41.5%	41.0%	$ 37,082.0	$ 32,056.0	$ 5,026.0	$ -	$ 22,276.2	$ 59,358.2	54.0%	8.5%	0.0%	37.5%
AVANGRID, INC.	AGR	74.4%	73.8%	69.4%	59.2%	67.5%	$ 7,920.0	$ 7,486.0	$ 434.0	$ -	$ 15,547.8	$ 23,467.8	31.9%	1.8%	0.0%	66.3%
ALLETE	ALE	59.0%	60.1%	61.4%	59.0%	58.0%	$ 2,026.8	$ 1,649.4	$ 377.4	$ -	$ 2,277.7	$ 4,304.5	38.3%	8.8%	0.0%	52.9%
AVISTA CORP.	AVA	52.8%	49.5%	50.6%	49.6%	52.5%	$ 2,398.9	$ 1,949.8	$ 449.1	$ -	$ 2,155.0	$ 4,553.9	42.8%	9.9%	0.0%	47.3%
BLACK HILLS CORP.	BKH	35.5%	42.5%	42.9%	42.1%	39.5%	$ 4,458.1	$ 4,125.6	$ 332.5	$ -	$ 2,693.6	$ 7,151.7	57.7%	4.6%	0.0%	37.7%
CMS ENERGY CORP.	CMS	32.4%	30.7%	29.4%	28.6%	34.0%	$ 12,660.0	$ 12,075.0	$ 585.0	$ 261.0	$ 6,354.9	$ 19,275.9	62.6%	3.0%	1.4%	33.0%
CENTER POINT EN'RGY	CNP	36.4%	37.5%	29.1%	29.9%	36.0%	$ 16,492.0	$ 15,394.0	$ 1,098.0	$ 790.0	$ 9,103.5	$ 26,385.5	58.3%	4.2%	3.0%	34.5%
DOMINION ENERGY, INC.	D	35.6%	39.2%	45.0%	39.5%	38.0%	$ 41,505.0	$ 34,775.0	$ 6,730.0	$ 2,387.0	$ 22,776.7	$ 66,668.7	52.2%	10.1%	3.6%	34.2%
DTE ENERGY CO.	DTE	43.8%	45.8%	42.3%	39.5%	42.5%	$ 17,609.0	$ 16,924.0	$ 685.0	$ -	$ 12,509.0	$ 30,118.0	56.2%	2.3%	0.0%	41.5%
DUKE ENERGY	DUK	46.0%	46.2%	44.1%	44.4%	44.0%	$ 64,900.0	$ 57,929.0	$ 6,971.0	$ 1,962.0	$ 47,057.2	$ 113,919.2	50.9%	6.1%	1.7%	41.3%
CON. EDISON	ED	51.1%	48.9%	49.3%	48.0%	47.0%	$ 23,316.0	$ 21,841.0	$ 1,475.0	$ -	$ 19,368.4	$ 42,684.4	51.2%	3.5%	0.0%	45.4%
EDISON INTERNAT'L	EIX	45.8%	38.3%	39.9%	39.5%	35.5%	$ 27,160.0	$ 23,342.0	$ 3,818.0	$ 3,136.0	$ 14,573.2	$ 44,869.2	52.0%	8.5%	7.0%	32.5%
EVERSOURCE ENERGY	ES	48.2%	46.9%	46.6%	47.1%	44.5%	$ 19,427.0	$ 17,874.0	$ 1,553.0	$ 155.6	$ 14,456.2	$ 34,038.8	52.5%	4.6%	0.5%	42.5%
ENTERGY CORP.	ETR	35.5%	35.9%	37.1%	33.7%	32.5%	$ 25,363.0	$ 24,212.0	$ 1,151.0	$ 254.4	$ 11,780.1	$ 37,397.5	64.7%	3.1%	0.7%	31.5%
EVERGY, INC.	EVRG	--	60.0%	49.4%	48.7%	49.0%	$ 10,784.0	$ 9,297.3	$ 1,486.7	$ -	$ 8,932.7	$ 19,716.7	47.2%	7.5%	0.0%	45.3%
EXELON CORP.	EXC	47.8%	47.2%	50.4%	47.9%	49.0%	$ 41,701.0	$ 35,659.0	$ 6,042.0	$ -	$ 34,260.6	$ 75,961.6	46.9%	8.0%	0.0%	45.1%
FIRST ENERGY	FE	15.7%	27.4%	26.2%	24.6%	27.0%	$ 23,733.0	$ 22,503.0	$ 1,230.0	$ -	$ 8,323.0	$ 32,056.0	70.2%	3.8%	0.0%	26.0%
FORTIS, INC.	FTS.TO	37.1%	37.2%	41.8%	40.5%	41.0%	$ 25,594.0	$ 24,720.0	$ 874.0	$ 1,623.0	$ 18,306.2	$ 45,523.2	54.3%	1.9%	3.6%	40.2%
HAWAIIAN ELECTRIC	HE	55.7%	51.7%	54.6%	52.7%	53.5%	$ 2,337.0	$ 2,244.8	$ 92.2	$ 34.3	$ 2,622.2	$ 4,993.5	45.0%	1.8%	0.7%	52.5%
IDACORP, INC.	IDA	56.3%	56.4%	58.7%	56.1%	55.5%	$ 2,000.6	$ 2,000.6	$ -	$ -	$ 2,495.1	$ 4,495.7	44.5%	0.0%	0.0%	55.5%
ALLIANT ENERGY	LNT	49.8%	45.7%	47.6%	44.9%	47.0%	$ 7,391.0	$ 6,692.0	$ 699.0	$ 200.0	$ 6,111.8	$ 13,702.8	48.8%	5.1%	1.5%	44.6%
MGE ENERGY INC.	MGEE	66.2%	62.3%	62.0%	64.5%	61.5%	$ 620.2	$ 615.3	$ 4.9	$ -	$ 982.9	$ 1,603.1	38.4%	0.3%	0.0%	61.3%
NEXTERA ENERGY	NEE	47.3%	56.0%	49.6%	46.5%	42.0%	$ 55,341.0	$ 48,092.0	$ 7,249.0	$ -	$ 34,825.2	$ 90,166.2	53.3%	8.0%	0.0%	38.6%
NORTHWESTERN	NWE	49.8%	47.8%	47.5%	47.2%	49.5%	$ 2,519.5	$ 2,516.7	$ 2.8	$ -	$ 2,466.9	$ 4,986.4	50.5%	0.1%	0.0%	49.5%
OGE ENERGY CORP.	OGE	58.3%	58.0%	56.4%	51.0%	45.5%	$ 4,879.0	$ 4,495.8	$ 383.2	$ -	$ 3,753.4	$ 8,632.4	52.1%	4.4%	0.0%	43.5%
OTTERTAIL CORP.	OTTR	58.7%	55.3%	53.1%	58.2%	57.0%	$ 862.4	$ 594.6	$ 267.8	$ -	$ 788.2	$ 1,650.6	36.0%	16.2%	0.0%	47.8%
P.S. ENTERPRISE GP.	PEG	53.4%	52.2%	52.3%	52.4%	46.5%	$ 19,780.0	$ 14,425.0	$ 5,355.0	$ -	$ 12,537.6	$ 32,317.6	44.6%	16.6%	0.0%	38.8%
PNM RESOURCES	PNM	43.6%	38.6%	39.9%	42.9%	40.5%	$ 3,514.1	$ 3,396.0	$ 118.1	$ 11.5	$ 2,319.4	$ 5,845.0	58.1%	2.0%	0.2%	39.7%
PINNACLE WEST	PNW	51.1%	53.0%	52.9%	47.2%	45.0%	$ 7,038.1	$ 6,763.1	$ 275.0	$ -	$ 5,533.4	$ 12,571.5	53.8%	2.2%	0.0%	44.0%
PORTLAND GENERAL	POR	49.9%	53.5%	48.7%	46.4%	44.0%	$ 3,301.0	$ 3,285.0	$ 16.0	$ -	$ 2,581.1	$ 5,882.1	55.8%	0.3%	0.0%	43.9%
PPL CORPORATION	PPL	35.2%	36.7%	38.5%	38.3%	45.5%	$ 11,139.0	$ 10,665.0	$ 474.0	$ -	$ 8,903.8	$ 20,042.8	53.2%	2.4%	0.0%	44.4%
SOUTHERN COMPANY	SO	35.0%	37.6%	39.5%	38.1%	36.0%	$ 52,836.0	$ 48,843.0	$ 3,993.0	$ 291.0	$ 27,637.9	$ 80,764.9	60.5%	4.9%	0.4%	34.2%
SEMPRA ENERGY	SRE	43.5%	38.4%	43.4%	44.8%	49.5%	$ 26,104.0	$ 20,042.0	$ 6,062.0	$ 909.0	$ 20,536.1	$ 47,549.1	42.2%	12.7%	1.9%	43.2%
WEC ENERGY GROUP	WEC	51.9%	49.4%	47.4%	47.1%	45.5%	$ 14,684.0	$ 12,678.0	$ 2,006.0	$ 30.4	$ 10,609.8	$ 25,324.2	50.1%	7.9%	0.1%	41.9%
XCEL ENERGY	XEL	44.1%	43.6%	43.2%	42.6%	42.0%	$ 23,347.0	$ 20,979.0	$ 2,368.0	$ -	$ 15,191.7	$ 38,538.7	54.4%	6.1%	0.0%	39.4%
Maximum		74.4%	73.8%	69.4%	64.5%	67.5%	$ 64,900.0	$ 57,929.0	$ 7,249.0	$ 3,136.0	$ 47,057.2	$ 113,919.2	70.2%	16.6%	7.0%	66.3%
Minimum		15.7%	27.4%	26.2%	24.6%	27.0%	$ 620.2	$ 594.6	$ -	$ -	$ 788.2	$ 1,603.1	31.9%	0.0%	0.0%	26.0%
Median		48.2%	47.1%	47.3%	45.7%	44.8%	$ 13,869.0	$ 12,561.0	$ 786.5	$ -	$ 9,391.8	$ 24,396.0	52.1%	4.5%	0.0%	42.4%
Average		47.0%	47.2%	46.7%	45.2%	45.2%	$ 18,191.0	$ 16,238.4	$ 1,952.6	$ 338.2	$ 12,286.9	$ 30,816.1	51.1%	5.4%	0.7%	**42.8%**

Sources:
[A] Value Line: Most current data available at time of schedule preparation.
[B] Percentage calculated on Total Capital including Short Term Debt.

CAPITAL STRUCTURE WITHOUT SHORT TERM DEBT
RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
		% Common Equity					($ millions)						Percentage			
		2017	2018	2019	2020	2021	Total Debt	LT Debt	ST Debt	Pfd Stock	Equity	Total Capital	LT Debt	ST Debt	Pfd Stock	Equity Ratio
		[A]	[A]	[A]	[A]	[A]	[A]	[A]	[B]	[A]	[A]	[A]	[B]	[B]	[B]	[B]
AMEREN	AEE	49.8%	48.8%	47.1%	44.3%	43.5%	$ 13,054.0	$ 12,444.0		$ 129.0	$ 9,680.1	$ 22,253.1	55.9%	0.0%	0.6%	43.5%
AMERICAN ELEC. PWR.	AEP	48.5%	46.8%	43.9%	41.5%	41.0%	$ 37,082.0	$ 32,056.0		$ -	$ 22,276.2	$ 54,332.2	59.0%	0.0%	0.0%	41.0%
AVANGRID, INC.	AGR	74.4%	73.8%	69.4%	59.2%	67.5%	$ 7,920.0	$ 7,486.0		$ -	$ 15,547.8	$ 23,033.8	32.5%	0.0%	0.0%	67.5%
ALLETE	ALE	59.0%	60.1%	61.4%	59.0%	58.0%	$ 2,026.8	$ 1,649.4		$ -	$ 2,277.7	$ 3,927.1	42.0%	0.0%	0.0%	58.0%
AVISTA CORP.	AVA	52.8%	49.5%	50.6%	49.6%	52.5%	$ 2,398.9	$ 1,949.8		$ -	$ 2,155.0	$ 4,104.8	47.5%	0.0%	0.0%	52.5%
BLACK HILLS CORP.	BKH	35.5%	42.5%	42.9%	42.1%	39.5%	$ 4,458.1	$ 4,125.6		$ -	$ 2,693.6	$ 6,819.2	60.5%	0.0%	0.0%	39.5%
CMS ENERGY CORP.	CMS	32.4%	30.7%	29.4%	28.6%	34.0%	$ 12,660.0	$ 12,075.0		$ 261.0	$ 6,354.9	$ 18,690.9	64.6%	0.0%	1.4%	34.0%
CENTER POINT EN'RGY	CNP	36.4%	37.5%	29.1%	29.9%	36.0%	$ 16,492.0	$ 15,394.0		$ 790.0	$ 9,103.5	$ 25,287.5	60.9%	0.0%	3.1%	36.0%
DOMINION ENERGY, INC.	D	35.6%	39.2%	45.0%	39.5%	38.0%	$ 41,505.0	$ 34,775.0		$ 2,387.0	$ 22,776.7	$ 59,938.7	58.0%	0.0%	4.0%	38.0%
DTE ENERGY CO.	DTE	43.8%	45.8%	42.3%	39.5%	42.5%	$ 17,609.0	$ 16,924.0		$ -	$ 12,509.0	$ 29,433.0	57.5%	0.0%	0.0%	42.5%
DUKE ENERGY	DUK	46.0%	46.2%	44.1%	44.4%	44.0%	$ 64,900.0	$ 57,929.0		$ 1,962.0	$ 47,057.2	$ 106,948.2	54.2%	0.0%	1.8%	44.0%
CON. EDISON	ED	51.1%	48.9%	49.3%	48.0%	47.0%	$ 23,316.0	$ 21,841.0		$ -	$ 19,368.4	$ 41,209.4	53.0%	0.0%	0.0%	47.0%
EDISON INTERNAT'L	EIX	45.8%	38.3%	39.9%	39.5%	35.5%	$ 27,160.0	$ 23,342.0		$ 3,136.0	$ 14,573.2	$ 41,051.2	56.9%	0.0%	7.6%	35.5%
EVERSOURCE ENERGY	ES	48.2%	46.9%	46.6%	47.1%	44.5%	$ 19,427.0	$ 17,874.0		$ 155.6	$ 14,456.2	$ 32,485.8	55.0%	0.0%	0.5%	44.5%
ENTERGY CORP.	ETR	35.5%	35.9%	37.1%	33.7%	32.5%	$ 25,363.0	$ 24,212.0		$ 254.4	$ 11,780.1	$ 36,246.5	66.8%	0.0%	0.7%	32.5%
EVERGY, INC.	EVRG	--	60.0%	49.4%	48.7%	49.0%	$ 10,784.0	$ 9,297.3		$ -	$ 8,932.7	$ 18,230.0	51.0%	0.0%	0.0%	49.0%
EXELON CORP.	EXC	47.8%	47.2%	50.4%	47.9%	49.0%	$ 41,701.0	$ 35,659.0		$ -	$ 34,260.6	$ 69,919.6	51.0%	0.0%	0.0%	49.0%
FIRST ENERGY	FE	15.7%	27.4%	26.2%	24.6%	27.0%	$ 23,733.0	$ 22,503.0		$ -	$ 8,323.0	$ 30,826.0	73.0%	0.0%	0.0%	27.0%
FORTIS, INC.	FTS.TO	37.1%	37.2%	41.8%	40.5%	41.0%	$ 25,594.0	$ 24,720.0		$ 1,623.0	$ 18,306.2	$ 44,649.2	55.4%	0.0%	3.6%	41.0%
HAWAIIAN ELECTRIC	HE	55.7%	51.7%	54.6%	52.7%	53.5%	$ 2,337.0	$ 2,244.8		$ 34.3	$ 2,622.2	$ 4,901.3	45.8%	0.0%	0.7%	53.5%
IDACORP, INC.	IDA	56.3%	56.4%	58.7%	56.1%	55.5%	$ 2,000.6	$ 2,000.6		$ -	$ 2,495.1	$ 4,495.7	44.5%	0.0%	0.0%	55.5%
ALLIANT ENERGY	LNT	49.8%	45.7%	47.6%	44.9%	47.0%	$ 7,391.0	$ 6,692.0		$ 200.0	$ 6,111.8	$ 13,003.8	51.5%	0.0%	1.5%	47.0%
MGE ENERGY INC.	MGEE	66.2%	62.3%	62.0%	64.5%	61.5%	$ 620.2	$ 615.3		$ -	$ 982.9	$ 1,598.2	38.5%	0.0%	0.0%	61.5%
NEXTERA ENERGY	NEE	47.3%	56.0%	49.6%	46.5%	42.0%	$ 55,341.0	$ 48,092.0		$ -	$ 34,825.2	$ 82,917.2	58.0%	0.0%	0.0%	42.0%
NORTHWESTERN	NWE	49.8%	47.8%	47.5%	47.2%	49.5%	$ 2,519.5	$ 2,516.7		$ -	$ 2,466.9	$ 4,983.6	50.5%	0.0%	0.0%	49.5%
OGE ENERGY CORP.	OGE	58.3%	58.0%	56.4%	51.0%	45.5%	$ 4,879.0	$ 4,495.8		$ -	$ 3,753.4	$ 8,249.2	54.5%	0.0%	0.0%	45.5%
OTTERTAIL CORP.	OTTR	58.7%	55.3%	53.1%	58.2%	57.0%	$ 862.4	$ 594.6		$ -	$ 788.2	$ 1,382.8	43.0%	0.0%	0.0%	57.0%
P.S. ENTERPRISE GP.	PEG	53.4%	52.2%	52.3%	52.4%	46.5%	$ 19,780.0	$ 14,425.0		$ -	$ 12,537.6	$ 26,962.6	53.5%	0.0%	0.0%	46.5%
PNM RESOURCES	PNM	43.6%	38.6%	39.9%	42.9%	40.5%	$ 3,514.1	$ 3,396.0		$ 11.5	$ 2,319.4	$ 5,726.9	59.3%	0.0%	0.2%	40.5%
PINNACLE WEST	PNW	51.1%	53.0%	52.9%	47.2%	45.0%	$ 7,038.1	$ 6,763.1		$ -	$ 5,533.4	$ 12,296.5	55.0%	0.0%	0.0%	45.0%
PORTLAND GENERAL	POR	49.9%	53.5%	48.7%	46.4%	44.0%	$ 3,301.0	$ 3,285.0		$ -	$ 2,581.1	$ 5,866.1	56.0%	0.0%	0.0%	44.0%
PPL CORPORATION	PPL	35.2%	36.7%	38.5%	38.3%	45.5%	$ 11,139.0	$ 10,665.0		$ -	$ 8,903.8	$ 19,568.8	54.5%	0.0%	0.0%	45.5%
SOUTHERN COMPANY	SO	35.0%	37.6%	39.5%	38.1%	36.0%	$ 52,836.0	$ 48,843.0		$ 291.0	$ 27,637.9	$ 76,771.9	63.6%	0.0%	0.4%	36.0%
SEMPRA ENERGY	SRE	43.5%	38.4%	43.4%	44.8%	49.5%	$ 26,104.0	$ 20,042.0		$ 909.0	$ 20,536.1	$ 41,487.1	48.3%	0.0%	2.2%	49.5%
WEC ENERGY GROUP	WEC	51.9%	49.4%	47.4%	47.1%	45.5%	$ 14,684.0	$ 12,678.0		$ 30.4	$ 10,609.8	$ 23,318.2	54.4%	0.0%	0.1%	45.5%
XCEL ENERGY	XEL	44.1%	43.6%	43.2%	42.6%	42.0%	$ 23,347.0	$ 20,979.0		$ -	$ 15,191.7	$ 36,170.7	58.0%	0.0%	0.0%	42.0%
Maximum		74.4%	73.8%	69.4%	64.5%	67.5%	$ 64,900.0	$ 57,929.0		$ 3,136.0	$ 47,057.2	$ 106,948.2	73.0%	0.0%	7.6%	67.5%
Minimum		15.7%	27.4%	26.2%	24.6%	27.0%	$ 620.2	$ 594.6		$ -	$ 788.2	$ 1,382.8	32.5%	0.0%	0.0%	27.0%
Median		48.2%	47.1%	47.3%	45.7%	44.8%	$ 13,869.0	$ 12,561.0		$ -	$ 9,391.8	$ 23,176.0	54.8%	0.0%	0.0%	44.8%
Average		47.0%	47.2%	46.7%	45.2%	45.2%	$ 18,191.0	$ 16,238.4		$ 338.2	$ 12,286.9	$ 28,863.5	54.0%	0.0%	0.8%	**45.2%**

Sources:

[A] Value Line: Most current data available at time of schedule preparation.

[B] Percentage calculated on Total Capital excluding Short Term Debt.

Exhibit ALR-A

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2019-290-WS - ORDER NO. 2020-306

APRIL 9, 2020

IN RE:	Application of Blue Granite Water Company for Approval to Adjust Rate Schedules and Increase Rates	))))	ORDER RULING ON APPLICATION FOR ADJUSTMENTS IN RATES

EXECUTIVE SUMMARY

■ **Executive Summary**

To provide a condensed summary explanation of our reasoning with respect to certain significant components of this Order for the convenience of the reader, we offer the following Executive Summary which is not exclusive all findings and actions below in the Order of the Commission. This Executive Summary shall not be controlling, or have any substantive impact, regarding all findings and rulings contained in this Order by the Commission if there is any conflict between the Executive Summary and remainder of the Order. The Commission deems that this Summary shall not be controlling if any conflict exists between the text of Executive Summary and the text of the findings and actions of the Commission below in this Order. It is the text of the findings and actions of the Commission's Order, beginning at Section I below, that is controlling in construing the plain meaning of any finding or ruling of the Commission.

► **Return on Equity ("ROE")**

The Commission is the fact finder in rate proceedings and must balance the interests of the using and consuming public with that of the utility appearing before it. From witnesses presented by the Office of Regulatory Staff (ORS) and the South Carolina Department of Consumer Affairs (Consumer Affairs), the record of evidence before the Commission indicates that the cost of common equity nationally is on the decline. Tr. p. 672.13. Also, the evidence in the record clearly supports the Commission's conclusion that Blue Granite Water Service Company ("Blue Granite," "Company," or "utility") witness D'Ascendis' proposed Return on Equity ("ROE") is too high. Witness D'Ascendis initially recommended in his direct testimony a ROE between 10.20% and 10.70% Tr. p. 547.4, ln. 9-12. However, in his rebuttal testimony, witness D'Ascendis updated his analysis and recommended a range between 9.75% and 10.25%. Tr. p. 548.4, ln. 4-9. In contrast, both ORS witness Parcell and Consumer Affairs witness Rothschild presented ROE recommendations for Blue Granite that comply with the requirements set forth in *Federal Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 602-03(1944) ("*Hope*") and *Bluefield Water Works and Improvement Co. v. Pub. Ser. Comm'n of West Virginia*, 262 U.S. 679, 692-93 (1923) ("*Bluefield*").

Considering the quality of service issues known to exist with Blue Granite and the setting of just and reasonable rates and all of the evidence, including the analysis and methodologies used by the three ROE witnesses in this proceeding, the Commission concludes that the analysis used by Consumer Affairs witness Rothschild is the most compelling, applies cost of equity models using water utility companies without the influence of non-utility companies, is objectively just and reasonable, and supported by ample evidence in the record. Tr. pp. 672.8-672.10. After review of all evidence and analysis provided by the witnesses of the parties, we conclude and find that the ROE of 7.46% provided by Consumer Affairs witness Rothschild is the appropriate ROE for Blue Granite based upon (a) the evidence on the whole record, (b) the rate of return methodology, and (c) a historical test year beginning July 1, 2018 and ending June 30, 2019. The Commission approves a ROE of 7.46% for Blue Granite.

With the above approved ROE of 7.46%, the Commission finds and adopts the resulting total Revenue Requirement for Blue Granite of $28,733,986, which is an increase of $4,958,848 consisting of an additional $2,161,536 in water revenues and an additional $2,797,312 in sewer revenues. This represents an approximate 57% reduction from the Company's requested operating revenue increase of $11,589,537 made in its Application. Additionally, the resulting Operating Margin of 10.54% is found to be just and reasonable and is adopted by the Commission for Blue Granite in accordance with S.C. Code Ann. §58-5-240(H).

► **Depreciation Schedule**

As part of this Application proceeding, Blue Granite conducted its first depreciation study of its water and sewer plant assets in thirty-five (35) years. Blue Granite witness Spanos stated that the Company's current depreciation rates are outdated and were premised upon unrealistically long depreciable lives for facilities and equipment. Tr. p. 564, ln. 17 – p. 565, ln. 3. ORS witness Garrett recommended that the Commission reduce Blue Granite's depreciation accrual by approximately $760,236 calculated as of December 31, 2018. Tr. p. 1065, ln. 19. Based on the evidence in the record, Blue Granite's existing depreciation rates, which assume a 66 2/3-year useful life for all asset accounts, are largely inaccurate. The service lives proposed by witness Spanos for several of the plant accounts in the depreciation studies prepared by Company witness Spanos are too short given the evidence supporting such service life proposals. Tr. p. 1066, ln. 21-25.

The evidence is clear in this case that an update to Blue Granite's depreciation rates and depreciation expense is needed. Both Company witness Spanos and ORS witness Garrett agree on this. The evidence in the record shows that Blue Granite's current depreciation rates are artificially low and out of date. The question before the Commission is whether witness Spanos or witness Garrett's proposed accrual rates and expense level are more reasonable and supported by the evidence in the record.

The Commission finds that ORS witness Garrett was credible and compelling in his analysis. Garrett employed reasonable and objective orientated methodology in proposing accrual rates, service lives, and net salvage estimates. In addition to reducing Blue Granite's depreciation accrual by approximately $760,236, the Commission further adopts ORS witness Garrett's recommended service life estimates and net salvage cost estimates for the purposes of setting Blue Granite's depreciation rates and depreciation expense.

► **Non-Revenue Water Loss Expense Recovery**

Based upon the Record and the public interest, the Commission deems that it is appropriate, just and reasonable to continue to the current ten percent (10%) threshold for recovery of non-revenue water set in Blue Granite's prior rate case. See Order No. 2018-345 & 2018-345(A). While Blue Granite is correct that the American Water Works Association (AWWA) no longer appears to recommend across-the-board thresholds, Blue Granite has not provided subdivision-specific proposals for the Commission to consider. Instead, Blue Granite proposes to recover all non-revenue water from customers, or that a threshold of 20% be set.

The Commission finds the approach of "recovering all non-revenue water from customers" is unreasonable and not beneficial to the customer. It also does not adequately incentivize Blue Granite to reduce nonrevenue water losses. With regard to increasing the non-revenue water loss recovery threshold to twenty percent (20%), the Commission finds that Blue Granite has not provided sufficient justification to double the threshold set in the prior case. While Blue Granite testifies to projects undertaken to reduce non-revenue water, the Company did not provide any quantifiable support for how those projects have reduced non-revenue water. Therefore, the Commission finds that the current ten percent (10%) threshold for the recovery of non-revenue water shall remain in place at this time.

► **Annual Rate Adjustment Mechanism ("ARAM")**

The Commission denies Blue Granite's request in its Application for its proposed Annual Rate Adjustment Mechanism ("ARAM"). The ARAM originally proposed by Blue Granite would have allowed Blue Granite to charge customers for all water they did not consume and for all wastewater that they did not create. It is a "pass-through" mechanism to charge customers for changes in purchased water and wastewater expenses and to recover a significant expense with little to no review and inadequate consumer protections. Tr. p. 1214.2, ln. 13-15, 19-20.

Additionally, the Commission finds that the ARAM would not improve bill clarity for customers because the methodology for calculating the purchased water and sewer charges is confusing and does not yield a number that reflects the actual cost of the purchased water or sewer treatment charged by the third-party provider.

The Commission also declines to approve the changes Blue Granite proposed to its rate structure to add separate purchased water and sewer treatment charges, which were proposed to effectuate the ARAM. Blue Granite shall maintain its existing rate structure of a Base Facility Charge (unchanged and without increase), a commodity charge based on water consumption for water customers, and per Single Family Equivalent charge for sewer customers. As further discussed herein, and as provided in the attached approved Rate Schedule in Attachment No. 2, the rate schedule/tariff incorporate the changes approved herein reflecting an Operating Margin of 10.54% and 7.46% ROE, including all adjustments approved and adopted by the Commission, which retains the present base facility charge for water service and distributes the rate increase volumetrically to lessen the impact of the rate increase on low-usage water customers.

► **Greenville Office Move, Upfit and Rent Expense**

The Commission approves the adjustment recommended by ORS to disallow the costs of the upfit to Blue Granite's new Greenville office in the amount of $495,206. Blue Granite indicated employee retention issues were the reason the Company moved its headquarters to Greenville. The Company testified that "[a]ttracting talent in the Columbia market [was] extremely difficult due to the legacy brand issues in that market." The legacy brand issues were caused by Carolina Water Service, which is now rebranded as Blue Granite. Blue Granite's customers should not have to pay the costs to upfit the Greenville office, given the move was necessitated by legacy brand problems the Company created, and Blue Granite previously represented to this Commission and its customers that the refreshing of its brand would be at no cost to customers. Exhibit KDM-2.

Additionally, based upon the record and for same legacy issues as the reason for the sale of its office and move to Greenville, the Commission further finds and determines that the pro-forma rent expense of $84,839 should also be removed from the Company's recoverable General Expenses for Rent and is hereby denied.

► **LETTS Tank Pumping Charge**

Blue Granite, in its Application, requested authority to amend its tariff language and fees related to solids interceptor ("LETTS") tanks to change the pumping charge from $150 to the actual cost to access, pump, and service the tanks on a periodic basis. Tr. p. 362.13, ln. 3-8. Due to cost concerns for all customers, ORS does not oppose Blue Granite's request to change the treatment of LETTS tanks in its tariff such that customers who cause the expense will pay the actual cost of the service; however, ORS asserts that several customer protections must be incorporated into Blue Granite's revised LETTS tariff to protect its customers. Tr. p. 1190.7, ln. 3 - p. 1190.8, ln. 9. ORS witness Bickley provided proposed tariff language for Blue Granite to use and for the Commission to review which incorporated the ORS's proposed modifications to Blue Granite's LETTS tank tariff, including language of "what constitutes an emergency condition" under which Blue Granite could pump the tank without giving the customer the opportunity to select a different vendor. *Id*; Exhibit 38.

Based upon the testimony and evidence in the record, including that of Intervenor Forty Love Point Homeowners' Association, Commission grants Blue Granite's request to amend its tariff language and fees related to Solids Interceptor ("LETTS") Tanks to change the pumping charge from $150 to the actual cost to access, pump, and service the tanks on a periodic basis, with and incorporating the changes recommended by ORS to Blue Granite's proposal. The Commission further approves and adopts ORS's proposed tariff language related to Solids Interceptor ("LETTS") Tanks in Exhibit 38, including ORS's language of what constitutes an emergency condition under which Blue Granite could pump the tank without giving the customer the opportunity to select a different vendor. Exhibit No. 38; *See, also*, Exhibit No. BSB-1. Blue Granite provided no alternate definition of "what constitutes an emergency condition" for the Commission to consider.

► **Contributions in Aid of Construction Under Tax Cuts and Jobs Act**

Due to a lower corporate tax rate as changed by the Tax Cuts and Jobs Act (TCJA), Blue Granite seeks Commission authority to initiate a one-time credit to each customer water and sewer account, to return overcollections of Federal tax expenses accumulated during the period of January 1, 2018 through June 28, 2018. Tr. p. 1115.25, ln. 11-13. Blue Granite witness DeStefano testified that Blue Granite over-collected $335,713. It is undisputed by Blue Granite and the ORS that this overcollection of funds needs to be returned to each customer water and sewer service account.

Consumer Affairs witness Morgan recommends that these over-collected tax funds from customers should be used to offset the deferred purchased water and sewer treatment costs instead of providing a direct refund to customers. Tr. p. 651.15. ORS verified the Company's calculations using updated pro forma customer bills of 31,710 and calculated a one-time credit of $10.59 per account. Tr. p. 1115.25, ln. 14-16. Blue Granite agreed with this updated calculation by ORS based on adjusted pro-forma customer counts. Tr. p. 764.4, ln. 18-19.

The Commission concurs with Blue Granite and ORS and finds that this overcollection of funds needs to be returned to each customer water and sewer service account by providing the one-time credit of $10.59. The evidence in the record supports the proposed adjustment in the amount of $335,713 and the calculated one-time credit of $10.59 as verified and calculated by ORS using the Company's updated data. The Commission further finds that the same is just and reasonable and therefore, orders this one-time credit by Blue Granite in the amount of $10.59 as proposed by ORS for each customer water account and sewer account effective upon the date of this Order. Blue Granite is to issue these credits to customers as soon as possible and within its next billing cycle following the date of this Order.

► **Storm Reserve Fund**

In addition to an increase in base rates, Blue Granite is seeking the authority to create a Storm Reserve Fund for extraordinary storm restoration costs such as those experienced following Hurricane Florence. Tr. p. 354.22, ln 17-20. Blue Granite wants to set aside $200,000 which would be funded through a monthly surcharge of $0.53 per customer. Once the $200,000 threshold is reached, the monthly charge would be suspended, and any over-collections during that last month would be refunded to customers the following month. Tr. p. 764.24, ln. 18-20.

Blue Granite witness Mendenhall testified that major storm events cause the utility to experience service disruptions due to temporary power loss and damage to supply or treatment infrastructure. Tr. p. 363.11, ln. 3-6. The Storm Reserve Fund would be used for extraordinary storm restoration costs that were not included in the Company's revenue requirement or part of its current rate base recovery.

Blue Granite witness DeStefano also rejected the modifications to the Storm Reserve Fund offered by ORS and by Consumer Affairs. Tr. p. 764.23, ln. 16-22. Even though witness DeStefano agreed that periodic reporting and utilization of funds only for named storms was reasonable, DeStefano testified that such modifications to the Storm Reserve Fund would not serve Blue Granite's ultimate purpose for the Fund.

ORS reviewed Blue Granite's past ten (10) years of storm restoration costs using a ten-year average. After removing the high and low values, ORS witness Bickley testified that ORS's review found the average yearly storm cost to be $28,320.51. Tr. p. 1186, ln. 15-19. The ORS also recommends a normalization adjustment of storm costs which would be $23,481. The "method of normalization of storm costs more accurately reflects storm costs for each year." Tr. p. 1186, ln. 23-25. ORS witness further testified that the proposed Storm Reserve Fund by Blue Granite did not have any guidelines on how the Company would access the Fund or customer protections to restrict use, access, or operation of the Fund. Tr. p. 1187, ln. 4-14; Tr. p. 1188.

ORS witness Bickley provided ORS's recommendation to modify the Fund to include sufficient customer protections. With these modifications, the ORS was willing to support a Storm Reserve Fund which limited the Fund balance to $50,000 and adoption of storm normalization so that once the Company had incurred $28,321 in storm damage, it could access the money in the account. Tr. p. 1187, ln. 7-14.

Consumer Affairs witness Morgan testified that the Storm Reserve Fund was not necessary because a significant portion of the water and sewer utility infrastructure is below ground. Tr. p. 651.19. He also testified that the establishment of the storm fund is not necessary at this time. Tr. p. 649, ln. 9; Tr. p. 651.19. Consumer Affairs also believed that a monthly surcharge of $0.53 per customer account was an unnecessary fee to impose on customers and that Blue Granite's data did not support the creation of a Storm Reserve Fund.

The Commission finds ORS witness Bickley's testimony compelling and agrees with Consumer Affairs witness Morgan that it is unreasonable to make a significant policy change based upon a rare occurrence. The current process established by the Commission allows the utility to seek deferred accounting treatment for unusual circumstances. There is no need to burden Blue Granite customers with higher rates to create a fund that history shows will likely end up unused on Blue Granite's balance sheet. We conclude that the Storm Reserve Fund is not necessary.

Based upon the evidence in the record, the Commission finds that Blue Granite's request to establish a $200,000 Storm Reserve Fund is not needed at this time and that the request is denied. According to the Company's own data, there have been only two times when the Company was allowed deferred accounting treatment. Tr. p. 658.5. The Commission further adopts the position of Consumer Affairs that not only is the fund not needed by Blue Granite to provide safe and reliable service, but also it is unreasonable to establish a $200,000 Reserve Fund because a level of storm costs was incurred one-time due to unusual circumstances of two back to back hurricanes occurring in a short span of time from the other.

► **Round Up Program**

Like Consumer Affairs and ORS, the Commission encourages Blue Granite's efforts to assist and help its customers. Its proposed Round Up Program ("Program") can provide some level of financial aid to certain low-income customers in its service territories. There was no evidence presented by the Company to indicate how many of its customers, if any, would benefit from such a program in Blue Granite's service territory. The Commission also realizes in reviewing proposed rate schedule of Blue Granite and the average water and sewer bills that a $50 benefit level may not completely pay a customer's entire water bill, sewer bill, or water/sewer bill.

The Company also did not provide any supporting evidence for its estimated administrative costs for the Program; therefore, the costs are not known or measurable.

None of Blue Granite's affiliate companies have a similar program and ORS did not know of any other water or sewer utility regulated by the Commission with a similar program. The Program will not impact the ability of Blue Granite to provide safe and reliable services or to manage its administrative duties in maintaining and operating well-functioning water and sewer systems for the public. Therefore, the Commission finds that Blue Granite should pay for all the Program costs and not its ratepayers or customers.

As discussed herein and based upon the record, the Commission approves the Round Up Program as modified by ORS as reflected in testimony of ORS witness Bickley and in witness Sullivan's Audit Exhibit DFS-5, Adjustment 15b ($0). The

Commission denies Blue Granite's request to recover the estimated costs for the Round Up Program related to modifications of its billing system and MyUtilityConnect customer service application for recovery in the Company's next rate proceeding. Blue Granite's request for recovery of the estimated cost for bill inserts/flyers to be used for the Round Up Program is also denied per recommendation of ORS that is adopted by the Commission.

The Commission further clarifies that Blue Granite is prohibited from passing onto its customers the administrative and implementation costs for the Program, including the bill inserts, notice or flyers, and for the modifications to Blue Granite's billing and customer service systems.

► **Cost of Service Study**

It became clear that throughout this proceeding that the parties recognized that a Cost of Service Study is essential to determine the proper rate design or that there cannot be significant rate design structural changes without such information. ORS recommends that the Commission require Blue Granite conduct a cost of service study to coincide with the test year and include it as part of its next rate case. Tr. p. 1214.7. Blue Granite agreed that it was willing to conduct and file a cost of service study in its next rate case. Tr. p. 764.37. ORS asserts a cost of service study is essential to determine the proper rate design and previously the Commission has required significant rate design changes to be fully supported by relevant data prior to implementing the proposed changes. Tr. 1214.7. Fundamentally, the cost of service study will demonstrate which costs need to be recovered and from which customer classes the cost should be recovered. Id. ORS believes Blue Granite should retain its existing rate structure of a Base Facility Charge, a commodity charge based on water consumption for water customers and per Single Family Equivalent charge for sewer customers until a cost of service study is completed.

► **Service and Billing Issues**

The Commission held six public night hearings at locations spread throughout Blue Granite's two service territories: Lexington, Irmo, Union, Greenville, Columbia, and York. In the aggregate, over 500 people attended these hearings, and more than 150 requested the opportunity to testify. The witnesses who testified were angry at the size of Blue Granite's proposed increase. They also complained that the proposed rates, when compared to neighboring utilities, were extremely high, and that the flat-rate design used by the Company for its sewer customers was unfair to low-usage customers. The customers testified about poor service, including poor water quality, unresponsive customer service representatives, inaccurate meter readings, billing errors, and unwarranted service cut-offs, among other problems. The Commission found the customer testimony presented at the night hearings both credible and compelling. It is evident that customer service problems are persistent, widespread, and pervasive throughout Blue Granite's service territories.

While the applicable law set out by the South Carolina Supreme Court will not permit us to deny outright Blue Granite's application for a rate increase in this case, we are entitled to consider the night hearing testimony in creating incentives for the utility to improve its business practices, cut costs, improve efficiency, and enhance quality of service.

Accordingly, we order the Company to implement systems designed to improve customer service and to issue reports to the Commission periodically providing the results and details of its efforts.

► **Disallowed Expenditures**

Based upon the record and evidence presented by the parties in this Docket, the Commission did find that certain expenditures, costs and revenue recovery by the Company were imprudent and should not be allowed. These are discussed in detail in the Order below and in the adjustments supported in the record.

The Commission received detail information from ORS witness about its audit and examination of the Company, as well the responses and rebuttal by the Company's witnesses about costs, expenses, supporting documentation and its accounting for all revenues and expenditures. For example, the Commission received testimony about audited expenditures for employee service awards. It was discovered that Blue Granite had contained expenses for a 65" LED Curved Samsung TV and a 1.15 carat diamond ring for employee service awards. As explained in the Order, the Commission finds that these expenses are disallowed and cannot be recovered by the Company from the ratepayers. *See*, Tr. p. 1133.7, ln. 1-6. Also, expenses that did not have supporting data or that did not provide a benefit to the customer were also disallowed by the Commission. Another example is rejecting the Company's request to recover expenses for dinners with alcohol or items not supported by documentation. Tr. p. 1133.8, ln. 8-11. These were expenses incurred by Blue Granite that were not necessary to provide water and wastewater services and do not provide a benefit to customers.

The Commission ordered Blue Granite to provide the written reports on capital improvements no less than semiannually filed with the Commission and provided to ORS.

As stated in the beginning, the above Executive Summary is only provided for the convenience of the reader. It is not an exclusive summary of all findings and actions below in the Order of the Commission. The Commission deems that this Summary shall not be controlling if any conflict exists between the text of Executive Summary and the text of the findings and actions of the Commission below in this Order. It is the text of the findings and actions of the Commission's Order below that is controlling in construing the plain meaning of any finding or ruling of the Commission. Also, any heading in this Summary or anywhere contained in this Order shall not be construed to limit the plain meaning of the text. Although titles and headings are part of state statutes and rules, they may not be construed to limit or undo what the text makes plain. *Brotherhood of Railroad Trainmen v. Baltimore & O.R. Co.,* 331 U.S. 519, 67 S.Ct. 1387, 91 L.Ed. 1646 (1947); *Garner v. Houck*, 312 S.C. 481, 486, 435 S.E.2d 847, 849 (1993).

ORDER

I. Introduction

This matter is before the Public Service Commission of South Carolina (the "Commission") on the Application of Blue Granite Water Company ("Blue Granite" or "the Company") filed on October 2, 2019, requesting approval of an increase in the monthly water and sewer rates and charges, as well as approval of all fees and charges, modification of certain terms and conditions for water and sewer services that Blue Granite provides to its customers in its Commission-approved service territories 1 and 2 throughout South Carolina. The Application was filed pursuant to S.C. Code Ann. § 58-5-240 and S.C. Code Ann. Regs. 103-712(4)(A) and 103-512(4)(A).

In its Application, Blue Granite requested to increase service revenues for combined operations by $11,731,803, consisting of a water revenue increase of $5,575,957 and a sewer revenue increase of $6,155,846, and a requested Return on Equity (ROE) of 10.70%. Tr. p. 354.21, ln. 12-17.[1]

Blue Granite Water Company
Summary of Proposed Revenue Increases

	Proposed Revenue Increase	Proposed Percentage Increase
Water Service Revenues – Territory 1	$ 3,636,850	53.5%
Water Service Revenues – Territory 2	$ 1,939,107	34.9%
Consolidated Sewer Service Revenues	$ 6,155,846	55.7%
Total Service Revenues	$ 11,731,803	

Blue Granite's requested revenue increase results in a potential Operating Margin (OM) of 12.26%. According to the Application, Blue Granite requires an increase in rates because it has invested approximately $23 million in its water and sewer systems in order to continue to provide reliable and high-quality water and sewer service to its customers. Tr. p. 362.4. These recent capital investments by Blue Granite include the Shandon Interconnect (Water) project, the Stonegate Interconnect project, the Friarsgate

[1] However, in his rebuttal testimony, Blue Granite witness D'Ascendis updated his analysis and recommended a ROE range between 9.75% and 10.25%. Tr. p. 548.4, ln. 4-9.

Wastewater (Sewer) Interconnect project, the Lake Wylie Charlotte water system interconnection and a series of wastewater collection system ("WWCS") improvement projects. Tr. p. 362.4, ln. 7-12.

Blue Granite has approximately 28,300 customers (16,500 water customers and 11,800 sewer customers) in sixteen (16) counties: Lexington, Richland, Sumter, Aiken, Saluda, Orangeburg, Beaufort, Georgetown, Abbeville, Union, Anderson, York, Cherokee, Greenville, Greenwood, and Williamsburg. Tr. p. 354.7, ln. 4-5; Tr. p. 362.3, ln. 18-21. The Company operates 105 water systems and 28 sewer systems in South Carolina and has 105 drinking water permits, 18 NPDES permits, and 10 satellite sewer system permits to support operations to these systems. Tr. p. 362.3, ln. 21 – p. 362.4, ln. 3. *See, also* Tr. p. 1213.4-1213.5 (ORS witness Sandonato provides updated and specific Test Year data on the exact number of customers of Blue Granite); Exhibit AMS-4.

Blue Granite provides water supply and distribution-only services to its residential and commercial customers in its service territories. Water is provided to its customers by Blue Granite through Blue Granite-operated wells or by third party water providers. Tr. p. 1213.4, ln. 15-16. ORS witness Sandonato testified that:

> During the Test Year, Blue Granite purchased water to distribute to its customers from governmental entities including the City of West Columbia, York County, City of Charlotte [North Carolina], Lexington County Joint Municipal Water and Sewer Authority, City of Columbia, town of Lexington, West Anderson Water District, Broadway Water and Sewer, Hammond Water, City of Rock Hill, City of York, Starr-Iva Water co., Electric City Utilities, and Sandy Springs Water District. There are one hundred and five (105) water supply and distribution-only systems with active South Carolina Department of Health and Environmental Control ("DHEC") Drinking Water Permits operated by Blue Granite. . . . Blue Granite provides fire protection service to customers in the Lake

> Wylie service area, the Oakwood Baptist Church, Washington Heights, and Hidden Valley Mobile Home Park located in the I-20 service area.

Tr. p. 1213.4, ln. 16 – p. 1213.5, ln 2.

Blue Granite operates a total of twenty-eight (28) sewer collection and treatment systems. Tr. p. 1213.5, ln 15-16. Blue Granite operates nine (9) sewer collection-only systems for which it collects wastewater from its customers and transports the sewer wastewater to another entity for treatment and disposal. Sewer treatment and disposal is provided to Blue Granite collection-only customers by York County, Richland County, Georgetown County Water and Sewer, the Town of Chapin, Beaufort-Jasper Water and Sewer, City of Columbia, and the Town of Lexington. Tr. p. 1213.5, ln 16-21.

Blue Granite states that it is making this Application for a rate increase at this time due to increases in expenses and the inability of the Company to earn its currently authorized rate of return. Blue Granite witness DeStefano testified that:

> With the plant investments the Company has made to maintain and improve its service to customers, and the increased operating expenses we have experienced since August of 2017, the end of the Test Year in the Company's last rate case, we are unable to earn our authorized rate of return and therefore are requesting rate relief. More specifically, we have made capital investments of over $23 million since the last rate case, including several interconnection projects and numerous wastewater collection system improvement projects, to serve our customers.

Tr. p.763.4, ln. 9-15.

Blue Granite asserts in its Application that its operation and maintenance expenses have increased by approximately $7.5 million since the last rate case, primarily driven by increases in rates from third-party providers for purchased water and wastewater treatment services, property tax expenses due to the aforementioned capital investment, and updates in depreciation rates. According to the Company, rate relief is needed to enable the Company to provide safe, reliable, and compliant water and wastewater service to South Carolina customers, and to attract capital for future needed investments in its service territories. Tr. p.763.4, ln. 9-21. According to witness DeStefano, the Company's authorized rate of return is 8.62%[2]; however, Blue Granite is currently earning only 0.10% on an unadjusted basis which means it is actually earning negative 3% on an adjusted basis. Tr. p.763.6, ln. 10-13.

Blue Granite has a current performance bond for utility operations in the form of an Irrevocable Letter of Credit ("ILC") from JPMorgan Chase Bank, N.A. as surety in the amount of $350,000 for water and $350,000 for wastewater operations.[3] Tr. p. 1213.6.

In addition to an increase in base rates adjustment, Blue Granite is also seeking authority for the following new authorizations as discussed by Blue Granite witness DeStefano:

- Authority to create a Storm Reserve Fund for extraordinary storm restoration costs such as those experienced following Hurricane Florence;
- Authority to implement a purchased water and purchased sewer services rate adjustment mechanism; and
- Authority to implement a voluntary customer "Round Up" program.

Tr. pp. 354.22 – 354.23.

[2] Order No. 2018-802 at 35, Docket No. 2017-292-WS (Jan. 25, 2019). Blue Granite's authorized Operating Margin is 13.28% and authorized ROE is 10.50%. *Id.*

[3] As part of this proceeding, ORS does request that the Commission require blue Granite to continue to maintain its current performance bond amount for water operations in the amount of $350,000 and for sewer operations in the amount of $350,000 in compliance with S.C. Code Ann. §58-5-720 (2015).

II. Procedural History

Blue Granite Water Company filed its notice of intent to apply to adjust its rates on August 30, 2019, and it filed its Application on October 2, 2019. The Company filed amended exhibits to its application on October 16, 2019. The Clerks' Office filed the revised customer and newspaper notices on October 24, 2019. On December 3, 2019, the Company filed an Affidavit of Mailing of the revised notice to all customers, a Certification of Mailing to County and City Administrators, and proofs of publication for The State, the Post and Courier, the Greenville News, the Herald Fort Mill Times, and the Greenwood Index-Journal.

On December 19, 2019, ORS filed a Motion for Partial Summary Judgment Regarding the Proposed Annual Rate Adjustment Mechanism. After an extension, Blue Granite responded on January 6, 2020. ORS withdrew its motion on January 15, 2020, in light of representations in Blue Granite's direct testimony that the Company was willing to agree to procedural protections in connection with the ARAM that were not delineated in its application.

The Commission Clerk's Office established a deadline to file a petition to intervene of December 16, 2019. The Commission received petitions to intervene from Forty Love Point Homeowners' Association ("Forty Love"); the Building Industry Associations of South Carolina; the South Carolina Department of Consumer Affairs ("Consumer Affairs"); the Town of Irmo; James S. ("Jim") Knowlton; Stefan Dover; and

York County, South Carolina. The Commission granted all petitions to intervene filed in this docket[4].

Pursuant to the schedule for prefiled testimony established by the Clerk's Office, the deadline for the Company's Direct Testimony was December 30, 2019; Intervenor Direct Testimony was due January 22, 2020; the Company's Rebuttal Testimony was due February 5, 2020; and Intervenor Surrebuttal testimony was due February 12, 2020.

Blue Granite filed the Direct Testimony of Dylan D'Ascendis, Donald Denton, Dante DeStefano, Shawn Elicegui (confidential and public versions), Bryce Mendenhall, and John Spanos on December 30, 2020. Blue Granite filed the Corrected Testimony and Exhibit of Dylan D' Ascendis on January 10, 2020.

Following request for a one-day extension of the remaining prefiled testimony deadlines, the deadline to file direct testimony was extended to January 23, 2020. See Order No. 2020-7-H. ORS, Consumer Affairs, York County, Forty Love, Jim Knowlton, and Stefan Dover filed Direct Testimony. ORS filed the Direct Testimony and Exhibits of Daniel F. Sullivan, David J. Garrett, Kyle D. Maurer, Sr., P.E., Anthony D. Briseno, Anthony M. Sandonato, Brandon S. Bickley, and David C. Parcell, and the Direct Testimony of Charles E. Jackson. Consumer Affairs filed the Direct Testimony and Exhibits of Jerome D. Mierzwa, Lafayette K. Morgan, and Aaron L. Rothschild. Consumer Affairs filed corrected Direct Testimony of Lafayette K. Morgan and Aaron L. Rotshchild on January 31, 2020 and Corrected Exhibits for Mr. Morgan and Mr. Rothschild on February 2, 2020.

[4] See Orders No. 2020-22; 2020-21; 20200-20; 2020-19; 2019-849; 2019-799; 2019-746.

Forty Love filed the Direct Testimony of Barbara King and Reid Radtke. York County filed the Direct Testimony of Eric Rekitt. Stefan Dover and Jim Knowlton also prefiled Direct Testimony. Mr. Dover filed corrected testimony on March 3, 2020.

On February 6, 2020, Blue Granite filed the Rebuttal Testimony and Exhibits of Dante DeStefano, J. Bryce Mendenhall, and Dylan D'Ascendis, and the Rebuttal Testimony of John Spanos and Donald Denton.

Following ORS's request for a one-day extension, the deadline to file Surrebuttal Testimony was extended to February 14, 2020[5]. Consumer Affairs filed the Surrebuttal Testimony of Jerome D. Mierzwa (with Exhibit), Aaron L. Rothschild, and Lafayette Morgan, Jr. Consumer Affairs filed updated Corrected Exhibits for Aaron L. Rothschild on February 25, 2020.

ORS filed the Surrebuttal Testimony and Exhibits of Brandon S. Bickley, Anthony D. Briseno, Dr. Kyle Maurer, Sr., P.E., Daniel F. Sullivan, David C. Parcell, and Testimony of Charles E. Jackson and David J. Garrett. On February 24, 2020, ORS filed the Revised Surrebuttal Testimony and Exhibits of Daniel F. Sullivan, and Anthony M. Sandonato, and the Revised Surrebuttal Testimony of Kyle D. Maurer Sr. and Anthony D. Briseno. The revisions primarily reflected a change to ORS's recommended adjustment for purchased water and sewer expenses going forward.

As discussed in Item IV herein, six (6) public night hearings were held in Lexington, Union, Greenville, York and Richland Counties. A total of more than one hundred sixty (160) Blue Granite customers provided testimony at the night hearings.

[5] Order No. 2020-l0H.

These public witnesses voiced objections to the amount of the requested increase in rates and raised general and specific concerns about the quality of water and customer service provided to them by Blue Granite.

The evidentiary hearing was held at the Commission's Hearing Room, beginning on February 26, 2020, at 10:00 a.m. to receive testimony from the parties and any public witnesses. The Honorable Comer H. "Randy" Randall, Chairman of the Commission, presided.

Blue Granite was represented by Frank R. Ellerbe, III, Esquire, and Samuel J. Wellborn, Esquire.

ORS was represented by Andrew M. Bateman, Esquire, Christopher M. Huber, Esquire, and Alexander W. Knowles, Esquire.

Consumer Affairs was represented by Carri Grube Lybarker, Esquire, Laura Becky Dover, Esquire, Roger P. Hall, Esquire, and Richard L. Whitt, Esquire.

Intervenor Town of Irmo was represented by S. Jahue Moore, Esquire.

Intervenor Forty Love Point Homeowner's Association was represented by Laura P. Valtorta, Esquire.

Intervenor York County, South Carolina, was represented by Michael Kendree, Esquire.

Intervenor James S. Knowlton represented himself pro se.

Intervenor Stefan Dover represented himself pro se.

The other intervenor, the Building Industry Association of South Carolina, represented by John J. Pringle, Esquire, did not file any prefiled testimony or otherwise participate or appear at any public night hearing or in the evidentiary hearing in this Docket. The Building Industry Association of South Carolina did not present any witnesses, nor appear to cross-examine the other party witnesses.

All witnesses were sworn in and had their pre-filed Direct and Rebuttal/Surrebuttal Testimonies, as applicable, accepted into the record, including any corrections and corresponding accompanying exhibits. All witnesses presented summaries of their testimonies and were made available for cross-examination by the other parties to this proceeding. The Town of Irmo did not present any additional witnesses other than those citizen-customers being served by Blue Granite who testified at the night public hearing(s) whose testimony was made part of the record. Tr. pp. 331-336. However, Town of Irmo did cross-examine the other party witnesses during the evidentiary hearing.

III. Public Night Hearings

The Commission held six public night hearings at locations spread throughout Blue Granite's two service territories: Lexington, Irmo, Union, Greenville, Columbia, and York[6]. In the aggregate, over 500 people attended these hearings, and more than 150 requested the opportunity to testify[7]. Most of the customers who testified at these hearings expressed anger at the magnitude of the rate increase sought by the Company in its application, and several of them also complained that the rates charged by Blue Granite were much higher than those charged by neighboring utilities. Many customers

[6] An additional night hearing was scheduled to be held in Anderson, but it was canceled due to severe weather conditions. Anderson-area customers were invited to attend the Greenville night hearing instead.
[7] The night hearing sign-in sheets were entered into evidence as Hearing Exhibits No. 1, 6, 9, 10, 24, and 43.

also complained of the inequity of flat sewer rates. Customers also reported numerous incidents of poor water quality, unresponsive customer service, inaccurate meter readings, billing errors, and unwarranted cut-offs, among other problems. Perhaps the most egregious example of the Company's poor service was presented at the Irmo night hearing, where Pat Steadman testified that the Company had wrongfully plugged his sewer line in July 2019, resulting in his house being flooded with sewage[8].

Many customers urged the Commission to deny the application outright. Some customers complained of the number of increases Blue Granite and related companies had been granted in the recent past, and at least one customer complained that the Company had not been denied a rate increase since 2004.[9] Another accused the Commission of being a "rubberstamp."[10] Neither of these assertions has any basis in fact.

While we find the customer testimony at the public night hearings in this case to be very compelling and indicative of persistent, widespread, and pervasive problems consistent with those which have frustrated customers of this utility for many years, the Supreme Court of South Carolina has made amply clear that these problems are insufficient justification for an outright denial of the Company's application for a rate increase.

In its *USSC* decision, the Supreme Court made several rulings directly relevant to the case before us today. The Court held that the PSC, while no longer charged with the

[8] Tr. pp. 158-61.
[9] Lexington witness Johnny R. Cribb, Jr., Tr. p. 26, ll. 16-17.
[10] Irmo witness Chris Kessler, Tr. p. 178, ll. 9-10.

investigative duties it had performed prior to 2004, remained entitled to create incentives for utilities to improve their business practices, to determine what portions of expenses incurred by utilities should be passed on to their customers, and to encourage measures to cut costs and improve efficiency. *USSC,* 708 S.E.2d 755, 760, 392 S.C. 96, 105. The PSC is the ultimate factfinder in a ratemaking application, with the power to determine, independent of any party, whether a utility has shown that its expenses should be passed on to its customers. 708 S.E.2d at 761, 392 S.C. at 106.

While the *USSC* decision reiterated the longstanding rule that the utility is entitled to a presumption that its expenditures were reasonable and incurred in good faith, 708 S.E.2d at 762-63, 392 S.C. at 109-110, *citing*, *Hamm v. S.C. Pub. Service Comm'n*, 422 S.E.2d 110, 112, 309 S.C. 282, 286 (1992), the PSC is entitled to consider the testimony of non-party customers or other members of the public ("protestants"), which may, when supported by other evidence, overcome the utility's presumption of reasonableness.[11]

One case in which the utility's presumption of reasonableness was overcome by the testimony of a non-party protestant was *Hilton Head Plantation Utilities, Inc. v. Public Service Comm'n of S.C.*, 441 S.E.2d 321, 312 S.C. 448 (1994). In *Hilton Head*, the president of the development's property owner's association testified that some of the expenses incurred by the utility were paid to an affiliate entity. On appeal, the Supreme Court held that affiliate transactions were not entitled to a presumption of reasonableness, and that where the Commission found that the utility failed to present sufficient evidence

[11] "Because the PSC is both entitled and required to consider the evidence presented to it in the formal record, we hold that the PSC is entitled to rely on sworn testimony by non-party protestants to overcome the presumption of reasonableness." 708 S.E.2d at 763, 392 S.C. at 111.

to ascertain reasonableness of the expenditure, the Commission could disallow it. 441 S.E.2d at 323, 312 S.C. at 451.

Construing the Court's opinion in *Hilton Head*, the Court in *USSC* held that the Commission's right to rely upon non-party protestant testimony was not limited to cases in which affiliate transactions are at issue. Rather, the Court held that the Commission was required to "believe or disbelieve [the] evidence submitted," including non-party protestant testimony. *USSC,* 708 S.E.2d 755, 763, 392 S.C. 96, 110-11, *quoting*, *Hilton Head*, 441 S.E.2d at 323, 312 S.C. at 451. The Commission had credited the testimony of several non-party protestants alleging that the quality of the water provided by USSC had not improved, and that they saw no evidence that the Company had made capital improvements as it had claimed in its application. On appeal, however, the Supreme Court held that while the customer testimony raised the specter of imprudence, there was insufficient evidence in the record to overcome the Company's presumption of reasonableness as to its expenditures.

The *USSC* decision also made clear that it was error for the Commission to have denied the Company's application entirely where some of the utility's claimed expenditures were not contested. The Court held that the Commission should have evaluated each claimed expenditure individually and should have credited the Company with those expenditures that were not specifically disallowed based upon the evidence presented. Therefore, where a utility's expenses are found to have increased, even after disallowance of expenditures found imprudent, the utility would be entitled to a rate increase. 708 S.E.2d at 763-64, 392 S.C. at 111-12.

The Supreme Court also held that the Commission erred in finding the rates charged by USSC to distribution-only water customers unfair based upon comparisons to rates charged by neighboring utilities, absent a showing that the utilities were similar enough to be meaningfully compared. 708 S.E.2d at 765, 392 S.C. at 114. And lastly, the Court held that to the extent that the PSC relied upon the recency of the Company's prior rate increase as justification for denial of the application, such reliance was in error. 708 S.E.2d at 765, 392 S.C. at 114-15.

Giving effect to the above-cited Supreme Court decisions as we must, we are legally foreclosed from denying Blue Granite's application for a rate increase in its entirety. Applying the standards set by the Supreme Court, we have evaluated the evidence presented and determined which expenditures we deem properly recoverable from ratepayers and which ones we believe should be disallowed. We have further considered all the customer night hearing testimony and used it to guide us in creating incentives for Blue Granite to improve its business practices, cut costs, improve efficiency, and enhance quality of service.

Accordingly, in response to the customer testimony we received in the night hearings, we order the Company to implement systems designed to monitor customer complaints and track resolution of these complaints to ensure that they are timely and effectively addressed. The Company shall prepare quarterly reports to the Commission and the ORS detailing its efforts to improve responsiveness and customer satisfaction. Additionally, the reports shall provide details of every complaint and the resolution of every complaint, as well as the names and addresses of all complainants for use by ORS in the event follow-up contacts are necessary. The first quarterly reports must be submitted on or before July 1, 2020.

IV. Statutory Standards and Applicable Laws

The current rates now in effect, were approved in Commission Order No. 2018-802, in Docket No. 2017-292-WS. (Commission Order No. 2018-802 and Application, p. 4, ¶ 16). Blue Granite proposes a Test Year of July 1, 2018 to June 30, 2019. (Application, p. 2, ¶ 5).

The Application, testimony, exhibits, affidavits of publication, and public notices submitted by Blue Granite comply with the procedural requirements of the South Carolina Code of Laws and the Regulations promulgated by this Commission.

South Carolina Code Ann. § 58-5-210 provides,

> "[t]he Public Service Commission is hereby, to the extent granted, vested with power and jurisdiction to supervise and regulate the rates and service of every public utility in this State, together with the power, after hearing, to ascertain and fix such just and reasonable standards, classifications, regulations, practices and measurements of service to be furnished, imposed, observed and followed by every public utility in this State and the State hereby asserts its rights to regulate the rates and services of every 'public utility.'"

S.C. Code Ann. § 58-5-210 (2015). Also, "adjustments for known and measurable changes in expenses may be necessary in order that the resulting rates reflect the actual rate base, net operating income, and cost of capital. The adjustments are within the discretion of the Commission and must be known and measurable within a degree of reasonable certainty. Absolute precision, however, is not required." *Hamm v. S.C. Pub. Serv. Comm'n*, 309 S.C. 282, 291, 422 S.E.2d 110, 115 (1992) (citing *Michaelson v. New England Tel. & Tel. Co.,* 121 R.I. 722, 404 A.2d 799 (1979).

> Although the burden of proof of the reasonableness of all costs incurred which enter into a rate increase request rests with the utility, the utility's expenses are presumed to be reasonable and incurred in good faith. *Missouri ex rel. Southwestern Bell Co. v. Public Service Comm'n of Missouri,* 262 U.S. 276, 43 S.Ct. 544, 67 L.Ed. 981 (1923) (Brandis, Jr., J., concurring); *West Ohio Co. v. Pub. Util. Comm'n,* 294 U.S. 63, 55 S.Ct. 316, 79 L.Ed. 761 (1935); *Boise Water Corp. v. Idaho Pub. Util. Comm'n,* 97 Idaho 832, 555 P.2d 163 (1976); *City of Chicago v. Illinois Commerce Comm'n,* 133 Ill.App.3d 435, 88 Ill.Dec. 643, 478 N.E.2d 1369 (1985) (modified by statute as noted in *People ex rel. Hartigan v. Illinois,* 117 Ill.2d 120, 109 Ill.Dec. 797, 510 N.E.2d 865 (1987); *Long Island Lighting Co. v. Pub. Serv. Comm'n,* 134 A.D.2d 135, 523 N.Y.S.2d 615 (1987); *City of Norfolk v. Chesapeake & Potomac Tel. Co.,* 192 Va. 292, 64 S.E.2d 772 (1951). This presumption does not shift the burden of persuasion but shifts the burden of production on to the . . . other contesting party to demonstrate a tenable basis for raising the specter of imprudence. *Long Island, supra.* . . . . The ultimate burden of showing every reasonable effort to minimize . . . costs remains on the utility. *Hamm v. South Carolina Pub. Serv. Comm'n and Carolina Power and Light Co.,* 291 S.C. 119, 352 S.E.2d 476 (1987).

Hamm v. S.C. Pub. Serv. Comm'n, 309 S.C. 282, 286–87, 422 S.E.2d 110, 112–13 (1992). The Commission's ratemaking authority "to supervise and regulate" rates and service and "to fix just and reasonable standards, classifications, regulations, practices, and measurements of service," S.C. Code Ann. § 58–3–140(A) (1976 & Supp.2020), entitles the Commission

> **to create incentives for utilities to improve their business practices**. Accordingly, the **PSC may determine that some portion of an expense** actually incurred by a utility **should not be passed on to consumers**. *Patton v. S.C. Public Service Comm'n,* 280 S.C. 288, 292, 312 S.E.2d 257, 259–60 (1984); *see Southern Bell Telephone,* 270 S.C. at 599, 244 S.E.2d at 283 (finding it was not improper for the PSC to consider whether a utility could undertake measures to cut costs and improve efficiency).

Utilities Servs. of S.C., Inc. v. S.C. Office of Regulatory Staff, 392 S.C. 96, 105, 708 S.E.2d 755, 760 (2011) (emphasis added).

The Commission must determine a fair rate of return that the utility should be allowed the opportunity to earn after recovery of the expenses of utility operations. The legal standards for this determination are set forth in *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 602-03(1944) ("*Hope*") and *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-93 (1923) ("*Bluefield*").

Bluefield holds that:

> What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting the opportunities for investment, the money market and business conditions generally.

Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. at 692-93.

When determining an appropriate return for public utilities, this Commission and South Carolina courts have consistently applied the principles set forth in *Bluefield* and *Hope*. In *Southern Bell Tel. &Tel. Co. v. Pub. Serv. Comm'n,* 270 S.C. 590, 597, 244 S.E. 2d 278, 281 (1978), quoting *Hope*, the South Carolina Supreme Court held:

> …[u]nder the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling…The ratemaking process under the Act, i.e., the fixing of 'just and reasonable' rates, involves the balancing of investor and the consumer interests.

Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 602-03(1944). It is the responsibility, duty and delegated charge granted by the Legislature for the Commission to weigh the evidence and to draw "the ultimate conclusion therefrom as to what return is necessary to enable a utility to attract capital . . . . It has been said many times that this is so because the Commission is a body of experts 'composed of men [and women] of special knowledge, observation, and experience' in the field of rate regulation." *S. Bell Tel. & Tel. Co. v. Pub. Serv. Comm'n*, 270 S.C. 590, 597, 244 S.E.2d 278, 282 (1978), holding modified by *Parker v. S.C. Pub. Serv. Comm'n,* 280 S.C. 310, 313 S.E.2d 290 (1984).

This Commission must exercise its dual responsibility of permitting utilities an opportunity to earn a reasonable return, on the one hand, and protecting customers from rates that are so excessive as to be unjust or unreasonable, on the other, by "(a) Not depriving investors of the opportunity to earn reasonable returns on the funds devoted to such use as that would constitute a taking of private property without just compensation [and] (b) Not permitting rates which are excessive." *Southern Bell*, 270 S.C. at 605.

Additionally, the Commission's determination of a fair rate of return must be documented fully in its findings of fact and based exclusively on reliable, probative, and substantial evidence on the whole record. *Porter v. South Carolina Public Service Commission*, 332 S.C. 93, 99, 504 S.E2d 320, 323 (1998).

> In establishing rates, it is incumbent upon the Commission to fix rates which "distribute fairly the revenue requirements [of the utility.]" See *Seabrook Island Property Owners Association v. S. C, Public Service Comm'n,* 303 S.C. 493, 499, 401 S.E.2d 672, 675 (1991). Our determination of "fairness" with respect to the distribution of the Company's revenue requirement is subject to the requirement that it be based upon some objective and measurable framework.

See *Utilities Services of South Carolina, Inc. v. South Carolina Office of Regulatory Staff*, 392 S.C. 96, 113-114, 708 S.E.2d 755, 764-765 (2011).

Although the burden of proof in showing the reasonableness of a utility's costs that underlie its request to adjust rates ultimately rests with the utility, the S.C. Supreme Court has concluded that the utility is entitled to a presumption that its expenses are reasonable and were incurred in good faith. *Hamm v. S.C. Pub. Serv. Comm'n*, 309 S.C. 282, 422 S.E.2d 110 (1992) (internal citations omitted). However, according to *Utils. Servs. of S.C., Inc. v. S.C. Office of Regulatory Staff*, 392 S.C. 96, 110, 708 S.E.2d 755, 762–63 (2011) "…[I]f an investigation initiated by ORS or by the PSC yields evidence that overcomes the presumption of reasonableness, a utility must further substantiate its claimed expenditures."

A fundamental principle of the ratemaking process is the establishment of a historical test year as the basis for calculating a utility's operating margin, and, consequently, the amount of the utility's requested rate increase. In order to determine what a utility's expense and revenues are for purposes of determining the reasonableness of proposed rates, one must select a 'test year' for the measurement of the expenses and revenues. *Heater of Seabrook v. Public Service Commission of South Carolina*, 324 S.C. 56, 478 S.E.2d 826, 828 n.1 (1996). While the Commission considers a utility's proposed rate increase based upon occurrences within the test year, the Commission will also consider adjustments for any known and measurable out-of-test year changes in expenses, revenues, and capital investments, and will also consider adjustments for any unusual situations which occurred in the test year. Where an unusual situation exists showing that the test year amounts are atypical, the Commission should adjust the test year data. *See Southern Bell v. The Public Service Commission*, 270 S.C. 590, 244 S.E. 2d 278 (1978); *see also*, *Parker v. South Carolina Public Service Commission*, 280 S.C. 310, 313 S.E.2d 290 (1984), *citing City of Pittsburgh v. Pennsylvania Public Utility Commission*, 187 P.A. Super. 341, 144 A.2d 648 (1958); *Southern Bell v. The Public Service Commission*, 270 S.C. 590, 244 S.E.2d 278 (1978).

Finally, according to Commission Regulation § 103-503(B) governing sewerage utilities:

> All rates, contract forms, and rules and regulations, proposed to be put into effect by any utility as defined in 103-502(11) shall be first approved by this commission before they shall become effective, unless they are exempt from such approval by statute or other provision of law.

S.C. Code Ann. Regs. § 103-503(B) (2007). Likewise, with water utilities, Commission rule and regulation state:

> All rates, contract forms, or rules and regulations, proposed to be put into effect by any utility as defined in 103-702(14), shall be first approved by this commission before they shall become effective, unless they are exempt from such approval by statute or other provision of law.

S.C. Code Ann. Regs. § 103-703(B) (2007). The findings of facts and conclusions of the Commission herein reflect these standards and they were employed by the Commission upon review of the evidence in the record.

V. Review of Evidence and Evidentiary Conclusions

A. Return on Equity

In its Application and testimony, Blue Granite requests that the Commission determine the just and reasonableness of its proposed rates in accordance with the rate base methodology, i.e., the rate base and rate of return treatment. Blue Granite presented Direct and Rebuttal Testimony of witness D'Ascendis recommending a capital structure, overall rate of return, and range of return on equity. Witness D'Ascendis initially recommended in his direct testimony a ROE between 10.20% and 10.70% Tr. p. 547.4, ln. 9-12. However, in his rebuttal testimony, witness D'Ascendis updated his analysis and recommended a range between 9.75% and 10.25%. Tr. p. 548.4, ln. 4-9.

No other party of record proposed an alternative method for determining just and reasonable rates. Both ORS witness Parcell and Consumer Affairs witness Rothschild presented ROE recommendations for Blue Granite. Tr. p. 672.4, ln. 19; 672.12, ln. 14-16.

The Commission has wide latitude in selecting a rate setting methodology. *Heater of Seabrook, Inc. v. Public Service Comm'n*, 324 S.C. 56, 64, 478 S.E. 2d 826, 830 (1996).

While the record of evidence before it from witnesses presented by the ORS and Consumer Affairs indicates that the cost of common equity nationally is on the decline.

Tr. p. 672.13. Also, the evidence in the record clearly supports the Commission's conclusion that Blue Granite witness D'Ascendis' Return on Equity ("ROE") is too high.

In considering the quality of service issues known to exist with Blue Granite and the setting of just and reasonable rates, the Commission concludes that the analysis used by Consumer Affairs witness Rothschild is the most compelling, applies cost of equity models using water utility companies without the influence of non-utility companies, is objectively just and reasonable, and supported by ample evidence in the record. Tr. pp. 672.8-672.10. We conclude that the average ROE of 7.46% by Consumer Affairs witness Rothschild is the approved and appropriate ROE for Blue Granite based upon (a) the evidence on the whole record, (b) the three witnesses, Consumer Affairs Rothschild's approach was unique in that he included the use of both historical and forward-looking, market-based data in his analysis. rate of return methodology, and (c) a Test Year beginning July 1, 2018 and ending June 30, 2019.

With the above approved ROE of 7.46%, the Commission finds and adopts the resulting total Revenue Requirement for Blue Granite of $28,733,986, which is an increase of $4,958,848 consisting of an additional $2,161,536 in water revenues and an additional $2,797,312 in sewer revenues. This represents an approximate 57% reduction from the Company's requested increase of $11,589,537 made in its Application. Additionally, the resulting Operating Margin of 10.54% is found to be just and reasonable and is adopted by the Commission for Blue Granite in accordance with S.C. Code Ann. §58-5-240(H).

The ROE is a key figure used in calculating a utility's overall rate of return. *Porter v. South Carolina Public Service Commission*, 333 S.C. 12, 504 S.E2d 320 (1998). A utility is entitled to the opportunity to earn a fair rate of return. *Hope*, supra; *Bluefield*, supra. There were three ROE witnesses presented in this Docket: Blue Granite witness D'Ascendis, ORS witness Parcell and Consumer Affairs witness Rothschild. Each of these three witnesses agreed that "ratemaking and the cost of capital are prospective in nature, i.e., forward looking." Tr. p. 546.19; p. 683.10; p. 1004.9.

The disagreement is on the overall rate of return or cost of capital, on the cost of equity or return on equity, and the methodology or analysis used to determine this value. Tr. p. 541.2, p. 661.2, pp. 1000.3-1000.4. All three ROE witnesses arrived at their recommended rates and ranges of rates by applying common equity models including Constant Growth Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM"). Tr. p. 541.2, p. 661.5, p. 1000.3-1000.4. Witness D'Ascendis also utilized Empirical Capital Asset Pricing Model ("ECAPM") and the Risk Premium Model ("RPM"). Tr. p. 541.2. ORS witness Parcell's additional model included the Comparable Earnings Model ("CEM"). Tr. pp. 1000.3-1000.4. Consumer Affairs witness Rothschild included the Non-Constant DCF method as his third approach. Tr. p. 661.5. Blue Granite witness D'Ascendis was the only witness to use a non-price regulated proxy group ("NonPrice Regulated Group") for application in his models, which was heavily criticized by ORS witness Parcell and Consumer Affairs witness Rothschild. Tr. pp. 541.2 – 541.3.

In his Direct, Rebuttal and live hearing testimony, Blue Granite witness D'Ascendis was not transparent regarding the data or methodology he used in applying criteria (iii) and (iv) to his Non-Price Regulated Group. Tr. pp. 564-584. Company witness D'Ascendis stated he purchased proprietary data from Value Line in the form of "hard-coded," "raw numbers" without "the data behind it" and which is "not included in the subscription to Value Line". Tr. p. 567. Even assuming this is the case, it was clear on cross examination by the Consumer Advocate Lybarker that witness D'Ascendis erroneously mixed the statistical concepts of simple data distribution and sampling errors. Tr. pp. 564-584. When asked, he was unable to clarify whether the Standard Deviation of Beta in his schedule corresponded to the Standard Deviation of historical returns provided by Value Line. Tr. p. 571. D'Ascendis stated that this Standard Deviation does not refer to the standard deviation of the unadjusted betas of the entire proxy group, yet his description and application to the average beta of the proxy group imply he used it as such. *Id*. For example, D'Ascendis stated "two standard deviations cover 95.5 percent of the population" but also stated "if two standard deviations only came up with three companies and three standard deviations came up with eight companies, I would use three standard deviations." Tr. p. 572-573. When asked about the entire population he was referring to, he stated "the entire population in the database is over 6,000 stocks"[12] yet in his parallel formula for the Standard Deviation of the Standard Error of the Regression he used "N=259" as the number of observations, a concept related to sampling error in the calculation of the beta coefficient for each company, implying a

[12] Tr. pp.573- 574.

larger relevant "population" of observations, which simply did not exist. Exhibit No. 17, p.25; Exhibit DWD-1R, p. 25.

While the concept of attempting to find companies with comparable overall risk by finding companies with similar beta coefficients and residual standard errors is not completely unreasonable, the process used by Blue Granite witness D'Ascendis in this case lacks analytical transparency and statistical coherence. This is further supported by the fact that witness D'Ascendis' resulting NonPrice Regulated Group indicated an average unadjusted beta that is twenty-five percent (25%) higher than his Water Proxy Group, making it inappropriate for comparison purposes regarding the most fundamental measurement of risk. Tr. p. 575. We find the methodology and analysis performed by Consumer Affairs witness Rothschild, which clearly and appropriately applied three different equity models to his Water Proxy Group, to be more thorough and compelling in this case. Having considered all evidence presented by the parties, the Commission finds that Consumer Affairs witness Rothschild presented a compelling, reasonable analysis regarding Blue Granite's Cost of Capital and Return on Equity. Tr. pp. 672.3-672.75.

Also, Consumer Affairs witness Rothschild fully rebutted witness D'Ascendis' testimony,[13] offering a more comprehensive and transparent application of his Constant Growth DCF, Non-Constant Growth DCF, and CAPM models to his proxy group. Further, the thorough critique presented by Consumer Affairs witness Rothschild

[13] For example, Consumer Affairs witness Rothschild addressed Blue Granite witness D'Ascendis' criticisms regarding his use of current market data to determine cost of capital by pointing out that witness D'Ascendis relies on non-market based data (Blue Chip consensus interest rate forecasts) in his analysis. Tr. p. 581, ln 25 - p.582, ln 6.

regarding the use of the non-price regulated proxy group is persuasive. The evidence in this proceeding clearly shows that the non-price regulated proxy group used by witness D'Ascendis is not comparable to the risk faced by Blue Granite.[14]

The primary reasons why witness Rothschild and Blue Granite witness D'Ascendis differ in their calculations for Blue Granite is because D'Ascendis includes a group of "14 non-price regulated companies" (i.e., non-public utilities) in his analysis. Tr. p. 672.5, ln. 4-11. These "non-price regulated companies" are not comparable in total risk to water utilities as witness D'Ascendis claims. Tr. p. 672.5. ln. 7-8. Therefore, witness Rothschild did not use these non-price regulated companies as they are significantly riskier than the six (6) water utilities used by witness D'Ascendis in his calculations. Tr. p. 672.5. ln. 10-11. Rothschild did use the same six (6) publicly traded water utilities used by witness D'Ascendis when Rothschild made his recommendations and applied three models to provide an ROE in the range of 7.46% to 8.75%. Tr. pp. 672.7-672.9; *See*, Table 4, Exhibit ALR-2; Tr. p. 672.9.

Table 1 below indicates the capital structure of the Company, as approved in this Order, which both Company witness D'Ascendis and Consumer Affairs witness Rothschild agree:

[14] As stated previously, Blue Granite witness D'Ascendis' Non-Price Regulated Group indicated an average unadjusted beta that is twenty-five percent (25%) higher than his Water Proxy Group, making it inappropriate for comparison purposes regarding the most fundamental measurement of risk. Tr. p. 575.

Table 1: Summary of Blue Granite's Capital Structure	
Type of Capital	Ratios
Long-Term Debt	47.09%
Common Equity	52.91%
Total	100.00%

Tr. p. 672.12.

Amongst the three witnesses, Consumer Affairs Rothschild's approach was unique in that he included the use of both historical and forward-looking, market-based data in his analysis. Based on the testimony and facts presented, the Commission therefore adopts the recommended ROE of 7.46% proposed by witness Rothschild. This ROE allows Blue Granite to raise the capital it needs to provide safe and reliable service to its' customers.

B. Depreciation Schedule

As part of his Application proceeding, Blue Granite conducted its first depreciation study of its water and sewer plant assets in thirty-five (35) years. Blue Granite witness Spanos stated that the Company's current depreciation rates are outdated and were premised upon unrealistically long depreciable lives for facilities and equipment. Tr. p. 564, ln. 17 – p. 565, ln. 3. ORS witness Garrett recommended that the Commission reduce Blue Granite's depreciation accrual by approximately $760,236 calculated as of December 31, 2018. Tr. p. 1065, ln. 19. Based on the evidence in the record, Blue Granite's existing depreciation rates, which assume a 66 2/3 useful life for all asset accounts, are largely inaccurate. The service lives proposed by witness Spanos for several of the plant accounts in the depreciation studies prepared by Company witness Spanos are too short given the evidence supporting such service life proposals. Tr. p. 1066, ln. 21-25. The evidence is clear in this case that an update to Blue Granite's depreciation rates and depreciation expense is needed. Both Company witness Spanos and ORS witness Garrett agree on this. The evidence in the record shows that Blue Granite's current depreciation rates are artificially low and out of date. The question before the Commission is whether witness Spanos or witness Garrett's proposed accrual rates and expense level are more reasonable and supported by the evidence in the record. The Commission finds that ORS witness Garrett was credible and that he employed reasonable, objective methodology in proposing accrual rates, service lives, and net salvage estimates. In addition to reducing Blue Granite's depreciation accrual by approximately $760,236, the Commission further adopts ORS witness Garrett's recommended service life estimates and net salvage cost estimates for the purposes of setting Blue Granite's depreciation rates and depreciation expense.

C. Non-Revenue Water Loss Expense Recovery

The parties disagree on whether a limit should be placed on the amount of non-revenue water Blue Granite can recover through rates and if so, what the limit should be. Currently, Blue Granite is operating under a current ten percent (10%) threshold for recovery of non-revenue water as set in Blue Granite's prior rate case. See Order No. 2018-345 & 2018-345(A); Docket No. 2017-292-WS. Prior to its most recent rate case proceeding, Docket No. 2017-292-WS, Blue Granite reported three (3) subdivisions served by third-party providers for which non-revenue water exceeded ten percent (10%) during the test year. In the prior proceeding, ORS requested an adjustment limiting non-revenue water expense to ten percent (10%). Blue Granite did not oppose the adjustment and it was accepted by the Commission.

However, in this proceeding Blue Granite proposed a twenty percent (20%) non-revenue water threshold. Company witness Mendenhall disagrees and believes

> that the Company's non-revenue performance should be evaluated consistent with the AWWA's recommendations, including recognizing the benefit-cost analysis to evaluate alternative activities for achieving compliance. While the Company is taking measures to actively address non-revenue water, infrastructure investigations, repairs, and replacements can be extremely expensive, and these costs would be passed along to customers. Tr. p. 363.7, ln. 3-8.

See, also, Tr. pp. 363.2-363.10. Company witness Mendenhall claims that while the cost of leak detection would cost more than the annual cost of non-revenue water expense, he did acquiesce that leak detection studies are the first step in addressing the non-revenue water issue. Tr. p. 363.7, ln. 14-19 ("…a leak detection study is not guaranteed to identify any and all water losses that lead to non-revenue water …, but such efforts would be an essential early step in addressing non-revenue water.").

In this case, ORS recommends that Blue Granite's recovery of non-revenue water from the purchase water deferral account[15] also be limited to ten percent (10%), resulting in an amortized annual adjustment of $16,976. Tr. p. 1202.7. As ORS witness Maurer

[15] In Docket No. 2015-199-WS, the Commission authorized the creation of a deferral account by Blue Granite to record rate increases by third-party water and sewer treatment providers. *See*, Order No. 2015-876, p. 29.

testified, the total adjustment is $50,929 amortized over three years. Tr. p. 1202.7, fn. 10. “[B]ecause 10% is both appropriate and reasonable, the monetary size of the adjustment should not change the non-revenue water threshold used by ORS or the Company’s position on the previously utilized non-revenue water threshold.” Tr. p. 1202.7., ln. 7-10.

D. Annual Rate Adjustment Mechanism

In its Application, Blue Granite sought approval of an Annual Rate Adjustment Mechanism ("ARAM" or "Mechanism'*) for purchased water and sewer treatment expenses. All the parties, except for Blue Granite, opposed the Mechanism.

The Mechanism Blue Granite proposes would initiate a rate adjustment between base rate filings to recover deferral of changes in third-party service provider rates. Application, p. 5. The annual rate adjustment for purchased water expense deferrals would be applied to "Distribution only" customers, and the annual rate adjustment for purchased sewer treatment deferrals would be applied to "Collection only" customers. Application pp. 5-6. Deferrals would be recorded for 12-month periods beginning on the date rates are effective in this proceeding, and the Company would file for a rate adjustment within 60 days of the end of each annual deferral period. Application p. 6. The Application proposed that "ORS and the Commission complete their respective review and audit of the request within 45 days thereafter, and that the Company notify its customers of the audited rate adjustment within 15 days of audit completion, with the approved rate becoming effective 30 days thereafter. The interim rate(s) would be reset to zero in the next base rate case as the amortization of deferred expenses is incorporated into the setting of base rates." Id.

In describing how the proposed adjustments would be calculated, Blue Granite witness DeStefano testified as follows:

> The expense amount for which the Company is seeking recovery through the rate adjustment represents the difference between the amount of purchased water or wastewater expense approved in this rate case, compared to the amount of expense that is known and measurable at the time of the annual rate adjustment, which could be higher or lower. The current amount of expense will be calculated by summing the consumption data from invoices making up the approved amount of expense in this rate case and applying the most current rates charged by third party suppliers where the rate has changed since this rate case. This method would be used to isolate the impact that changes in rates from third party providers have on changes to the expense level, not changes in expense levels due to consumption or customer growth. In addition, the Company will continue to accrue monthly the impact of the rate change from the vendor to a regulatory asset. The combined deferral balance and annualized impact of the change in vendor rates versus authorized will be divided by the annualized authorized consumption of the applicable customer group to determine the adjustment rate. After the initial implementation, the rate adjustments would include true-up calculations for over or under-collection on revenues attributed to the rate adjustments approved in the prior application. Any over- or under-recovery related to the difference between the revenues billed and the authorized recovery through the mechanism would be reconciled and charged or credited to customers, as appropriate, in the next Annual Purchased Water and Wastewater Rate Adjustment filing.

Tr. pp. 763.33-763.34.

Prior to Blue Granite's 2015 rate case, the Company utilized a pass-through approach whereby when a third-party water or wastewater services provider increased its rates, those increases were passed through to the customers serviced by that provider after a notice period and approval from the Commission. Tr. p. 763.25. In 2015, with ORS's support, Blue Granite moved away from the former pass-through system because of administrative issues with constantly altering 39 different rates due to changes in rates by the various third-party providers. Tr. pp. 763.25-763.26. Blue Granite asserts the newly proposed system will not have these issues because rates will change no more often than once per year, they will change on a consolidated basis utilizing the Company's current consolidated rate system, and the rate changes will be easier to understand because the purchased water and purchased sewer treatment costs will be reflected in separate line items on customer bills. Tr. p. 763.26. Purchased water and wastewater treatment expenses represent over 40% of the increase in costs Blue Granite seeks to recover in this rate proceeding. Tr. p. 763.27. From 2017 to 2018, purchased water expenses increased by 27% and purchased wastewater services expenses increased by 58%. Tr. p. 763.30.

DeStefano asserts purchased water expenses and wastewater services expenses are comparable to fuel costs in electric cases that vary significantly from year to year. Tr. p. 763.30. He testified "[p]ermitting recovery to track, on a one-to-one basis, actual costs—outside of a general rate proceeding—will match expenses to recovery on a more timely basis and mitigate large rate shocks in rate cases, thereby benefitting customers." Tr. p. 763.31. "Additionally, mechanisms such as these can help to alleviate large fluctuations in rates from base rate cases (ke., mitigate rate shock) by providing for more gradual adjustments to rates, while at the same time sending more accurate price signals to customers that reflect the true cost of service." Tr. p. 763.32.

Blue Granite is opposed to a pass-through mechanism that is territory-specific whereby a change in rates by third-party provider is only passed through to the customers who receive water or wastewater treatment from that provider. Tr. p, 763.38. Blue Granite asserts such an approach is inconsistent with the Commission-approved consolidated rate design it has and would disproportionately impact certain customer groups whose third-party providers have greater rate increases. *Id*.

Blue Granite asserts the ARAM is permissible under S.C. Code 5 58-5-240(G) because it does not require a determination of the Company's entire rate structure. Tr. pp. 763.40-763.41. Rather, the ARAM would adjust a single, segregated charge on customer's bills related to recovery of third-party provider rate changes. Id. Consequently, the notice and hearing process of a full rate case are not necessary. Tr. pp. 763.39-763.41. Nonetheless, Blue Granite is open to providing notice and opportunity for a hearing in the annual Mechanism proceedings, if the Commission deems it appropriate. (Tr. p, 907, I 11-p. 909, l. 13). The Company is agreeable to the public being given the opportunity to participate in the hearing process, also. (Tr. p. 910, ln. 19-21). However, Blue Granite's position is the calculation of the ARAM is "strictly a mathematical exercise," without much room for interpretation. (Tr. p. 909, l. 14-p. 911, 1. 3; p. 764.18, 11. 5-8). If a threshold is set for non-revenue water in this proceeding, that threshold could not be altered during the ARAM proceedings because that would affect base rates. (Tr. p. 918, 11. 4-14; p. 919, l. 20-p. 920, 1. 8; p. 922, ln. 6-14). Blue Granite is agreeable to whatever threshold for non-revenue set in this proceeding, if any, being factored into the ARAM calculation and carried forward until the next full rate case. (Tr. p. 917, l. 16-p. 918, l. 3; p. 925, 11. 13-25).

In response to York County's arguments in opposition to the ARAM, Blue Granite asserts York County has benefited from the consolidated rate structure which exists. Tr. pp. 764.12- 764.13. Also, rate increases York County has imposed since the last rate case are a significant component of the increased purchased water and purchased wastewater treatment costs Blue Granite seeks to recover in this proceeding. Id. These increased costs from York County will be spread among customers under the Company's consolidated rate structure. Id. In addition, Blue Granite argues York County can, at any time, amend the ordinance it enacted limiting further rate increases.

ORS opposes the ARAM as seeking to recover significant annual expenses with little to no review and inadequate customer protections. Tr. p. 1214.2. ORS asserts, through witness Sandonato, that the ARAM is not a pass-through of a change in rates but rather a pass-through of expenses. Id. The "pass-through" of a change in rates is fundamentally different than the "passthrough" of a change in expenses. Id. The Company's proposed ARAM bases the calculation of the annual rate change to customers on the level of expenses incurred by the Company which includes non-revenue water, changes in customer consumption, and inflow and infiltration. Tr. p. 1213.22. While Blue Granite stated the ARAM allows the Company to track and pass on to customers changes in third party rates on a dollar-for-dollar basis without markup or margin, this is not correct because the Company would be passing on additional costs that could be attributed to non-revenue water or inflow and infiltration ("I&I") for purchased sewer treatment systems. Tr. p. 1214.3. Non-revenue water and I&I are appropriately reviewed in a general rate proceeding. *Id.*

ORS witness Sandonato provided the following example to illustrate how additional costs such as non-revenue water and I&I would be passed on. Tr. pp. 1214.2-1214.3. If a third-party water provider increased the purchased water rate by $0.05 per

1,000 gallons and the Company was billed for 100,000,000 gallons of water at the updated purchased water rate for the year, then the Company's total increase in purchased water expense would be $5,000. *Id*. Under the pass-through of expenses the Company proposes in its Application, there would be an allocation of the increased purchased water expense to customers resulting in them paying the $3,750 attributed to customer consumption plus an additional $ 1,250 not attributable to customer consumption. Id.

In addition, the proposed additional, separate purchased water and sewer treatment charges do not improve clarity, as they do not reflect the actual cost of the purchased water or sewer treatment costs incurred by each customer. Tr. pp. 1211-1212, 1214.8. In other words, if a third-party water supplier for customers is charging $5 for 1,000 gallons, those customers bills are not going to reflect they are paying $5 per 1,000 gallons. The bills will reflect some other number because of the consolidated nature of Blue Granite's rate structure. Until Blue Granite is able to provide customers the actual purchased water or purchased sewer treatment expenses related to the services the customer receives from the third-party provider, clarity and transparency will not be improved. Tr. pp. 1212, 1214.8-1214.9. ORS recommends the Commission deny Blue Granite's request to establish an ARAM and continue the current system under which increases by third-party providers are placed into a deferral account to be considered as part of the next general rate proceeding. Tr. p. 1210. If the Commission determines the Company should recover its purchased water and sewer treatment charges more quickly than a general rate proceeding, ORS recommends that any rate customers pay for purchased water and sewer treatment be established in a way such as to reflect the actual rate from the third-party provider that provides the service to the customer. Tr. p. 1211. In other words, any mechanism approved should be the type of dollar-for-dollar pass-through utilities such as Kiawah Island Utilities, Inc. and Ocean Lakes Utility, L.P. have in place.

Should the Commission deny approval of the ARAM and continue the current deferral system, ORS further recommends the Commission not approve Blue Granite's request to apply carrying costs at the Company's cost of debt to the purchased water and sewer treatment deferral accounts. Tr. 1214.9. The request to receive carrying costs in addition to recovery of the deferral will impact customers negatively by increasing the amount to be recovered from them. Id. Purchased water and sewer treatment expenses are similar to power, contract labor, and chemicals. Id. The continuation of the deferral allows the Company the opportunity to recover expenses outside of the historic test year. Id. This benefit accrues to the Company and is sufficient. Id. The addition of carrying costs is not necessary and does not benefit the customer. Id. ORS also recommends the Commission require Blue Granite conduct a cost of service study that coincides with the test year and is included as part of its next rate case. Tr. p. 1214.7. Blue Granite stated it is open to filing a cost of service study in its next rate case. Tr. p. 764.37. ORS asserts a cost of service study is essential to determine the proper rate design and previously the Commission has required significant rate design changes to be fully supported by relevant data prior to implementing the proposed changes. Tr. 1214.7. Fundamentally, the cost of service study will demonstrate which costs need to be recovered and from which customer classes the cost should be recovered. Id. ORS believes Blue Granite should retain its existing rate structure of a Base Facility Charge, a commodity charge based on water consumption for water customers and per Single Family Equivalent charge for sewer customers until a cost of service study is completed. *Id*.

York County, through its witness Eric Rekitt, indicated it was opposed to the ARAM. York County, in December 2019, passed an ordinance suspending water and sewer rate increases. Tr. pp. 1029.2-1029.3. It is concerned that if other third-party providers increase their rates in the future, rates for York County customers could be impacted because of Blue Granite's consolidated rate structure. Tr. p. 1029.3. The County has concerns similar to that of ORS which are that an ARAM does not adequately incentivize Blue Granite to reduce I&I and non-revenue water loss. *Id*. York County supports a dollar for dollar territory-specific pass-through under which the rates for Blue Granite customers in York County only change in accordance with the rates of third-parties servicing customers in the County. *Id*. If an annual mechanism is approved, York County asserts it should include an opportunity for interested parties such as it to participate in the process. Tr. 1029.4.

The two witnesses for Forty Love Point Homeowners Association also expressed opposition to Blue Granite's proposed ARAM. Tr. pp. 732.1-732.3, 737.1-737.3.

Consumer Affairs witness Morgan testified to Consumer Affairs concerns about how non-revenue water loss recovery is treated under the ARAM and regarding the Blue Granite's effort to recover 100% of its non-revenue water from customers. (Tr. p. 698,1.

15-p. 700,1. 8). Witness Morgan agrees that Blue Granite's proposal is not a pass-through of rates. *Id*.

The Commission is charged with setting "just and reasonable standards, classifications, regulations, practices and measurements of service to be furnished, imposed, observed and followed." S.C. Code Ann. §58-5-210. Applying this statutory charge, the Commission declines to approve the ARAM that Blue Granite proposes based upon the record.

While Blue Granite has sought to address some of the concerns raised by the parties through incorporation of the non-revenue water threshold set in this Order and through agreeing to notice and a hearing in which the public can participate as part of the annual process, it also has stated the process would be a "strictly a mathematical exercise," without much room for interpretation. Blue Granite has indicated the threshold set for non-revenue water loss recovery herein could not be altered in the annual proceedings, as that would constitute a change in base rates and require a full rate case.

Blue Granite also has not demonstrated the ARAM would improve bill clarity for customers, as the methodology for calculating the purchased water and sewer charges is confusing and would not yield a number that reflects the actual cost of the purchased water or sewer treatment costs incurred by each customer.

The Commission finds that Blue Granite is authorized to continue the deferral accounting treatment of changes in purchased water and wastewater treatment rates established in Docket Number 2015-199-WS.

Additionally, with regard to additional adjustment to the Company's "Rate Base – Deferred Charges," the Commission finds and determines that Blue Granite is authorized to amortize $3,178,824 of Purchased Water and Sewer Deferrals over five (5) years and to remove the first year's amortization of $635,765 for a total increase of $2,543,059 in a regulatory asset.

With regard to additional adjustment to the Company's "Maintenance Expenses - Purchased Water and Sewer Expense," the Commission finds and determines that Blue Granite is authorized to amortize this expense over five (5) years and that one year's amortized expense of $635,765 will be included in expenses in this rate case. The unamortized portion, a total of $2,119,000, will be placed in a Regulatory Asset to be recovered annually.

The Commission finds and determines that Blue Granite is not authorized to apply carrying costs to these deferral accounts other than as approved and directed herein.

Lastly, the Commission also declines to approve the changes Blue Granite proposes to its rate structure to add separate purchased water and sewer treatment charges, which were proposed to effectuate the ARAM. Blue Granite shall maintain its existing rate structure of a Base Facility Charge, a commodity charge based on water consumption for water customers, and per Single Family Equivalent charge for sewer customers.

E. Greenville Office Move, Upfit and Rent Expense - $580,045

The evidence in record clearly supports the conclusion that Blue Granite's decision to sell its office building in West Columbia, South Carolina, and to relocate its office to downtown Greenville, South Carolina is unreasonable and that the cost of upfitting the leased space, as well as the cost of the leased space (i.e., in the form of rent) should not be the responsibility of Blue Granite's customers. Tr. p. 1201.8, ln. 3-5.

ORS witness Maurer recommends an adjustment of $495,206 to eliminate cost recovery for the Blue Granite Office Upgrades. This is reflected in ORS Adjustment 32. Tr. p. 1201.7, ln. 20-22.

ORS's recommendation is based on its position that Blue Granite's decision to relocate its West Columbia, South Carolina office to Greenville was unreasonable and the cost of upfitting the space the Company leased in Greenville should not be the responsibility of customers. Tr. p. 1201.8. When asked during discovery about its justification for moving the office, Blue Granite stated:

> The primary focus of the office relocation was to attract and retain the professionals needed to maintain and improve the Company's ability to provide utility service at reasonable cost. The Company and the industry as a whole has an aging workforce, and the eligible workforce is shrinking, so ensuring that the right professionals are being attracted to the Company and retained by the Company is fundamental to the Company's ability to continue providing quality and cost effective service. The Company looked at Greenville and Columbia/West Columbia as location options. We used CBRE data (attached) to compare labor statistics of Columbia versus Greenville and decided upon Greenville. The Greenville office is within walking distance of our outside engineers (GMC) and peer utilities, Pacolet Milliken and Duke Energy, and offers additional conveniences to current and potential employees. The Columbia area did not have these same benefits. Customers benefit from the acquisition and retention of talented employees for the Company, which can minimize turnover costs and institutional knowledge loss over time. Please see attached file "Office Expenses" for the Columbia office costs offset by rent expense for the Greenville office."

Id.

Blue Granite witness Denton objected to the disallowance of these upfit costs with the move and relocation of its office to Greenville. However, Company witness Denton testified on cross examination that the Blue Granite's relocation and lease of Greenville office space was due to legacy brand issues which were caused by the Company itself. Tr. p.355.6; Tr. p. 445, ln. 15 – p. 446, ln. 8. Witness Denton also repeatedly pointed to employee retention issues as the driving force behind the Greenville move, and further admitted through his testimony that "[a]ttracting talent in the Columbia market has been extremely difficult due to the legacy brand issues in that market." Tr. p.355.6, ln. 5-7.

ORS witness Maurer provided undisputed evidence of Blue Granite's prior statements before the Commission in Docket No. 2018-365-WS that rebranding by Carolina Water Service, now known as Blue Granite Water Company, would be "at no cost to [Blue Granite's] customers." Tr. p. 1202.8, ln. 5-25; *see, also*, Exhibit KDM-2. Now by seeking recovery from the ratepayers for these costs associated with the Greenville Office in this proceeding, Blue Granite is contradicting its prior representation by attempting to pass onto customers office upgrade costs and Greenville expenses that were part of its rebranding plan and self-caused talent acquisition issues. Tr. p. 1202.8.. The evidence in the record supports the finding by the Commission that the Greenville move and its resulting rent and upfit costs are directly and casually related to Blue Granite rebranding itself, and that the Company's customers should not have to pay the costs associated with Blue Granite continuing its rebranding process.

Notably, Blue Granite sought through its Application to have ratepayers pay for other expenses associated with its rebranding such as vehicle logo and decal expenses, new uniforms, and legal fees. Tr. pp. 1133.3- 1133.4, 1133.7-1133.8. Blue Granite agrees to the adjustments proposed by ORS witness Jackson to remove these other rebranding expenses but opposes the removal of the Greenville office upfit, moving and associated rent expenses. Tr. p. 764.4

Based upon the record, the Commission further finds that an additional adjustment or reduction of $84,839 to Blue Granite's revenue request for additional rent is just and reasonable. Blue Granite's headquarters were formerly located at 150 Foster Brothers Drive in West Columbia, South Carolina ("Property"). This Property was acquired by Blue Granite in 2014 for the sum of $214,500 and consists of a 4,050 square-foot office building along with 1.88 acres of treed acreage. *See,* Blue Granite Late-Filed Exhibit No. 1. The Property was sold during the Test Year on September 28, 2018 for $356,400 to Palmetto Services Properties, LLC. Id. Net proceeds received were $325,769. *See,* Blue Granite Late-Filed Exhibit No. 1, Attachment B.

> The Company removed the Property from the rate base in October 2018. At that time, the original cost of the Property, inclusive of improvements since acquisition, was credited as a reduction of the amount carried upon the books of the Company under NARUC Account 304, "Utility Plant in Service – Structures and Improvements," for $254,395. An offsetting entry was made to NARUC Account 421.1, Gain on Disposition of Property.

See, Blue Granite Late-Filed Exhibit No. 1.

The substantial evidence in record as a whole indicates that these adjustments reducing the additional revenue sought by Blue Granite related to the Greenville Office Move, Upfit and Rent/Lease as proposed by ORS and determined by Commission in the amount of $580,045 are just and reasonable.

F. LETT's Tank Pumping Charge

Blue Granite, in its Application, requested authority to amend its tariff language and fees related to solids interceptor ("LETTS") tanks to change the pumping charge from $150 to the actual cost to access, pump, and service the tanks on a periodic basis. Tr. p. 362.13, ln. 3-8. Blue Granite witness Mendenhall testified that this change is necessary to permit Blue Granite to recover from the responsible customer the actual costs associated with the necessity of pumping and cleaning a customer's tank when excessive solids have accumulated in the interceptor tank. The actual cost of performing this task, inclusive the cost to access the tank, is often more than the currently effective charge of $150 and it needs to be performed every three to five years. Blue Granite proposes to bill the applicable customer for the actual cost of pumping and cleaning the tank, and that the pumping charge be included as a separate line item on the customer's next bill. Tr. p. 362.13, ln. 9-16. If requested by the customer, Blue Granite would divide the pumping charge into twelve equal monthly installments. Tr. p. 362.13, ln. 17-18.

Blue Granite previously filed a request to amend its tariff in the manner it proposes in November 2018 in docket number 2018-361-S and subsequently withdrew that application without prejudice, indicating judicial economy would be best served by including the matter in its next general rate case. Blue Granite identified 581 tanks in its service territory and indicated it owned 301 of those tanks. Tr. p. 1191.3, 1n. 4-5. Blue Granite typically hired a third-party contractor to perform the work. Blue Granite confirmed to ORS the actual cost it would seek to recover from customers is the total cost quoted by a contractor to perform the service without any additional costs or markup. Tr. p. 1191.4, 1n. 8-11.

Blue Granite indicated that in advance of filing docket number 2018-361-S, it suspended charging customers the $150 fee for pumping the tanks, although one instance was identified during 2018 to 2019 where a customer was charged. Tr. p. 1190.4, 1n. 4-8. Blue Granite provided the ORS with thirty (30) instances of pumping charges during the Test Year. *Id*. 1n. 8-9. The work generally was performed by three different third-party vendors during the test year, with the average cost being approximately $750. *Id*. 1n. 9-13. Blue Granite did not bill twenty-nine (29) customers for the approved $150 pumping charge and included the full expense from the third-party vendors as an expense to be recovered from all customers. *Id*. 1n. 13-15. ORS recommends a miscellaneous revenue adjustment of $4,350 reflected in ORS's Adjustment No 3 (*see*, item VII.C below) for imputed revenue for services Blue Granite was able to charge for pumping LETTS tanks but for which Blue Granite did not. Tr. p. 1213.8-1213.9. Blue Granite indicated it agreed to this adjustment. Tr. pp. 764.3-764.4.

When ORS witness Bickley suggested that Blue Granite provide customers faced with the pumping of their LETTS tank the option of seeking alternative service providers, Company witness Mendenhall rejected the idea and was concerned that it could lead to unsanitary sewer overflows. When an interceptor or LETTS tank is full and in need of pumping, it creates the potential for an unsanitary sewer overflow or back-up into the customer's residence unless there is prompt response to pump out the interceptor tank in order to limit or prevent such overflows. Tr. p. 363.12, ln. 19-23.

For cost causation reasons, ORS does not oppose Blue Granite's request to change the treatment of LETTS tanks in its tariff such that customers who cause the expense will pay the actual costs of this service, but ORS asserts the proposal should be modified to incorporate the following customer protections:

(1) require Blue Granite to provide an estimate of the actual cost of the pumping service to the customer prior to the work being scheduled and completed;

(2) allow customers to seek alternative options for the pumping services by obtaining quotes/estimates from qualified and appropriately licensed third-party vendors and contractors;

(3) require customers to approve and authorize Blue Granite providing pumping services in writing prior to service being performed;

(4) the pumping charge may not exceed the estimate of the actual cost Blue Granite provided to the customer and the charge may not exceed the amount Blue Granite paid to any third-party vendor to perform the work;

(5) if the customer chooses to use an alternative third-party vendor to perform services on their LETTS tank, Blue Granite may oversee and inspect the work but will not charge the affected customers for the personnel and overhead costs incurred in managing the LETTS tank-related work;

(6) require the customer to provide, in a timely manner, Blue Granite proof the pumping and service on the tank occurred;

(7) if the customer authorizes Blue Granite to perform the work, require the pumping charge be included as a separate line item on the customer's next bill and allow the customer the choice to have the charge billed in twelve equal monthly installments; <u>and</u>

(8) if an emergency condition arises that presents a health risk to the customer, the public, or the environment, Blue Granite may proceed with pumping the tank without giving the customer the opportunity to select a different vendor. Blue Granite shall present, upon request, evidence supporting the need for immediate action.

Tr. p. 1190.7, ln. 3 - p. 1190.8, ln. 9. ORS witness Bickley also provided proposed tariff language for Blue Granite to use which would incorporate their proposed modifications to the LETTS tank tariff, including its language of what constitutes an emergency condition under which Blue Granite could pump the tank without giving the customer the opportunity to select a different vender. Exhibit No. 38; *See, also*, Exhibit No. BSB-1. Blue Granite witness Mendenhall testified in his Rebuttal that Blue Granite was in agreement with ORS's proposed modifications, with the exception of the exact definition of what constitutes an emergency condition under which Blue Granite could pump a tank without giving the customer the opportunity to select a different vendor. Tr. p. 395, ln. 8 -p. 396, ln. 5. However, Blue Granite did not provide an alternate definition for emergency condition for the Commission to consider other than what was in ORS's proposed tariff language.

Based upon the testimony and evidence in the record, including that of Intervenor Forty Love Point Homeowners' Association, Commission grants Blue Granite's request to amend its tariff language and fees related to Solids Interceptor ("LETTS") Tanks to change the pumping charge from $150 to the actual cost to access, pump, and service the tanks on a periodic basis, with and incorporating the changes recommended by ORS to Blue Granite's proposal. The Commission further approves and adopts ORS's proposed tariff language related to Solids Interceptor ("LETTS") Tanks in Exhibit 38, including ORS's language of what constitutes an emergency condition under which Blue Granite could pump the tank without giving the customer the opportunity to select a different vender. Exhibit No. 38; *See, also*, Exhibit No. BSB-1. Blue Granite provided no alternate definition of "what constitutes an emergency condition" for the Commission to consider.

G. Contributions in Aid of Construction Under Tax Cuts and Jobs Act

The Tax Cuts and Jobs Act (TCJA) lowered the federal corporate income tax rate from 35% to 21%. Due to this lower corporate tax rate, Blue Granite seeks Commission authority to initiate a one-time credit to each customer water and sewer account, to return overcollections of Federal tax expenses. Blue Granite witness DeStefano proposes to initiate a one-time credit of $10.64 to each customer water and sewer service account in order to return overcollections of federal income tax expenses accumulated between January 1, 2018 to June 28, 2018 related to the TCJA in the amount $335,713. Tr. p. 763.10. Blue Granite witness DeStefano testified that Blue Granite over-collected $335,713. It is undisputed by Blue Granite and the ORS that this overcollection of funds needs to be returned to each customer water and sewer service account.

SCDCA witness Morgan recommends that the deferred liability of $335,713 be used to offset the deferred purchased water and sewer treatment costs instead of providing a direct refund to customers. Tr. p. 651.15.

ORS verified the Company's calculations using updated pro forma customer bills of 31,710 and calculated a one-time credit of $10.59 per account. Tr. p. 1115.25, ln. 14-16. Blue Granite agreed with this updated calculation by ORS based on adjusted pro-forma customer counts. Tr. p. 764.4, ln. 18-19.

The Commission concurs with Blue Granite and ORS and finds that this overcollection of funds needs to be returned to each customer water and sewer service account by providing the one-time credit of $10.59. The evidence in the record supports the proposed adjustment in the amount of $335,713 and the calculated one-time credit of $10.59 as verified and calculated by ORS using the Company's updated data. The Commission further finds that the same is just and reasonable and therefore, orders this one-time credit by Blue Granite in the amount of $10.59 as proposed by ORS for each customer water account and sewer account effective upon the date of this Order. Blue Granite is to issue these credits to customers as soon as possible and within its next billing cycle following the date of this Order.

H. Storm Reserve Fund

In addition to an increase in base rates, Blue Granite is seeking the authority to create a Storm Reserve Fund for extraordinary storm restoration costs such as those experienced following Hurricane Florence. Tr. p. 354.22, ln 17-20. Blue Granite wants set aside $200,000 which would be funded through a monthly surcharge of $0.53 per customer. Once the $200,000 threshold is reached, the monthly charge would be suspended once the threshold amount was reached, and any overcollections during that last month would be refunded to customers the following month. Tr. p. 764.24, ln. 18-20.

Blue Granite witness Mendenhall testified that major storm events cause the utility to experience service disruptions due to temporary power loss and damage to supply or treatment infrastructure. Tr. p. 363.11, ln. 3-6. Storm damage can also cause main breaks which result in low pressure and boil water advisories. Tr. p. 363.11, ln. 6-7. Repairs can take less than an hour to several days to restore full service to customers depending on the nature of the damage to Blue Granite's systems. Tr. p. 363.11, ln. 7-9.

The Storm Reserve Fund would be used for extraordinary storm restoration costs that were not included in the Company's revenue requirement. For example, this could be generator services, damage assessments, damage inspections, site preparation and facilities repair. Tr. p. 363.11, ln. 9-13.

Blue Granite witness DeStefano also rejected the modifications to the Storm Reserve Fund offered by ORS and by Consumer Affairs. Tr. p. 764.23, ln. 16-22. Even though witness DeStefano agreed that periodic reporting and utilization of funds only for named storms was reasonable, DeStefano testified that such modifications to the Storm Reserve Fund:

> would not serve the ultimate purpose of the Storm Reserve Fund. The purpose of the fund is to set aside capital for immediate deployment in cases of an extraordinary level of storm recovery expense, an amount significantly above the annual average 'normal' level of storm-related expense we typically experience."

Tr. p. 764.23, ln 22 – p. 764.24, ln. 2. The $50,000 fund as proposed by ORS, according to witness DeStefano, would not accomplish the goals of the Company in maintaining the Fund which are: (a) to have funds on hand to respond to extraordinary storms, and (b) to save the administrative burden and expense of filing repeated deferred accounting petitions with the Commission. Absent a Storm Reserve Fund and absent a filing before the Commission by the Company for deferred accounting treatment, witness DeStefano states that Blue Granite has no available recourse to recover costs related to major storm events. Tr. p. 764.24, ln 3-20. Blue Granite believes that the potential for a catastrophic storm will erode the Company's earnings and impair the Company's financial ability; thus, adversely affecting customers because such issues or pressures lead to increasing capital costs, diminish resources for other operating needs, and contribute to the need for more frequent regulatory filings. Tr. p. 764.25, ln. 10-13.

ORS reviewed Blue Granite's past ten (10) years of storm restoration costs using a ten-year average. After removing the high and low values, ORS witness Bickley testified that ORS's review found the average yearly storm cost to be $28,320.51. Tr. p. 1186, ln. 15-19. The ORS also recommends a normalization adjustment of storm costs which was be $23,481. The "method of normalization of storm costs more accurately reflects storm costs for each year" and is a method approved by the Commission for use by utilities. Tr. p. 1186, ln. 23-25. ORS witness further testified that the proposed Storm Reserve Fund by Blue Granite did not have any guidelines on how the Company would access the Fund or customer protections to restrict use, access, or operation of the Fund. Tr. p. 1187, ln. 4-14; Tr. p. 1188.

ORS witness Bickley provided ORS's recommendation to modify the Fund to include sufficient customer protections. With these modifications, the ORS would support a Storm Reserve Fund if : (1) only allowed to be used for damage incurred as a result of a named storm (as named by the World Meteorological Organization); (2) use the Fund if the Company's insurance does not cover all costs related to damage from a named storm; (3) mandatory quarterly reporting to the Commission and ORS of the status of the Fund including, but not limited to, dates and amounts of withdrawals and expenditures from the Fund, current balance, and current monthly surcharge; (4) limit the maximum Fund balance to $50,000; and (5) the balance of Storm Reserve Fund should be included as a reduction to rate base. Tr. p. 1188, ln. 14 – p. 1189, ln. 8. ORS also recommends that the Commission approve its recommendation for storm normalization so that Blue Granite would have access to the Fund once the company had incurred $28,321 in storm damage. Tr. p. 1187, ln. 7-14.

Consumer Affairs witness Morgan testified that the Storm Reserve Fund was not necessary because a significant portion of the water and sewer utility infrastructure is below ground. Tr. p. 651.19. He also testified that the establishment of the storm fund is necessary at this time. Tr. p. 649, ln. 9; Tr. p. 651.19. While Blue Granite cites Hurricane Florence in September 2018 as an example of the type of storm where the resulting damage which would be covered by such a fund, the data shows that this type of storm is not incurred frequently. Tr. p. 649, ln. 10-15; Tr. p. 651.19, ln. 20-21. A monthly surcharge of $0.53 per customer account is an unnecessary fee to impose on customers. Tr. p. 649, ln. 15-17. Consumer Affairs witness Morgan continued to testify that in the data presented by Blue Granite in support of its request does not support a historical need for a fund. Tr. p. 649, ln. 15-17. See the following Table[16] from Rebuttal Testimony of witness DeStefano which was relied upon and referenced by witness Morgan as being "significantly less than $200,000". Tr. p. 658.5, ln. 17.

[16] Tr. p. 764.22, ln. 2-3.

Year	Storm Costs	Five-Year Average
2010	$16,207.41	$14,533.90
2011	$31,631.02	
2012	$1,510.19	
2013	$4,942.69	
2014	$18,378.21	
2015	$47,938.40	$42,493.62
2016	$43,737.13	
2017	$33,469.27	
2018	$54,716.21	
2019	$32,607.10	

Given that storm costs are already included in the cost of service, witness Morgan testified that an adequate allowance has been provided to the Blue Granite in its rate base to cover storm damage costs. Tr. p. 649, ln. 15-17; Tr. p. 658.3, ln. 16-19.

The Commission finds ORS witness Bickley's testimony compelling and agrees with Consumer Affairs witness Morgan that it is unreasonable to make a significant policy change based upon a rare occurrence. The current process established by the Commission allows the utility to seek deferred accounting treatment for unusual circumstances. There is no need to burden Blue Granite customers with higher rates to create a fund that history shows will likely end up unused on Blue Granite's balance sheet. We conclude that the Storm Reserve Fund is not necessary.

Based upon the evidence in the record, the Commission finds that Blue Granite's request to establish a $200,000 Storm Reserve Fund is not needed at this time and that the request is denied. According to the Company's own data, there have been only two times when the Company was allowed deferred accounting treatment. Tr. p. 658.5. Due to a storm in 2016, the Company was authorized to defer approximately $60,000 which is being amortized over a 5-year period. The other storm deferral occurred as a result of back to back Hurricanes in September and October 2018. Blue Granite incurred approximately $209,000 in storm restoration costs and is being allowed to recover those costs over a 5-year period. These are the only two instances over the most recent four (4) years of the Company's history where it incurred significant storm damage expenses to receive authority to defer the expenses. Blue Granite explains that the $200,000 amount that it seeks to accumulate in the Storm Reserve Fund is based upon the level of expenses incurred for back to back storms, Hurricane Florence and Hurricane Michael, in September and October 2018. The Commission further adopts the position of Consumer Affairs that not only is the fund needed by Blue Granite to provide safe and reliable service, but also it is unreasonable to establish a $200,000 Reserve Fund because a level of storm costs was incurred one-time due to unusual circumstances of two back to back hurricanes occurring in a short span of time from the other.

I. Round Up Program

With its Application, Blue Granite requests Commission authority to implement a voluntary Round Up Program ("Program"). This program would round the bills of participating customers to the nearest higher dollar, with the difference accumulated in a reserve fund for remittance to the South Carolina Office for Economic Opportunity ("SCOEO"). Tr. p. 1190.8, ln. 12-15. The funds would be distributed to community action agencies in Blue Granite's service territory to assist low income customers with the payment of their water and sewer bills. Tr. p. 1190.8, ln. 15-17. The funds would be (1) distributed to Community Action Agencies in Blue Granite's service territory to assist low income customers with their water and sewer bills; (2) issued in an amount not to exceed fifty dollars ($50) per qualifying household for the payment of outstanding water or sewer service charges, or a deposit on a residential customer account; and (3) provided as a one-time service for eligible residential customers during the Program Year. Tr. pp. 1190.10, ln. 1-12. Blue Granite also seeks approval from the Commission to defer implementation costs from the customer Round Up Program related to modification of its billing system and "MyUtilityConnect" customer service application, for recovery in the Company's next rate proceeding. Tr. p. 763.23-763.24; Tr. p. 1190.8, ln. 17-20; *See, also*, Application, page 7 of 8, item 26.

In its request for approval of the Round Up Program, Blue Granite also requested additional revenue adjustment in its office supplies and other office expenses to include expenses for annual filing notices associated with the bill inserts and notices associated with the Program's estimated costs as proposed Pro-Forma Adjustments within this rate case in the amount of $14,674. Tr. p. 1190.12, ln 16 – p. 1190.13, ln. 13. Blue Granite witness DeStefano continued to testify that the Company seeks to "defer implementation costs" for the recovery of the Program in the next base rate case. Tr. p. 763.24, ln. 2; *See, also*, Application, page 7 of 8, item 26.

Consumer Affairs was supportive of the Program to aid low-income customers but concerned that Blue Granite's customers would be shouldering the costs of implementing the Round Up Program. In fact, Consumer Affairs witness Morgan testified that Consumer Affairs was "opposed to the deferral of costs that assumes an automatic recovery in the next rate case." Tr. p. 650, ln 6-9; Tr. p. 651.20. Consumer Affairs recommended "that a cap be placed on the deferral of costs related to modifying the billing system and customer service applications…also …that the Commission require[] the deferred cost to be subject to scrutiny in the Company's next rate case." Tr. p. 650, ln 10-15; Tr. p. 651.20.

ORS witness Bickley testified that neither Blue Granite, nor its affiliates, currently have a similar Round Up Program. Tr. p. 1190.11, ln. 8-12. "ORS is not aware of any water or sewer utilities under the Commission's jurisdiction that utilize a Round Up Program that is the same or similar to the one proposed in this proceeding" testified witness Bickley. Tr. p. 1190.11, ln. 17-18. ORS was able to identify two electric utilities in the State of South Carolina subject to the jurisdiction of the Commission that have similar programs which work with local agencies to help customers pay their electric and/or natural gas bills and that the shareholders of those electric utilities pay for the program costs. Tr. p. 1190.11, ln. 20 – p. 1190.12, ln. 6.

ORS witness Bickley testified that ORS's review in this matter discovered that Blue Granite's actual total estimated cost range for implementation of the Program is between $29,000 and $50,000. Tr. p. 1190.13, ln. 19-20. Witness Bickley further testified that:

> the Round Up Program, as proposed by the Company, is a voluntary program that customers can opt in or out of at any time. It is not a program that would be required to assist, aid, or otherwise support the Company's ability to provide safe and reliable service to its customers. The proposed Round Up Program also does not impact the Company's

> ability to provide safe and reliable water and sewer service to customers.

Tr. p. 1190.14, ln. 5-9. ORS opposes Blue Granite's adjustment to include annual expenses associated with the Round-Up program as discussed in the direct testimony of ORS witness Bickley. Tr. p. 1190.14, ln. 10 – p. 1190.15, ln. 2; See, also, ORS Witness Sullivan's Audit Exhibit DFS-5, Adjustment 15b.

While ORS is supportive of a Round Up Program to assist the low-income customers of Blue Granite, ORS recommended changes to Blue Granite's Round Up Program to ensure that customers of Blue Granite did not pay the Company's estimated costs associated with the development, implementation, maintenance, and communication expenses. Tr. p. .1190.14, ln. 12-15. The ORS wanted to make modifications and adjustments ensuring that Blue Granite customers are treated in a similar manner as customers of Duke Energy customers. Tr. p. 1190.14, ln. 15-17.

The ORS recommends that the Commission deny Blue Granite's request to recover the estimated costs for the Round Up Program related to modifications of its billing system and MyUtilityConnect customer service application for recovery in the Company's next rate proceeding. Additionally, ORS recommends that the Commission deny Blue Granite's request for recovery of the estimated cost for bill inserts/flyers to be used for the Round Up Program. The Company's estimated costs are not known and measurable and this Program does not contribute to the provision of safe and reliable water and sewer service. ORS's adjustment is reflected in ORS Witness Sullivan's Audit Exhibit DFS-5, Adjustment 15b. Tr. p. 1190.14, ln. 10 - p. 1190.15, ln. 2; Tr. pp. 1191.5-1191.7.

The Commission encourages Blue Granite's efforts to assist and help its customers. Its proposed Round Up Program ("Program") can provide some level of financial aid to certain low-income customers in its service territories. There was no evidence presented by the Company to indicate how many of its customers, if any, would actually benefit from such a program in Blue Granite's service territory. The Commission also realizes in reviewing proposed rate schedule of Blue Granite and the average water and sewer bills that a $50 benefit level may not completely pay a customer's entire water bill, sewer bill, or water/sewer bill.

The Company also did not provide any supporting evidence for its estimated administrative costs for the Program; therefore, the costs are not known or measurable.

None of Blue Granite's affiliate companies have a similar program and ORS did not know of any other water or sewer utility regulated by the Commission with a similar community assistance program. The Program will not impact the ability of Blue Granite to provide safe and reliable services or to manage its administrative duties in maintaining and operating well-functioning water and sewer systems for the public. Therefore, and based upon the record, the Commission finds that it is just and reasonable that Blue Granite (i.e., its shareholders) should pay for all the costs associated with a Round Up Program authorized for it by the Commission and that Blue Granite's rate payers or customers should not pay for the costs of such Program.

Additionally, evidence in the record supports the Commission finding that it is just and reasonable to approve the Round Up Program for Blue Granite as modified by ORS in testimony of ORS witness Bickley and in Witness Sullivan's Audit Exhibit DFS-

5, Adjustment 15b ($0). Additionally, the Commission finds support in the record to deny Blue Granite's request to recover estimated costs for a Round Up Program related to modifications of its billing system and MyUtilityConnect customer service application in the Company's next rate proceeding when such costs are unknown and not measurable. The Commission further denies Blue Granite's request for recovery of the estimated cost for bill inserts/flyers to be used for the Round Up Program based upon the record.

Among other things, based upon the record, the Commission further finds that it is just and reasonable to prohibit Blue Granite from passing onto its customers the administrative and implementation costs for the Program, including the bill inserts, notice or flyers, and for the modifications to Blue Granite's billing and customer service systems. It is just and reasonable that Blue Granite, or its shareholders, should pay all the costs associated with a Round Up Program authorized for the Company by the Commission and that Blue Granite's rate payers or customers should not pay for the costs of such Program.

J. Cost of Service Study

Blue Granite did not perform a Class Cost of Service Study in order to justify the proposed rates in its application. Tr. p. 633.6, l. 1-4. Blue Granite's current base facility/monthly charge for water service in Territory 1 is $14.38 and it is $28.59 in its Service Territory 2. Tr. p. 631. Under Blue Granite's application, these charges would increase to approximately $22.09 in Territory 1 and $38.58 in Territory 2 for water service. Tr. p. 633.6.

It became clear that throughout this proceeding that the parties recognized that a Cost of Service Study is essential to determine the proper rate design or that there cannot be significant rate design structural changes without such information. Blue Granite agreed that it was willing to conduct and file a cost of service study in its next rate case. Tr. p. 764.37.

Consumer Affairs presented an analysis with its witness Mierzwa of the cost-based base facility charges for Blue Granite. Witness Mierzwa used the base-extra capacity method in the American Water Works Association's *Principles of Water Rates, Fees and Charges* ("AWWA M1 Manual"). His initial analysis indicated an appropriate cost-based facility charge for residential water service customers was approximately \$10.00 per month in each Service Territory. Tr. p. 633.9. However, the Company's current and proposed base facility charges are higher than that calculated by Consumer Affairs witness Mierzwa using the base-extra capacity method. Witness Mierzwa testified that Blue Granite's proposed increases in the base facility/monthly customer charges were unreasonable and that any increase in revenue authorized by the Commission should be recovered through increases in the volumetric usage (commodity and distribution) charges. Tr. p. 633.4.

ORS witness Sandonato also recommends that Blue Granite conduct a cost of service study. "A Cost of Service Study is essential to determine the proper rate design. Fundamentally, the Cost of Service Study will demonstrate which costs need to be recovered and from which customer classes the cost should be recovered. Due to its importance, ORS recommends the Commission require Blue Granite conduct a Cost of

Service Study that coincides with the test year and is included as part of its next rate case." Tr. p. 1214.7, ln. 1-5. Witness Sandonato continued to testify that the Company should retain its existing rate structure of a Base Facility Charge, a commodity charge based on water consumption for water customers and a Base Facility Charge for sewer customers until the Company completes a Cost of Service Study. Tr. p. 1214.7.

VI. Review of Evidence and Evidentiary Conclusions – Other Adjustments

In the rebuttal testimony of Dante DeStefano, Director of Financial Planning and Analysis for the Company, Blue Granite witness DeStefano stated that there were several areas of agreement and that the purpose of his testimony was to identify these points of agreement between the Company, ORS, Consumer Affairs and other intervenors. Tr. p. Tr. pp. 764.3, ln. 11-13. The record will show that the Company agreed with ORS' Adjustments No. 1, 2, 3, 4, 5, 6, 9b, 9e, 13a, 13b, 14, 15a, 15c, 16a, 17a, 19, 20, 21a, 21c, 21d, 21e, 23b, 26a, 26b, 27, 28, 35a, 35b, 37, and 39. *See*, Tr. p. 764.4, ln. 1-19. ORS also agreed without change to some of Blue Granite's filed Application known as Adjustments No. 7, 10, 11a, 11b, 12a, 12b, 21b, 22, 23a, 29, 30 and 31. *See*, Tr. p. 764.4, ln. 19-22.

A. Adjustment No. 1 – Water Service Revenues

ORS Witness Sandonato testified that during ORS' comprehensive review of the Company's Application and Test Year information, discrepancies were discovered in the water billing units used to calculate Blue Granite's water service revenue for the Test Year. ORS proposed this adjustment to more accurately reflect the total revenues for the Company. ORS' Accounting and Pro Forma Adjustment No. 1 is $280,468. Ex. DFS-1.

Blue Granite witness DeStefano agreed with ORS on this adjustment. Tr. p. 764.4, ln. 1-2. No party contested the $280,468 accounting and proforma adjustment proposed by ORS Witness Sandonato. The Commission finds that the evidence in the record supports the ORS proposed accounting and proforma adjustment and the Commission further finds the accounting and proforma adjustment to be just and reasonable.

With regard to the revenue adjustment for water service revenues following accounting and proforma adjustments (Adjustment No. 40), using the ROE methodology and the 7.46% ROE adopted by the Commission as supported by the evidence in the record and as discussed in this Order, the resulting revenue increase in water revenues is $2,176,490. For these reasons discussed herein, this Commission finds the revenues detailed in Order Exhibit 1 (PSC Prepared Reconciliation Document) to be just and reasonable.

B. Adjustment No. 2 – Sewer Service Revenues

There were also discrepancies discovered by ORS in the Company's Application and Test Year for sewer billing units per the direct testimony of ORS Witness Sandonato. (Dir. Pp. 6-7). Like the discrepancies found during ORS' comprehensive review of the Company's Application and Test Year information for water billing units, there were also errors in the sewer billing units used by Blue Granite to calculate its sewer service revenue for the Test Year. ORS proposed an accounting and proforma adjustment in the amount of $504,321 as Adjustment No. 2 to more accurately reflect the total revenues for the Company. Ex. DFS-1. Blue Granite witness DeStefano agreed with ORS on this adjustment. Tr. p. 764.4, ln. 1-2. No party contested the $504,321 accounting and proforma adjustment proposed by ORS Witness Sandonato. The Commission finds that the evidence in the record supports the ORS proposed accounting and proforma adjustment and the Commission further finds the accounting and proforma adjustment to be just and reasonable.

With regard to the revenue adjustment for sewer service revenues following accounting and proforma adjustments (Adjustment No. 41), using the ROE methodology and the 7.46% ROE adopted by the Commission as supported by the evidence in the record and as discussed in this Order, the resulting revenue increase in sewer revenues is $2,785,194. For these reasons discussed herein, this Commission finds the revenues detailed in Order Exhibit 1 (PSC Prepared Reconciliation Document) to be just and reasonable.

C. Adjustment No. 3 – Miscellaneous Revenues

ORS witness Sandonato also proposed an adjustment in the amount of $4,350 to the total miscellaneous revenues for water and sewer services. *See*, Exhibit AMS-3. This adjustment was due to the imputed revenue attributable to the Company regarding its suspension of charging its sewer customers $150 for pumping the LETTS tanks. Tr. p. 1214.7-1217.8. During the Test Year, Blue Granite identified one customer that was charged the $150 fee which was included in the Company's miscellaneous revenue. However, the Test Year showed that there were thirty (30) Blue Granite customers for which the Company's LETT's tank pumping service was performed, but while the Company was able to charge, it chose not to charge them for the service. ORS calculated that the imputed miscellaneous revenue adjustment of $4,350 for the twenty-nine (29) customers whose charge for the pumping service was not accounted. *Id*. Blue Granite witness DeStefano agreed with ORS on this adjustment. Tr. p. 764.4, ln. 1-2. No party contested the $4,350 accounting and proforma adjustment proposed by ORS Witness Sandonato. The Commission finds that the evidence in the record supports the ORS proposed adjustment and the Commission further finds the adjustment to be just and reasonable.

With regard to the revenue adjustment for miscellaneous revenues following accounting and proforma adjustments (Adjustment No. 41), using the ROE methodology and the 7.46% ROE adopted by the Commission as supported by the evidence in the record and as discussed in this Order, the resulting miscellaneous revenue increase is $49,482. For these reasons discussed herein, this Commission finds the revenues detailed in Order Exhibit 1 (PSC Prepared Reconciliation Document) to be just and reasonable.

D. Adjustment No. 4 – Uncollectible Accounts

Based upon the revenue requirements proposed by the Company and ORS, ORS witness Sullivan proposed to adjust uncollectible accounts of ($89,309) associated with the company's revenues after ORS's proposed accounting and pro forma Adjustments. (tr. P. 1115.6, 11. 2-3). The percentages used to calculate uncollectible accounts were provided by the company and were verified and found reasonable by ORS. (Tr. p. 1115.6, ln. 34). Company Witness DeStefano testified that Blue Granite agrees with ORS's proposed service uncollectible account adjustment as it relates to the uncollectible expenses for the utility; meaning that Blue Granite also agreed with the percentages used by the ORS to calculate the adjusted amount of uncollectible accounts. (tr. P. 764.4, ln. 1-2).

The record further clearly demonstrates that no party contested the percentages used by ORS witness Sullivan to calculate the uncollectible accounts based upon the proposed revenue increase. Instead rather, the percentages used by ORS for the calculation were accepted in the record. Other than the accounting and proforma adjustments by ORS, the Commission does not agree to and does not adopt the revenue adjustments or requests in Adjustment No 4 proposed by the Company or ORS. However, using the ROE methodology and the Commission's 7.46% ROE adopted herein, the Commission does adopt the percentages used by ORS witness Sullivan to calculate the adjusted amount in the utilities uncollectible accounts based upon the Commission's adopted total revenue increase for Blue Granite of $4,958,848.

Therefore, resulting in the adjusted amount of ($52,318) which is adopted, and found to be just and reasonable, by the Commission. The evidence in the record supports the proposed adjustment of ($52,318) regarding the utility's uncollectible accounts. See, Order Exhibit 1.

E. Adjustment No. 5 – Salaries and Wages – Maintenance

In its Application, the Company proposed an adjustment in the amount of ($1,155,286). ORS proposes to annualize operator's salaries for maintenance expenses details of this adjustment are reflected in the direct testimony of ORS witness Jackson. Tr. p.1133.3. Blue Granite witness DeStefano testified that this an Adjustment to which Blue Granite and ORS agree. Tr. p. 674.4, ln. 3. There is no dispute between the parties regarding this adjustment. The Commission finds that this adjustment is just and reasonable and adopts the same.

The evidence in the record supports the ORS's proposed adjustment of ($1,344,062). The Commission finds that this adjustment is just and reasonable and adopts the same.

F. Adjustment No. 6 – Capitalized Time

ORS witness Charles E. Jackson testified that an adjustment is need in the revenue requirement of Blue Granite "to reflect the capitalized time based on pro forma salaries." Tr. p. 1133.3, ln. 11-12. Blue Granite had proposed an adjustment of $58,345 using the salary and wages data as of June 30, 2019 which was the end of the Test Year. However, upon review and verification by ORS, witness Jackson updated the calculation and testified that an additional adjustment needed to be made of $73,614. Tr. p. 1133.3, ln. 13-15. "ORS verified the capitalized time percentages from the data as of June 30, 2019 and used those percentages on the annualized salary and wages data from October 31, 2019 to propose an adjustment of $73,614." Id.

The evidence in the record supports the ORS's proposed reduction adjustment of $73,614. Additionally, no party contests the adjustment that ORS witness Jackson proposed. In fact, in his rebuttal testimony Blue Granite witness DeStefano agrees with the proposal by ORS and its witness Jackson to the adjustment in Capitalized Time of $73,614. Tr. p. 764.4, ln. 3-4.

Blue Granite witness DeStefano testified that this an Adjustment to which Blue Granite and ORS agree. Tr. p. 674.4, ln. 3. There is no dispute between the parties concerning this adjustment. Supported by the record, the Commission finds this adjustment of $73,614 to be just and reasonable and hereby adopts the same.

G. Adjustment No. 7 – Purchased Power

The Company has purchased power expenses in the amount of $250,091 for Transmission and Distribution Expenses and in the amount of $531,717 for Treatment and Disposal Expenses in its Schedule 302 Operating Expenses (Operation and Maintenance Account No. 401). *See*, Application, p. 118 & p. 151 (Exhibit E).

Per the testimony of ORS witness Sullivan, ORS made no adjustments to the Company's purchased power amount of $771,660 as documented by the Company in its Application. Tr. p. 1115.6, ln. 11-12. Thus, there is zero ($0) adjustment by ORS who is agreeing with Company's position and request as provided in Blue Granite's Application as testified by Company witness DeStefano. Tr. p. 764.4, ln. 19-22. There is no disagreement and the parties agree regarding this adjustment. The Commission finds that there is $0 adjustment for No. 7, purchased power and hereby adopts the same.

H. Adjustment No. 8 – Purchased Water and Sewer

The purchased water and sewer adjustments are items of disagreement between the parties. ORS witness Sullivan testified in his direct that ORS's total purchased water and sewer adjustment is $3,178,824 . Tr. p. 1115.6; Surrebuttal Exhibit DFS-5.

In addition to the adjustments determined and adopted by the Commission related to "Maintenance Expenses – Purchased Water and Sewer Expense" above, the following additional adjustments are made to Adjustments No. 8a and No. 8b related to the ten percent (10%) threshold limitation more fully discussed in Section V.C above concerning the non-revenue recovery expense and Section V.D regarding the Commission finding and ordering that (1) Blue Granite amortize “Maintenance Expenses – Purchased Water and Sewer Expense” over five (5) years and include one year’s expense in the amount of $635,765 in expenses in this case so that the unamortized portion in the amount of $2,543,059 shall be placed in a Regulatory Asset; and (2) Blue Granite amortize $3,178,824 of Purchased Water and Sewer Deferral over five (5) years and remove one year’s amortization in the amount of $635,765 for a total increase of $2,543,059 in a Regulatory Asset.

(1) Adjustment No. 8a - Adjustment to Purchase Water Deferral Account $50,929

For the reasons discussed more fully above in Item V.C and findings herein, the Commission finds that Blue Granite failed to rebut ORS witness Maurer’s testimony that the Company regarding the adjustments for purchased water deferral account and the ten percent (10%) threshold limitation, and it therefore finds ORS’s adjustment just and reasonable to limit the customer’s responsibility for non-revenue water expenses to 10% in each subdivision for Blue Granite Service Territories 1 and 2 and to adopt the adjustment of $50,929 to reduce the Purchased Water Deferral Account for all of Blue Granite’s service territories.

(2) Adjustment No. 8b – Adjustment to Purchase Water Expense $271,930

For the reasons discussed more fully above in Item VII.C and findings herein, the Commission finds that Blue Granite failed to rebut ORS witness Maurer’s testimony that the Company regarding the adjustments for purchased water expense and the 10%

threshold limitation, and it therefore finds ORS's adjustment just and reasonable to limit the customer's responsibility for non-revenue water expenses to 10% in each subdivision for Blue Granite Service Territories 1 and 2 and to adopt the adjustment of $271,930 to reduce purchased water expenses for all Blue Granite's service territories.

I. Adjustment No. 9 – Maintenance and Repair

ORS's total maintenance and repair adjustment is $937,334 . This adjustment is comprised of the following maintenance and repair adjustments as noted below in the record. The Commission finds that this adjustment is supported by evidence in the record and is just and reasonable.

During the hearing, Blue Granite admitted that it did not seek or obtain approval from the Commission of its ClearWater Solutions, LLC contract ("ClearWater Solutions") as is required by S.C. Ann. Regs. 103-541 and 103-743. Tr. p. 775; *See, also*, Blue Granite Late-File Exhibit No. 4. The Commission further finds that Blue Granite immediately file with the Commission the contract between itself and ClearWater Solutions for review and possible approval by the Commission. The Commission further cautions the Company that it must file its contracts for approval in the future in compliance with the Commission's regulations.

(1) Adjustment No. 9a - Deferred Maintenance Adjustment

ORS proposes an adjustment to maintenance and repair for the amortization of deferred maintenance in amount of ($232,402). Details of this adjustment are reflected in the direct testimony of ORS witness Briseno. Tr. pp. 1128.4-5. Blue Granite witness DeStefano testified that this an Adjustment to which Blue Granite and ORS agree. Tr. p.

674.4, ln. 5. There is no dispute between the parties regarding this adjustment. The Commission finds that this adjustment is just and reasonable and adopts the same.

(2) Adjustment No. 9b - ClearWater Solutions – Maintenance and Repair

ORS proposes an adjustment in the amount of $851,676 to maintenance and repair for Clearwater Solutions contract cost impacts. Details of this adjustment are reflected in the direct Testimony of ORS witness Briseno. Tr. pp. 1128.5-6. Blue Granite witness DeStefano testified that this an Adjustment to which Blue Granite and ORS agree. Tr. p. 674.4, ln. 6. There is no dispute between the parties regarding this adjustment. The Commission finds that this adjustment is just and reasonable and adopts the same.

(3) Adjustment No. 9c - Amortization of Litigation Deferrals, Deferred Storm Costs Decommissioning Costs and Net Book Value ("NBV") of Decommissioned Assets

ORS proposes an adjustment in the amount of $354,373 to maintenance and repair for the amortization of deferred litigation expenses, deferred storm costs, decommissioning costs and the NBV of decommissioned assets. Details of this adjustment are reflected in the revised surrebuttal testimony of ORS witness Sullivan. Tr. p. 1128.6.

There is disagreement between the parties regarding this adjustment. The Commission finds that this adjustment is just and reasonable and adopts the same.

(4) Adjustment No. 9d - Normalize Storm Costs

ORS proposes an adjustment in the amount of ($23,481) to maintenance and repair to normalize test year storm costs. Details of this adjustment are reflected in the direct testimony of ORS witness Bickley. Tr. pp. 1186-87.

There is disagreement between the parties regarding this adjustment. The Commission finds that this adjustment is just and reasonable and adopts the same.

(5) Adjustment No. 9e - Rebranding – Maintenance

It is ORS's position that the rebranding expenses in the amount of $12,832requested by Blue Granite should not be allowable for ratemaking purposes as they are not necessary to provide water and sewer services and do not provide a benefit to customers. ORS witness Jackson testified that ORS views rebranding expenses as comparable to the transition costs deemed not recoverable from customers in Commission Order No. 2018-804. Tr. p. 1133.3, ln. 18-21.

ORS proposes an adjustment to maintenance and repair for the removal of rebranding expenses incurred within the test year. Details of this adjustment are reflected in the direct testimony of ORS witness Jackson. Tr. p. 1133.7-8. Blue Granite witness DeStefano testified that this an Adjustment to which Blue Granite and ORS agree. Tr. p. 674.4, ln. 19-22. There is no dispute between the parties regarding this adjustment. The Commission finds that this adjustment is just and reasonable and adopts the same.

J. Adjustment No. 10 – ClearWater Solutions – Maintenance Testing

ORS agrees to the adjustment of ($174,416) regarding maintenance testing for ClearWater Solutions contract cost impacts proposed by Blue Granite. Blue Granite witness DeStefano testified that this item is one in which Blue Granite and ORS agree as ORS did not make any adjustment from Blue Granite's filed Application in adjustment 10. Tr. p. 674.4, ln. 19-22. Details of this adjustment are reflected in the direct testimony of ORS witness Briseno. Tr. p. 1128.8. There is no dispute between the parties regarding this adjustment. The Commission finds that this adjustment is just and reasonable and adopts the same.

K. Adjustment No. 11 – Meter Reading

ORS's total meter reading adjustment is ($72,815). Blue Granite witness DeStefano testified that this item is one in which Blue Granite and ORS agree as ORS did not make any adjustment from Blue Granite's filed Application in these two adjustments 11a and 11b by ORS. Tr. p. 674.4, ln. 19-22. This adjustment is comprised of the following meter reading adjustments detailed below in items K(1) & K(2) and there is no dispute by the parties. The evidence in the record supports the ORS's proposed reduction adjustment of $72,815. The Commission finds that this adjustment is just and reasonable and adopts the same.

(1) Adjustment No. 11a - ClearWater Solutions – Meter Reading

ORS proposes an adjustment of ($44,748) to meter reading for ClearWater Solutions contract cost impacts. Details of this adjustment are reflected in the direct testimony of ORS witness Briseno. Tr. p. 1128.8.

(2) Adjustment No. 11b - Remove Meter Reading Expenses due to Advance Metering Infrastructure ("AMI")

ORS proposes an adjustment of ($28,067) to meter reading to reflect the reduction in meter reading expenses due to the deployment of AMI. Details of this adjustment are reflected in the direct testimony of ORS witness Jackson. Tr. p. 1133.4.

l. Adjustment No. 12 – Chemicals

ORS's total chemicals adjustment is ($99,043). Blue Granite witness DeStefano testified that this item is one in which Blue Granite and ORS agree as ORS did not make any adjustment from Blue Granite's filed Application in these two adjustments 12a and 12b by ORS. Tr. p. 674.4, ln. 19-22. This adjustment is comprised of the following chemical adjustments in items L(1) and L(2) below and there is no dispute by the parties. The evidence in the record supports the ORS's proposed reduction adjustment of ($99,043). The Commission finds that this adjustment is just and reasonable and adopts the same.

(1) Adjustment #12a - ClearWater Solutions – Chemicals

ORS proposes an adjustment of ($67,524) to chemicals for ClearWater Solutions contract cost impacts. Details of this adjustment are reflected in the direct testimony of ORS witness Briseno. Tr. p. 1128.8. There was no dispute between the parties.

(2) Adjustment #12b – Remove Chemicals Associated with Decommissioned Plants

ORS proposes an adjustment of ($31,519) to adjust test year chemical expenses for the removal of chemical expenses associated with the decommissioned Stonegate and

Friarsgate treatment plants. Details of this adjustment are reflected in the direct testimony of ORS witness Jackson. Tr. p. 1133.4. There was no dispute between the parties.

M. Adjustment No. 13 – Transportation

ORS'S total Transportation Adjustment is ($118,674). This Adjustment is comprised of the following Transportation Adjustment as more fully detailed in items M(1) and M(2) below. Blue Granite witness DeStefano testified that Blue Granite agreed with these two adjustments 13a and 13b by ORS which were greater that the originally proposed adjustments in blue Granite's application. Tr. p. 674.3-674.4. The evidence in the record supports the ORS's proposed reduction adjustment of $118,674. The Commission finds that this adjustment is just and reasonable and adopts the same.

(1) Adjustment #13a - ClearWater Solutions – Transportation

ORS proposes an adjustment of ($110,230) to transportation for ClearWater Solutions contract cost impacts. Details of this adjustment are reflected in the direct testimony of ORS witness Briseno. Tr. p. 1128.8. Blue Granite fully agrees with the Adjustment 13a made by ORS. Tr. p. 764.4, ln. 6. The evidence in the record supports that there was no dispute and it supports proposed reduction adjustment of $110,230. The Commission finds that this adjustment is just and reasonable and adopts the same.

(2) Adjustment #13b - Rebranding - Transportation

ORS proposes an adjustment of ($8,444) to transportation expenses for the removal of rebranding expenses incurred within the test year. Details of this adjustment are reflected in the direct testimony of ORS witness Jackson. Tr. p. 1133.4. Blue Granite fully agrees with the Adjustment 13b made by ORS. Tr. p. 764.4, ln. 8. The evidence in the record supports that there was no dispute and it supports proposed reduction adjustment of $8,444. The Commission finds that this adjustment is just and reasonable and adopts the same.

N. Adjustment No. 14 – Salaries and Wages - General

ORS proposes to annualize office employee salaries for general expenses in the amount of ($118,674). Details of this adjustment are reflected in the direct testimony of ORS witness Jackson. Tr. p. 1133.9.

Blue Granite fully agrees with the Adjustment 14 made by ORS which is greater than the adjustment originally proposed by Blue Granite. Tr. p. 764.4, ln. 3. The evidence in the record supports that there was no dispute and it supports proposed reduction adjustment of $118,674. The Commission finds that this adjustment is just and reasonable and adopts the same.

O. Adjustment No. 15 – Office Supplies and Other Office Expenses

ORS's total office supplies and other office expenses adjustment is ($1,564,724). ORS witness Sullivan testified that this adjustment is comprised of the following office supplies and other office expense adjustments detailed below. Tr. p. 1115.10, ln. 5-7. Adjustment No. 15 has three subparts, 15a to 15c. Adjustment 15b is the only adjustment in dispute as it relates to Blue Granite's proposed Round Up Program and its proposed Annual Rate Adjustment Mechanism ("ARAM"). There is no dispute between the parties regarding adjustments 15a and 15c.

The evidence in the record supports this adjustment of ($1,564,724) as more fully explained below in the subitems regarding Adjustments 15a, 15b, 15c, 15d and 15e. The

Commission finds that Adjustment 15 and all of its subitems, Adjustment No. 15a, 15b, and 15c, are just and reasonable and adopts the same.

(1) Adjustment No. 15a - Company Excluded Items

Blue Granite proposed removing $1,549,457 in expenses from the Test Year which were the following items: (a) $758,000 for I-20 settlement expenses, (b) $16,024 for Congaree River Keeper litigation, (c) $759,730 for vandalized site restoration, and (d) $15,703 for penalties, fines and contributions. Blue Granite witness DeStefano testified as to this expenses and the Company's agreement with ORS. Tr. p. 764.4, ln. 8-9.

The ORS proposed the same adjustments to remove these same items that Blue Granite has removed and excluded, as well as correctly removing an additional $8,268 in penalties, fines and contributions recorded on Blue Granite's books and records. Tr. p. 1115.10, ln. 9-17. However, according ORS witness Sullivan, Blue Granite inadvertently removed allowable bank charges rather than contributions in the calculation of the adjustment. Tr. p. 1115.10, ln. 9-17. Thus, ORS's adjustment 15a is in the amount of $1,542,022.

Blue Granite fully agrees with the Adjustment 15a made by ORS. Tr. p. 764.4, ln. 8. The evidence in the record supports ORS's adjustment of $1,542,022. There is also no dispute between the parties regarding this adjustment. The Commission finds that this adjustment is just and reasonable and adopts the same.

(2) Adjustment No. 15b - Purchased Services Annual Filing Notices and Round-Up Inserts or Flyers

For the reason discussed herein, particularly in Section V.I, the Commission adopts and approves ORS's Adjustment 15b of $0. Blue Granite has asked for an additional $22,670 in its Application. Based upon the record, the Commission approves the Round Up Program as modified by ORS as reflected in testimony of ORS witness Bickley and in Witness Sullivan's Audit Exhibit DFS-5, Adjustment 15b ($0). Additionally, the Commission finds supports in the record that it is just and reasonable to deny Blue Granite's request to recover the estimated costs for the Round Up Program related to modifications of its billing system and MyUtilityConnect customer service application for recovery in the Company's next rate proceeding, and for the Commission to deny Blue Granite's request for recovery of the estimated cost for bill inserts/flyers to be used for the Round Up Program.

Among other things, based upon the record, the Commission further finds that it is just and reasonable to prohibit Blue Granite from passing onto its customers the administrative and implementation costs for the Program, including the bill inserts, notice or flyers, and for the modifications to Blue Granite's billing and customer service systems. Therefore, the Company cannot charge ratepayers $22,670 for this expense.

(3) Adjustment No. 15c - Non-Allowables – Office Supplies & Other Office Expenses

ORS proposes an adjustment to office supplies and other office expenses to remove expenses within the Test Year that should not be allowable for ratemaking purposes. Details of this adjustment are reflected in the direct testimony of ORS witness

Jackson. Tr. p. 1133.5-6. Blue Granite fully agrees with the Adjustment 15c made by ORS. Tr. p. 764.4, ln. 8. The evidence in the record supports that there was no dispute and it supports proposed reduction adjustment of $22,702. The Commission finds that this adjustment is just and reasonable and adopts the same.

P. Adjustment No. 16 – Regulatory Commission Expense

For the reasons discussed below, the Commission finds that an adjustment in the amount of $164,724 to be just and reasonable and adopts the same. Details are reflected in and comprised of the following regulatory commission expense adjustments:

(1) Adjustment 16a - Rate Case Expenses

Blue Granite fully agrees with the Adjustment 16a made by ORS. Tr. p. 764.4, ln. 12. ORS proposes an adjustment to regulatory commission expense for the amortization of rate case expenses over a three (3) year period. Tr. p. 1115.11, ln. 14 – p. 1115.13, ln. 7.

The Company's proposed adjustment includes $227,077 of rehearing expenses, $152,196 of 2017 and prior unamortized rate case expenses as of December 31, 2019, and current estimated rate case expenses of $258,000, for total rate case expenses of $637,273. The Company's per book rate case expense amount was $108,294, resulting in a Company adjustment of $104,130. *Id*.

ORS's adjustment includes $232,435 of rehearing expenses based on updated supporting documentation provided by the Company and $116,608 of prior unamortized rate case expenses as of April 30, 2020. ORS's adjustment also includes actual incurred current rate case expenses based on supporting documentation provided by the Company as of the audit cutoff date of December 20, 2019 of $145,148, for total rate case expenses of $494,191. ORS's calculation of current rate case expenses includes legal expenses of $36,864 associated with Docket Nos. 2018-358-WS and 2018-361-WS and Company provided supporting documentation as of December 20, 2019. The Company's per book rate case expense amount was $108,294, resulting in an ORS adjustment of $61,813. Tr. p. 1115.11, ln. 14 – p. 1115.13, ln. 7. Subsequent to the hearing, Blue Granite submitted to ORS, and ORS verified additional rate case expenses in the amount of $345,590.

The evidence in the record supports that the amount of rate case expenses submitted to, and verified by, ORS are just and reasonable with the exception of legal expenses associated with Docket Nos. 2018-358-WS and 2018-361-WS. Disallowance of these expenses is discussed below in section U, Adjustment 21c - Reclassify Annual Rate Adjustment Mechanism and Pumping Interceptor Tank Legal Expenses to Rate Case Expenses. Rate case expenses amortized over three years less the Company's per book amount yields an adjustment of $164,724. The Commission finds that this adjustment is just and reasonable.

(2) Adjustment 16b – Purchased Services – Annual Rate Adjustment Mechanism Legal Fees

There is disagreement between Blue Granite and ORS regarding Adjustment 16b reflecting legal cost associated with purchased services annual rate adjustment mechanism filings by Blue Granite. ORS recommends denying the request by Blue Granite to recover $3,394 for expenses related to annual rate adjustment mechanism for which Blue Granite is not authorized to utilize.

The Company proposes an adjustment to regulatory commission expense to include annual legal expenses associated with the purchased water and sewer annual rate adjustment mechanism. ORS opposes this adjustment as discussed in the direct testimony of ORS witness Sandonato. Tr. p. 1213.24-25. Additionally, the record is clear that Consumer Affairs, York County, and Forty Love Homeowners Association also oppose the ARAM.

The evidence in the record supports that the Commission adopt the recommendation of ORS and there was no dispute and it supports proposed reduction adjustment of $56,437 to $0 as proposed by ORS. This is the current and unamortized prior rate case expenses over a three-year period. The Commission finds that this adjustment of $0 recommended by ORS to be just and reasonable and adopts the same.

Q. Adjustment No. 17 – Pension & Other Benefits

ORS's total pension and other benefits adjustment is ($165,041). Blue Granite sought ($62,113) in total Pension and Other Benefits Expense. For the reasons discussed below, the Commission finds that ORS's adjustment in the amount of ($165,041) to be just and reasonable and adopts the same. Details are reflected in and comprised of the following regulatory commission expense adjustments:

(1) Adjustment 17a - Pension & Other Benefits

Blue Granite fully agrees with the Adjustment 17a made by ORS. Tr. p. 764.4, ln. 3. ORS proposes an adjustment to annualize pension and other benefits associated with pro forma salaries in the amount of $(161,830). Blue Granite had sought an adjustment of ($62,113). Details of this adjustment are reflected in the direct testimony of

ORS witness Jackson. Tr. p. 1133.6, ln. 7-12. The evidence in the record supports the proposed reduction recommended by ORS. The Commission finds that this adjustment is just and reasonable and adopts the same.

(2) Adjustment 17b – Service Awards

ORS proposes an adjustment in the amount of ($3,211) to remove Blue Granite's service award for ratemaking purposes. Details of this adjustment are reflected in the direct testimony of ORS witness Jackson. Tr. p. 1133.6, ln. 13 – p. 1133.7, ln. 6. ORS reviewed the service award for employees reaching career milestones. Witness Jackson testified that sample was selected and analyzed by ORS which contained expenses for a 65" LED Curved Samsung TV and a 1.15 carat diamond ring from a vender named Awards Network. ORS determined that all the items from this vendor were service awards and should be treated as expenses that are not necessary to provide water and wastewater services and do not provide a benefit to customers. Tr. p. 1133.7, ln. 1-6.

The evidence in the record supports the proposed reduction of $3,211 as recommended by ORS. The Commission finds that this adjustment is just and reasonable and adopts the same.

R. Adjustment No. 18 – Rent Expense

For the reasons discussed more fully above in Section V.E regarding rent expense and findings herein, the Commission denied any increase or additional revenue for rent expense to the Company as the it found that the evidence contained in the record did not support such an increase adjustment, and that such a finding by the Commission is just and reasonable.

Blue Granite sought an increase in its rent expense of $84,839. See Exhibit DFS-1. Its current rent expense is $97,022. *Id*. The Company testified that "[a]ttracting talent in the Columbia market [was] extremely difficult due to the legacy brand issues in that market." The legacy brand issues were caused by Carolina Water Service, which is now rebranded as Blue Granite. Blue Granite's customers should not have to pay the costs to upfit the Greenville office, given the move was necessitated by legacy brand problems the Company created, and Blue Granite previously represented to this Commission and its customers that the refreshing of its brand would be at no cost to customers. Exhibit KDM-2.

Additionally, based upon the record and for same legacy issues as the reason for the sale of its office and move to Greenville above in Section V.E, the Commission further finds and determines that the proforma rent expense of $84,839 should be removed from the Company's recoverable General Expenses for Rent and is hereby denied.

S. Adjustment No. 19 – Insurance Expense

As testified by Blue Granite witness DeStefano, the company agrees with ORS Adjustment No. 19 in the amount of $163,371 as detailed in the testimony of ORS witness Sullivan. Tr. p. 764.33, ln. 8-18 Witness Sullivan's testimony updates as-filed estimates for policy premiums confirmed in the company's insurance renewal process, completed and effective November 1, 2019. Blue Granite has therefore provided data sufficient to support ORS Adjustment No. 19 and the pro-forma amount included in ORS Exhibit DFS-1. Accordingly, Consumer Affairs' concern about using estimates is moot.

The parties appear to agree with the same as a result of these updates. The Commission finds that this adjustment is supported by evidence in the record and is just and reasonable.

T. Adjustment No. 20 – ClearWater Solutions – Lawn Care

Blue Granite fully agrees with the Adjustment 20 of ($98,634) made by ORS to adjust for the removal of lawn care expenses that will no longer be applicable due to the Company entering into a contract with ClearWater Solutions to run and maintain their Midlands BUs. Tr. p. 764.4, ln. 3. Blue Granite's proposed adjustment was($27,003) in its Application for this item. ORS proposes an adjustment to office utilities for ClearWater Solutions contract cost impacts. Details of this adjustment are reflected in the direct testimony of ORS witness Briseno. Tr. p. 1128.9, ln. 11-22. The difference between the two figures proposed by ORS and Blue Granite is the removal of an additional $71,631, as calculated by the Company for lawn care/landscaping expenses which Blue Granite admitted to ORS that "it was an oversight to not remove these costs in the preparation of their adjustment request." Tr. p. 1128.9, ln. 19-20.

The evidence in the record supports that there was no dispute and it supports proposed reduction adjustment of $98,634 as recommended by ORS. The Commission finds that this adjustment is just and reasonable and adopts the same.

U. Adjustment No. 21 – Outside Services – Other

ORS's total outside services adjustment is ($188,889). For the reasons discussed below, the Commission finds that ORS's adjustment in the amount of $196,091 to be just and reasonable and adopts the same. Details are reflected in and comprised of the following outside services adjustments:

(1) Adjustment 21a – Outside Services – Annualize Corix Allocations

Blue Granite fully agrees with the Adjustment 21a of ($341,915) made by ORS. Tr. p. 764.4, ln. 11. ORS proposed this adjustment to outside services to reflect the annualized Corix corporate cost allocations.

Blue Granite had proposed an adjustment of ($362,759) in its Application, calculated by annualizing the first and second quarters of 2019 for a total of $426,283, less per book management fees of $789,042. Whereas, ORS's adjustment is calculated by annualizing the first, second and third quarters of 2019 as provided by Blue Granite in response to its Audit Request to the Company for a total of $447,126, less per book management fees of $789,042.

The Company provided the Corix Group of Companies Cost Allocation Manual ("CAM"), which provides an explanation of services performed and the methods used to allocate indirect costs to the operating businesses. ORS reviewed the CAM and verified the methods specified in the CAM to allocate costs were followed by the Company to calculate the allocation of costs to Blue Granite. Corporate services performed by Corix for Blue Granite and its other operating businesses include: communications, finance, information technology, human resources, legal, and chief executive officer functions. ORS found the allocation of Corix corporate costs to Blue Granite for this Docket to be reasonable. Tr. p. 1115.15, ln. 1-5.

ORS witness Sullivan testified that ORS will continue to examine, test and analyze the corporate services performed by Corix for Blue Granite, the costs incurred by Corix, and the allocation of those costs to Blue Granite in future dockets to ensure these costs continue to be reasonable and beneficial for Blue Granite customers. Tr. p. 1115.15, ln. 6-9.

The evidence in the record supports that there was no dispute and it supports proposed adjustment of ($341,915). Tr. p. 1115.14, ln. 12 – p. 1115.15, ln. 9. The Commission finds that this adjustment is just and reasonable and adopts the same.

(2) Adjustment 21b – AMI Data Support, York County Franchise Fees and York County Asset Lease

Blue Granite witness DeStefano testified that Adjustment 21b of $214,731 is one in which Blue Granite and ORS agree as ORS did not make any adjustment from Blue Granite's filed Application regarding this adjustment by the Company. Tr. p. 674.4, ln. 19-22.

ORS witness Jackson proposes the same adjustment as Blue Granite to outside services reflecting the cost of AMI data support for AMI installation in Lake Wylie, York County franchise fees and York County asset leases. Tr. p. 1133.7, ln. 9-15. The York County franchise agreement describes the terms and conditions with respect to the lease of certain water and sewer service facilities in York County that provide Blue Granite the non-exclusive franchise to operate water and sewer systems in designated areas of the county. The franchise agreement was approved by this Commission on May 2, 2018, per Order No. 2018-325. *Id*.

There is no dispute by the parties. The evidence in the record supports the ORS's proposed adjustment of $214,731. Tr. p. 1115.15, ln. 10-14. The Commission finds that this adjustment is just and reasonable and adopts the same.

(3) Adjustment 21c – Reclassify Annual Rate Adjustment Mechanism and Pumping Interceptor Tank Legal Expenses to Rate Case Expenses

Blue Granite fully agrees with the Adjustment 21c made by ORS. Tr. p. 764.4, ln. 12. ORS witness Sullivan proposed to remove legal expenses associated with the annual rate adjustment mechanism and pumping interceptor tanks of ($36,864) from Test Year legal expenses and reclassify them as current rate case expenses as part of ORS Adjustment #16a to be amortized over a three-year period. The Company withdrew its petition in Docket Nos. 2018-358-WS and 2018-361-WS and has included the requests as part of this docket.

The evidence in the record supports that there was no dispute and it supports proposed reduction adjustment of $36,864. Tr. p. 1115.15, ln. 15-22. The Commission finds that this adjustment is just and reasonable, but reclassification of these legal expenses as rate case expenses is denied. The Company filed proceeding in Docket Nos. 2018-358-WS and 2018-361-WS and later requested to withdraw its applications in each docket. Ratepayers should not bear the burden of expenses from proceedings that are duplicitous in nature to the Company's current rate case before this Commission.

(4) Adjustment No. 21d – Rebranding- Outside Services - Other

Blue Granite fully agrees with the Adjustment 21d of ($9,833) made by ORS. Tr. p. 764.4, ln. 8. ORS proposed this adjustment to outside services for the removal of rebranding expenses incurred within the Test Year. Details of this adjustment are reflected in the direct testimony of ORS witness Jackson. Tr. p. 1133.7, ln. 16 – p. 1133.8, ln. 3. Witness Jackson testified that ORS's position is that rebranding expenses should not be allowable for ratemaking purposes as they are not necessary to provide water and wastewater services and do not provide a benefit to customers. Tr. 1133.7, ln. 18-20. When responding to an Audit request by ORS to the utility, ORS discovered that Blue Granite has included legal fees as expenses related to the rebranding of Carolina Water Service to Blue Granite Water Company. ORS also found additional legal fees related to rebranding that the Company did not identify, and those expenses were removed as well. Tr. p. 1133.8, ln. 1-3.

The evidence in the record supports that there was no dispute and it supports proposed reduction adjustment of $9,833. Tr. p. 1115.16, ln. 1-3. The Commission finds that this adjustment is just and reasonable and adopts the same.

(5) Adjustment No. 21e – Remove Legal Expenses - Outside Services – Other

Blue Granite fully agrees with the Adjustment 21e of ($15,008) made by ORS. Tr. p. 764.12, ln. 3. ORS proposes to remove and defer $31,788 of legal expenses associated with civil actions that have not yet concluded for Blue Granite. ORS also proposes to remove $151,589 of legal expenses associated with Congaree River Keeper litigation that were not removed by the Company. The Commission deemed and ordered legal expenses for the Congaree River Keeper ("CRK") litigation as not recoverable by Blue Granite from its customers in Commission Order No. 2020-57.

In addition, ORS proposes to add back $168,310 to eliminate the effects of transactions related to I-20 condemnation. This is comprised of legal fees in the amount of $7,844 and a credit in the amount of $176,154 that Blue Granite posted to Account 6025 for reimbursement from the Town of Lexington for a previous condemnation attempt in the early 2000's (see, Civil Action No. 2001-CP-32-0711). ORS testified that it will continue to review the appropriate accounting treatment for the reimbursement and reserves its rights to make further recommendations. The Company is not seeking treatment of I-20 condemnation related expenses as part of the determination of the Company's revenue requirement. ORS also proposes to remove $7,143 of legal expenses for services performed outside of the Test Year.

The evidence in the record supports that there was no dispute and it supports proposed reduction adjustment of $15,008. Tr. p. 1115.16, ln. 4–22. The Commission finds that this adjustment is just and reasonable and adopts the same.

V. Adjustment No. 22 – Non-Utility Miscellaneous Expense

Blue Granite witness DeStefano testified that Adjustment 22 is one in which Blue Granite and ORS agree as ORS did not make any adjustment from Blue Granite's filed Application regarding this adjustment by the Company. Tr. p. 674.4, ln. 19-22. ORS witness Sullivan testified that ORS removed non-utility activity from the Test Year. The activity is related to the CRK litigation and Commission ordered adjustments. Tr. p. 1115.17, ln. 1-3.

There is no dispute by the parties. The evidence in the record supports the ORS's proposed reduction adjustment of $442,691. Tr. p. 1115.17, ln. 1-3. The Commission finds that this adjustment is just and reasonable and adopts the same.

W. Adjustment No. 23 – Miscellaneous

ORS's total miscellaneous adjustment is $4,566. For the reasons discussed below, the Commission finds that ORS's adjustment in the amount of $4,566 to miscellaneous to be just and reasonable and adopts the same. Details are reflected in and comprised of the following miscellaneous expense adjustments:

(1) Adjustment No. 23a – Customer Deposit Interest Expense

Blue Granite witness DeStefano testified that Adjustment 23a is one in which Blue Granite and ORS agree as ORS did not make any adjustment from Blue Granite's filed Application regarding this adjustment by the Company. Tr. p. 674.4, ln. 19-22.

There is no dispute by the parties. The evidence in the record supports the ORS's proposed reduction adjustment of $442,691. The Commission finds that this adjustment is just and reasonable and adopts the same.

(2) Adjustment No. 23b – Non-Allowables - Miscellaneous

Blue Granite fully agrees with the Adjustment 23b of ($6,678) recommended by ORS. Tr. p. 764.4, ln. 8. ORS recommended an adjustment to miscellaneous expenses to remove items from the Test Year should not be included by the Company and would not be allowable for ratemaking purposes. Details of this adjustment are reflected in the direct testimony of ORS witness Jackson. Tr. p. 1133.8, ln. 4-11. These were expenses incurred by Blue Granite that were not necessary to provide water and wastewater services and do not provide a benefit to customers. Tr. p. 1133.8, ln. 6-7. ORS witness Jackson testified that these expenses were for dinners with alcohol in the amount of $3,992, and for items not supported by sufficient documentation in the amount of $2,686. The items which were removed for lack of supporting documentation did not contain a clear or valid business purpose or were not supported by itemized receipts. Tr. p. 1133.8, ln. 8-11. As a result, ORS proposes an adjustment in the amount of $6,678. *Id*.

The evidence in the record supports that there was no dispute and it supports proposed reduction adjustment of $6,678. The Commission finds that this adjustment is just and reasonable and adopts the same.

X. Adjustment No. 24 – Depreciation Expense

ORS proposes an adjustment of $1,494,488 to annualize depreciation expense for known and measurable plant in service. Details of this adjustment are reflected in Audit Exhibit DFS-6 and the direct testimony of ORS witness Briseno. Tr. p. 1128.10; Exhibit DFS-6. ORS witness Briseno presented credible evidence from his audit and review of the Company supporting ORS's recommendation.

The evidence in the record supports proposed depreciation expense adjustment proposed by ORS of $1,494,488. The Commission finds that this adjustment is just and reasonable, and adopts the same.

Y. Adjustment No. 25 – Amortization of Contributions in Aid of Construction ("CIAC")

ORS proposes an adjustment of (538,846) to the amortization of CIAC for known and measurable changes. Details of this adjustment are reflected in Audit Exhibit DFS-6 and the direct testimony of ORS witness Briseno. Tr. p. 1128.10; Exhibit DFS-6. ORS witness Briseno presented credible evidence from his audit and review of the Company supporting ORS's recommendation.

The evidence in the record supports proposed depreciation expense adjustment proposed by ORS of ($538,846). The Commission finds that this adjustment is just and reasonable, and adopts the same

Z. Adjustment No. 26 – Taxes Other Than Income

ORS's total taxes other than income adjustment is $166,467. For the reasons discussed below, the Commission finds that ORS's adjustment in the amount of $356,303 to taxes other than income to be just and reasonable and adopts the same. Details are reflected in and comprised of the following taxes other than income adjustments:

(1) Adjustment No. 26a - Payroll Taxes

Blue Granite fully agrees with the Adjustment 26a made by ORS of ($33,874). Tr. p. 764.4, ln. 8. Blue Granite proposes in its Application an adjustment of ($14,449) using the salary and wages data as of June 30, 2019.

ORS witness Jackson testified that ORS's recommended adjustment in the amount of ($33,874) is based on the annualized salary and wages data from October 31, 2019 that was provided to ORS by the Company. This adjustment reflects the payroll taxes associated with the pro forma adjusted salaries & wages. Tr. p. 1133.8, ln. 12-17.

The evidence in the record supports that there was no dispute and it supports proposed reduction adjustment of $33,874. The Commission finds that this adjustment is just and reasonable and adopts the same.

(2) Adjustment No. 26b - Gross Receipts Taxes

ORS witness Sullivan testified regarding Adjustment No. 26b to adjust gross receipts taxes for the adjustments to accounting and pro forma revenue using a factor of .00527282 in the amount of $4,160. Details of this adjustment are reflected in the Surrebuttal Testimony of ORS witness Sullivan. Tr. pp. 1116.6-7; Surrebuttal Exhibit DFS-5.

The evidence in the record supports proposed depreciation expense adjustment proposed by ORS of $4,160. The Commission finds that this adjustment is just and reasonable and adopts the same.

(3) Adjustment No. 26c - Pro Forma Property Taxes

ORS proposes to adjust taxes other than income for property taxes on pro forma plant balances in the amount of $196,181. Details of this adjustment are reflected in the direct testimony of ORS witness Briseno. Tr. pp. 1128.10-11.

The evidence in the record supports proposed depreciation expense adjustment proposed by ORS of $196,181. The Commission finds that this adjustment is just and reasonable and adopts the same.

AA. Adjustment No. 27 – Federal Income Taxes

Blue Granite fully agrees with the Adjustment 27 made by ORS. Tr. p. 764.4, ln. 15. ORS proposes to adjust federal income taxes after accounting and pro forma adjustments using the federal income tax rate of 21%. In addition, ORS and the Company propose to reduce the calculated federal income taxes by the amortization of protected and unprotected Excess Deferred Income Taxes ("EDIT"). The amortization of

EDIT reduces federal income taxes by $129,064, which is comprised of $50,402 related to protected EDIT and $78,662 related to unprotected EDIT. The amortization of EDIT of $129,064 in this Docket differs from the amount ordered by the Commission of $136,924 in Docket No. 2017-292-WS due to the tax net operating loss ("NOL") balance for the Company per the 2017 tax return. Based on ORS Audit Request #20, the original entry booked in December 2017 to remeasure Accumulated Deferred Income Taxes did not include a component for NOL remeasurement. ORS accepts the Company's calculation of $129,064 for the amortization of EDIT that is included as a reduction to federal income taxes in this docket. Details of this adjustment are reflected in Audit Exhibit DFS-7. Tr. p. 1115.18, ln. 16 – p. 1115.19, ln. 6; Exhibit DFS-7.

The evidence in the record supports that there was no dispute and it supports proposed reduction adjustment of $456,552. The Commission finds that this adjustment is just and reasonable and adopts the same.

BB. Adjustment No. 28 – State Income Taxes

Blue Granite fully agrees with the Adjustment 28 made by ORS. Tr. p. 764.4, ln. 15. ORS witness Sullivan testified regarding an adjustment of $5,184 to state income taxes after accounting and pro forma adjustments using the state income tax rate of five percent (5%). Details of this adjustment are reflected in Exhibit DFS-7. Tr. p. 1115.19, ln. 7-9.

The evidence in the record supports that there was no dispute and it supports proposed reduction adjustment of $5,184. The Commission finds that this adjustment is just and reasonable and adopts the same.

CC. Adjustment No. 29 – Sale of Utility Property

Blue Granite witness DeStefano testified that Adjustment 29 is one in which Blue Granite and ORS agree as ORS did not make any adjustment from Blue Granite's filed Application regarding this adjustment by the Company. Tr. p. 674.4, ln. 19-22. ORS witness Sullivan testified that the ORS proposes for the Commission to adopt an adjustment in the amount of $20,253 to remove the sale of utility property for ratemaking purposes from the Test Year. Tr. p. 1115.19, ln. 11-13.

There is no dispute by the parties. The evidence in the record supports the ORS's proposed reduction adjustment of $$20,253. The Commission finds that this adjustment is just and reasonable and adopts the same.

DD. Adjustment No. 30 – Customer Growth

According to the ORS witness Sullivan, no accounting and pro forma adjustments have been proposed for customer growth by ORS. Tr. p. 1115.19, ln. 14-15. Blue Granite witness DeStefano testified that Adjustment 30 is one in which Blue Granite and ORS agree as ORS did not make any adjustment from Blue Granite's filed Application regarding this adjustment by the Company. Tr. p. 674.4, ln. 19-22. There is no dispute by the parties. The Commission finds that this adjustment is just and reasonable and adopts the same.

EE. Adjustment No. 31 – Interest During Construction ("IDC")

Blue Granite witness DeStefano testified that Adjustment 31 is one in which Blue Granite and ORS agree as ORS did not make any adjustment from Blue Granite's filed

Application regarding this adjustment by the Company. Tr. p. 674.4, ln. 19-22. There is no dispute by the parties.

The adjustment is in the amount of $172,635 to remove IDC from the test year for rate making purposes. Construction work in progress is not included in rate base. Tr. p. 1115.19, ll. 16-18. The Commission finds that this adjustment is supported by evidence in the record and is just and reasonable.

FF. Adjustment No. 32 – Gross Plant in Service

ORS proposes an adjustment in the amount of $415,288 to adjust gross plant in service to reflect plant additions and retirements since the last rate case as well as pro forms general ledger additions, pro forma plant, pro forma retirements, removal of the Company's Northbrook Office, removal of the Stonegate WTP and Friarsgate WWTP, and the removal of vehicles sold to Clearwater Solutions as part of the contract. The Company proposes an adjustment in the amount of $2,600,952 Tr. p. 1128.11, ll. 4-9. ORS Witness Briseno testified that the difference in adjustment amounts is attributable to the following:

1. ORS opposes the recovery by the Company of $495,206 in upgrades to its Greenville office. Tr. p. 1201.7, ln. 20-22.

2. ORS proposes to increase gross plant in service by $19,361 to account for the Company's erroneous removal of the Stonegate WTP decommissioning balance. ORS also proposes a corresponding adjustment to accumulated depreciation.

3. ORS proposes to adjust gross plant in service by $98 to account for errors in the Company's calculation of the Northbrook Office removal.

4. ORS used actual numbers provided by the Company through its audit, while the Company used estimates.

See, Tr. pp. 1128.11-12.

We have reviewed the recommendations of ORS and found them to be just and reasonable. The adjustments to gross plant in service are not disputed.

GG. Adjustment No. 33 – Accumulated Depreciation

ORS proposes an adjustment in the amount of $3,337,761 to adjust accumulated depreciation to reflect the updated gross plant in service whereas the Company proposes an adjustment in the amount of $3,701,703. Tr. p. 1128.12, ll. 5-7. ORS witness Briseno testified that the difference in adjustment amounts is attributable to the following:

1. ORS proposes to adjust accumulated depreciation by $4,929 to correctly account for the Company's erroneous Stonegate WTP decommissioning removal.

2. ORS proposes to adjust accumulated depreciation by ($310,276) for prior rate case adjustments related to the Indian Pines extraordinary retirement, Purdy Shores & Foxwood retirement, and engineering expenses.

3. ORS proposes to adjust accumulated depreciation by ($98).

4. ORS proposes to adjust accumulated depreciation for the depreciation expense ORS calculated utilizing ORS witness Garrett's depreciation rates applied to ORS's calculation of gross plant in service.

See, Tr. p. 1128.12, ll. 7-21.

ORS adjusted accumulated depreciation and accumulated amortization of CIAC using the proposed depreciation rates as proposed by ORS witness Garrett. Tr. p. 1129.5, ll. 6-8. Witness Briseno testified that Blue Granite's accounting books must balance, like a scale. Tr. p. 1129.5, l. 15. Accordingly, he testified that if one side of the scale receives increased depreciation expense, the other side of the scale should receive an equal increase to accumulated depreciation expense. Tr. p. 1129.5, ll. 15-17. When a journal entry is made to record a debit to depreciation expense, a corresponding credit entry is made in the same amount to accumulated depreciation. Tr. p. 1129.6, ll. 13-14. The Accounting for Public Utilities Manual, Chapter 7.08, Section 2, states:

> Depreciation and amortization expenses are also based upon forecasted levels or upon historical levels with proforma adjustments to recognize changes in depreciation rates or changes in test year depreciable plant (e.g., to recognize depreciation requirements on year-end plant levels or construction projects added to the rate base because of imminent completion and use). Some commissions, in annualizing depreciation expenses to a year-end rate base, have concurrently added an equal amount (or sometimes one-half of the expense amount) to the recorded yearend depreciation reserve. The adjustment to the reserve is generally based on the rationale that double entry accounting concepts will produce an equal impact on the accumulated provisions for depreciation and on the assumption that to fail to recognize the impact on net plant will result in an overstated rate base on a prospective basis.

Tr. p. 1129.7, ll. 10-21.

Briseno also cited the Accounting for Public Utilities Manual, Chapter 6.04:

> Regulators typically require recording the depreciation reserve at the same depreciable group level used for calculating annual provisions.

Tr. p. 1129.7, ll. 23-26.

Briseno further testified that several past Commission rulings concur with ORS's proposed treatment. He cited Dockets No. 2018-319-E (Duke Energy Carolinas), 2018-318-E (Duke Energy Progress), and 2017-292-WS (Carolina Water Service) as three recent dockets in which the Commission adopted the methodology recommended by ORS. Tr. p. 1129.7, ll. 28-30.

Finally, witness Briseno testified that by only utilizing 1.5% on the impact to accumulated depreciation and accumulated amortization of CIAC, Blue Granite fails to adjust for known and measurable changes. Tr. p. 1129.5, ll. 11-13. A rate case adjusts a test year for known and measurable changes to reflect the expected expense levels and rate base in order to set fair and reasonable rates providing a company an opportunity to earn a fair and reasonable return. Tr. p. 1129.5, ll. 18-21. Incorporating the impact of depreciation expense based upon proposed rates without accounting for the impact of proposed rates in the calculation of accumulated depreciation does not reflect known and measurable changes. Tr. p. 1129.5-6. Briseno testified that Blue Granite's proposal is not fair or reasonable for customers in that Blue Granite seeks to receive the benefit of increased depreciation expense using the new depreciation rates to determine the revenue requirement without being required to make an equal offsetting entry to accumulated depreciation. Tr. p. 1129.6, ll. 3-8).

Company witness DeStefano testified that ORS is improperly incorporating the effects of post-audit cutoff changes for only certain components of rate base-without the ability to similarly account for the effects of interrelated activity in Utility Plant in Service and CIAC (*i.e.,* capital and CIAC additions after 12/20/2019), thereby violating the matching principle prioritized in utility regulation. Tr. p. 764.34, ll. 12-19. He recommends that the Commission approve a rate base balance utilizing a consistent cutoff period for interrelated components, in this case Utility Plant in Service with Accumulated Depreciation and CIAC with Accumulated Amortization. Tr. p. 764.34, ll. 20-23.

The Commission has considered the positions of ORS and the Company. Furthermore, we credit ORS witness Briseno's observation that ORS's treatment of accumulated depreciation is consistent with that adopted by the Commission in recent rate proceedings. The substantial evidence on the whole record indicates that the adjustments proposed by ORS are just and reasonable.

HH. Adjustment No. 34 – Deferred Charges

ORS's total deferred charges adjustment is $4,818,974. This adjustment, set out in Hearing Exhibit 34, is comprised of the following:

(1) Adjustment #34a – Unamortized Balance for Deferred Maintenance

The Company proposes an adjustment of $348,417 to include the unamortized balance of proposed deferred maintenance in deferred charges in rate base. The Company's adjustment included an unamortized amount of $49,167 related to a wastewater treatment plant tank recoating and $299,250 related to hydrotank inspections. Tr. p. 1115.20, ll. 8-12.

Company witness DeStefano testified that it should be permitted to defer the costs associated with the hydrotank inspection and include the unamortized balance of the deferred tank inspections in rate base because they are significant, do not recur annually, and provide the Company and its customers a multi-year benefit. The Company seeks rate base treatment for these deferred maintenance costs. Tr. p. 764.27, ll. 4-13.

Blue Granite provided documentation to support the hydrotank inspection expenses, but no documentation to support the wastewater treatment tank recoating. ORS has included annual amortization of $62,926 for the hydrotank inspections as part of ORS Adjustment #9a as reflected in the direct testimony of ORS witness Briseno. ORS's calculated unamortized balance for the hydrotank inspections is $251,704. ORS takes the view that this unamortized balance should not be included in rate base. Such treatment is consistent with the treatment of deferred maintenance in several recent rate cases[17]. Tr. pp. 1115.20-21.

ORS recommends that the recovery of the costs associated with the hydrotank inspections be amortized over a five-year period rather than placed in rate base. We agree with ORS. This treatment is consistent with prior treatment of similar expenditures in previous rate cases and is just and reasonable to both the utility and its customers.

(2) Adjustment #34b – Unamortized Balances for Decommissioned Assets, NBV on Decommissioned Assets and EDIT

ORS proposes an adjustment in the amount of $4,818,974 to adjust deferred charges to include the unamortized balances as of April 30, 2020 net of a full year of amortization for removal costs on decommissioned assets, NBV on decommissioned assets and EDIT. Witness Briseno testified that the difference in adjustment amounts is

[17] *See, e.g.*, Dockets No. 2015-199-WS and 2017-292-WS (Carolina Water Service) and 2018-257-WS (Kiawah Island Utility).

attributable to the differences identified in the Amortization of Litigation Deferrals, Deferred Storm Costs, Decommissioning Costs and Net Book Value of Decommissioned Assets adjustment and the full year of amortization netted against the April 30, 2020, balances. Based upon calculations that were updated in the Amortization of Litigation Deferrals, Deferred Storm Costs, Decommissioning Costs and Net Book Value of Decommissioned Assets adjustment, this adjustment is updated to total $4,818,972. Tr. p. 1129.3, ll. 1-7. ORS witness Briseno testified that a similar adjustment was accepted by the Commission in Docket No. 2017-292-WS (Carolina Water Service), Order No. 2018-345(A), p. 24.

The Company proposes an adjustment in the amount of $4,596,244. Company witness DeStefano testified that deferral balances and their related amortization are "known and measurable" in a complete sense, and he therefore rejects ORS's calculation of the decommissioning/NEV and EDIT balances through 4/30/2021. Instead, Blue Granite recommends all deferral balances be calculated as of the same cut-off date of 4/30/2020, because no foreseeable change in the amortizable balance would occur between the audit cut-off and 4/30/2020. Tr. pp. 764.35-36.

Having reviewed the evidence in the record, including the testimony of ORS witness Briseno which we find credible, we credit his testimony and adopt the ORS position.

II. Adjustment No. 35 – Cash Working Capital

According to witness Sullivan, ORS's total cash working capital adjustment is ($300,581), as detailed in Hearing Exhibit 34. After ORS was able to verify additional rate case expenses, Order Exhibit 1 indicates a cash working capital adjustment of ($286,181).

(1) Adjustment 35a – Cash Working Capital – Accounting and Pro-Forma Adjustments

Witness Sullivan testified that ORS proposes an adjustment to reflect cash working capital after accounting and proforma adjustments. According to witness Sullivan, ORS and the Company used a 45-day allowance or 1/8 of maintenance and general expenses for the cash working capital adjustment. According to witness DeStefano, the Company agrees with ORS's proposed Cash Working Capital adjustment. Tr. p. 764.4, ll. 13-17. No party contests this adjustment. The evidence contained in the record supports this adjustment, and the Commission finds it to be just and reasonable.

(2) Adjustment 35b -- Cash Working Capital Rate Mitigation

ORS proposes to remove purchased services from the calculation of cash working capital. ORS requested the Company to explain the change in methodology for calculating cash working capital from Carolina Water Service Docket Nos. 2015-199-WS and 2017-292-WS. According to Blue Granite's response, it removed purchased services expenses as that is the practice with the Company's North Carolina affiliate and Blue Granite proposed this adjustment to mitigate the overall rate request. Tr. p. 1115.21-22. ORS accepts the Company's methodology in this docket to calculate cash working capital. (Tr. p. 1115.22, ll. 10-11). ORS's adjustment to remove purchased services from the calculation of cash working capital results in a reduction to cash working capital of $1,055,693. Hearing Exhibit 34. The Company agrees with this adjustment. No party contests the adjustment that ORS has proposed. The evidence in the record supports the ORS proposed adjustment, and this Commission finds it to be just and reasonable.

JJ. Adjustment No. 36 – CIAC

ORS proposes an adjustment in the amount of $2,205,788 to adjust CIAC to reflect the amortization of CIAC expenses, pro forma CIAC additions, and decommissioned plants. The Company proposes an adjustment in the amount of $1,068,166. Witness Briseno testified that the difference is attributable to the utilization of ORS witness Garrett's depreciation rates and the updates to CIAC provided by Blue Granite to ORS. ORS updated its calculation to capture the inverse of its calculation of CIAC expense, resulting in a total adjustment of $2,205,787. Tr. p. 1128.13, ll. 8-13. The Commission approves this adjustment.

KK. Adjustment No. 37 – Plant Held for Future Use

ORS has accepted Company witness DeStefano's proposal to remove $350,000 associated with a land purchase. Tr. p. 1128.13, ll. 15-21. Witness DeStefano testified that the Company agrees with ORS's proposed Plant Held for Future Use adjustment. Tr. p. 764.4, l. 14. No party contests the adjustment that ORS has proposed. As a result, the evidence in the record supports the ORS proposed adjustment of $0 for plant held for future use and this Commission finds it to be just and reasonable.

LL. Adjustment No. 38 – Excess Book Value

ORS proposes to remove excess book value for ratemaking purposes by removing $1,937,905 from plant and $1,473,259 from accumulated depreciation through April 30, 2020, due to new rates going into effect in May 2020. The Company proposes an adjustment in the amount of ($435,586). According to witness Briseno, there has historically been a difference between ORS and Blue Granite's calculations of the excess book value adjustment because Blue Granite utilized the incorrect carry forward amount in Docket No. 2004-357-WS. Tr. p. 1128.14, 1n. 1-8. Company witness DeStefano testified that excess book value has been included for ratemaking purposes in prior proceedings. Tr. p. 763.15, ll. 1-2.

The Commission finds that Blue Granite failed to rebut ORS witness Briseno's testimony that the Company had utilized an incorrect carry forward amount, and it therefore finds ORS's adjustment just and reasonable.

MM. Adjustment No. 39 – Interest Expense

ORS proposes an adjustment to synchronize interest expense with rate base after accounting and pro forma adjustments, using the capitalization ratio of 47.09% for long-term debt and 52.91% for equity, with a cost of debt of 5.73%. Tr. p. 1115.23, II. 4-7.

ORS Witness Sullivan testified that ORS's calculated synchronized interest expense of $2,001,300, less the Company's per book interest expense of $1,828,315, yields an ORS adjustment of $172,985, as indicated in Hearing Exhibit 34. As a result of the addition of verified rate case expenses, the interest expense adjustment becomes $173,374, as indicated in Order Exhibit 1. Company witness DeStefano agrees with ORS's proposed Interest Expense adjustment. Tr. p. 764.4, ll. 15-17. No party contests the adjustment that ORS has proposed, and the Commission finds it to be just and reasonable.

NN. Adjustment No. 40 – Service Revenues -Water

For the reasons discussed herein and based upon the record, this Commission finds the revenues detailed in Order Exhibit 1 to be just and reasonable.

OO. Adjustment No. 41 – Service Revenues – Sewer

For the reasons discussed herein and based upon the record, this Commission finds the revenues detailed in Order Exhibit 1 to be just and reasonable.

PP. Adjustment No. 42 – Service Revenues – Miscellaneous Accounts

For the reasons discussed herein and based upon the record, this Commission finds the revenues detailed in Order Exhibit 1 to be just and reasonable.

QQ. Adjustment No. 43 – Uncollectible Accounts

ORS proposes to adjust uncollectible accounts for ORS's adjustments to revenues. The percentages used to calculate uncollectible accounts were provided by the Company and were verified and found reasonable by ORS. While Blue Granite contests ORS's proposed treatment of Blue Granite's revenues, because this Commission has accepted ORS's proposed adjustment, as indicated in this Order, it finds ORS's proposed uncollectible account adjustment to be reasonable. Tr. p. 1115.24, ll. 1-3.

RR. Adjustment No. 44 – Taxes Other Than Income – Gross Receipts

ORS proposes an adjustment to gross receipts taxes after ORS's adjustments to revenues using a factor of .00527282. Tr. p. 1115.24, ll. 5-6. This Commission has found ORS's proposed taxes other than income-gross receipts adjustment to be reasonable and accepted it.

SS. Adjustment No. 45 – Federal Income Taxes

ORS proposes to adjust federal income taxes after ORS's adjustments to revenues and gross receipts taxes using the federal income tax rate of 21%. In addition, ORS proposes to reduce the calculated federal income taxes by the amortization of protected and unprotected Excess Deferred Income Taxes EDIT. Tr. p. 1115.24, ll. 8-11. While Blue Granite contests certain ORS adjustments that impact ORS's proposed Federal Income Tax adjustment, this Commission has found ORS's proposed Federal Income Tax adjustment to be reasonable and has accepted it.

TT. Adjustment No. 46 – State Income Taxes

ORS proposes to adjust state income taxes after ORS's adjustments to revenues and gross receipts taxes using the state income tax rate of 5%. Tr. p. 1115.24, ll. 13-15). While Blue Granite contests certain ORS adjustments that impact ORS's proposed State Income Tax adjustment, this Commission has found ORS's proposed State Income Tax adjustment to be reasonable and has accepted it.

UU. Adjustment No. 47 – Customer Growth

According to ORS witness Sullivan's testimony, the growth factors of 2.0392% for water territory 1, 0.0904% for water territory 2 and 2.0076% for sewer are discussed in the direct testimony of ORS witness Sandonato. Tr. p. 1115.24, ll. 19-20. This Commission accepts ORS's proposed customer growth factors for water territories 1 and 2 as reasonable.

VII. FINDINGS OF FACT AND CONCLUSIONS OF LAW

Based upon the Discussion, Findings of Fact as set forth herein, and the record of the instant proceeding, the Commission makes the following Findings of Fact and Conclusions of Law:

1. Blue Granite is a water and sewer utility providing water and sewer service in its assigned service areas located in sixteen (16) counties throughout South Carolina. The Commission is vested with authority to regulate rates of every public utility in this state and to ascertain and fix just and reasonable rates for service. S.C. Ann. §58-5-210, et. seq. Blue Granite's operations in South Carolina are subject to the jurisdiction of the Commission.

2. Blue Granite is a direct subsidiary of CRU (previously named Utilities, Inc.) which in turn is an indirect subsidiary of CII. In addition to Blue Granite, CRU has 15 utility subsidiaries in several other states. CII is a diversified, privately held corporation that designs, builds, installs, finances and operates local utility infrastructure on behalf of municipal, institutional, military, and private-sector customers.

3. The appropriate Test Year period for this proceeding, selected by Blue Granite, is July 1, 2018 through June 30, 2019. Blue Granite submitted evidence in this case with respect to its revenues and expenses using a Test Year consisting of the twelve (12) months ending June 30, 2019.

4. Blue Granite requested an overall increase in revenue requirements of $11,731,803 for combined operations of water and sewer services and which is an increase of 49.18% over pro-forma present rate revenues of $23,856,072. Tr. p. 354.21,

ln. 12-14. Blue Granite is seeking a grand total of $35,587,875 in total revenue. Blue Granite's requested revenues increase consists of a $5,575,957 water revenue increase and a sewer revenue increase of $6,155,846; meaning, that Blue Granite is seeking an overall 44.42% increase in water revenue and an overall 54.45% increase in wastewater (sewer) revenues. Tr. p. 354.21, ln. 12-17.

5. Of the $11,731,803 in additional revenue sought by Blue Granite, $4,774,305 results from third-party purchased water and sewer treatment expenses while the remaining $6,987,498 is primarily recovering revenue for shareholders from investments in infrastructure needed to serve customers. With its plant investments made to maintain and improve its service to customers and the increased operating expenses that the Company has experienced, Blue Granite asserts that it has been unable to earn its authorized rate of return and it is requesting rate relief. Tr. p. 750, ln. 12-22; p.763.4, ln. 9-21.

6. The Commission declines to approve the Annual Rate Adjustment Mechanism ("ARAM") requested by Blue Granite, as well as declines to approve any proposed ARAM for the Company as suggested, modified, or altered by any other another party in this Docket. The Commission finds and holds that an ARAM does not incentivize Blue Granite to reduce wastewater infiltration and inflow or non-revenue water losses and that it is just and reasonable to deny and decline this request. The Commission further finds that the proposed ARAM as designed would recover significant annual expenses with little to no review and does not provide adequate customer protections. All risk is borne by the customers under this mechanism.

Additionally, the Commission also finds that the proposed ARAM in this Docket would not improve bill clarity. The methodology for calculating the purchased water and sewer charges is confusing under this mechanism and does not yield a number reflecting the actual costs of the purchased water or sewer treatment charged by the third-party provider.

7. Based upon the above findings and discussion regarding an ARAM, the Commission further refuses to adopt the changes the Company proposed to its rate structure to add separate purchased water and sewer treatment charges. The Commission finds that it is just and reasonable to adopt the Company's its existing rate structure at this time which provides for a Base Facility Charge, a commodity charge based on water consumption and per Single Family Equivalent charge (a/k/a flat rates) for sewer customers.

8. The Commission finds that the evidence in the record demonstrates that flat rates for sewer service are burdensome to Blue Granite's customers who have low water usage, who only have one or two people in a household, who are senior citizens on fixed incomes, and who are on low and moderate income customers. However, the Commission finds that Blue Granite does not have any other rate methodology at this time available for its sewer service customers. The Commission finds that it is just and reasonable to direct and order that Blue Granite provide alternate rate designs for its water and sewer services in its next rate proceeding. Additionally, the Commission finds that is also just and reasonable given the continued complaints and issues raised by the more than one hundred and fifty (150) customers testifying in the hearings before the

Commission and the utility's ongoing problems wastewater infiltration and inflow and its increased non-revenue water losses, to order the Company to investigate the feasibility of converting its sewer rate to a volumetric rate design and to provide a report to the Commission when Blue Granite files its next rate case.

9. The Commission finds that Blue Granite has water usage data for a little more than fifty-three percent (53%) of its customers per ORS witness Sandonato with 16,848 of its overall 31,710 customers from Service Territories 1 and 2 receiving water service from Blue Granite as provided in the Chart below and in Exhibit AMS-4.[18]

Date	6/30/2018	6/30/2019	Average	Growth Factor
Service Territory 1 Water # of Customers	9,800	10,208	10,004	2.0392%
Service Territory 2 Water # of Customers	6,628	6,640	6,634	0.0904%
Service Territory 1 & 2 Sewer -- # of Customers	14,277	14,862	14,570	2.0076%
Consolidated # of Customers	30,705	31,710	31,208	1.6102%

10. Given the issues with Blue Granite's sewer service rates as discussed herein and more fully detailed in the whole record, it is reasonable and just for the Commission to find and to order that Blue Granite should obtain water usage, or volumetric water consumption, data from entities providing water service to Blue Granite's sewer only customers so that this information may be used in the development

[18] See, Exhibit AMS-4. As of the end of the Test Year, Blue Granite was providing water supply/distribution services to 16,848 residential and commercial customers and wastewater (sewer) collection/treatment services to 14,862 residential and commercial customers. Tr. p. 1213.4, ln. 5-7.

of a just and reasonable volumetric sewer service rate methodology to be reviewed, and subject to approval, by the Commission in its next rate case.

11. Additionally, the Commission finds that it is just and reasonable to order that, within one hundred and twenty (120) days from the date of this Decision, Blue Granite shall provide to the Commission a Report on its progress to obtain water usage, or volumetric water consumption, data from other entities providing water service to Blue Granite's sewer only customers, as well as the cost of installing flow meters. The Report must be filed in the Docketing Management System (DMS) for this Docket and served upon all parties in accordance with S.C. Code Ann. Reg. 103-830.1 and applicable rules.

12. The Company originally requested the opportunity to earn a 10.7% Return on Equity (ROE); however, later in its rebuttal testimony of witness D'Ascendis, Blue Granite updated its analysis and recommended a range between 9.75% and 10.25%. Tr. p. 548.4, ln. 4-9. The Commission agreed with witnesses from ORS and Consumer Affairs and finds that witness D'Ascendis' ROE recommendation is too high.

13. The Commission finds that analysis and testimony provided by Consumer Affairs witness Rothschild is credible, compelling, unbiased and without prejudice in balancing the interests of the consumer and the utility by allowing the utility the opportunity to earn a 7.46% return on equity. *See*, Tr. pp. 672.8-672.10.

14. The Commission finds that analysis of witness Rothschild shows that it is just and reasonable to conclude the approved and appropriate ROE for Blue Granite is 7.46% based upon (a) the evidence in the whole record, (b) the rate of return

methodology, and (c) a historical test year beginning July 1, 2018 and ending June 30, 2019.

15. With the above approved ROE of 7.46% for utility, the Commission finds that it is just and reasonable to further adopt the resulting Revenue Requirement for Blue Granite of $28,733,986, resulting in an increase of $4,958,848 consisting of an increase in water revenues of $2,161,536 and an increase in sewer revenues of $2,797,312. This represents an approximate 57% reduction from the Company's requested increase of $11,589,537 made in its Application, and therefore, the resulting Operating Margin of 10.54% is likewise adopted by the Commission for Blue Granite pursuant to S.C. Code Ann. §58-5-240(H).

Blue Granite Water Company
Summary of Commission Revenue Increase and Findings (7.46% ROE)

	Approved Additional Revenue Increase	Percentage Increase
Water Service Revenues – Territory 1	$1,491,460	23%
Water Service Revenues – Territory 2	$670,076	12%
Consolidated Sewer Service Revenues	$2,797,312	24%
Total Operating Revenues	**$4,958,848**	**21%**

16. For the reasons discussed herein, the Commission finds the revenues detailed in Order Exhibit No. 1 to be just and reasonable and based upon credible evidence in the record.

17. Blue Granite filed its application with rates set on an ROE and OM basis, as well as requesting a purchased water and purchased sewer services rate adjustment mechanism. Tr. p. 763.3; Tr. pp. 1214.2-1214.6. While there is no requirement that OM

methodology be used in determining a fair rate of return, Blue Granite requested OM treatment in its Application. ORS performed its audit and recommendation based on an OM methodology. No party contested Blue Granite's use of an OM methodology. The weight of the evidence, including witnesses' testimony, supports this methodology.

18. The ROE and OM methodology are appropriate for determining the lawfulness of the Company's rates and in fixing just and reasonable rates.

19. Consumer Affairs proposed the option and analysis for the ROE of 7.46% with witness Rothschild. We conclude that the weight of the evidence, including witnesses' testimony and the credibility of Rothschild analysis which demonstrated flawed ROE calculations based upon non-utility business by Blue Granite witness DeStefano, support the 7.46% ROE and OM of 10.54% for Blue Granite as determined by the Commission.

20. Supported by the evidence, we conclude that the ROE of 7.46% and resulting OM of 10.54% herein is just and reasonable while allowing Blue Granite to continue to provide its customers with quality water and sewer service.

21. The requested revenue increase of $11,731,803 for a total revenue requested of $35,587,875 by Blue Granite results in a potential OM of 12.26% and ROE of 10.70%.

22. Even the adjusted revenue increase of $8,435,953 by ORS results in a potential OM of 11.34% and ROE of 9.45%.

23. Blue Granite apportioned its requested revenue requirement equally to all base facility charges and monthly water consumption rates. The proposed increase to all

customer classes proposed by Blue Granite and by ORS is approximately the following Table:

	Current Rate	COMPANY PROPOSAL Proposed Rate	Proposed Increase	% Increase	ORS PROPOSAL Proposed Rate	Proposed Increase	% Increase
Service Territory 1							
Water Supply Customers	$	$	$	%	$	$	%
Monthly Residential Base Facilities Charge	14.38	21.91	7.53	52.36%	20.13	5.75	39.99%
Water Commodity Charge per 1,000 gallons	5.59	8.53	2.94	52.59%	7.88	2.29	40.97%
Monthly Residential Water Rate based on 6,000 gallons usage	47.92	73.09	25.17	52.53%	67.41	19.49	40.67%
Water Distribution Customers Only							
Monthly Residential Base Facilities Charge	14.38	21.91	7.53	52.36%	20.13	5.75	39.99%
Water Commodity Charge per 1,000 gallons	7.55	4.33	(3.22)	-42.65%	10.65	3.10	41.06%
Purchased Water Charge per 1,000 gallons	N/A	7.19	6.85	N/A	0.00	0.00	N/A
Monthly Residential Water Rate based on 6,000 gallons usage	59.68	91.03	31.35	52.53%	84.03	24.35	40.80%
Service Territory 2							
Water Rates - Water Supply Customers	$	$	$	%	$	$	%
Monthly Residential Base Facilities Charge	28.59	36.49	7.90	27.63%	34.74	6.15	21.51%
Water Commodity Charge per 1,000 gallons	10.27	13.12	2.85	27.75%	12.45	2.18	21.23%
Monthly Residential Water Rate based on 6,000 gallons usage	90.21	115.21	25.00	27.71%	109.44	19.23	21.32%
Water Distribution Customers Only							
Monthly Residential Base Facilities Charge	28.59	36.49	7.90	27.63%	37.74	9.15	32.00%
Water Commodity Charge per 1,000 gallons	11.85	4.35	(7.50)	-63.29%	14.36	2.51	21.18%
Purchased Water Charge	N/A	10.79	11.08	N/A	0.00	0.00	N/A
Monthly Residential Water Rate based on 6,000 gallons usage	99.69	127.33	27.64	27.73%	123.90	24.21	24.29%

24. With regard to the changes or increases in the sewer rates for customers using the same ROE and OM respectively proposed by Blue Granite and ORS for Service Territories 1 & 2 is as follows:

	Current Rate	COMPANY PROPOSAL Proposed Rate	Proposed Increase	% Increase	ORS PROPOSAL Proposed Rate	Proposed Increase	% Increase
Service Territories 1 & 2							
Sewer Collection and Treatment Rates							
Monthly Residential Base Facilities Charge	65.08	95.21	30.13	46.30%	91.25	26.17	40.21%
Monthly Residential Base Facilities Charge - Mobile Home	47.50	69.49	21.99	46.29%	66.60	19.10	40.21%
Service Territories 1 & 2							
Sewer Collection Only Rates							
Monthly Residential Base Facilities Charge	65.08	45.81	(19.27)	-29.61%	91.25	26.17	40.21%
Sewer Treatment Charge	N/A	49.40	54.20	N/A	0.00	0.00	0.00%
The Village Sewer Collection	33.86	49.54	15.68	46.31%	47.48	13.62	40.22%

25. The Commission finds that it is just and reasonable to accept ORS's recommendation to limit the water service Territory 2 increase to 31% of total water service revenue requirement and finds that it is just and reasonable. The Commission

orders that Blue Granite prepare a rate schedule consist with this finding, as well as all other findings, so that water service Territory 2 increase to 31% of total water service revenue requirement.

26. The Commission finds that Blue Granite did not seek or obtain approval from the Commission of its ClearWater Solutions contract as is required by S.C. Ann. Regs. 103-541 and 103-743 prior to use and engagement thereof.

27. The Commission further finds that Blue Granite immediately file with the Commission the contract between itself and ClearWater Solutions for review and possible approval by the Commission. The Commission further cautions the Company that it must file its contracts for approval in the future in compliance with the Commission's regulations.

28. The Commission finds that Blue Granite is authorized to continue the deferral accounting treatment of changes in purchased water and wastewater treatment rates established in Docket Number 2015-199-WS.

29. Additionally, with regard to additional adjustment to the Company's "Rate Base – Deferred Charges," the Commission finds and determines that Blue Granite is authorized to amortize $3,178,824 of Purchased Water and Sewer Deferrals over five (5) years and to remove the first year's amortization of $635,765 for a total increase of $2,543,059 in a regulatory asset.

30. With regard to additional adjustment to the Company's "Maintenance Expenses - Purchased Water and Sewer Expense," the Commission finds and determines that Blue Granite is authorized to amortize this expense over five (5) years and that one

year's amortized expense of $635,765 will be included in expenses in this rate case. The unamortized portion, a total of $2,119,000, will be placed in a Regulatory Asset to be recovered annually.

31. The Commission finds and determines that Blue Granite is not authorized to apply carrying costs to these deferral accounts other than as approved and directed herein.

32. The Commission finds that it is just and reasonable to decline approval of the changes proposed by Blue Granite to its rate structure to add separate purchased water and sewer treatment charges, which were proposed to effectuate the ARAM.

33. The Commission finds that Blue Granite shall maintain its existing rate structure of a Base Facility Charge, a commodity charge based on water consumption for water customers, and per Single Family Equivalent charge for sewer customers.

34. The Commission finds that the adjustments as discussed and listed previously above in this Order are just and reasonable and the Commission hereby adopts and approves the same.

35. Attached as Order Exhibit No 2, Blue Granite filed the rate schedule/tariff on March 30, 2020 incorporating the changes approved herein reflecting an Operating Margin of 10.54% and 7.46% ROE which retains the present base facility charge for water service and distributes the rate increase volumetrically to lessen the impact of the rate increase on low-usage water customers.[19]

[19] On April 1, 2020, the Commission issued Commission Directive Order No. 2020-280 adopting the rate schedule during the Commission's regularly scheduled Business Meeting which is Order Exhibit No. 2. On

VIII. ORDERING PROVISIONS

IT IS THEREFORE ORDERED THAT:

1. The accounting adjustments reflected in Order Exhibit No. 1 are approved, adopted and accepted into the record and are incorporated and made part of this Order by reference. Order Exhibit 1 includes adjustments and modifications by the Commission as discussed herein this Order to adjustments which may have been agreed upon by Blue Granite, ORS, and other parties, as well as to adjustments for which no party objected.

2. While the record contains ample credible evidence supporting the Commission's concern as to what rate increase, or any rate increase, is appropriate in this Docket, existing law binds the Commission and there is credible evidence in the record supporting a limited increase in the Company's revenue requirement.

3. The record of evidence, and the controlling law binding the Commission, support a finding that the rate request or revenue requirement sought by Blue Granite is not just and reasonable and as Blue Granite witness testified is equal to "rate shock." See, Tr. pp. 887-894 (Company witness DeStefano testifying that "rate shock would be -- again, generally is --- a steep – or spike in – in end cost to – to consumers" when being cross examined about a 50% rate increase by Intervenor York County. Tr. p. 887, ln. 11-13); Tr. pp. 1055.8-1055.9.

March 25, 2020, Blue Granite was ordered pursuant to Commission Directive of the same date to provide and file alternate rate schedules on March 30, 2020 consistent with the Commission's findings so that this rate schedule would be included in this final Order dated April 9, 2020.

4. Based on the information provided by the parties, the Commission concludes the appropriate rate setting methodology to use as a guide in determining the lawfulness of Blue Granite's proposed rates and for fixing just and reasonable rates is return on equity base with a resulting operating margin.

5. Based upon the rates, charges and accounting adjustments discussed, adopted and approved herein in Order Exhibit Nos. 1 & 2, Blue Granite is authorized to have the opportunity to earn an 7.46% ROE and the resulting 10.54% Operating Margin is approved for Blue Granite.

6. For Blue Granite to have the opportunity to earn the 7.46% ROE, found fair and reasonable herein and within the public's interest, Blue Granite must be allowed additional revenues of $4,958,848.

7. The Commission orders Blue Granite to limit the water service Territory 2 increase to 31% of total water service revenue requirement and further orders that Blue Granite shall prepare a rate schedule consist with this ruling, as well as all other findings and rulings, so that water service Territory 2 increase to 31% of total water service revenue requirement.

8. As offered by the utility, Blue Granite is ordered to delay implementation of any new rates authorized and allowed by this Order until September 1, 2020 so that there will be no change in the current rates for water and for sewer charges to Blue Granite customers until on or after September 1, 2020.[20]

[20] Commission Directive dated March 25, 2020 references the March 19, 2020 letter offer by Blue Granite to delay implementation of any rate increase or change in Docket No. 2019-290-WS in response to Commission Order No. 2020-240 dated March 18, 2020. Upon issuance of a final order by the

9. The schedule of rates, terms and conditions in the attached Exhibit 2 are approved for use by Blue Granite effective on September 1, 2020 and are just and reasonable without undue discrimination and are also designed to meet revenue requirements for Blue Granite as discussed herein.

10. Due to the Company's voluntary offer to delay implementation of any rates until September 1, 2020, the Company has time and is ordered to provide at least thirty (30) days' advance notice of the increase to customers of its water and wastewater services prior to the rates and schedules being put into effect for service rendered. The schedules shall be deemed to be filed with the Commission pursuant to S.C. Code Ann. § 58-5-240.

11. The following Table reflects an operating margin of 10.54%:

Operating Revenues	$28,733,986
Operating Expenses	23,715,106
Net Operating Income (Loss)	5,018,880
Customer Growth	78,664
Total Income for Margin	$ 5,097,544
Operating Margin (After Interest)	10.54%
Return on Equity	7.46%
Interest Expense for Operating Margin	$ 2,069,789

See, Order Exhibit No. 1.

12. Blue Granite's capital structure is 47.09% debt and 52.91% common equity.

Commission, Blue Granite states that it "would commit to not putting new rates into effect until September 1, 2020." Letter on behalf of Blue Granite, dated March 19, 2020 and filed in this Docket.

13. Blue Granite is ordered to provide a one-time credit in the amount of $10.59 for each customer water account and sewer account effective upon the date of this Order. Blue Granite is to issue these credits to customers as soon as possible and within its next billing cycle following the date of this Order.

14. The Commission finds Blue Granite's updated rate case expenses submitted at the conclusion of the hearing following review by the ORS, to be reasonable and that Blue Granite's rate case expenses shall be amortized over a 3-year period as the Company and ORS agreed.

15. The Company shall continue to maintain current performance bonds in the amounts of $350,000 for water operations and $350,000 for wastewater operations pursuant to S.C. Code Ann. § 58-5-720.[21]

16. Blue Granite shall conduct a cost of service study prior to filing its next adjustment to rates case in order to ensure that cost allocation is appropriate and to propose a rate design methodology that eliminates subsidization. Evidence does exist in the record to conclude there is inequity in the existing rate design among Blue Granite's customers. However, in order for the Commission to set rates that fairly distribute the revenue requirement of the utility equitably between its customers, the Commission finds and directs that Blue Granite conduct a cost of service study prior to filing its next rate case.

[21] ORS requested that Commission continue to require a performance bond for Blue Granite. Currently, Blue Granite has a Commission required performance bond pursuant to S.C. Code Ann. §58-5-720 for utility operations for Blue Granite, which is in the form of an Irrevocable Letter of Credit ("ILC") from JP Morgan Chase Bank, N.A. as surety in the amount of $350,000 for water and $350,000 for sewer operations.

17. Blue Granite's books and records shall be maintained according to NARUC Uniform System of Accounts. The Company is directed to make any necessary adjustments to its accounting system to conform to the NARUC Uniform System of Accounts.

18. Blue Granite will provide the Commission an update on information provided in its bill format on or before July 1, 2020.

19. Blue Granite shall prepare quarterly reports to the Commission and the ORS detailing its efforts to improve responsiveness and customer satisfaction. Additionally, the reports shall provide details of every complaint and the resolution of every complaint, as well as the names and addresses of all complainants for use by ORS in the event follow-up contacts are necessary. The first quarterly reports must be submitted on or before July 1, 2020.

20. The Company shall provide the written reports on capital improvements no less than semiannually as described above to ORS and filed with the Commission.

21. The Commission further orders Blue Granite to immediately file with the Commission the contract between itself and ClearWater Solutions for review and possible approval by the Commission. The Commission further cautions the Company that it must file its contracts for approval in the future in compliance with the Commission's regulations.

22. The Commission overrules Blue Granite's objection to York County Councilwoman Allison Love's testimony at the Public Night Hearing in this Docket held in York, South Carolina, on March 5, 2020. Further, all hearing exhibits presented at the

evening public hearings in this case are admitted into the evidence as well as any late filed exhibits.

23. This Order will remain in full force and effect until further order of the Commission.

BY ORDER OF THE COMMISSION:

Comer H Randall

Comer H. "Randy" Randall, Chairman

ATTEST:

Jocelyn Boyd

Jocelyn Boyd, Chief Clerk/Executive Director

BLUE GRANITE WATER COMPANY
OPERATING EXPERIENCE, RATE BASE AND RATE OF RETURN - 7.46% ROE
TEST YEAR ENDED JUNE 30, 2019
COMBINED OPERATIONS

Description	(1) Per Books	(2) Accounting & Pro Forma Adjustments	(3) As Adjusted	(4) Effect of Proposed Increase	(5) After Increase
	$	$	$	$	$
Operating Revenue:					
Service Revenue-Water	11,868,922	280,468	12,149,390	2,176,490	14,325,880
Service Revenue-Sewer	10,929,933	504,321	11,434,254	2,785,194	14,219,448
Miscellaneous Revenue	445,566	4,043	449,609	49,482	499,091
Uncollectibles	(250,471)	(7,644)	(258,115)	(52,318)	(310,433)
Total Operating Revenues	22,993,950	781,188	23,775,138	4,958,848	28,733,986
Maintenance Expenses					
Salaries and Wages	2,670,783	(1,344,062)	1,326,721	0	1,326,721
Capitalized Time	(333,423)	73,614	(259,809)	0	(259,809)
Purchased Power	771,660	0	771,660	0	771,660
Purchased Water and Sewer	5,266,724	635,765	5,902,489	0	5,902,489
Maintenance and Repair	3,031,412	880,789	3,912,201	0	3,912,201
Maintenance Testing	314,455	(174,416)	140,039	0	140,039
Meter Reading	112,607	(72,815)	39,792	0	39,792
Chemicals	360,819	(99,043)	261,776	0	261,776
Transportation	238,985	(118,674)	120,311	0	120,311
Operating Exp. Charged to Plant	0	0	0	0	0
Total Maintenance Expenses	12,434,022	(218,842)	12,215,180	0	12,215,180
General Expenses					
Salaries and Wages	871,623	538,807	1,410,430	0	1,410,430
Office Supplies and Other Office Exp	1,980,731	(1,564,724)	416,007	0	416,007
Regulatory Commission Exp	138,293	164,724	303,017	0	303,017
Pension and Other Benefits	779,623	(165,041)	614,582	0	614,582
Rent	97,022	0	97,022	0	97,022
Insurance	348,323	163,371	511,694	0	511,694
Office Utilities	491,952	(98,634)	393,318	0	393,318
Outside Services	1,062,984	(188,889)	874,095	0	874,095
Non-Utilitiy Misc Income	442,691	(442,691)	0	0	0
Miscellaneous	61,301	4,566	65,867	0	65,867
Total General Expenses	6,274,543	(1,588,511)	4,686,032	0	4,686,032
Depreciation	1,788,412	1,494,488	3,282,900	0	3,282,900
Amortization of CIAC	(406,510)	(538,846)	(945,356)	0	(945,356)
Taxes Other Than Income	3,499,587	166,467	3,666,054	26,423	3,692,477
Income Taxes - Federal	(431,984)	68,529	(363,455)	984,019	620,564
Income Taxes - State	(185,161)	126,416	(58,745)	246,621	187,877
Sale of Utility Property	(20,253)	20,253	0	0	0
Amort. Investment Tax Credit	(8,854)	0	(8,854)	0	(8,854)
Amortization of PAA	(15,713)	0	(15,713)	0	(15,713)
Total Other Expenses	4,219,524	1,337,307	5,556,831	1,257,063	6,813,894
Total Operating Expenses	22,928,089	(470,046)	22,458,043	1,257,063	23,715,106
Net Operating Income	65,861	1,251,234	1,317,095	3,701,785	5,018,880
Customer Growth	0	0	0	78,664	78,664
Interest During Construction	(172,635)	172,635	0	0	0
Net Income For Return	**238,496**	**1,078,599**	**1,317,095**	**3,780,449**	**5,097,544**
Original Cost Rate Base:					
Gross Plant In Service	103,656,698	415,288	104,071,986	0	104,071,986
Accumulated Depreciation	(16,190,845)	3,337,761	(12,853,084)	0	(12,853,084)
Net Plant In Service	87,465,853	3,753,049	91,218,902	0	91,218,902
Deferred Charges	0	7,362,033	7,362,033	0	7,362,033
Cash Working Capital	1,680,231	(305,391)	1,374,840	0	1,374,840
Contributions in Aid of Construction	(20,300,003)	2,205,788	(18,094,215)	0	(18,094,215)
Accumulated Deferred Income Taxes	(3,522,916)	0	(3,522,916)	0	(3,522,916)
Customer Deposits	(334,350)	0	(334,350)	0	(334,350)
Advances in Aid of Construction	0	0	0	0	0
Plant Acquisition Adjustment	(831,277)	0	(831,277)	0	(831,277)
Excess Book Value	0	(464,646)	(464,646)	0	(464,646)
Total Rate Base	64,157,538	12,550,833	76,708,371	0	76,708,371
Return on Rate Base	0.37%		1.72%		6.65%
Operating Margin After Interest Exp.	-6.91%		-3.17%		10.54%
Return on Equity					7.46%
Interest Expense for Oper. Margin	1,828,315	241,474	2,069,789		2,069,789

SCHEDULE OF RATES AND CHARGES

WATER

Service Territory 1

Monthly Charges - Water Supply Customers Only

Where water is supplied by wells owned and operated by the Utility, the following rates apply:

	Current	Per Order
Base Facilities Charge	$ 14.38 per unit	$ 14.38 per unit
Commodity Charge	$ 5.59 per 1,000 gal. or 134 cft.	$ 7.39 per 1,000 gal. or 134 cft.
Commercial		
Base Facilities Charge by meter size		
5/8" meter *	$ 14.38 per unit	$ 14.38 per unit
3/4" meter	$ 14.38 per unit	$ 14.38 per unit
1" meter	$ 37.43 per unit	$ 37.43 per unit
1.5" meter	$ 74.86 per unit	$ 74.86 per unit
2" meter	$ 119.78 per unit	$ 119.78 per unit
3" meter	$ 224.59 per unit	$ 224.59 per unit
4" meter	$ 374.42 per unit	$ 374.42 per unit
8" meter	$1,150.51 per unit	$1,150.51 per unit
Commercial Commodity Charge	$ 5.59 per 1,000 gal or 134 cft.	$ 7.39 per 1,000 gal. or 134 cft.

Monthly Charges – Water Distribution Customers Only

Where water is purchased from a governmental body or agency or other entity for distribution and resale by the Utility, the following rates apply:

	Current	Per Order
Base Facilities Charge per single-family house, condominium, mobile home, or apartment unit	$14.38 per unit	$14.38 per unit
Residential Commodity Charge	$ 7.55 per 1,000 gal. or 134 cft.	$ 9.98 per 1,000 gal. or 134 cft.
Commercial		
Base Facilities Charge by meter size		
5/8" meter *	$ 14.38 per unit	$ 14.38 per unit
3/4" meter	$ 14.38 per unit	$ 14.38 per unit
1" meter	$ 37.43 per unit	$ 37.43 per unit

1.5” meter	\$ 74.86 per unit	\$ 74.86 per unit
2” meter	\$ 119.78 per unit	\$ 119.78 per unit
3” meter	\$ 224.59 per unit	\$ 224.59 per unit
4” meter	\$ 374.42 per unit	\$ 374.42 per unit
8” meter	\$1,150.51 per unit	\$1,150.51 per unit
Commercial Commodity Charge	\$ 7.55 per 1,000 gal. or 134 cft.	\$ 9.98 per 1,000 gal. or 134 cft.

***

Service Territory 2

Monthly Charges - Water Supply Customers

Where water is supplied by wells owned and operated by the Utility, the following rates apply:

	Current	Per Order
Base Facilities Charge	\$ 28.59 per unit	\$ 28.59 per unit
Commodity Charge	\$ 10.27 per 1,000 gal. or 134 cft.	\$ 12.34 per 1,000 gal. or 134 cft.
Commercial Base Facilities Charge by meter size		
5/8” meter*	\$ 28.59 per unit	\$ 28.59 per unit
1” meter	\$ 79.59 per unit	\$ 79.59 per unit
1.5” meter	\$ 146.27 per unit	\$146.27 per unit
3” meter	\$ 499.14 per unit	\$499.14 per unit
Commercial Commodity Charge	\$ 10.27 per 1,000 gal. or 134 cft.	\$12.34 per 1,000 gal. or 134 cft.

Monthly Charges – Water Distribution Customers Only

Where water is purchased from a governmental body or agency or other entity for distribution and resale by the Utility, the following rates apply:

	Current	Proposed
Base Facilities Charge	\$28.59 per unit	\$28.59 per unit
Commodity Charge	\$11.85 per 1,000 gal. or 134 cft.	\$14.24 per 1,000 gal. or 134 cft.
Commercial Base Facilities Charge by meter size:		
5/8” meter*	\$ 28.59 per unit	\$ 28.59 per unit
1” meter	\$ 79.59 per unit	\$ 79.59 per unit
1.5” meter	\$ 146.27 per unit	\$146.27 per unit
3” meter	\$ 499.14 per unit	\$499.14 per unit

Commercial Commodity Charge	$ 11.85 per 1,000 gal. or 134 cft.	$ 14.24 per 1,000 gal. or 134 cft.

SEWER

Monthly Charges – Sewer Collection & Treatment Only

Where sewage collection and treatment are provided through facilities owned and operated by the Utility, the following rates apply:

	Current	Per Order
Residential	$65.08 per unit	$80.93 per unit
Mobile Homes	$47.50 per unit	$59.07 per unit
Commercial, per Single Family Equivalent	$65.08 per SFE	$80.93 per SFE

Commercial customers are those not included in the residential category above and include, but are not limited to, hotels, stores, restaurants, offices, industry, etc.

Monthly Charges – Sewer Collection Only

When sewage is collected by the Utility and transferred to a government body or agency, or other entity for treatment, the Utility's rates are as follows:

	Current	Per Order
Residential – per single-family house, condominium, or apartment unit	$65.08 per unit	$80.93 per unit
Commercial	$65.08 per SFE*	$80.93 per SFE*
The Village Sewer Collection	$33.86 per SFE*	$42.11 per SFE*

Blue Granite Water Company
Calculated Revenues
Docket No. 2019-290-WS

Calculated Revenue Summary - BGWC (Service Territory #1 and Service Territory #2)

A	B	C	D	E
Operating Revenue	**Calculated Test Year Revenue**	**Additional Revenue at Calculated Rates**	**Revenue at Calculated Rates**	**% Increase**
Service Territory 1 - Well Water	$1,022,329	$233,227	$1,255,556	23%
Service Territory 1 - Purchased Water	$5,557,459	$1,283,227	$6,840,686	23%
Service Territory 1 - Water - Misc. Revenue	$84,650	$5,275	$89,926	6%
Total Service Territory 1 Water	**$6,664,438**	**$1,521,729**	**$8,186,168**	23%
Service Territory 2 - Well Water	$3,917,788	$458,219	$4,376,007	12%
Service Territory 2 - Purchased Water	$1,651,814	$201,403	$1,853,217	12%
Service Territory 2 - Water - Misc. Revenue	$115,189	$4,197	$119,386	4%
Total Service Territory 2 Water	**$5,684,791**	**$663,819**	**$6,348,610**	12%
Service Territory 1 & 2 - Sewer	$11,434,254	$2,784,790	$14,219,043	24%
Service Territory 1 & 2 - Sewer - Misc. Revenue	$249,770	$37,194	$286,964	15%
Total Service Revenue Sewer	**$11,684,024**	**$2,821,984**	**$14,506,008**	24%
Total Water and Sewer Service Revenues	**$24,033,254**	**$5,007,532**	**$29,040,786**	21%

Exhibit ALR-A
ATTACHMENT A-2

Blue Granite Water Company
Calculated Revenues
Docket No. 2019-290-WS

Calculated Revenue at Current Rates - Service Territory 1

A	B	C	D	E		G	H
	Customer Classi ication	**Average Mont ly Consumption per Customer**	**sage C arge per 1,000 gallons**	**Test Year End Customers [1]**	**Annuali ed Service nits**	**Base acility C arge (B C)**	**Test Year Revenue (D C 1000) (G)**
WATER	400PW M - 1" Purchase Water o ercial	12,561	$7.55	5	60	$37.43	$7,936
	400PW M - 1.5" Purchase Water o ercial	1,166	$7.55	1	12	$74.86	$1,004
	400PW M - 2" Purchase Water o ercial	60,650	$7.55	7	84	$119.78	$48,526
	400PW M - 3" Purchase Water o ercial	108,723	$7.55	1	12	$224.59	$12,545
	400PW M - 3 4" Purchase Water o ercial	0	$7.55	2	24	$14.38	$345
	400PW M - 5 8" Purchase Water o ercial	7,336	$7.55	20	240	$14.38	$16,744
	400PW R - 1" Purchase Water o ercial - Riverhills	12,212	$7.55	41	492	$37.43	$63,778
	400PW R - 1.5" Purchase Water o ercial - Riverhills	35,220	$7.55	38	456	$74.86	$155,392
	400PW R - 2" Purchase Water o ercial - Riverhills	66,720	$7.55	43	516	$119.78	$321,734
	400PW R - 3" Purchase Water o ercial - Riverhills	121,237	$7.55	5	60	$224.59	$68,396
	400PW R - 3 4" Purchase Water o ercial - Riverhills	4,500	$7.55	22	264	$14.38	$12,766
	400PW R - 4" Purchase Water o ercial - Riverhills	107,190	$7.55	3	36	$374.42	$42,613
	400PW R - 5 8" Purchase Water o ercial - Riverhills	6,137	$7.55	101	1,212	$14.38	$73,586
	400PW R - 8" Purchase Water o ercial - Riverhills	592,148	$7.55	1	12	$1,150.51	$67,455
	400PWR S - 1" Purchase Water Residential	3,302	$7.55	88	1,056	$14.38	$41,511
	400PWR S - 1.5" Purchase Water Residential	1,845	$7.55	56	672	$14.38	$19,024
	400PWR S - 2" Purchase Water Residential	2,957	$7.55	93	1,116	$14.38	$40,963
	400PWR S - 3 4" Purchase Water Residential	10,752	$7.55	1	12	$14.38	$1,147
	400PWR S - 4" Purchase Water Residential	599	$7.55	16	192	$14.38	$3,629
	400PWR S - 5 8" Purchase Water Residential	4,636	$7.55	3,028	36,336	$14.38	$1,794,337
	400PWRR - Purchase Water Res - R ll Meter Si es	4,610	$7.55	4,683	56,196	$14.38	$2,764,028
	400W M - 1" o ercial	611	$5.59	1	12	$37.43	$490
	400W M - 5 8" o ercial	7,998	$5.59	7	84	$14.38	$4,963
	400W R - o ercial rrigation	30,295	$7.55	16	192	$0.00	$43,916
	400WR R - Residential rrigation	7,412	$7.55	212	2,544	$0.00	$142,364
	400WR S - Water Residential ll Meter Si es	4,716	$5.59	1,545	18,540	$14.38	$755,365
	402WR S - Water Residential ll Meter Si es	3,948	$5.59	172	2,064	$14.38	$75,231
	Water Service Total						**$6,579,788**
	Miscellaneous Revenues - ate ees						$23,123
	ew usto er harges						$28,731
	Miscellaneous Service Revenue						$36
	S hec & Reconnect ee						$32,760
	Total Miscellaneous Revenues						**$84,650**
	Total Operating Revenues						**$6,664,438**

Blue Granite Water Company
Calculated Revenues
Docket No. 2019-290-WS

Revenue at Calculated Rates - Service Territory 1

A	B	C	D	E		G	H
	Customer Classi ication	**Average Mont ly Consumption per Customer**	**sage C arge per 1,000 gallons**	**Test Year End Customers [1]**	**Annuali ed Service nits**	**Base acility C arge (B C)**	**Test Year Revenue (D C 1000) (G)**
WATER	400PW M - 1" Purchase Water o ercial	12,561	$9.98	5	60	$37.43	$9,767
	400PW M - 1.5" Purchase Water o ercial	1,166	$9.98	1	12	$74.86	$1,038
	400PW M - 2" Purchase Water o ercial	60,650	$9.98	7	84	$119.78	$60,906
	400PW M - 3" Purchase Water o ercial	108,723	$9.98	1	12	$224.59	$15,716
	400PW M - 3 4" Purchase Water o ercial	0	$9.98	2	24	$14.38	$345
	400PW M - 5 8" Purchase Water o ercial	7,336	$9.98	20	240	$14.38	$21,022
	400PW R - 1" Purchase Water o ercial - Riverhills	12,212	$9.98	41	492	$37.43	$78,378
	400PW R - 1.5" Purchase Water o ercial - Riverhills	35,220	$9.98	38	456	$74.86	$194,418
	400PW R - 2" Purchase Water o ercial - Riverhills	66,720	$9.98	43	516	$119.78	$405,393
	400PW R - 3" Purchase Water o ercial - Riverhills	121,237	$9.98	5	60	$224.59	$86,072
	400PW R - 3 4" Purchase Water o ercial - Riverhills	4,500	$9.98	22	264	$14.38	$15,653
	400PW R - 4" Purchase Water o ercial - Riverhills	107,190	$9.98	3	36	$374.42	$51,990
	400PW R - 5 8" Purchase Water o ercial - Riverhills	6,137	$9.98	101	1,212	$14.38	$91,660
	400PW R - 8" Purchase Water o ercial - Riverhills	592,148	$9.98	1	12	$1,150.51	$84,722
	400PWR S - 1" Purchase Water Residential	3,302	$9.98	88	1,056	$14.38	$49,985
	400PWR S - 1.5" Purchase Water Residential	1,845	$9.98	56	672	$14.38	$22,037
	400PWR S - 2" Purchase Water Residential	2,957	$9.98	93	1,116	$14.38	$48,982
	400PWR S - 3 4" Purchase Water Residential	10,752	$9.98	1	12	$14.38	$1,460
	400PWR S - 4" Purchase Water Residential	599	$9.98	16	192	$14.38	$3,909
	400PWR S - 5 8" Purchase Water Residential	4,636	$9.98	3,028	36,336	$14.38	$2,203,680
	400PWRR - Purchase Water Res - R ll Meter Si es	4,610	$9.98	4,683	56,196	$14.38	$3,393,553
	400W M - 1" o ercial	611	$7.39	1	12	$37.43	$503
	400W M - 5 8" o ercial	7,998	$7.39	7	84	$14.38	$6,173
	400W R - o ercial rrigation	30,295	$9.98	16	192	$0.00	$58,050
	400WR R - Residential rrigation	7,412	$9.98	212	2,544	$0.00	$188,184
	400WR S - Water Residential ll Meter Si es	4,716	$7.39	1,545	18,540	$14.38	$912,747
	402WR S - Water Residential ll Meter Si es	3,948	$7.39	172	2,064	$14.38	$89,899
	Water Service Total						**$8,096,242**
	Miscellaneous Revenues - ate ees						$28,399
	ew usto er harges						$28,731
	Miscellaneous Service Revenue						$36
	S hec & Reconnect ee						$32,760
	Total Miscellaneous Revenues						$89,926
	Total Operating Revenues						**$8,186,168**

[1] ro Res onse to 1 dated 1.4
fro w .

Blue Granite Water Company
Calculated Revenues
Docket No. 2019-290-WS

Exhibit ALR-A
ATTACHMENT A-3

Calculated Revenue at Current Rates - Service Territory 2

A	B	C	D	E		G	H
	Customer Classi ication	**Average Mont ly Consumption per Customer**	**sage C arge per 1,000 gallons**	**Test Year End Customers [1]**	**Annuali ed Service nits**	**Base acility C arge (B C)**	**Test Year Revenue (D C 1000) (G)**
WATER							
	401W M - 5 8" o ercial Water Service	8,498	$10.27	1	12	$28.59	$1,390
	401W M - 1" o ercial Water Service	1,006	$10.27	2	24	$79.59	$2,158
	401W M - 1.5" o ercial Water Service	5,492	$10.27	1	12	$146.27	$2,432
	401W M - 3" o ercial Water Service	3,820	$10.27	3	36	$499.14	$19,381
	401WR S - Water Residential ll Meter Si es	3,880	$10.27	4,641	55,692	$28.59	$3,811,427
	401PWR W - o wood Purchased Water	1,089	$11.85	210	2,520	$28.59	$104,567
	401WRP R - 1" Water istri ution and Purchased Water harge	22,758	$11.85	4	48	$28.59	$14,317
	401WRP R - 2" Water istri ution and Purchased Water harge	33,126	$11.85	18	216	$28.59	$90,965
	401WRP R - 3 4" Water istri ution and Purchased Water harge	23,996	$11.85	1	12	$28.59	$3,755
	401WRP R - 5 8" Water istri ution and Purchased Water harge	3,640	$11.85	1,671	20,052	$28.59	$1,438,210
	403WR S - Water Residential ll Meter Si es	4,685	$10.27	88	1,056	$28.59	$81,000
	Water Service Total						**$5,569,602**
	Miscellaneous Revenues - ate ees						$35,884
	ew usto er harges						$21,985
	Miscellaneous Service Revenue						$0
	S hec & Reconnect ee						$57,320
	Total Miscellaneous Revenues						**$115,189**
	Total Operating Revenues						**$5,684,791**

Exhibit ALR-A
ATTACHMENT A-3

Blue Granite Water Company
Calculated Revenues
Docket No. 2019-290-WS

Revenue at Calculated Rates - Service Territory 2

A	B	C	D	E		G	H
	Customer Classi ication	**Average Mont ly Consumption per Customer**	**sage C arge per 1,000 gallons**	**Test Year End Customers [1]**	**Annuali ed Service nits**	**Base acility C arge (B C)**	**Test Year Revenue (D C 1000) (G)**
WATER							
	401W M - 5 8" o ercial Water Service	8,498	$12.34	1	12	$28.59	$1,601
	401W M - 1" o ercial Water Service	1,006	$12.34	2	24	$79.59	$2,208
	401W M - 1.5" o ercial Water Service	5,492	$12.34	1	12	$146.27	$2,568
	401W M - 3" o ercial Water Service	3,820	$12.34	3	36	$499.14	$19,666
	401WR S - Water Residential ll Meter Si es	3,880	$12.34	4,641	55,692	$28.59	$4,258,723
	401PWR W - o wood Purchased Water	1,089	$14.24	210	2,520	$28.59	$111,125
	401WRP R - 1" Water istri ution and Purchased Water harge	22,758	$14.24	4	48	$28.59	$16,928
	401WRP R - 2" Water istri ution and Purchased Water harge	33,126	$14.24	18	216	$28.59	$108,066
	401WRP R - 3 4" Water istri ution and Purchased Water harge	23,996	$14.24	1	12	$28.59	$4,444
	401WRP R - 5 8" Water istri ution and Purchased Water harge	3,640	$14.24	1,671	20,052	$28.59	$1,612,654
	403WR S - Water Residential ll Meter Si es	4,685	$12.34	88	1,056	$28.59	$91,241
	Water Service Total						**$6,229,224**
	Miscellaneous Revenues - ate ees						$40,081
	ew usto er harges						$21,985
	Miscellaneous Service Revenue						$0
	S hec & Reconnect ee						$57,320
	Total Miscellaneous Revenues						**$119,386**
	Total Operating Revenues						**$6,348,610**

[1] ro Res onse to 1 dated 1.4
fro w .

Blue Granite Water Company
Docket No. 2019-290-WS

Exhibit ALR-A
ATTACHMENT A-4

Calculated Revenue at Current Rates - Service Territory 1 2

A	B	C	D		G
	Customer Classi ication	**Test Year End Customers [1]**	**Annuali ed Service nits [1]**	**B C**	**Test Year Revenues (D)**
SEWER	400WW M - WW o ercial ll Meter Si es	233	2,796	$65.08	$181,964
	400WW R - o ercial WW Treat ent - R ll Meter Si es	1,896	22,752	$65.08	$1,480,700
	400WWR P - Residential WW Service ll Meter Si es	414	4,968	$65.08	$323,317
	400WWR S - WW Residential ll Meter Si es	6,171	74,052	$65.08	$4,819,304
	400WWR - Residential WW Service ll Meter Si es	89	1,068	$65.08	$69,505
	400WWRR - Residential WW Treat ent - ll Meter Si es	4,455	53,460	$65.08	$3,479,177
	400WWRT - Town of ha in Purchase WW Res ll Meter Si es	88	1,056	$65.08	$68,724
	400WWTR - WW Trailer Residential ll Meter Si es	2	24	$47.50	$1,140
	400WWTRT - an rsdale WW Treat ent ll Meter Si es	2	24	$33.86	$813
	400WW P - o ercial Wastewater Service Richland ounty	2	24	$65.08	$1,562
	400WWR T - Riverhills WW Treat ent ll Meter Si es	10	120	$65.08	$7,810
	401WWR S - Residential WW Service ll Meter Si es	358	4,296	$65.08	$279,584
	401WW M - o ercial WW Treat ent - ll Meter Si es	16	192	$65.08	$12,495
	403WWR S - Residential WW Service ll Meter Si es	593	7,116	$65.08	$463,109
	403WWM - Mo ile o e Wastewater Service	174	2,088	$47.50	$99,180
	403WW - Wastewater Residential ollection harge	359	4,308	$33.86	$145,869
	Sewer Service Total		**178,344**		**$11,434,254**
	Miscellaneous Revenues - ate ees				$79,143
	ew usto er harges				$39,595
	Miscellaneous Service Revenue				$113,153
	S hec & Reconnect ee				$17,880
	Total Miscellaneous Revenues				**$249,770**
	Total Operating Revenues				**$11,684,024**

Blue Granite Water Company
Docket No. 2019-290-WS

Exhibit ALR-A
ATTACHMENT A-4

Revenue at Calculated Rates - Service Territory 1 2

A	B	C	D		G
	Customer Classi ication	**Test Year End Customers** [1]	**Annuali ed Service nits** [1]	**B C**	**Test Year Revenues (D)**
SEWER	400WW M - WW o ercial ll Meter Si es	233	2,796	$80.93	$226,280
	400WW R - o ercial WW Treat ent - R ll Meter Si es	1,896	22,752	$80.93	$1,841,319
	400WWR P - Residential WW Service ll Meter Si es	414	4,968	$80.93	$402,060
	400WWR S - WW Residential ll Meter Si es	6,171	74,052	$80.93	$5,993,028
	400WWR - Residential WW Service ll Meter Si es	89	1,068	$80.93	$86,433
	400WWRR - Residential WW Treat ent - ll Meter Si es	4,455	53,460	$80.93	$4,326,518
	400WWRT - Town of ha in Purchase WW Res ll Meter Si es	88	1,056	$80.93	$85,462
	400WWTR - WW Trailer Residential ll Meter Si es	2	24	$59.07	$1,418
	400WWTRT - an rsdale WW Treat ent ll Meter Si es	2	24	$42.11	$1,011
	400WW P - o ercial Wastewater Service Richland ounty	2	24	$80.93	$1,942
	400WWR T - Riverhills WW Treat ent ll Meter Si es	10	120	$80.93	$9,712
	401WWR S - Residential WW Service ll Meter Si es	358	4,296	$80.93	$347,675
	401WW M - o ercial WW Treat ent - ll Meter Si es	16	192	$80.93	$15,539
	403WWR S - Residential WW Service ll Meter Si es	593	7,116	$80.93	$575,898
	403WWM - Mo ile o e Wastewater Service	174	2,088	$59.07	$123,338
	403WW - Wastewater Residential ollection harge	359	4,308	$42.11	$181,410
	Sewer Service Total		**178,344**		**$14,219,043**
	Miscellaneous Revenues - ate ees				$98,424
	ew usto er harges				$39,595
	Miscellaneous Service Revenue				$131,066
	S hec & Reconnect ee				$17,880
	Total Miscellaneous Revenues				**$286,964**
	Total Operating Revenues				**$14,506,008**

[1] ro Res onse to 1 dated 1.4

Blue Granite Water Company
Bill Comparison
Docket No. 2019-290-WS

Service Territory #1 Residential Customers

Rate description	Mont ly sage in Gallons	Current olume Rate	Current Base C arge	Current Bill	roposed olume Rate	roposed Base C arge	roposed Bill	% C ange
Residential - Wells	1,000	$5.59	$14.38	$19.97	$7.39	$14.38	$21.77	9.01%
Residential - Wells	2,000	$5.59	$14.38	$25.56	$7.39	$14.38	$29.16	14.08%
Residential - Wells	3,000	$5.59	$14.38	$31.15	$7.39	$14.38	$36.55	17.34%
Residential - Wells	4,000	$5.59	$14.38	$36.74	$7.39	$14.38	$43.94	19.60%
Residential - Wells	5,000	$5.59	$14.38	$42.33	$7.39	$14.38	$51.33	21.26%
Residential - Wells	6,000	$5.59	$14.38	$47.92	$7.39	$14.38	$58.72	22.54%
Residential - Wells	7,000	$5.59	$14.38	$53.51	$7.39	$14.38	$66.11	23.55%
Residential - Wells	8,000	$5.59	$14.38	$59.10	$7.39	$14.38	$73.50	24.37%
Residential - Wells	9,000	$5.59	$14.38	$64.69	$7.39	$14.38	$80.89	25.04%
Residential - Wells	10,000	$5.59	$14.38	$70.28	$7.39	$14.38	$88.28	25.61%

Rate description	Mont ly sage in Gallons	Current olume Rate	Current Base C arge	Current Bill	roposed olume Rate	roposed Base C arge	roposed Bill	% C ange
Residential - Purchased Water	1,000	$7.55	$14.38	$21.93	$9.98	$14.38	$24.36	11.08%
Residential - Purchased Water	2,000	$7.55	$14.38	$29.48	$9.98	$14.38	$34.34	16.49%
Residential - Purchased Water	3,000	$7.55	$14.38	$37.03	$9.98	$14.38	$44.32	19.69%
Residential - Purchased Water	4,000	$7.55	$14.38	$44.58	$9.98	$14.38	$54.30	21.80%
Residential - Purchased Water	5,000	$7.55	$14.38	$52.13	$9.98	$14.38	$64.28	23.31%
Residential - Purchased Water	6,000	$7.55	$14.38	$59.68	$9.98	$14.38	$74.26	24.43%
Residential - Purchased Water	7,000	$7.55	$14.38	$67.23	$9.98	$14.38	$84.24	25.30%
Residential - Purchased Water	8,000	$7.55	$14.38	$74.78	$9.98	$14.38	$94.22	26.00%
Residential - Purchased Water	9,000	$7.55	$14.38	$82.33	$9.98	$14.38	$104.20	26.56%
Residential - Purchased Water	10,000	$7.55	$14.38	$89.88	$9.98	$14.38	$114.18	27.04%

Service Territory #2 Residential Customers

Rate description	Mont ly sage in Gallons	Current olume Rate	Current Base C arge	Current Bill	roposed olume Rate	roposed Base C arge	roposed Bill	% C ange
Residential - Wells	1,000	$10.27	$28.59	$38.86	$12.34	$28.59	$40.93	5.33%
Residential - Wells	2,000	$10.27	$28.59	$49.13	$12.34	$28.59	$53.27	8.43%
Residential - Wells	3,000	$10.27	$28.59	$59.40	$12.34	$28.59	$65.61	10.45%
Residential - Wells	4,000	$10.27	$28.59	$69.67	$12.34	$28.59	$77.95	11.88%
Residential - Wells	5,000	$10.27	$28.59	$79.94	$12.34	$28.59	$90.29	12.95%
Residential - Wells	6,000	$10.27	$28.59	$90.21	$12.34	$28.59	$102.63	13.77%
Residential - Wells	7,000	$10.27	$28.59	$100.48	$12.34	$28.59	$114.97	14.42%
Residential - Wells	8,000	$10.27	$28.59	$110.75	$12.34	$28.59	$127.31	14.95%
Residential - Wells	9,000	$10.27	$28.59	$121.02	$12.34	$28.59	$139.65	15.39%
Residential - Wells	10,000	$10.27	$28.59	$131.29	$12.34	$28.59	$151.99	15.77%

Rate description	Mont ly sage in Gallons	Current olume Rate	Current Base C arge	Current Bill	roposed olume Rate	roposed Base C arge	roposed Bill	% C ange
Residential - Purchased Water	1,000	$11.85	$28.59	$40.44	$14.24	$28.59	$42.83	5.91%
Residential - Purchased Water	2,000	$11.85	$28.59	$52.29	$14.24	$28.59	$57.07	9.14%
Residential - Purchased Water	3,000	$11.85	$28.59	$64.14	$14.24	$28.59	$71.31	11.18%
Residential - Purchased Water	4,000	$11.85	$28.59	$75.99	$14.24	$28.59	$85.55	12.58%
Residential - Purchased Water	5,000	$11.85	$28.59	$87.84	$14.24	$28.59	$99.79	13.60%
Residential - Purchased Water	6,000	$11.85	$28.59	$99.69	$14.24	$28.59	$114.03	14.38%
Residential - Purchased Water	7,000	$11.85	$28.59	$111.54	$14.24	$28.59	$128.27	15.00%
Residential - Purchased Water	8,000	$11.85	$28.59	$123.39	$14.24	$28.59	$142.51	15.50%
Residential - Purchased Water	9,000	$11.85	$28.59	$135.24	$14.24	$28.59	$156.75	15.91%
Residential - Purchased Water	10,000	$11.85	$28.59	$147.09	$14.24	$28.59	$170.99	16.25%

Service Territory Consolidated Sewer

Rate description			Current Base C arge	Current Bill		roposed Base C arge	roposed Bill	% C ange
Residential - Per S			$65.08	$65.08		$80.93	$80.93	24.35%

STATE OF CONNECTICUT

PUBLIC UTILITIES REGULATORY AUTHORITY
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 17-10-46RE03	**APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY D/B/A EVERSOURCE ENERGY TO AMEND ITS RATE SCHEDULES – INTERIM RATE DECREASE, LOW-INCOME RATES, AND ECONOMIC DEVELOPMENT RATES**
DOCKET NO. 17-12-03RE11	**APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY D/B/A EVERSOURCE ENERGY TO AMEND ITS RATE SCHEDULES – INTERIM RATE DECREASE, LOW-INCOME RATES, AND ECONOMIC DEVELOPMENT RATES**

September 14, 2021

By the following Commissioners:

Marissa P. Gillett
John W. Betkoski, III
Michael A. Caron

PROPOSED INTERIM DECISION

This proposed Interim Decision is being distributed to the parties in this proceeding for comment. The proposed Interim Decision is not final. The Authority will consider the parties' arguments and exceptions before reaching a final Interim Decision, which may differ from the proposed Interim Decision. Therefore, this proposed Interim Decision does not establish any precedent and does not necessarily represent the Authority's final conclusion.

TABLE OF CONTENTS

PROPOSED INTERIM DECISION

I. INTRODUCTION

A. SUMMARY

In this Interim Decision, pursuant to Section 5 of Public Act 20-5, An Act Concerning Emergency Response by Electric Distribution Companies, the Regulations of other Public Utilities and Nexus Provisions for Certain Disaster-Related or Emergency-Related Work Performed in the State (Take Back Our Grid Act) and §§ 16-19(g) and 16-19e of the General Statutes of Connecticut (Conn. Gen. Stat.), the Public Utilities Regulatory Authority (Authority or PURA) finds that The Connecticut Power and Light Company d/b/a Eversource Energy's (Eversource or Company) allowed return on equity (ROE), pursuant to the Authority's Decision dated April 18, 2018 in Docket No. 17-10-46, Application of The Connecticut Light and Power Company d/b/a Eversource Energy to Amend its Rate Schedules (2017 Rate Case Decision), and the corresponding rates it is collecting, are in excess of what is just and reasonable. The Authority also finds that Eversource failed to adequately demonstrate that earning an excessive ROE or collecting excessive rates is directly beneficial to its customers. Accordingly, the Authority in this Interim Decision orders Eversource to implement an interim rate decrease by establishing an 8.80% authorized ROE to take effect November 1, 2021, until the Company's next approved rate plan.[1]

In addition, the Authority implements the 90 basis point ROE reduction imposed on Eversource in the April 28, 2021 Decision in Docket No. 20-08-03, Investigation into Electric Distribution Companies' Preparation for and Response to Tropical Storm Isaias (Storm Decision) through the end of its next approved rate plan, as opposed to indefinitely as initially directed in the Storm Decision. During Eversource's next ratemaking proceeding, the Authority will consider performance-based opportunities by which Eversource may earn back the ROE basis point reduction during the rate plan period.

B. BACKGROUND OF THE PROCEEDING

The Authority initiated this proceeding during an unprecedented and unique time in the State of Connecticut. In March 2020, the global COVID-19 pandemic began to significantly impact the State of Connecticut and its residents. In response to the COVID-19 pandemic, on March 10, 2020, the Governor of the State of Connecticut declared a public health and civil preparedness emergency, which, after being renewed and extended multiple times, currently remains in effect. In addition to the broad-reaching national and global impacts of the pandemic, the COVID-19 pandemic specifically impacted electricity usage by customers in the State of Connecticut, many of whom began

[1] The Authority orders a 45 basis point reduction of Eversource's current allowed ROE of 9.25%, established in Docket No. 17-10-46. The 90 basis point ROE reduction imposed on Eversource pursuant to the Storm Decision represents an additional, incremental ROE adjustment necessary in order to incentivize Eversource to improve their management of future storm preparation and responses. Therefore, Eversource's adjusted allowed ROE shall be 7.90% until the Company's next approved rate plan.

working from home, and impaired the ability of many customers to pay electric bills due to the closing of businesses, loss of jobs, and reduction of work hours.

In the summer of 2020, in the midst of the COVID-19 pandemic, Eversource customers received higher than anticipated electric bills due to the convergence of a number of events, partially attributed to higher than normal temperatures contributing to increased electricity usage. In addition, the July 1 administrative rate adjustment to Eversource's Non-Bypassable Federally Mandated Congestion Charge, Transmission Adjustment Clause, Revenue Decoupling Mechanism and Electric System Improvement reconciliation mechanisms exacerbated higher than anticipated electric bills amidst the ongoing COVID-19 pandemic. Tropical Storm Isaias then impacted Eversource customers, causing widespread and prolonged outages throughout the State in early August 2020.

In the fall of 2020, in response to the extreme challenges posed by the COVID-19 pandemic and Tropical Storm Isaias, and the resulting impact these events had on Connecticut residents, the General Assembly passed the Take Back Our Grid Act. Section 5 of the Take Back Our Grid Act explicitly authorized the Authority to consider the implementation of an interim rate decrease, low-income rates, and economic development rates for customers of electric distribution companies (EDCs), pursuant to Conn. Gen. Stat. §§ 16-19(g), 16-19e, and 16-19oo. The interim rate decrease was invoked to "provide much needed relief to all ratepayers during these unprecedented pandemic times." 63 S. Proc., Pt. 3, 2020 Special Sess., p. 985. Although the Authority already was statutorily empowered to initiate an interim rate decrease, "it was important for [the members of the General Assembly] to signal [their] intent and to show [their] constituents that [they] are listening." 63 H.R. Proc., Pt. 3, 2020 Special Sess., p. 1511.

Several months later, on April 28, 2021, the Authority issued the Storm Decision. In the Storm Decision, in accordance with Conn. Gen. Stat. § 16-19e(a)(3) and (5), the Authority found that "the record evidence in [Docket No. 20-08-03] supports a determination that the respective storm performances of The United Illuminating Company (UI) and Eversource were inadequate and deficient and, therefore, warrant a ratemaking ROE reduction to properly align the EDCs' financial incentives with performance." Storm Decision, p. 127. Pursuant to its authority under Conn. Gen. Stat. § 16-19e(a), the Authority imposed a 15 basis point ROE reduction for UI and a 90 basis point ROE reduction for Eversource to incentivize the EDCs to improve their management of future storm responses. Id., pp. 127-128. The Authority stated in the Storm Decision that it would reduce the ROE approved for each EDC in the next applicable ratemaking proceeding in which a final decision is issued, such as through the instant docket. Id., p. 127.

C. CONDUCT OF THE PROCEEDING

In the Interim Decision dated October 2, 2019, in Docket No. 17-12-03, PURA Investigation into Distribution System Planning of the Electric Distribution Companies (Equitable Modern Grid Decision), the Authority specified a series of reopened proceedings to further investigate near-term topics integral to realizing the objectives of

PURA's Framework for an Equitable Modern Grid, including "Docket No. 17-12-03RE11 [to] explore new rate designs." Equitable Modern Grid Decision, pp. 24-25.

On October 30, 2020, in accordance with the Equitable Modern Grid Decision and pursuant to Section 5 of the Take Back Our Grid Act, the Authority initiated Docket No. 17-12-03RE11 to consider the implementation of an interim rate decrease, low-income rates, and economic development tariffs. Notice of Proceeding, Oct. 30, 2020.

On February 3, 2021, the Authority issued a decision in which it reopened Dockets Nos. 16-06-04 and 17-10-46 (Reopening Decision), and designated them as Docket No. 16-06-04RE04, Application of The United Illuminating Company to Increase Its Rates and Charges – Interim Rate Decrease, Low-Income Rates, and Economic Development Rates, and Docket No. 17-10-46RE03, Application of The Connecticut Light and Power Company d/b/a Eversource Energy to Amend its Rate Schedules – Interim Rate Decrease, Low-Income Rates, and Economic Development Rates (together, Reopened Rate Cases). The Authority consolidated the Reopened Rate Cases for administrative purposes under Docket No. 17-12-03RE11. Reopening Decision, Feb. 3, 2021, p. 2.

On February 18, 2021, the Authority issued a Notice Regarding Investigation Timeline that established a multi-phase proceeding. In the Notice Regarding Investigation Timeline, the Authority indicated its intention to issue an interim decision with respect to the topics of an interim rate decrease, a low-income rate, and other economic development rates, as Phase II of this proceeding. Notice Regarding Investigation Timeline, Feb. 18, 2021.

On May 5, 2021, the Authority issued a Revised Notice Regarding Investigation Timeline that further bifurcated the multi-phase proceeding. In the Revised Notice Regarding Investigation Timeline, the Authority indicated its intention to issue an interim decision with respect to the topic of an interim rate decrease, designated as Phase IIa of this proceeding (Phase IIa). In the Revised Notice Regarding Investigation Timeline, the Authority indicated that it would also contemplate as part of Phase IIa the implementation of reductions in the EDCs' ROE authorized in the Storm Decision. Revised Notice Regarding Investigation Timeline, May 5, 2021. This was reiterated on June 14, 2021 when the Authority issued a Revised Notice of Proceeding in which it confirmed that Phase IIa would consider the implementation of reductions in the EDCs' ROE authorized in the Storm Decision. Revised Notice of Proceeding, June 14, 2021.

By Notice of Hearing dated May 21, 2021, the Authority held public hearings on May 27, 2021, and May 28, 2021, via teleconference, in Phase IIa.

By Revised Notice of Hearing dated June 18, 2021, the Authority held public hearings as part of Phase IIa on June 23, 2021, and June 24, 2021, via teleconference.

On June 23, 2021, the Authority issued an Interim Decision in Docket No. 21-01-04, PURA Annual Review of the Rate Adjustment Mechanisms of The United Illuminating Company, Docket No. 17-12-03RE11, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – New Rate Designs and Rates Review, and Docket No. 16-06-04RE04, Application of The United Illuminating Company to

Increase its Rates and Charges – Interim Rate Decrease, Low-Income Rates, and Economic Development Rates (UI Settlement Decision), in which the Authority approved an amended settlement agreement entered into by UI, the Office of Consumer Counsel (OCC), the Office of the Attorney General (AG), the Department of Energy and Environmental Protection (DEEP), and the PURA Office of Education, Outreach, and Enforcement (EOE) that, *inter alia*, satisfies for UI the interim rate decrease topic examined in Phase IIa. UI Settlement Decision, dated June 23, 2021.

On June 24, 2021, the Authority issued a Notice of Request for Briefs for Phase IIa in which it requested briefs from the Parties and Intervenors in Phase IIa that address the following topic:

> Provide and discuss metrics or other standards that the Authority should consider in determining how and when the ninety (90) basis point return on equity reduction imposed on [Eversource] in the [Storm Decision], is no longer necessary to "ensure improved emergency management, protect the foreseeable public interest, and reduce the risk that the performance failures exhibited in response to Tropical Storm Isaias will not be repeated in future storm events." Storm Decision, p. 128.

Notice of Request for Briefs, June 24, 2021.

On July 14 and 15, 2021, the Authority held Late Filed Exhibit (LFE) Hearings, via teleconference, in Phase IIa.

By Notice of Additional LFE Hearing dated July 20, 2021, the Authority held an additional LFE Hearing on August 9, 2021, via teleconference, in Phase IIa.

On September 14, 2021, the Authority issued a Proposed Interim Decision for Phase IIa in this proceeding and provided an opportunity for the Parties and Intervenors to file Written Exceptions and to present Oral Argument.

D. PARTIES AND INTERVENORS

The Authority designated the following as Parties to this proceeding: the Office of Consumer Counsel, Ten Franklin Square, New Britain, CT 06051; the Commissioner of the Department of Energy and Environmental Protection, 79 Elm Street, Hartford, CT 06106; the Office of the Attorney General, Ten Franklin Square, New Britain, CT 06051; the Office of Education, Outreach, and Enforcement, Ten Franklin Square, New Britain, CT 06051; Connecticut Power and Light Company d/b/a Eversource Energy, 107 Selden Street, Berlin, CT 06037; and The United Illuminating Company, 180 Marsh Hill Road, MS AD-2A, Orange, CT 06477.

The Authority granted Intervenor status to the following: Solar Connecticut, Inc.; Connecticut Industrial Energy Consumers; Key Capture Energy; Connecticut Legal Services, Inc.; Northeast Clean Energy Council; Operation Fuel, Inc.; Center for Children's Advocacy; and Walmart, Inc.

II. UNIQUE PROCEDURAL CONTEXT

At the crux of this investigation are several unique and, perhaps at first blush, disparate facts. *One*, the State is eighteen months into a devastating public health and civil preparedness emergency, with far-reaching consequences for all residents and businesses. *Two*, during this same timeframe, Eversource ratepayers expressed (and continue to articulate) overwhelming concerns with respect to the affordability of the Company's rates – both in terms of the structure and magnitude – in light of the quality of service provided by the Company and the State's current macroeconomic conditions. Such objections are often raised in the context of concerns about the relative proportion of supply and delivery charges on monthly electric bills, or in the context of the Company's preparation for and response to Tropical Storm Isaias. <u>See</u>, <u>e.g.</u>, Storm Decision, pp. 6-7; December 2, 2020 Decision in Docket No. 20-01-01, <u>Administrative Proceeding to Review The Connecticut Light and Power Company's Standard Service and Supplier of Last Resort Service 2020 Procurement Results and Rates</u>. *Third*, the General Assembly, through a September 2020 Special Session, passed landmark bipartisan energy legislation that imbued the Authority with new accountability mechanisms and otherwise enhanced existing discretionary tools, specifically intending for the Authority to leverage such tools as a means to "provide much needed relief to all ratepayers during these *unprecedented* pandemic times." 63 S. Proc., Pt. 3, 2020 Special Sess., p. 985. (emphasis added).[2] *Fourth*, Eversource's existing rate plan, established pursuant to a negotiated settlement, has since expired.

When taken together, the aforementioned puzzle pieces amount to an incomparable set of circumstances underlying the instant proceeding. To infer that the analysis contained herein translates into a hostile or unpredictable regulatory environment is disingenuous at best.[3] We are, quite simply, collectively facing a series

[2] The Leadership of the Energy and Technology Committee referenced the first and second facts discussed in this Section during the floor debate for the Take Back Our Grid Act. <u>See</u>, <u>e.g.</u>, 63 H.R. Proc., Pt. 3, 2020 Special Sess., p. 1384 ("Yes, thank you, Mr. Speaker. Mr. Speaker, to say that this year has been an incredibly hard year for the State of Connecticut and for our constituents would be an understatement. This year has had some unknown challenges and anxiety for everyone across our State. Entering the summer, Connecticut was experiencing a run of good fortune with daily improving Covid metrics and then we were hit with another challenge during this pandemic. In July, our constituents faced incredibly high utility bills and in August we faced Tropical Storm Isaias paired with an unacceptable storm response which left thousands of customers without power for days. This is why we are here today."). <u>See</u> <u>also</u>, 63 H.R. Proc., Pt. 3, 2020 Special Sess., p. 1387 ("The leadership of the Committee worked together, bipartisanly to come up with this Bill and as the Esteemed Chairman has said, we were confronted with the perfect storm where many people were, families were suffering from COVID-19 pandemic, sequestering at home without just some of them not working, without jobs, then the utility companies raised the rates on consumers. We heard from many, many consumers at the time, it was overbearing and too difficult for them and then we got hit with Storm Isaias which put 800,000 people out of power and over a week without service left many people in the dark. And so with that being said, this Bill is an attempt as the Chairman said, to bridge the gap for the consumers with the utility companies and to reprioritize the ratepayers over the shareholders.").

[3] This assertion was emphasized repeatedly, to varying degrees, by a number of Eversource witnesses throughout this proceeding, oft-times citing to recent credit outlooks issued by rating agencies. The Authority rejects these contentions outright. The June 14, 2021 Moody's statement, for example, cited only to the ROE reduction imposed on Eversource through the Storm Decision as the basis for revising Eversource's credit outlook to negative. Eversource Response to FI-6, dated 6/16/2021, Attachment 1,

of unprecedented events as both a State and an industry. It is, therefore, neither unreasonable nor unexpected that a regulatory body would act to address such conditions, particularly on an *interim* basis and with the explicit backing of authorizing legislation and regulatory tools to do so.

In the context of natural monopolies, such as electric utilities, regulation replaces competition as the determinant of prices.[4] The impact of such regulation may be different depending on the macroeconomic condition of the economy.[5] The argument follows that "[i]f agencies could take account of these macroeconomic effects on a large scale, regulatory policy would be countercyclical … just like monetary and fiscal policy," which typically aims to increase discretionary income of consumers during recessionary periods.[6] Indeed, a rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. Bluefield Waterworks & Imp. Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679, 692 (1923).

Further, picking up the seemingly disparate fact referenced above with respect to Eversource's current rate structure – both the expiration of the Company's rate plan, as well as its negotiated status, lend meaningful perspective to the instant situation. In 2018, the Authority approved an Amendment to the Settlement Agreement (Settlement Agreement) in the 2017 Rate Case Decision by and between Eversource, OCC, and the Prosecutorial Staff of the Authority (Together, Settling Parties). In the Settlement Agreement, the Settling Parties agreed to a new three-year rate plan, which began on May 1, 2018, and ended on April 30, 2021. 2017 Rate Case Decision, p. 4. Accordingly, Eversource is currently operating under an expired rate plan and utilizing an ROE that the Authority authorized over three and a half years ago and prior to the COVID-19 pandemic.

Notably, "the Settling Parties requested that negotiated ratemaking capitalization mix and ROE be accepted as they are and not disturbed by the Authority." 2017 Rate Case Decision, p. 18. In other words, the 9.25% negotiated ROE was not subject to the rigor typically performed in rate case proceedings. Eversource's allowed ROE of 9.25% has remained in place after the expiration of the rate plan on April 30 of this year.[7] It is possible that the Settling Parties consented to an above-market ROE in exchange for

Moody's Rating Action dated June 14, 2021, p. 2. That the Authority exercised its discretion to hold the Company's management and its shareholders accountable for extensive deficiencies documented through an eight-month storm investigation means little other than that the Authority is hostile to imprudence and failures to achieve acceptable performance standards. Assigning a negative connotation to the Authority doing its job is nonsensical.

[4] See, Lazar, J. (2016). Electricity Regulation in the US: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project, p. 5. Retrieved from https://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf.

[5] See, Listokin, Yair, *Law and Macroeconomics: The Law and Economics of Recessions*, 34 Yale J. on Reg. 791 (2017).

[6] See, Masur, Jonathan S. and Eric A. Posner, *Should Regulation Be Countercyclical?*, 34 Yale J. on Reg. 858-859 (2017).

[7] Eversource asserts that it is not over-earning, citing its past three quarterly financial reports that calculate the five-quarter average earned ROE. Eversource Brief, pp. 17-18. However, the fact that Eversource had the opportunity to earn an ROE of 9.25%, but did not, is not relevant to the specific question of whether a 9.25% authorized ROE remains reasonable, particularly after the expiration of the Company's three-year rate plan.

other concessions in the rate plan. Consequently, an ROE authorized through a settlement agreement is less persuasive than one authorized through a fully litigated rate proceeding.[8]

In sum, many factors – unprecedented in their severity and confluence – contributed to the unique cross-section at which we now find ourselves. As such, attributing the origins or conclusions of this proceeding to any one factor would drastically misrepresent the underlying complexity of the above context.

III. LEGAL STANDARD

In accordance with Section 5 of the Take Back Our Grid Act, the Authority may initiate a proceeding to consider the implementation of an interim rate decrease for EDC customers, pursuant to its authority in Conn. Gen. Stat. §§ 16-19(g), 16-19e, and 16-19oo[9].

Conn. Gen. Stat. §§ 16-19(g) permits the Authority to implement an interim rate decrease if, *inter alia,* "it finds that a public service company may be collecting rates which are more than just, reasonable and adequate..." Conn. Gen. Stat. § 16-19(g)(3). After conducting a proceeding under Conn. Gen. Stat. § 16-19(g), the Authority "may order an interim rate decrease if it finds that [an EDC's] return on equity . . . exceeds a reasonable rate of return . . . as determined by the authority." Conn. Gen. Stat. § 16-19(g). In exercising its discretion to impose an interim rate decrease, the Authority will consider whether the *company* has "demonstrate[d] to the satisfaction of the authority that earning such a return on equity . . . is directly beneficial to its customers." Id.; see, generally, Office of Consumer Counsel v. Dep't of Pub. Util. Control et al., 252 Conn. 115, 125 (1999). If the Authority finds that such ROE or rates exceeds a reasonable rate of return or is more than just, reasonable and adequate, it may order an interim rate decrease. Conn. Gen. Stat. § 16-19(g). "Any such interim rate decrease shall be subject to a customer surcharge if the interim rates collected by the company are less than the rates finally approved by the [Authority] or fixed at the conclusion of any appeal taken as a result of any finding by the [Authority]." Id.

Pursuant to Conn. Gen. Stat. §§ 16-19(g), the Authority is authorized to direct an interim rate decrease during the intervening years between rate case proceedings. In acknowledging that an interim rate decrease is essentially the front end of a rate case, the Connecticut Supreme Court held that it:

[8] For context, the Authority authorized an ROE of 9.17% in the Company's the previous rate case (2014), Docket No. 14-05-06, Application of the Connecticut Light and Power Company to Amend Rate Schedules.

[9] Conn. Gen. Stat. § 16-19oo pertains to the promotion of an electric distribution, gas, telephone and water company's conservation and load management programs or other programs promoting the State's economic development, energy and other policy, and, therefore, is not applicable to Phase IIa of this proceeding; although, it may be relied on in subsequent phases.

> . . . cannot ignore the statutory scheme to which an interim rate decrease is, as the term suggests, temporary. An interim rate decrease hearing is to be followed by a full rate case determination hearing. The fact that an interim rate hearing results in only temporary ratemaking until more information is available at a subsequent full rate case indicates that the legislature vested the department with the discretion to determine whether an interim rate adjustment was necessary at all.

<u>Office of Consumer Counsel v. Dep't of Pub. Util. Control et al.</u>, 252 Conn. 115, 124 (2000).

Thus, the Connecticut Supreme Court recognized that an interim rate decrease is a statutorily created temporary ratemaking convention. Accordingly, a consideration of all the factors that are part of the rate-setting process is not required when conducting an interim rate decrease proceeding.[10]

IV. AUTHORITY ANALYSIS – INTERIM RATE DECREASE

The Authority finds that Eversource's ROE exceeds a reasonable rate of return and that Eversource failed to demonstrate that the excessive ROE directly benefits ratepayers. Consequently, the Authority orders an interim rate decrease through a 45 basis point reduction in the Company's allowed ROE, commencing November 1, 2021, and remaining in effect until the Company's next approved rate plan.

A. CONN. GEN. STAT. § 16-19(G) TRIGGERING CONDITION

The Authority possesses broad regulatory authority and discretion. <u>See</u>, <u>Office of Consumer Counsel v. Dep't of Pub. Util. Control</u>, 279 Conn. 584, 593 (2006). In this instance, the Authority's discretion is further enhanced by the plain language of the applicable statute – Conn. Gen. Stat. § 16-19(g). Specifically, the third condition of the statute, which is operative in this proceeding, authorizes PURA to conduct proceedings when it "finds that a public service company *may* be collecting rates which are more than just, reasonable an adequate, *as determined by the authority*[.]" Conn. Gen. Stat. § 16-19(g)(3) (emphasis added). The statute provides no mandated form or mechanism for reaching such a determination; the statute refers to the provision of notice "in such form as the authority deems reasonable." Conn. Gen. Stat. § 16-19(g)(3).

For its part, Eversource belatedly asserts that the Authority was required to disclose its Conn. Gen. Stat. § 16-19(g)(3) finding as a condition precedent to the convening of the instant proceeding. Eversource objects on procedural grounds that the Authority did not make an initial finding that Eversource "may" be overcollecting <u>prior</u> to initiating this proceeding and, as such, Eversource was "given no notice whatsoever of the basis for opening this interim rate decrease proceeding." Eversource Brief, August 25, 2021 (Eversource Brief), pp. 19, 23. The objection is both untimely and illogical. This

[10] Eversource makes assertions to the contrary. <u>See</u>, Horton Rebuttal Prefiled Test., pp. 12-13; Rea Rebuttal Prefiled Test., p. 10; Eversource Brief, pp. 26-27. Nonetheless, the Authority is guided by the above-referenced holding of the Connecticut Supreme Court.

proceeding commenced nearly a year ago (see, October 30, 2020 Notice of Proceeding) and at no point during its active participation in the docket did Eversource claim to be unaware of the basis of the proceeding. Further, the October 30, 2020 Notice of Proceeding states that the "Authority will consider the implementation of an interim rate decrease . . . for customers of electric distribution companies (EDCs), pursuant to its authority in [Conn. Gen. Stat. § 16-19(g)] . . . ." The only logical reading of this notice is that the Authority had determined that the EDCs "may" have been overcollecting and opened the proceeding accordingly.

Likewise, by invoking in its October 30, 2020 Notice of Proceeding Section 5 of Public Act 20-5, enacted by the General Assembly in direct response to a convergence of several events impacting the macroeconomic conditions of the State (as detailed above in Section II), the Authority clearly signaled its concurrence that Eversource *may* be collecting rates in excess of what is just, reasonable, and adequate. Notably, "[t]he Legislature is always presumed to have created a harmonious and consistent body of law." Hartford/Windsor Healthcare Prop. LLC v. Hartford, 298 Conn. 191, 198 (2010). Here, the General Assembly was well aware of the Authority's existing statutory powers to implement an interim rate decrease through Conn. Gen. Stat. § 16-19(g); thus, the only logical conclusion as to why such authority was restated in Section 5 of Public Act 20-5 – this time with a time constraint of initiating a proceeding no later than November 1, 2020 – was to permit the Authority to consider the current macroeconomic conditions facing the State (e.g., the COVID-19 pandemic, customer hardships attributable to the July 2020 Eversource rate adjustments, and the Company's response to Tropical Storm Isaias) as a causal factor vis-à-vis Conn. Gen. Stat. § 16-19(g).

Moreover, the Company's assertion that the notice in the instant proceeding was deficient and therefore precluded Eversource from "mak[ing] possible intelligent preparation for participation in the hearing"[11] is illogical in the context of the remedies and next steps articulated in the controlling statute. Indeed, Conn. Gen. Stat. § 16-19(g)(3) articulates clearly the subsequent steps that follow the triggering condition, wherein the burden is situated squarely on the public service company to "demonstrate to the satisfaction of the authority that earning such a return on equity. . . is directly beneficial to its customers."[12] Thus, even *if* the Company's assertion was credible, the applicable statute makes crystal clear how Eversource should have prepared for the proceeding; the Company *should* have focused its efforts toward demonstrating to the satisfaction of the Authority that earning an excessive ROE is directly beneficial to its customers. Conn. Gen. Stat. § 16-19(g)(3). It did not.

[11] Goldstar Medical Services, Inc. v. Dept. of Social Services, 288 Conn. 790, 823-24 (2008), citing, Conn. Gen. Stat. § 4-177 (b).

[12] This is consistent with the applicable statutory framework in Connecticut generally. The General Assembly has placed squarely on regulated utilities the burden of demonstrating that a utility's costs and associated rates are reasonable and prudent. See, Conn. Gen. § 16-22 ("At any hearing involving a rate . . . of a public service company, the burden of proving that said rate under consideration is just and reasonable . . . shall be on the public service company.").

B. DEMONSTRATION OF DIRECT BENEFIT TO CUSTOMERS

As noted above, Eversource had the obligation (and the extensive, year-long opportunity through this proceeding) to demonstrate to the satisfaction of the Authority that earning an excessive ROE is directly beneficial to its customers. If the utility fails to demonstrate that such excessive ROE and rates are directly beneficial to its customers, then the Authority may issue an interim rate decrease. See, Office of Consumer Counsel v. Dep't of Pub. Util. Control et al., 252 Conn. 115, 125-126 (1999).

Eversource failed to demonstrate that earning an excessive ROE is directly beneficial to its customers. According to Eversource, its current ROE benefits customers in two ways: "[(1)] the stability provided by Eversource's current rates and [(2)] maintaining strong credit ratings that keep capital costs low." See, Horton Rebuttal Prefiled Test., p. 8.

First, Eversource claims that rate stability benefits customers. The Company, however, failed to demonstrate how such benefit is realized, especially if the rates are too high. Put simply, rate stability is not an inherent benefit to consumers and does not benefit consumers if their rates are too high. AG Brief, August 25, 2021, p. 7.

Second, Eversource claims that customers benefit from a utility's strong credit rating. Horton Prefiled Test., p. 23. According to Eversource, the Company's current financial profile enables cost-effective financing that, in turn, enables the Company to efficiently deploy capital for critical infrastructure investments, customers, and other public policy initiatives. Id. Eversource testified that the value inherent in Eversource's strong credit profiles is conveyed to customers in the form of reduced financing costs and capital investment enablement. Id. Eversource argued that these benefits would be diminished if the Company were to be downgraded as a result of an interim rate decrease or regulatory uncertainty. Id.; see, also, Tr. 5/27/21, pp. 244, 245-246, 255-257; Tr. 7/14/21, pp. 648-649, 651; Eversource Brief, p. 27.

Eversource asserted that a downward adjustment to the Company's allowed ROE within the range recommended by Rothschild (i.e., 6.04% and 8.29%, with a mid-point of 7.17%) will result in a credit downgrade from one or more of the three major credit rating agencies. Horton Rebuttal Prefiled Test., pp. 35-36. These assertions were contradicted, however, by other credible analysis presented during the course of the proceeding. Rothschild analyzed the potential impact of his recommended adjustments to Eversource's capital structure, including ROE, using the following methodologies to calculate the relevant financial metrics: Moody's Analytics's financial strength, key financial metrics; Fitch Rating's financial profile; and S&P Global Ratings's cashflow/leverage, capital structure, and liquidity. Rothschild Supplemental Response to LFE-12. Rothschild concluded that a proposed ROE of 7.17% would have little, if any, impact on the financial metrics used by the major credit rating agencies in evaluating and setting Eversource's credit rating; see, Tables 1 through 3 for a summary of Rothschild's analysis.[13] Id.; Tr. 5/26/21, pp. 170-171, 173, 174-175; Tr. 5/27/21, pp. 216-218; Tr. 8/9/21, pp. 804, 832, 835, 836-837, 867-868, 881-882, 896-897, 902-903.

Table 1
Moody's Analytics Credit Rating Methodology: Financial Strength Metrics

Sub-Factors of Moody's Financial Strength Factor	Authorized in 2017 Rate Case Decision	Metrics Applying Rothschild's Midpoint Recommendation	Analysis on Potential Credit Rating Impact[14]
(Cash Flow from Operations Pre-Working Capital (CFO Pre-WC) + Interest) / Interest	6.7x	6.33x	"A" range = 4.5 – 6.0x "Aa" range = 6.0 – 8.0x *Remains in the "Aa" range (7.5% sub-factor weighting)*
CFO Pre-WC / Debt	21.4%	20.1%	"A" range = 19 – 27%[15] *Remains in the "A" range (15% sub-factor weighting)*
(CFO Pre-WC – Dividends) / Dividends	19.8%	18.4%	"A" range = 15 – 23% *Remains in the "A" range (10% sub-factor weighting)*
Debt / Capitalization	40.3%	40.3%	"A" range = 40 – 50% *Remains unchanged (7.5% sub-factor weighting)*

Rothschild Supplemental Response to LFE-12 dated 7/27/21; Eversource Response to FI-6 dated 1/21/21, Attachment 4, Moody's Rating Methodology, p. 22.

[13] Tables 1 through 3 are for illustrative purposes only and do not incorporate any authorized interim rate decreases or changes to the Company's ROE authorized elsewhere in this Decision.

[14] Rothschild used the "Low Business Risk Grid" category of Moody's Financial Strength factor in his analysis summarized in Table 1. Moody's currently considers Eversource to be in the Low Business Risk Grid category. See, Eversource Supplemental Response to FI-6 dated 6/16/21, Attachment 1, p. 2; Eversource Supplemental Response to FI-6 dated 6/18/21, Attachment 1, p. 1.

[15] In its Credit Opinion dated June 17, 2021, Moody's states that a stable outlook could be considered if "CL&P's credit metrics are maintained at levels appropriate for its rating, including a ratio of CFO pre-W/C to debt at or above 18%." See, Eversource Response to FI-06 dated 6/28/21, Attachment 1, p. 2.

Table 2
S&P Global Credit Rating Methodology: Financial Risk Profile

S&P's Cash Flow/Leverage Analysis Ratios (Low Volatility)	Authorized in 2017 Rate Case Decision	Metrics Applying Rothschild's Midpoint Recommendation	Analysis on Potential Credit Rating Impact[16]
Funds from Operations (FFO) / Debt	22.5%	21.0%	"Intermediate" = 13 – 23% *Assessment remains "Intermediate"*
Debit / Earnings Before Interest, Taxes, Depreciation, and Amortization (EBITDA)	3.78x	4.10x	"Intermediate" = 3 – 4x "Significant" = 4 – 5x *Assessment increases from "Intermediate' to "Significant"*
Free Operating Cash Flow (FOCF) / Debt	9.1%	7.6%	"Intermediate" = 4 – 10% *Assessment remains "Intermediate"*

Rothschild Supplemental Response to LFE-12 dated 7/27/21; Eversource Supplemental Response to FI-6 dated 1/21/21, Attachment 5, S&P Global Ratings, Corporate Methodology, pp. 28, 33-34.

[16] S&P Global utilizes the following range of financial risk assessments to its cash flow/leverage analysis ratios: minimal; modest; intermediate; significant; aggressive; and highly leveraged. Rothschild used the "Low Volatility" ranges of S&P's Cash Flow/Leverage Analysis ratio in his analysis summarized in Table 2. See, Eversource Response to FI-6 dated 1/21/21, Attachment 5, S&P Global Ratings, Corporate Methodology, pp. 33-34.

Table 3
Fitch Ratings Credit Rating Methodology: Financial Profile Key Factors

Fitch Ratings' Financial Profile Key Factors	Authorized in 2017 Rate Case Decision	Metrics Applying Rothschild's Midpoint Recommendation	Analysis on Potential Credit Rating Impact[17]
FFO Leverage (Debt / (FFO + Interest))	5.32x	5.79x	"BBB" range = 5.0 – 6.5x *Remains in this BBB range*
Total Debt Equity with Equity Credit / Operating EBITDA	3.75x	4.09x	"A" range = 3.25 – 3.75x "BBB" range = 3.75 – 4.75x *Borderline between "A" and "BBB" range to within "BBB" range*
FFO Interest Coverage ((FFO + Interest) / Interest)	4.50x	4.13x	"A" range = 5.5 – 4.5x "BBB" range = 4.5 – 3.5x *Borderline between "A" and "BBB" range to within "BBB" range*

Rothschild Supplemental Response to LFE-12 dated 7/27/21; Eversource Supplemental Response to FI-6 dated 1/21/21, Attachment 7, Fitch Rating Corporates – Sector Navigator: US Utilities, Power and Gas, p. 214.

Ultimately, no docket participant, nor the Authority, can predict with certainty a future credit rating downgrade, or upgrade. Indeed, despite the detailed ratings methodologies utilized by Moody's Analytics, Fitch Ratings, and S&P Global, the specific inputs utilized by the agencies are unknown and aspects of the firms' analysis are subjective; therefore, only the credit rating agencies themselves could calculate the metrics in the above tables or determine if a specific rate reduction would result in a credit rating change with complete certainty.

However, regardless of whether Eversource's credit rating is downgraded, Rothschild asserted that the impact of such a credit rating downgrade would likely still benefit ratepayers on net, as an interim rate decrease would outweigh any potential costs incurred as a result of the impact to the Company's credit rating. Tr. 8/9/21, p. 895-897. Specifically, Rothschild estimated "the incremental cost of debt for every notch of credit downgrade could be as high as 5 basis points today." Id.; EOE Brief, August 25, 2021 (EOE Brief), p. 32. Under a "worst case scenario," where all outstanding debt would be refinanced, Rothschild calculated Eversource would incur an additional \$22 million annually on \$4.441 billion of debt. Eversource Supplemental Response to FI-6 dated 6/18/21, Attachment 1, p. 2. In contrast, Rothschild's recommended range of adjusted

[17] S&P Global utilizes the following range of financial risk assessments to its cash flow/leverage analysis ratios: minimal; modest; intermediate; significant; aggressive; and highly leveraged. Rothschild used the "Low Volatility" ranges of S&P's Cash Flow/Leverage Analysis ratio in his analysis summarized in Table 2: See, Eversource Response to FI-6 dated 1/21/21, Attachment 5, S&P Global Ratings, Corporate Methodology, pp. 33-34.

ROEs, if implemented, would result in a reduced revenue requirement of more than $60 million, thereby translating into monthly bill savings for ratepayers (i.e., conservatively, $60+ million - $22 million). EOE Response to LFE-10, LFE-11; EOE Brief, p. 4. The Authority concurs with Rothschild that any credit rating downgrade associated with the interim rate decrease authorized herein is highly likely to be more than offset by the associated reduction in base distribution rates.

Separately, as discussed herein, the Storm Decision imposed a 90 basis point ROE reduction on Eversource. Any credit rating downgrade that cites the implementation of this ROE reduction is the direct result of the deficient performance by Eversource management, documented extensively through the Storm Decision. In short, it is Eversource, not the Authority, that failed to comply with certain applicable performance standards; it is Eversource, not the Authority, that failed to manage its preparation for and response to Tropical Storm Isaias prudently and efficiently. The two ROE adjustments ordered herein must not be conflated, particularly as it relates to any potential actions taken by credit rating agencies.

Accordingly, the Authority has determined that Eversource has failed to meet its burden to show that its excessive ROE and rates are directly beneficial to ratepayers.

C. REASONABLE RETURN ON EQUITY

In determining what constitutes a reasonable rate of return, the Authority is guided by statute and legal precedent. Under Conn. Gen. Stat. § 16-19e(a)(4), public service companies are allowed "to cover their . . . capital costs, to attract needed capital and to maintain their financial integrity. . ." This statutory prerogative is based upon principles established in several landmark United States Supreme Court cases.

Specifically, a regulated utility is entitled to an opportunity to recover "the capital costs of the business," which "include service on the debt and dividends on the stock." Fed. Power Comm'n v. Hope Nat. Gas Co., 320 U.S. 591, 603 (1944) (Hope Decision). "[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." Id. "That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." Id.; see, also, Bluefield Waterworks & Imp. Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679, 690 (1923); Duquesne Light Co. v. Barasch, 488 U.S. 299, 310 (1989) (finding that "whether a particular rate is 'unjust' or 'unreasonable' will depend to some extent on what is a fair rate of return given the risks under a particular rate-setting system, and on the amount of capital upon which the investors are entitled to earn that return.")

Ultimately, however, rate setting requires "a balancing of the investor and the consumer interests." In re Permian Basin Area Rate Cases, 390 U.S. 747, 770 (1968) (citing the Hope Decision, 320 U.S. at 603). Further, the Authority "is not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function . . . involves the making of 'pragmatic adjustments.'" Hope Decision, 320 U.S. at 602 (citing Fed. Power Comm'n v. Nat. Gas Pipeline Co. of Am., 315 U.S. 575, 586

(1942)). Within this legal framework, the Applicant "has the burden of proving the proposed rate under consideration is just and reasonable." Conn. Gen. Stat. §16-22.

Importantly, a rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. Bluefield Waterworks & Imp. Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679, 692 (1923).

1. Methodologies

EOE's witness, Aaron L. Rothschild (Rothschild), advocated for basing the EDCs' ROE on investors' return expectations as indicated by market data, rather than on previously authorized EDCs' ROEs, as such authorized historical ROEs are not necessarily informed by current market conditions. Rothschild Prefiled Test., pp. 10, 11; EOE Response to ES-54. Unless the authorized ROE is based on current market conditions, Rothschild asserts that the resulting rate will either be too low to enable the utility to raise the capital required to provide safe and reliable service or too high, thereby, causing customers to overpay for their service. Rothschild Prefiled Test., pp. 10, 11; Tr. 5/27/21, p. 185. According to Rothschild, "[s]etting rates based on historical data is like driving a car by looking out the rear-view mirror." Rothschild Prefiled Test., p. 10.

Rothschild recommends applying a market-based methodology to measure investors' expectations directly, since investors are the ones that provide the capital to the EDCs. Id., p. 11; Tr. 5/26/21, p. 68. In determining investors' return expectations, Rothschild uses current market prices, such as stocks, bonds, and options, which capture investors' expectations directly, instead of relying solely on historical data and analysts' forecasts. Rothschild Prefiled Test., pp. 11, 17, 37, 38. Rothschild asserts that one of the reasons why factoring in current market conditions is particularly appropriate in this proceeding is because of the COVID-19 pandemic and its impact on the market. COVID-19 caused significant capital market disruption through most of 2020, and the recovery is happening in real-time, thereby rendering the calculation of the cost of equity while looking backward particularly ineffective, Rothschild concludes. Id., pp. 10, 14, 36; Tr. 5/27/21, p. 204.

Rothschild recommends an adjusted Eversource ROE of between 6.04% and 8.29%, with a mid-point of 7.17%. Rothschild Supplemental Prefiled Test., pp. 4, 6, 8. To arrive at an adjusted ROE range of between 6.04% and 8.29%, Rothschild applied the Discounted Cash Flow (DCF) method, including the constant growth and non-constant growth methods, and the Capital Asset Pricing Model (CAPM) to a proxy group of 22 publicly traded electric utility companies using data available through March 31, 2021 (RFC Proxy Group), as further discussed below. Rothschild Prefiled Test., p. 12.

As a check on the reasonableness of his model results, Rothschild reviewed capital market data in general and the model results of leading financial institutions. Id. Rothschild noted that his cost of equity recommendation midpoint of 7.17% for Eversource is on the upper half of the range of the equity return expectations published by major banks and brokerage houses, which ranged from 5.5% to 8.5%. Id., p. 9. For example, Rothschild cites a 2020 Long-Term Capital Market Assumptions analysis from

J.P. Morgan Asset Management, which projected a 7.2% expected return for U.S. corporations with large market capitalizations. Id. In addition, in its own 2020 Annual Report, Eversource Energy's pension plan assumed an 8.5% rate of return for U.S. equity securities. Id. Therefore, according to Rothschild, his recommended cost of equity range is consistent with the cost of equity demanded by investors and therefore will not impede Eversource's ability to raise the capital needed to provide safe and reliable service. Id., pp. 9, 78.

Conversely, Eversource recommends that its current ROE of 9.25% be maintained. Rea Rebuttal Prefiled Test., p. 120. According to Eversource, Rothschild's cost of equity evaluation, both his model results and his recommendations, are "extremely understated," Id., p. 9, and his recommendation falls far outside of the range of recently authorized ROEs for electric utilities nationwide. Id., p. 7. In addition, Eversource claims that the record shows that its currently authorized ROE of 9.25% is significantly below conservative estimates of the Company's prevailing cost of equity, which is in the range of 9.60% to 10.10%. Id., p. 15. Eversource's witness (Rea) conducted his own cost of equity analysis utilizing the Constant Growth DCF Method, CAPM, and the Risk Premium Method, noting his evaluation was conducted to generally align with Rothschild's approach. Id., pp. 10-11. Eversource asserts that its witness's prevailing cost of equity evaluation ranged from 8.80% to 10.62%, and which reflect a central tendency of 9.60% to 10.10%. Id., p. 11.

Tables 4 and 5 outline the cost of equity calculations proposed by Rothschild and Eversource, respectively.

Table 4
Rothschild ROE Recommendations

TABLE 3: COST OF EQUITY MODEL RESULTS		
DCF	**Low**	**High**
Constant Growth	7.91%	7.96%
Non-Constant Growth	9.08%	9.29%
CAPM		
Spot (Mar. 31, 2021)		
Risk Free Rate - 3-Month T Bill	6.08%	6.15%
Risk Free Rate - 30-Yr T Bond	6.96%	7.02%
3-Mo. Weighted Average (Jan. to Mar. 2021)		
Risk Free Rate - 3-Month T Bill	5.95%	6.14%
Risk Free Rate - 30-Yr T Bond	6.87%	7.02%
Outer Quartile Range	**6.05%**	**8.29%**
Midpoint of Range	**7.17%**	

EOE Brief, p. 8.

Table 5
Rea Rebuttal ROE Recommendations

Table VVR-18 Range of Estimates of the Cost of Equity RFC Electric Proxy Group	
DCF Estimates	8.80% - 9.40%
CAPM Estimates	10.13% - 10.62%
RPM Estimate	10.04% - 10.04%
Cost of Equity – Central Tendency of Estimates	9.60% - 10.10%
Eversource's Currently Authorized ROE	9.25%

Rea Rebuttal Prefiled Test., p. 118.

a. Proxy Group

Rothschild's selection of the RFC Proxy Group used to provide the above calculations is based on the following five criteria: (1) the company is characterized by Value Line as an electric utility; (2) the company has at least 80% of its assets dedicated to regulated operations; (3) the company pays dividends and has not cut the size of its dividend in the past six months; (4) the company is not involved in any significant merger and acquisition activity; and (5) the company is not being impacted by extraordinary events that could significantly impact its risk characteristics. Rothschild Prefiled Test., p. 39. Rothschild determined the cost of equity for the average company in his RFC Electric Proxy Group to be between 6.05% and 8.29%. Rothschild Supplemental Prefiled Test., May 25, 2021, p. 4. It is important to note that Eversource, in calculating its cost of capital, evaluated the same 22 publicly traded electric utility companies that Rothschild evaluated in his RFC Proxy Group. Rea Rebuttal Prefiled Test., p. 11.

b. Discounted Cash Flow (DCF) Method

The DCF model is a market-based financial model that attempts to replicate the valuation process that sets the price investors are willing to pay for a share of stock. The premise of the DCF model is that the intrinsic value of common stock can be estimated as the present value of future cash that flows to the investor plus the expected growth in selling the stock discounted to the present. In estimating the expected cash flows an investor expects in terms of dividends and capital gains, and given the current market price, an analyst can back-into the discount rate or cost of common equity. In its simplest form, the DCF consists of a current cash dividend yield (dividend) and a future price appreciation (growth) of the investment.

Rothschild used both the constant growth form of the DCF method and the non-constant growth form. Rothschild Prefiled Test., pp. 12, 38, 41. According to Rothschild, the constant growth form is a form of the DCF method that can be used in determining the cost of equity when investors can reasonably expect that the growth of retained earnings and dividends will be constant. Id., p. 43. Rothschild's constant growth form of the DCF analysis indicates a cost of equity range of between 7.91% and 7.96% for the RFC Electric Proxy Group. Id., pp. 14, 41-42, 50.

The non-constant growth form of the DCF method determines the return on investment expected by investors based on an estimate of each separate annual cash flow the investor expects to receive. Id., p. 51. It relies on an expectation of future cash flows. Id. at 53. The results of Rothschild's non-constant form of the DCF method indicates a cost of equity of between 9.08% and 9.29% for the RFC Electric Proxy Group. Id., pp. 14, 42, 56.

Similarly, Eversource's expert witness, Rea, provided DCF estimates based on an approach that generally aligns with Rothschild's own, producing a range of ROEs from 8.80% to 9.60%. Rea Rebuttal Prefiled Test., pp. 89-90.

c. Capital Asset Pricing Model (CAPM)

CAPM evaluates the cost of equity by determining first an appropriate risk-free rate. To this rate it adds a beta, or the degree of co-movement of the security's rate of return with the market's rate of return, times the expected equity risk premium, which is the amount by which investors expect the future return on equities, in general, to exceed that on the riskless asset. CAPM relates the expected return on an investment in a security to the risk of investing in that security. Rothschild Prefiled Test., p. 56. According to the theory underlying the CAPM, since the risk cannot be removed by diversification, investors must bear it no matter what. Id., p. 57.

Rothschild's CAPM is based on methodologies used by Value Line, the Chicago Board of Options Exchange, and published in peer-reviewed academic journals (e.g., The Review of Financial Studies). Id., p. 13. In his CAPM calculations, Rothschild first determined appropriate values or ranges for each of the three inputs used in the CAPM: (a) Risk-Free Rate, (b) Beta, and (c) Equity Risk Premium. Id., p. 58. He then used the following equation to calculate the cost of equity implied by the model:

$$K = Rf + \beta i^* (Rm-Rf).$$

Where:
K = the cost of equity;
βi = a measure of non-diversifiable, or systemic, risk;
Rf = the risk-free interested rate; and
Rm = the expected return on the market as a whole.

In this specification, the term (Rm – Rf) represents the market risk premium or equity risk premium and βí (Beta) is the measure of non-diversifiable, or systematic, risk. Id., pp. 57-58.

With respect to the risk-free rate, Rothschild asserted that it is generally preferable to use the market yield on short-term U.S. Treasury yields as the risk-free rate because these bonds have a beta close to zero. Id., p. 58. However, Rothschild used a risk-free rate based on both long- and short-term Treasury yields in his CAPM because investors with a longer investment horizon are likely to use a higher risk-free rate as an opportunity cost for their investment decisions. Id. His short-term risk-free rate is based on the yield on 3-month U.S. Treasury bills and his long-term risk-free rate is based on the yield on 30-year U.S. Treasury bills. Id., p. 60. Rothschild then used both spot values as of March 31, 2021 and weighted averages over the three months ending on that date for these two yields. Id., pp. 58- 59. Rothschild's spot and weighted average short-term risk-free rates are 0.03% and 0.04%, respectively, and his spot and weighted average long-term risk-free rates are 2.41% and 2.20%, respectively. Id., p. 59. According to Rothschild, any form of averaging or weighing approach applied to the last eight months of historical yield data would not have any significant effect on his CAPM results. Id.

Given that Rothschild's recommended approach is to calculate the cost of equity based on investor expectations, Rothschild used two betas, a "forward beta," also known as an option-implied beta, based on forward-looking investor expectations of non-diversifiable risk, and a "hybrid beta" based on both forward-looking investor expectations and historical return data. Id., p. 62. The only significant difference between Rothschild's beta calculations and Value Line's calculations is that, whereas Value Line uses the NYSE Composite Index as the market index, Rothschild used the S&P 500 Index. Id., p. 66. According to Rothschild, the S&P Index has a much larger number of options traded, thereby making the calculation of option-implied betas more reliable. Id.

Rothschild stated that calculating option-implied betas of a company requires (1) obtaining stock option data for that company and a market index, (2) filtering the stock option data, (3) calculating the option-implied volatility for the company and for the index, (4) calculating the option-implied skewness for the company and for the index, and (5) calculating option-implied betas for the company based on implied volatility and skewness for the company and for the index. Id.

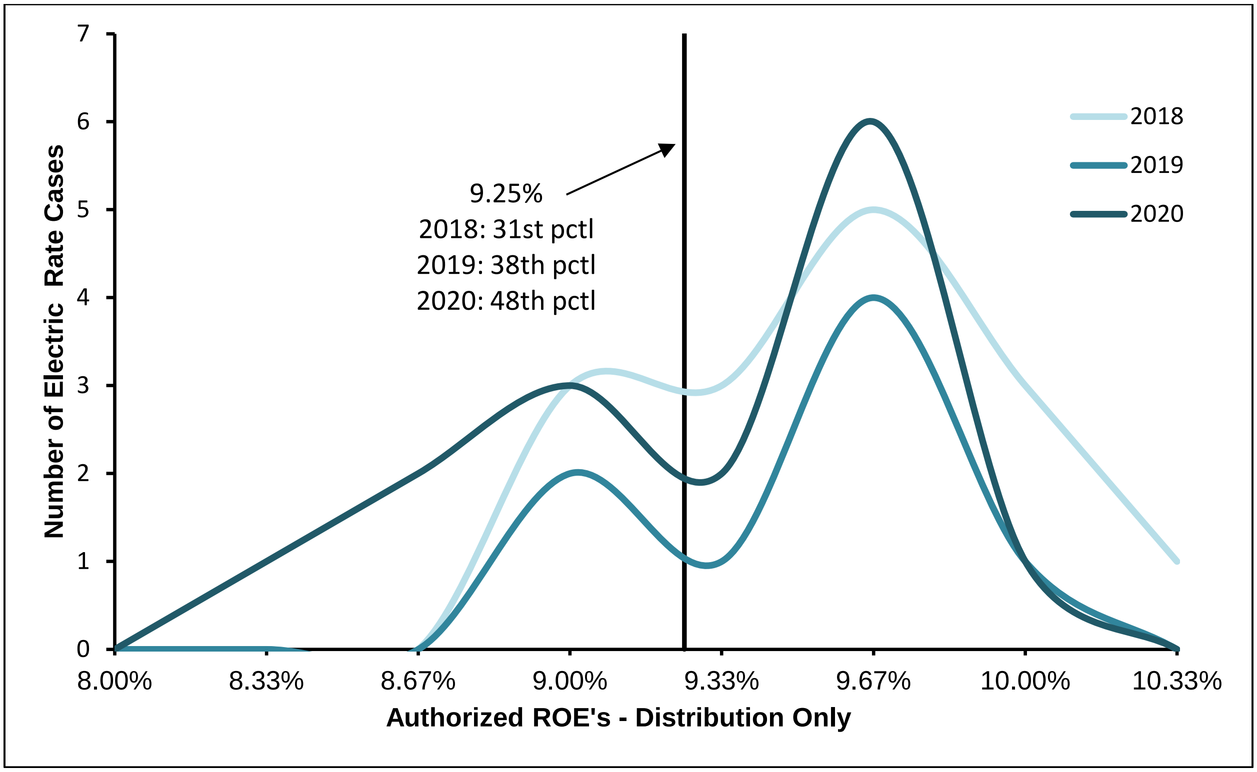
Traditionally, the risk premium used in CAPM calculations is calculated from historical returns and/or equity analyst projections, which, while historically accurate, does not take into account investors' expectations for future market risks and returns. Rothschild instead recommends applying a market-based approach to calculate the equity risk premium. The equity risk premium used by Rothschild is the expected return on the S&P 500 minus the risk-free rate. Id., p. 73. Rothschild calculates his equity risk premium by subtracting the risk-free rate from the expected return on the S&P 500. Id. Rothchild's CAPM analysis, which resulted in eight variations, indicated a cost of equity range of between 5.95% and 7.02% for the RFC Electric Proxy Group. EOE Response to Interrogatory ES-2 dated May 14, 2021; EOE Brief, p. 8.

2. Recently Authorized ROEs

Evidence of recently authorized ROEs for electric distribution companies nationally indicates a downward trend. Authorized ROEs approved for EDCs (i.e., distribution-only electric utilities) in 2018 averaged 9.38%, while those in 2019 and 2020 averaged 9.37% and 9.10%, respectively. Eversource Response to LFE-09. Eversource's allowed ROE of 9.25% was in the 31st percentile of ROEs approved in 2018; if it had been approved in

2019 or 2020, Eversource's allowed ROE would have fallen in the 38th percentile and the 48th percentile, respectively. Id. Figure 1 illustrates that while Eversource's allowed ROE has remained at 9.25%, approved ROEs across the country have continuously shifted downward, with more allowed ROEs falling below 9.00% in 2020 (6), than in both 2018 and 2019 combined (5). While not reflected in Figure 1, there are also two pending rate case proceedings in Illinois where the electric utilities have proposed an allowed ROE of 7.36%. Id; Rothschild Response to LFE-04.

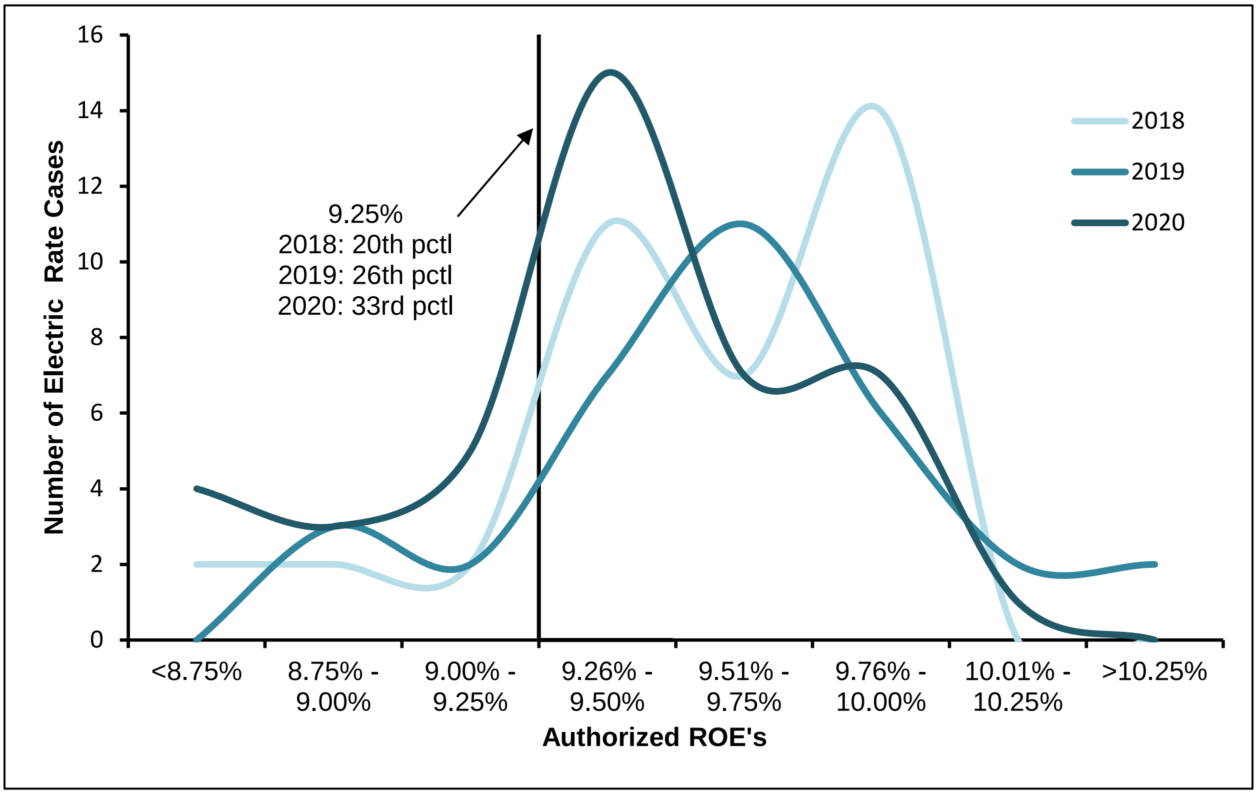
Figure 1
EDC Authorized ROE Determinations (Distribution Utility-Only), 2018-2020



Data source: Eversource Response to LFE-09.

An analysis of the allowed ROEs since 2018 of all electric utilities further highlights this trend. Authorized ROEs approved for all electric utilities in 2018 averaged 9.60%, while those in 2019 and 2020 averaged 9.66% and 9.42%, respectively. Eversource Response to LFE-09. Eversource's allowed ROE of 9.25% was in the 20th percentile of ROEs approved in 2018; if it had been approved in 2019 or 2020, Eversource's allowed ROE would have fallen in the 26th percentile and the 33rd percentile, respectively. Id. Figure 2 illustrates that while Eversource's allowed ROE has remained at 9.25%, approved ROEs for all electric utilities across the country have continuously shifted downward, with the same number of allowed ROEs falling below 9.00% in 2020 (7), as in 2018 and 2019 combined (7).

Figure 2
EDC Authorized ROE Determinations, 2018-2020



Data source: Eversource Response to LFE-09.

3. ROE Determination

In determining a reasonable ROE for Eversource, the Authority considered Rothschild's proposed market-based approach applied to the DCF Model and CAPM to calculate a cost of equity reflecting current market expectations as a means of implementing an interim rate decrease. The Authority also considered Eversource's rebuttal testimony and associated cost of equity calculations. The Authority also reviewed the DCF Model and CAPM inputs and assumptions presented by both witnesses.

The Authority finds Rothschild's market-based approach for determining a reasonable ROE to be credible and persuasive. Specifically, the Authority finds that the incorporation of investor market return expectations into the historically applied DCF and CAPM methodologies enables the Authority, and all docket participants, to better consider a just and reasonable rate of return based on the same *prospective basis* that base distribution rates are set. As such, the Authority determines that this added layer of analysis provides appropriate protection to the relevant public interests, both existing and foreseeable, pursuant to Conn. Gen. Stat. § 16-19e(a). Therefore, the Authority considered Rothschild's DCF and CAPM calculations, as outlined below, in this Decision; moreover, on a going forward basis, the Authority shall consider a similar approach to incorporating investor expectations into the historically applied DCF and CAPM methodologies in all future rate proceedings.

As outlined in Section IV.C.1., Rothschild calculated a DCF model ROE range of 7.91% to 9.29%. The mid-point of Rothschild's DCF model ROE range is 8.60%. However, Rothschild notes that the low-end of the DCF model ROE calculations "should be considered conservatively high [as] analysts' forecasts of…growth have been notoriously overstated." Rothschild Prefiled Test., p. 50. Also as noted in Section IV.C.1., Eversource's witness, Rea, calculated a DCF model ROE range between 8.80% and 9.40%, which results in a mid-point of 9.10%. Similarly, Section IV.C.1. outlines that both Rothschild's and Rea's CAPM ROE ranges, 5.95% to 7.02% for Rothschild and 10.13% to 10.62% for Rea, result in respective mid-point ROE calculations of 6.49% and 10.38%. Table 6 provides a summary of the mid-points calculated using both the DCF and CAPM models by each expert witness.

Table 6
Mid-Point of Calculated DCF Model and CAPM ROEs

ROE %	DCF Model	CAPM
EOE (Rothschild)	8.60%	6.49%
Eversource (Rea)	9.10%	10.38%
Average	8.85%	8.43%

Historically, the Authority has weighted the DCF model result more heavily than it weights the CAPM result, as it is generally more reflective of current market conditions as it relies on directly observable market data.[18] See, 2021 Connecticut Water Rate Case, p. 46; See also, 2016 UI Rate Case, p. 86. Further, as the Authority determined that Rothschild's market-based approach is credible and persuasive, the Authority finds an ROE in the range of Rothschild's DCF model ROE mid-point (8.60%) and the mid-point between Rothschild and Rea's DCF ROE calculations (8.85%) to be just and reasonable in setting an adequate ROE for Eversource. While the Authority finds this range (8.60-8.85%) to be just, reasonable and adequate, it is noteworthy that both the mid-point between Rothschild's and Rea's CAPM ROE calculations (8.43%) and Eversource's own assumption of the rate of return for U.S. equity securities included in its pension plan (8.5%) is slightly below this range. Furthermore, Rothschild's recommended ROE (7.17% without adjusting for changes to the capital structure) is more than 140 basis points.[19]

Conducting additional analysis of the recently authorized ROEs for EDCs (i.e., distribution-only electric utilities) nationwide (See Section III.C.3.), the Authority calculates that an ROE of 8.60% would be in 22nd percentile for ROEs authorized in 2020 and an ROE of 8.85% would be in the 39th percentile for ROEs authorized in 2020. As noted above, Eversource's allowed ROE of 9.25% was in the 31st percentile of ROEs

[18] In the Company's next rate case, the Authority will further consider whether weighing the DCF model over the CAPM is appropriate moving forward given Rothschild's approach to the CAPM.

[19] This range is more than 170 basis points above Rothschilds' recommended ROE adjusted for Eversource's current capital structure (6.90%).

approved in 2018. The Authority calculates that an allowed ROE of 8.80% is in the 31st percentile of allowed ROEs for 2020, and falls in the range of just and reasonable ROEs determined above (8.60% to 8.85%). An ROE of 8.80% also falls within Rea's DCF model ROE calculations.

Based on the foregoing, the Authority finds that an 8.80% ROE is just, reasonable and adequate. Accordingly, Eversource will be ordered in this Interim Decision to implement an interim rate decrease using the 8.80% ROE to take effect November 1, 2021.

D. OTHER COST OF CAPITAL COMPONENTS

The Authority also examined Eversource's cost of debt and capital structure in its review of Eversource's cost of capital. The Authority examines these factors in rate proceedings to ensure that a utility's overall cost of capital is reasonable and efficient.

1. Cost of Debt

Eversource's authorized cost of debt is 4.64%. See, 2017 Rate Case Decision, Table 3, p. 16. According to Rothschild's calculations, however, Eversource's current cost of debt has declined, which is due to the lower than estimated debt incurred on bonds it forecasted would be issued in the last rate case and the issuance of such debt at a cost rate of between 0.75% and 4.00%. Tr. 8/9/21, pp. 792, 810-11.

Eversource demonstrated its actual cost of debt for the twelve-month period ending March 31, 2021 is 4.24%. Horton Rebuttal, p. 20; Eversource Brief, p. 53. Eversource maintains, however, that it is not appropriate to modify the Company's currently authorized cost of debt or to use Eversource Energy's cost of debt or that of any other company. Id., p. 18. Eversource asserted that using the cost of debt of its parent company, Eversource Energy, or that of any other company would misrepresent the actual cost associated with debt that the Company would be able to issue. Id. Eversource emphasized that the Authority should not lower its cost of debt from what was previously authorized. Id.

2. Capital Structure

Eversource's authorized capital structure consists of 53.00% common equity. 2017 Rate Case Decision, Table 3, p. 16. Rothschild recommends using the consolidated capital structure currently being used by Eversource's parent, Eversource Energy, which is 46.26% common equity.[20] Rothschild Rebuttal Prefiled Test., p. 4. According to Rothschild, it is a red flag when a more conservative subsidiary, such as Eversource, has a higher capital structure than the parent. Tr. 5/26/21, pp. 86-87. Using the consolidated capital structure of Eversource's parent, Rothschild asserted, is also consistent with previous Authority decisions. Rothschild Prefiled Test., pp. 5, 19, citing Docket No. 16-06-04, Application of The United Illuminating Company to Increase Its Rates and Charges, p. 87; Rothschild Supplemental Prefiled Test., p. 5; see also, Tr. 5/26/21, p. 26.

[20] Rothschild also noted that the Eversource Energy's common equity ratio is almost the same as the average ratio of Rothschild's proxy group, which is 46.18%. Rothschild Supplemental Prefiled Test., p. 6; Tr. 5/26/21, p. 27.

According to Eversource, the Settlement Agreement specified that the Company's capital structure for ratemaking purposes remain at 53.00% common equity until the time of the next rate case. Horton Rebuttal Prefiled Test.[21] Eversource posits that the Settlement Agreement precludes the imposition of the capital structure of Eversource Energy for ratemaking purposes because Section 9(b) of the Settlement Agreement set the percentage of common equity in the Company's capital structure for ratemaking purposes at 53.00% until the time of the next rate case. Id.

Eversource stated that for the five quarters ending March 31, 2021, the common equity ratio 55.79%, long-term debt ratio was 42.85%, and preferred stock was 1.37%. Tr. 5/27/21, p. 227. Table 7 compares Eversource's capital structure authorized in the 2017 Rate Case Decision with Rothschild's recommended capital structure used for calculating an adjusted ROE.

Table 7
Eversource Capital Structure: Authorized vs. Rothschild Recommendation

	Authorized in 2017 Rate Case Decision	Rothschild's Recommendation
Common Equity Ratio	53.00%	46.26%
Long-Term Debt	45.38%	51.12%
Preferred Stock	1.62%	1.62%
ROE – Adjusted for Capital Structure	9.25%	7.17% (midpoint)

3. Conclusion on other Cost of Capital Components

The Settlement Agreement relied on by the Company does not preclude the Authority from imposing the capital structure of Eversource Energy for ratemaking purposes as Eversource Energy's common equity ratio is currently 46.26%, which is below the 53.00% cap for Eversource. Further, relevant precedent informs reliance on the EDC's holding company equity ratio for ratemaking purposes.[22] Nonetheless, the Authority declines to make a determination in this Interim Decision regarding adjustments to Eversource's cost of debt or capital structure.[23] Rather, the Authority will make a determination regarding Eversource's cost of debt and capital structure in the next rate case proceeding.

[21] Section 9(b) of the Settlement Agreement states that its capital structure "shall be capped at 53.00% common equity," meaning it cannot exceed 53.00%. Settlement Agreement, Section 9(b). The Settlement Agreement, therefore, does not preclude the Authority from imposing the capital structure of Eversource Energy for ratemaking purposes as Eversource Energy's common equity ratio is currently 46.26%, which is below the 53.00% cap for Eversource. Rothschild Supplemental Prefiled Test., p. 4.

[22] See, the December 14, 2016 Decision in Docket No. 16-06-04, Application of The United Illuminating Company to Increase its Rates and Charges, p. 62.

[23] In the June 9, 2021 Decision in Docket No. 21-03-25, Application of the Connecticut Light and Power Company dba Eversource Energy for Approval of the Issuance of Long-Term Debt, the Authority authorized Eversource to issue long-term debt securities in an aggregate principal amount not to exceed $350 million during a period from the date of the Authority's decision through December 31, 2021. This issuance of debt will likely change Eversource's cost of debt.

V. AUTHORITY ANALYSIS – ROE REDUCTION PURSUANT TO THE STORM DECISION

Eversource is currently subject to an ROE reduction related to its performance in preparing for and responding to Tropical Storm Isaias, and the Authority will use this rate proceeding to implement the reduction. In the Storm Decision, the Authority stated that:

> [P]ursuant to its authority under Conn. Gen. Stat. § 16-19e(a), the Authority will order a reduction in each company's ROE in order to incentivize the EDCs to improve their management of future storm responses. The ROE approved for the EDCs in the next applicable ratemaking proceeding in which a final decision is issued, such as the pending Docket No. 17-12-03RE11, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – New Rate Designs and Rates Review, will accordingly be reduced.

Id., p. 127.

Specifically, the Authority imposed an indefinite 90 basis point ROE reduction on Eversource, finding that a reduction in its ROE is "necessary and appropriate to adequately incentivize improved storm response performance moving forward." Id. The purpose of the reduction in ROE is to "align [Eversource's] management performance in future storm response efforts with [its] financial performance". Id., p. 2.

In imposing the 90 basis point ROE reduction on Eversource, the Authority found in the Storm Decision that the previous one-year 15 basis point ROE reduction imposed on Eversource by PURA in 2012 after Tropical Storm Irene and the October Nor'easter did not sufficiently incentivize the Company to implement long-term improvements to its performance. Id., p. 128. The Authority also found in the Storm Decision that it could not "reasonably rely on claims by Eversource that it has or will implement improvements to its emergency response as a basis for reducing the warranted ROE reduction given that many of the same deficiencies identified [in the Storm Decision] were present in the [August 1, 2012 Decision in Docket No. 11-09-09, PURA Investigation of Public Service Companies' Response to 2011 Storms]". Id. As stated in the Storm Decision, Eversource's customers "have a right to expect that performance failures exhibited in response to Tropical Storm Isaias will not be repeated going forward". Id., p. 127.

In the Notices issued in this Docket, the Authority announced that it would use Phase IIa to implement the 90 basis ROE reduction authorized for Eversource in the Storm Decision. See, e.g., Revised Notice Regarding Investigation Timeline, May 5, 2021; Revised Notice of Proceeding, June 14, 2021. Throughout the Phase IIa proceeding, the Authority sought input from Parties and Intervenors regarding whether the duration of the 90 basis point ROE reduction imposed on Eversource in the Storm Decision should be reduced from an indefinite period to a specific period. See, e.g., Notice of Request for Briefs for Phase IIa, June 24, 2021; Notice of Additional Late Filed Exhibit Hearing, July 20, 2021.

Rather than providing information regarding whether the duration of the ROE reduction should be reduced, Eversource testified that "[n]o ROE reduction should be implemented for Eversource in relation to storm performance because the Company is already properly incented to improve its [Emergency Response Plan] performance to a material degree". Hayhurst Prefiled Test., p. 5 (emphasis added). However, when asked to identify the specific incentives to which the Company was referring, Eversource stated that "the incentive to do a good job is kind of intangible," Tr. 8/9/21, p. 787, and that "our incentives are to do the best job that we can for our customers." Id., p. 788. Further, when asked to identify when Eversource became properly incented, Eversource testified that "[w]e are always incented to do the best job that we can for our customers." Tr. 8/9/21, p. 784. Unfortunately, Eversource's "intangible" desire to "do the best job" is simply not good enough. As a utility regulator, it is evident to the Authority (and Eversource's own history demonstrates) that actual financial incentives are necessary to ensure the Company prioritizes performance for ratepayers on par with performance for shareholders.[24] Given the Company's deficient performance in preparing for and responding to Tropical Storm Isaias, Eversource is not currently properly incented to meet its obligations as a public service company.

Consequently, based on the Storm Decision and the record evidence in this proceeding, the Authority will impose the 90 basis point ROE reduction on Eversource effective November 1, 2021, through the end of its next approved rate plan. See, e.g., Hayhurst Prefiled Test., p. 6; Tr. 7/14/21, pp. 630-632. During Eversource's next rate case proceeding, the Authority will again[25] consider performance-based opportunities by which Eversource may earn back the ROE basis point reduction during the rate plan period.

VI. CONCLUSION AND ORDERS

A. CONCLUSION

In this Interim Decision, pursuant to Section 5 of the Take Back Our Grid Act and Conn. Gen. Stat. §§ 16-19(g) and 16-19e, the Authority finds that the Company's currently authorized ROE, along with the corresponding rates it is collecting, are in excess of what is just and reasonable. The Authority also finds that Eversource failed to adequately demonstrate that earning an excessive ROE or collecting excessive rates is directly beneficial to its customers. Accordingly, the Authority in this Interim Decision orders

[24] While not entered into the record evidence, the Authority doubts that the Company's incentives for achieving quarterly financial results for shareholders are equally "intangible."

[25] On June 24, 2021, the Authority invited briefs from Parties and Intervenors on potential metrics or standards that the Authority should consider in determining how and when the imposed 90 basis point reduction would no longer be necessary to achieve the desired performance. See, Notice of Request for Briefs for Phase IIa, dated June 24, 2021. The Company declined to provide substantive input and declared the matter "legally invalid." See, Eversource Response to Briefing Question, dated July 9, 2021, p. 3. The Authority once again sought input on the imposition of the ROE reduction through an additional late filed exhibit hearing, scheduled for August 9, 2021. Rather than provide substantive input, again, Company witnesses asserted that no ROE reduction should be implemented. See, Hayhurst Prefiled Test., p. 5; Tr. 8/9/21, pp. 787-788.

Eversource to implement an interim rate decrease through a 45 basis point reduction to the Company's authorized ROE, effective November 1, 2021.

In addition, the Authority simultaneously implements the 90 basis point ROE reduction imposed on Eversource in the Storm Decision through the end of its next approved rate plan.[26] During Eversource's next rate case, the Authority will consider performance-based opportunities by which Eversource may earn back the ROE basis point reduction during the rate plan period.

Consequently, effective November 1, 2021, Eversource's authorized ROE will be 7.90%, and shall be reflected in rates in accordance with the direction provided herein.

B. ORDERS

For the following Orders, the Company shall file an electronic version through the Authority's website at www.ct.gov/pura. Submissions filed in compliance with the Authority's Orders must be identified by all three of the following: Docket Number, Title and Order Number. Compliance with orders shall commence and continue as indicated in each specific Order or until the Company requests and the Authority approves that the Company's compliance is no longer required after a certain date.

1. No later than October 20, 2021, the Company shall submit exhibit(s) in an unlocked worksheet to calculate adjusted base distribution rates that account for a 45 basis point ROE reduction effectuating an interim rate decrease for Authority review and approval, effective beginning November 1, 2021. Unless otherwise stated by the Authority, the 45 basis point ROE reduction shall remain in effect until Eversource's next approved rate plan begins.

2. No later than October 20, 2021, the Company shall submit exhibit(s) in an unlocked worksheet to calculate adjusted base distribution rates that account for a 90 basis point ROE reduction imposed in the Storm Decision for Authority review and approval, effective beginning November 1, 2021. Unless otherwise stated by the Authority, the 90 basis point ROE reduction shall remain in effect until Eversource's next approved rate plan ends.

3. No later than October 20, 2021, the Company shall submit a clean and redlined version of all tariffs reflecting the cumulative adjustment to base distribution rates (i.e., a cumulative reduction of 135 basis points, resulting in an allowed ROE of 7.90%), as calculated in accordance with Orders 1 and 2 of this Interim Decision, for Authority review and approval. Should the rates filed in accordance with this order be found in violation of any directive or Order issued in this Interim Decision, the Authority may direct the Company to change rates starting December 1, 2021, and to reimburse customers for any difference charged in the interim.

[26] The Storm Decision initially specified an indefinite period for the ROE reduction.

THE STATE OF SOUTH CAROLINA
In The Supreme Court

In re Application of Blue Granite Water Company for Approval to Adjust Rate Schedules and Increase Rates, Appellant.

Appellate Case No. 2020-001283

Appeal from the Public Service Commission

Opinion No. 28055
Heard June 15, 2021 – Filed September 1, 2021

AFFIRMED IN PART AND REVERSED IN PART

Frank R. Ellerbe III and Samuel J. Wellborn, both of Robinson Gray Stepp & Laffitte, LLC, of Columbia, for Appellant Blue Granite Water Company.

Andrew M. Bateman, Alexander W. Knowles, Christopher M. Huber, and Steven W. Hamm, all of Columbia, for Respondent South Carolina Office of Regulatory Staff; Carri Grube Lybarker, Roger P. Hall, and Connor J. Parker, all of Columbia, and Richard L. Whitt, of Whitt Law Firm, LLC, of Irmo, all for Respondent South Carolina Department of Consumer Affairs; Michael K. Kendree Sr., of York, for Respondent York County; S. Jahue Moore, of Moore Taylor Law Firm, P.A., of West Columbia, for Respondent Town of Irmo; John Julius Pringle Jr., of Columbia, for Respondent Building Industry Association of South Carolina; and Laura P. Valtorta, of Valtorta Law Office, of Columbia, for Respondent Forty Love Point Homeowners' Association.

JUSTICE KITTREDGE: This is an appeal from the South Carolina Public Service Commission (PSC). The PSC is a quasi-judicial body established by the South Carolina General Assembly. The legislature has delegated to the PSC the "power and jurisdiction to supervise and regulate the rates and service of every public utility in this State and to fix just and reasonable standards, classifications, regulations, practices, and measurements of service to be furnished, imposed, or observed, and followed by every public utility in this State." S.C. Code Ann. § 58-3-140(A) (2015). Part of this power includes the authority "to create incentives for utilities to improve their business practices." *Utils. Servs. of S.C., Inc. v. S.C. Office of Regul. Staff*, 392 S.C. 96, 105, 708 S.E.2d 755, 760 (2011) ("The PSC [has the] power[] . . . to fix just and reasonable standards, classifications, regulations, practices, and measurements of service. Pursuant to these powers, the PSC is entitled to create incentives for utilities to improve their business practices. Accordingly, the PSC may determine that some portion of an expense actually incurred by a utility should not be passed on to consumers." (citations omitted) (internal quotation marks omitted)). The PSC's order on appeal here is primarily focused on providing incentives to the utility to improve its business practices.

The appellant, Blue Granite Water Co. (Blue Granite), is a utility that provides water and sewer services. Blue Granite was formerly known as Carolina Water Service (CWS). CWS changed its name to Blue Granite as part of a rebranding campaign, for the utility had earned an unfavorable reputation throughout the state. In rejecting Blue Granite's request for an approximate 50% rate increase, and in an effort to incentivize Blue Granite to improve its business practices, the PSC set a lower return on equity (ROE) than requested and allowed only certain portions of Blue Granite's requested costs, citing to the utility's known, poor reputation and service problems. On appeal, Blue Granite contends the PSC's attempts to incentivize the utility actually unfairly punished the company in violation of law.

While Blue Granite raises nine specific concerns, we have condensed those concerns to four primary issues on appeal: whether the PSC erred in (1) setting the permissible ROE; (2) using a ten-year average—rather than a five-year average—to calculate typical storm costs; (3) disallowing all costs associated with Blue Granite moving its headquarters from West Columbia to Greenville, including any office rental expenses; and (4) staying Blue Granite's ability to implement its new, higher rates under bond during the course of the appeal. We reverse in part and affirm in part. As to the issues involving the ROE, storm costs, and bond, we find the PSC's decision was not unfairly punitive, not arbitrary or capricious, and not clearly erroneous. However, as to the Greenville office expenses, we find the PSC's decision to *completely* deny yearly rental expenses was arbitrary and capricious. We therefore remand to the PSC for additional proceedings.

I.

Blue Granite is a relatively small-size utility providing water and sewer services to approximately 28,000 customers in South Carolina. In October 2019, Blue Granite filed an application for ratemaking with the PSC. Prior to that application, Blue Granite received annual rate revenues of almost $24 million. It sought to increase those rates by nearly $12 million per year, an approximate 50% increase.

Unsurprisingly, Blue Granite (and former CWS) customers from all over the state protested such a large increase, and, at the affected customers' requests, the PSC scheduled six hearings to receive testimony from customers. At those hearings, customers complained extensively about Blue Granite's relatively-high rates compared to other utilities in the area and the impact Blue Granite's proposed flat fees would have on low-income customers. Likewise, many of the customers who testified reported "incidents of poor water quality, unresponsive customer service, inaccurate meter readings, billing errors, and unwarranted cut-offs, among other problems." For example, one of the customers testified Blue Granite had wrongfully plugged his sewer line, resulting in his house being flooded with sewage. Another testified to a similar event in her neighborhood, resulting in raw sewage running through the entire neighborhood, including the community park and pool. Due to the extensive service problems, a number of the customers requested the PSC deny Blue Granite's application outright, particularly because of the number of rate increases Blue Granite had been granted in the recent past, and the dollar amounts associated with those past increases.[1]

Ultimately, the PSC granted Blue Granite a rate increase of approximately $5 million, an amount comparable to the increases granted to other similarly-sized utilities in the state. Notably, in its final order, the PSC found the customer testimony "very compelling and indicative of persistent, widespread, and pervasive

[1] One customer testified, "Blue Granite is applying for a 50 percent average rate increase, only two years after a 30 percent rate increase, which is unreasonable for their consumers. Add to that their statement to Representative Chris Wooten that they intend to pursue additional rate cases every two years following this one."

problems consistent with those which have frustrated customers of this utility for many years." However, the PSC explained,

> Giving effect to [*Utilities Services of South Carolina*,] as we must, we are legally foreclosed from denying Blue Granite's application for a rate increase in its entirety. . . . We have further considered all the customer [] hearing testimony and used it to guide us in creating incentives for Blue Granite to improve its business practices, cut costs, improve efficiency, and enhance quality of service.

Blue Granite filed a petition for rehearing, but the PSC denied the petition in large part. Blue Granite then directly appealed to this Court pursuant to Rule 203(d)(2)(A), SCACR.

II.

In reviewing a decision from the PSC, this Court employs a deferential standard of review. *S.C. Energy Users Comm. v. S.C. Pub. Serv. Comm'n*, 388 S.C. 486, 490, 697 S.E.2d 587, 589 (2010). As set forth in section 1-23-380 of the South Carolina Code, the Court may not substitute its own "judgment for the judgment of the [PSC] as to the weight of the evidence on questions of fact," but may reverse or modify the decision if the PSC's findings are "clearly erroneous in view of the reliable, probative, and substantial evidence on the whole record" or "arbitrary or capricious or characterized by abuse of discretion or clearly unwarranted exercise of discretion." S.C. Code Ann. § 1-23-380(5)(e)–(f) (Supp. 2020). "A decision by the [PSC] is arbitrary if it is without a rational basis, is based not upon any course of reasoning and exercise of judgment, is made at pleasure, without adequate determining principles, or is governed by no fixed rules or standards." *Daufuskie Island Util. Co. v. S.C. Office of Regul. Staff*, 427 S.C. 458, 464, 832 S.E.2d 572, 575 (2019) (internal alteration and quotation marks omitted) (citation omitted). Likewise, substantial evidence is "something less than the weight of the evidence, and the possibility of drawing two inconsistent conclusions from the evidence does not prevent an administrative agency's finding from being supported by substantial evidence." *Lark v. Bi-Lo, Inc.*, 276 S.C. 130, 136, 276 S.E.2d 304, 307 (1981) (citation omitted). "Because the [PSC's] findings are presumptively correct, the party challenging the [PSC's] order bears the burden of convincingly proving the decision is clearly erroneous, or arbitrary or capricious, or an abuse of discretion, in view of the substantial evidence of the record as a whole." *S.C. Energy Users Comm.*, 388 S.C. at 491, 697 S.E.2d at 590 (citation omitted).

III.

Return on Equity

a. Underlying Facts

Three witnesses testified about the proper ROE before the PSC: (1) David Parcell on behalf of the South Carolina Office of Regulatory Staff (ORS, one of the two respondents here); (2) Aaron Rothschild on behalf of the South Carolina Department of Consumer Affairs (the Department, the second respondent); and (3) Dylan D'Ascendis on behalf of Blue Granite. According to Parcell, the ROE is the "most difficult" portion of the rate of return to estimate, and experts therefore employ various analytical models to attempt to narrow down what an appropriate ROE might be. Thus, here, each witness used three models to calculate a reasonable ROE for Blue Granite. The results of their analyses under each model resulted in an ROE range, rather than a single number. Averaging the low results for each model and the high results for each model, Parcell calculated an overall ROE range of 7.7% to 8.36%; Rothschild calculated an ROE range of 7.46% to 8.75%; and D'Ascendis calculated an ROE range of 10.2% to 10.7%.[2]

In Blue Granite's previous ratemaking applications, the PSC had expressed concern that the utility's relatively-small size could make it a riskier investment and, therefore, required a higher ROE in order to attract investors. However, both Parcell and Rothschild strongly disagreed Blue Granite's small size automatically required a higher ROE.[3] Nonetheless, both witnesses based the remainder of their

---

[2] Following Parcell's and Rothschild's criticism of his calculations, D'Ascendis later revised his ROE range to 9.75% to 10.25%.

[3] For example, Parcell explained many small water utilities were subsidiaries of larger companies, and those smaller water utilities did not raise equity capital directly from their individual investors, but rather as part of a consolidated entity from the investors in the larger parent company. Thus, according to Parcell, smaller water utilities were not riskier merely because of their size, and did not require a correspondingly larger ROE to compensate for their small size because they were not a truly risky investment. Of note, Blue Granite is a wholly-owned subsidiary of Corix Regulated Utilities, Inc. (formerly known as Utilities, Inc.), one of the three largest private water and wastewater utility operators in the United States.

calculations on the high ends of the ranges for each model in recognition of the PSC's prior concerns.

More specifically, in generating his particular ROE recommendation, Parcell used the high values from two of his three models "in order to give some consideration to any perceived unique attributes of" Blue Granite, specifically, its relatively small size—although, as stated, he disagreed the size of the utility should affect its ROE. Likewise, Parcell discounted the results from his third model because they appeared "to be somewhat low at this time, relative to the" results from the other two models. Consequently, Parcell recommended an ROE range between 8.9% (the high result from one model) and 10% (the high result from the other model), ultimately selecting 9.45% as the midpoint of that range.

In contrast, Rothschild considered the results of all three of his selected models, using the high values of the ranges "primarily because this Commission expressed concern in [Blue Granite's 2018] rate case . . . regarding its size" and whether its relatively-small size made it a riskier investment, therefore requiring a higher ROE to attract investors. However, Rothschild recommended a slightly lower ROE than the average high result of his three chosen models (8.75%) because (1) Blue Granite had less financial risk than other water utilities due to having "more equity in its capital structure" following its recent reorganization; and (2) "its business risk ha[d] declined since its last rate case and therefor[e] its cost of capital ha[d] decreased as well."[4] As a result, Rothschild recommended an ROE of 8.65%.

Rothschild further explained the 8.65% figure was "on the high end of results to account for *the possibility* that [Blue Granite's] small size impact[ed] the return expectations required by investors." (Emphasis added.) Rothschild reiterated several times that he had seen no evidence—and, in fact, there seemed to be

---

Additionally, Parcell acknowledged that, on an overall market basis, it was true that smaller companies tended to be riskier investments. However, he stated that was "not the case for regulated utilities." Specifically, Parcell asserted that "*all public utilities operate in an environment with regional monopolistic power . . . . As a result, the business and financial risks are very similar among the utilities regardless of their size.*" (Emphasis added.)

[4] Moreover, according to Rothschild, "the cost of equity for utility companies [was] decreasing." Parcell similarly testified the current low-equity returns were "reflective of a decline in investor expectations of equity returns and risk premiums."

evidence to the contrary—that smaller companies had a higher cost of equity. Nonetheless, Rothschild stated, "*to be conservative*, to recognize *the possibility* that that's [the case,] I went to the higher end of my range." (Emphasis added.)

Before Rothschild was excused from the witness stand, one PSC Commissioner questioned why Rothschild had picked a specific number for his recommended ROE, rather than a range. Rothschild said he had provided ranges to other public utilities commissions in the past, but he was then usually asked to provide a single, specific number. Nonetheless, Rothschild explained, "to assume that [] this exercise is that precise is an excellent question, so I think you generally can't say it's 8.65 or 8.61. So there are various ranges that I do show in my testimony that I hope would help understand a range that's reasonable."

Rothschild additionally provided data from other major financial institutions that indicated returns on stock market investments generally ranged from 5.25% to 8.75% at the time. According to Rothschild, investments in the overall stock market were much riskier than investments in a utility of any size and, therefore, generally earned a higher ROE than an investment in a utility. He concluded, "It is unlikely that investors would expect to earn a higher return of equity for a cost[-]of[-]service regulated utility company than the overall stock market."

In its final order, the PSC considered and rejected D'Ascendis's testimony and ROE recommendation.[5] The PSC further found Rothschild to be the most credible witness, placing special emphasis on the fact that his analysis "was unique in that he included the use of both historical and forward-looking, market-based data." The PSC explained Rothschild's results from his three chosen analytical models "provide[d] an ROE in the range of 7.46% to 8.75%." Noting it was "[c]onsidering the quality of service issues known to exist with Blue Granite," the PSC concluded the "recommended ROE of 7.46% proposed by witness Rothschild" was appropriate.

---

[5] There is ample basis supporting the rejection of D'Ascendis's testimony. For example, after summarizing Parcell's and Rothschild's testimony in which they thoroughly discredited D'Ascendis, the PSC found D'Ascendis's calculations lacked "analytical transparency" and "statistical coherence." Having reviewed the record, the evidence firmly supports the PSC's extensive criticism of D'Ascendis's testimony, and we thus do not discuss the specifics of that testimony any further. *See* S.C. Code Ann. § 1-23-380(5) ("The court may not substitute its judgment for the judgment of the agency as to the weight of the evidence on questions of fact.").

b. Analysis

Blue Granite now argues an ROE of 7.46% is unsupported by the evidence in the record because Parcell and Rothschild both recommended a higher ROE. We disagree with the suggestion that the PSC was foreclosed as a matter of law from selecting an ROE within the range provided by the evidence. While the PSC was, of course, empowered to select a higher ROE in accordance with the witnesses' precise recommendations, the question before us is whether the ROE actually selected (7.46%) is supported by substantial evidence.

We find there is substantial evidence in the record supporting the PSC's decision. Specifically, the PSC found Rothschild's testimony to be the most credible, including when Rothschild testified there was no reason to artificially inflate the ROE simply because Blue Granite was a smaller utility—an opinion, we note, with which Parcell completely agreed. Thus, although Rothschild *and* Parcell testified they selected the high values of their ranges in deference to the PSC's prior concern that Blue Granite's size *could* affect its level of risk, the PSC apparently reevaluated and discarded that prior concern after hearing Rothschild's and Parcell's explanations for why such a concern was unwarranted. *See S. Bell Tel. & Tel. Co. v. Pub. Serv. Comm'n*, 270 S.C. 590, 610, 244 S.E.2d 278, 288 (1978) (Ness, J., concurring in part and dissenting in part) (noting the PSC is "not bound by its prior decisions, and it may re-examine and alter its previous findings as to reasonableness when conditions warrant"); 73A C.J.S. *Public Administrative Law and Procedure* § 352 (June 2021 Update) (explaining administrative agencies are not bound by stare decisis and may reevaluate their prior decisions so long as they rationally justify their change of position). Once the PSC's prior concern—that Blue Granite's small size could impact its cost of equity—was diminished, the testimony suggested the low end of the range from Rothschild's three models (7.46%) was equally justifiable to the high end of the range (8.75%).

Blue Granite contends the PSC had no authority to select an ROE other than the ones specifically recommended by either Rothschild (8.65%) or Parcell (9.45%). However, the precise number selected by the PSC need not come from a witness's specific recommendation, but may instead be determined from the totality of the evidence in the record before the agency. Here, the record supports the 7.46% ROE determination, as it is within the stated range calculated by Rothschild. Moreover, Rothschild testified selecting an ROE is not a precise exercise. Given the fact that, regardless of which model was used, Rothschild and Parcell calculated an ROE range rather than a precise number, and those numbers did not always overlap even when both experts used the same model, we see no reason to doubt Rothschild's testimony that selecting an ROE is not an exercise in precision.

Cf. In re Permian Basin Area Rate Cases, 390 U.S. 747, 790 & n.59 (1968) ("[N]either law nor economics has yet devised generally accepted standards for the evaluation of rate-making orders.").

Finally, the PSC specifically stated it set the ROE at the low end of the proffered ranges in an effort to incentivize Blue Granite to improve its admittedly-poor business practices, evidenced by the extensive customer complaints at the PSC hearings. As we previously stated in *Utilities Services of South Carolina*, the PSC is empowered to do so in appropriate circumstances, and there is nothing inherently wrong or punitive in the PSC choosing to follow that path here. *See Utils. Servs. of S.C., Inc.*, 392 S.C. at 105, 708 S.E.2d at 760. Rather, a utility's business practices and reputation are two of a number of factors the PSC may consider in selecting an appropriate ROE.[6]

As a result, because there is a basis on which a reasonable person could find a 7.46% ROE appropriate, the PSC's decision is supported by substantial evidence in the record, and we therefore affirm. *See Parker v. S.C. Pub. Serv. Comm'n*, 281 S.C. 22, 24, 314 S.E.2d 148, 149 (1984) ("We recognize that the [PSC's] interpretation of the evidence on this issue is not indisputable, but we cannot substitute our judgment for that of the [PSC] upon a question as to which there is room for a difference of intelligent opinion." (internal alteration and quotation marks omitted) (citation omitted)); *see also Hamm v. S.C. Pub. Serv. Comm'n*, 294

---

[6] Additionally, there were other factors present here that supported the PSC's decision to impose a lower ROE, including: (1) the ROEs and overall rate increases allowed to other similarly-sized utilities in the same general time frame; (2) the ROEs expected by investors in the overall (i.e., riskier) stock market; (3) the apparent lack of a need to artificially inflate the ROE of relatively-smaller utilities such as Blue Granite; (4) Blue Granite's decreased financial risk following its reorganization due to now having more equity in its capital structure; (5) Blue Granite's decrease in business risk since its last rate case, resulting in a decreased cost of capital; (6) the overall decreased cost of equity for utility companies; and (7) a "decline in investor expectations of equity returns and risk premiums." *See generally Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944) ("[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."); *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679, 692–93 (1923) ("A public utility . . . has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures," such as those earned in the overall stock market.).

S.C. 320, 323, 364 S.E.2d 455, 456 (1988) ("This Court is without authority to set aside an agency's judgment on a factual issue where there is evidence of record to support the agency's decision." (citation omitted)).

IV.

Storm Costs

a. Underlying Facts

Blue Granite sought allowance of $51,802 per year in costs associated with anticipated future storm damage—the amount incurred during the test year. ORS reviewed Blue Granite's storm costs for the past ten years and found the average yearly storm costs were only $28,320.51.[7] As a result, ORS proposed a downward adjustment to account for the unusually-high storm costs incurred in the test year.

In response, Blue Granite stated it was "not opposed to using a multi-year historical average of costs," but that it believed the average storm costs should be calculated from the last five years of data, rather than the ten years proposed by ORS.[8] However, ORS rejected using a five-year average, explaining:

> ORS has consistently used a ten [] year average when proposing normalization of storm costs in past rate proceedings . . . . This is a more representative method to ensure enough data is gathered and used over a reasonable period of time to form an accurate view of storm costs. Using a five [] year average as proposed by [Blue Granite] would not allow for significant outliers that occur due to fluctuations in annual costs to be determined and removed from the average. Using a ten [] year average allows for a more complete assessment of costs over time. Therefore, ORS recommends the Commission reject [Blue Granite's] proposal to use a five [] year average for the normalization of storm costs.

The PSC found use of a ten-year average more accurately reflected storm costs for each year than use of a five-year average. Additionally, the PSC found it had

---

[7] ORS excluded the highest and lowest values from the past ten years to account for the possibility that those extremes were statistical outliers.

[8] Were the PSC to adopt the five-year average, the allowed amount would have been $42,494, rather than the $28,320.51 proposed by ORS.

previously used a ten-year average in normalizing storm costs from a test year. Therefore, the PSC adopted ORS's proposed downward adjustment, finding the adjustment to be "just and reasonable."

b. Analysis

Blue Granite contends the PSC's decision to apply a ten-year average, rather than a five-year average, was arbitrary and capricious and unsupported by substantial evidence. We disagree. As explained by the PSC and ORS, using a larger sample size more accurately establishes the true average cost of storm damages to Blue Granite's system in any given year, thus providing a more accurate forecast in setting prospective rates for anticipated storm damages in years to come.

Moreover, in adopting the ten-year average, the PSC did not foreclose Blue Granite from seeking a deferred account for unusually high storm damages in future years. For example, in 2018, South Carolina was hit in back-to-back months with Hurricanes Florence and Michael, resulting in substantial costs to Blue Granite due to storm damages above and beyond the amount granted in its prior ratemaking proceeding. However, the PSC allowed Blue Granite to create a deferred account and recover those additional, unexpected expenses from its customers. Thus, even though the PSC used the ten-year average here, Blue Granite can request deferred accounting treatment in the event of unusually high storm costs in the future. *See Porter v. S.C. Pub. Serv. Comm'n*, 328 S.C. 222, 231–32, 493 S.E.2d 92, 97–98 (1997) (explaining that in the event a utility experiences expenses that are truly "extraordinary," i.e., "unanticipated and non-recurring," the PSC should allow the utility to create a deferred account for those expenses and amortize the expenses in calculating the rate base in the utility's next ratemaking application).

Accordingly, we find the PSC's decision to use a ten-year average to normalize storm costs was neither arbitrary nor capricious, nor unsupported by substantial evidence. We therefore affirm the PSC's decision as to this issue.

V.

Greenville Office Expenses

a. Underlying Facts

Until 2018, Blue Granite/CWS owned an office building located in an industrial park in West Columbia. That office building cost ratepayers $27,260 annually for things such as water, sewer, electric, gas, landscaping, and property taxes.

However, according to Blue Granite, the location had no other office buildings or amenities nearby, so it was not a "viable location" to retain highly-qualified employees. Likewise, Blue Granite conceded that "[a]ttracting talent in the [West] Columbia market [was] extremely difficult [for the utility] due to the legacy brand issues in that market," including CWS's abysmal reputation for customer service and wastewater leaks. Therefore, in 2018, when changing its name from CWS to Blue Granite, the utility decided to relocate its headquarters, selling the West Columbia building and removing the $27,260 in annual expenses from its rate base.

Blue Granite then explored three alternate locations for its headquarters: Greenville, Columbia, and West Columbia. In selecting the new location, Blue Granite analyzed the labor statistics (also known as CBRE data[9]) in all three cities. According to Blue Granite, the CBRE data was the most favorable in Greenville, and the utility therefore opted to locate its new headquarters there, renting prime office space downtown at the historic Family Court building on South Main Street.

The yearly rent for Blue Granite's new Greenville office space was $73,665—almost triple the $27,260 annual cost of office space in West Columbia. Moreover, the $73,665 annual rent in Greenville's prime real estate market stood in stark contrast to the $11,174 in yearly, combined rental expenses for Blue Granite's other five locations throughout the state.[10] Equally perplexing, the new Greenville office required extensive upgrades to make it a functional office space, including things such as new drywall, paint, telephone ports, wiring, and office furniture. While Blue Granite repeatedly claimed that its new office was "not luxurious or gold-plated," the upfit expenses totaled approximately $500,000 for an office space intended to house only ten employees.

At the PSC hearing, ORS contested the Greenville office upfit and rental expenses. As to the $500,000 in upfit expenses, ORS contended the amount was unreasonably incurred by Blue Granite. In particular, ORS pointed to a letter from the utility to its customers explaining the name change from CWS to Blue Granite. In that letter, Blue Granite stated it was "refreshing [its] brand *at no cost to [its]*

---

[9] CBRE stands for Coldwell Banker Richard Ellis Group, Inc., an American commercial real estate services and investment firm.

[10] These locations included an office and warehouse in Rock Hill, an office in Anderson, a Water Service Corporation public storage unit, and a Water Service Corporation office.

customers to reflect [its] legacy and to showcase [its] new direction." (Emphasis added.) ORS explained:

> [Blue Granite] reasons that legacy brand issues diminished the Company's ability to acquire talented workers in the [West] Columbia market. The Company asserts its rebranding and relocation were aimed to alleviate the Company's talent acquisition issues. The Company represented to its customers that the refreshing of the Company's brand would be at no cost to them and is now contradicting that representation by attempting to pass on to customers relocation and office upgrade costs that were part of its rebranding.
>
> The long-term issues that caused the Company's brand to hinder talent acquisition in the [West] Columbia area [are] not the fault of customers. Nor is the former location of the Company's headquarters in [West] Columbia the cause of any talent acquisition problems. Such problems were caused by the Company, not its location.

ORS pointed out the new office space "contain[ed] many amenities for employees such as the premium location in a historic building, luxury office finishes and appointments, high-end office furniture, large communal spaces, and an overall large footprint relative to the small number of employees." Thus, ORS concluded, the upfit expenses were unreasonable and "difficult to explain to customers that struggle[d] to pay their water and sewer bills."

Likewise, as to the rental expenses, ORS argued (1) the rental expenses were for a "premium" space in the most expensive area of town, rather than a merely functional space in a more modestly-priced area; and (2) the PSC should "thoroughly review[]" the costs associated with "office relocation and office rent . . . to ensure [Blue Granite] took steps to minimize cost[s]" to the ratepayers.

Additionally, ORS took issue with the rental expenses due to inconsistencies in the CBRE data relied upon by Blue Granite in selecting Greenville for its new headquarters location, rather than Columbia or West Columbia. In particular, CBRE scores are inverted, such that a score above 100 indicates a market with overall lower costs than the national average. ORS stated the CBRE scores provided by Blue Granite for all three prospective locations were above 100, with Greenville scoring 105, Columbia scoring 103, and West Columbia scoring 101. Critically, however, in generating the CBRE scores, Blue Granite used different criteria for Greenville and Columbia as compared to West Columbia. Specifically, Blue Granite "used a 20-mile radius to evaluate market metrics for Columbia and Greenville, whereas [it] used a 10-mile radius for West Columbia." Blue Granite made no attempt to explain why it used different criteria to evaluate the labor market around West Columbia, stating only it "no longer had access to the CBRE database." ORS admitted it would be difficult to say how the different radii would impact the scores, although the smaller 10-mile radius excluded the potential workforces in Blythewood, Chapin, and portions of Lexington, among other municipalities that would have been included if Blue Granite had used a 20-mile radius as it did with Greenville and Columbia. Likewise, ORS stated "that the 2- to 4- point difference in [s]cores d[id] not justify the high cost to relocate [] and upfit the Company's new office [or pass those costs along to Blue Granite's] customers."

Finally, ORS pointed out the incongruity of locating the new office in Greenville, where only 2.6% of Blue Granite's customers lived, rather than in Lexington County or York County, where 43% and 38.6% of Blue Granite's customers lived, respectively. Moreover, apparently, Blue Granite did not even evaluate the CBRE scores for Rock Hill or Anderson, despite already having offices in those locations. Likewise, even in comparing only Greenville, Columbia, and West Columbia, Blue Granite witnesses could not say whether the utility had considered or compared office space prices in the three locations, or only labor statistics.

Ultimately, the PSC concluded that "the Greenville move and its resulting rent and upfit costs are directly and ca[us]ally related to Blue Granite rebranding itself," not mere talent acquisition issues. The PSC cited the testimony of a Blue Granite witness who stated "Blue Granite's relocation and lease of Greenville office space was due to legacy brand issues which were caused by the Company itself," and "attracting talent in the Columbia market has been extremely difficult due to the legacy brand issues in that market." Thus, the PSC found the upfit expenses were unreasonably incurred, stating "Blue Granite's customers should not have to pay the cost to upfit the Greenville office, given the move was necessitated by legacy brand problems the Company created."

The PSC additionally disallowed all rental expenses for the Greenville office ($73,665), explaining those expenses also stemmed from Blue Granite's legacy brand issues. The PSC therefore concluded the rental expenses were unreasonable and denied them in their entirety.

b. Analysis

Blue Granite now argues the PSC's disallowance of upfit and rental expenses was arbitrary and capricious and unsupported by substantial evidence in the record. Regarding the upfit expenses, we disagree. However, we agree the complete disallowance of rental expenses amounts to reversible error.

As to the upfit expenses, there is a wealth of evidence in the record supporting the PSC's finding that the headquarters relocation was caused by Blue Granite's self-created "legacy brand issues," and not merely by its employee-retention problems. In fact, as quoted in the PSC's order, Blue Granite itself conceded that its employee-retention problems were caused, at least in part, by the utility's poor reputation in the community. We therefore hold the PSC's finding—that "Blue Granite's customers should not have to pay the cost to upfit the Greenville office, given the move was necessitated by legacy brand problems the Company created"—is supported by substantial evidence.

Similarly, we find the PSC's decision to deny the upfit costs was not arbitrary or capricious, and that the upfit costs were unreasonably incurred. First, Blue Granite promised its customers its rebranding would come at no cost to them. Because there is substantial evidence in the record tending to show the rebranding required moving the utility's headquarters, the upfit costs associated with that headquarters relocation also directly stemmed from the rebranding. The PSC's decision to hold Blue Granite to its promise not to pass along rebranding costs to its customers was in no way whimsical or irrational.

Second, we find the amount of upfit costs incurred was entirely unreasonable, particularly for a small utility such as Blue Granite. Blue Granite chose to move to a historic building that required extensive modernization to turn it into a functional office space. The utility produced no evidence that it attempted to evaluate the cost of other potential office locations in Greenville, much less that other potential locations would have required similar upfit expenses.[11] It is, of course, not unreasonable for Blue Granite to want to provide its executives opulent offices as a job perk. However, as the PSC found, it is unacceptable to pass the costs

---

[11] Likewise, it is unclear from the record why, for example, the office furniture from the West Columbia office could not be reused in the new Greenville office, rather than buying new "high-end office furniture."

associated with that opulence on to ratepayers, who receive no quantifiable benefit from an expenditure of that type. We therefore find the PSC's decision to deny the upfit expenses was not arbitrary or capricious.

As to the rental expenses, we first express our concern that, upon realizing it might be necessary to relocate the utility's headquarters, Blue Granite's management made the decision to rent some of the highest-priced real estate in Greenville—and did so after trying to disassociate itself from the poor public perception of CWS and its business practices. The decision to rebrand the company while simultaneously moving into an unnecessarily-expensive office location is yet another example of Blue Granite self-inflicting wounds to its reputation and requesting its customers reimburse it for the associated expense. We find there is overwhelming evidence in the record to support the PSC's refusal to allow the full amount of the rental expenses requested, as the rental expenses—like the upfit costs—stemmed directly from Blue Granite's poor reputation and subsequent effort to rebrand itself.

However, notwithstanding Blue Granite's regrettable reputation in the community, we find it was arbitrary and capricious for the PSC to entirely deny *all* rental expenses. While the decision of the PSC to disallow the requested $73,665 for rental expenses is supported by the evidence, Blue Granite is entitled to collect from ratepayers some reasonable amount for its headquarters office rental. After all, neither ORS nor the Department object to allowing Blue Granite some sort of reasonable rental rate.

We therefore reverse the PSC's decision to deny all rental expenses for the Greenville office and remand for additional proceedings to determine what a reasonable amount of yearly office rental expenses would be. The burden remains on Blue Granite to establish a reasonable rental allowance. Should Blue Granite continue to rely on CBRE data, Blue Granite must produce comparable CBRE data for Greenville, Columbia, West Columbia, Rock Hill, and Anderson—the three original, prospective locations plus the locations of its two existing offices—including using an identical geographical radii for each city. Moreover, it is incumbent upon Blue Granite to present evidence of reasonable rental amounts for similarly-sized offices, regardless of their location in Greenville or throughout the state. We find it highly likely there are a number of alternate office locations—in Greenville and elsewhere—that would demand significantly less in yearly rental expenses than a historic building on South Main Street.[12] Such a consideration is

[12] We find this to be particularly true given that the Greenville office rental expenses are six to seven times the amount of rental expenses for all of Blue

crucial for a utility that serves the public, and for whom the public ordinarily is required to pay for office expenses, rent or otherwise.

We therefore affirm the PSC's disallowance of upfit expenses, but reverse and remand the PSC's disallowance of office rental expenses. On remand, the PSC shall determine a reasonable rental allowance for Blue Granite's headquarters.

VI.

Stay of Bond

a. Underlying Facts

Following the PSC's denial of Blue Granite's motion for reconsideration, the utility filed a motion pursuant to section 58-5-240(D) of the South Carolina Code (2015), which provides, in relevant part, that if the PSC issues a ruling,

> and the utility shall appeal from the order, by filing with the Commission a petition for rehearing, the utility may put the rates requested in its schedule [(i.e., its original application to the PSC for ratemaking)] into effect under bond only during the appeal and until final disposition of the case. *Such bond must be in a reasonable amount approved by the Commission*, with sureties approved by the Commission, conditioned upon the refund . . . to the persons . . . entitled to the amount of the excess, if the rate or rates put into effect are finally determined to be excessive; *or there may be substituted for the bond other arrangements satisfactory to the Commission for the protection of parties interested. . . .*

(Emphasis added.) Via directive—rather than formal, written order—the PSC unanimously voted to approve Blue Granite's proposed appellate bond.

Shortly thereafter, the Department filed a letter with the PSC seeking clarification as to whether Blue Granite was permitted to implement the rates under bond the following month, as the utility had informed its customers it intended to do.

Granite's other office locations combined. Additionally, although not directly relevant to the rental expenses issue, it seems equally likely that many alternate office locations in Greenville would have required significantly less in upfit costs as well, demonstrating again that the PSC's decision to deny the upfit expenses was not arbitrary or capricious.

Specifically, the Department was concerned the bond had only been approved via directive, rather than a written order, and therefore the decision might not be final. The Department also raised concerns about the impact the new rates-under-bond would have on Blue Granite's customers during the coronavirus pandemic, and offered alternatives to the immediate implementation of the bond.

The PSC subsequently issued an order staying Blue Granite's ability to implement the higher rates under bond until further notice and scheduled oral arguments on the matter. Three days before the arguments, Blue Granite filed a Conditional Petition for Approval of an Accounting Order. In that petition, Blue Granite stated denying it the ability to implement higher rates under bond would constitute an unconstitutional taking. However, according to Blue Granite,

> *There are two possible remedies to avoid an unconstitutional taking.* The preferred remedy, which would result in the least customer confusion and future rate impact, is to lift the stay and permit the Company to implement the rates under bond for which the Company's customers are on notice. *An alternative remedy is to grant the instant deferral request.*

(Emphasis added.) More specifically, Blue Granite proposed the PSC allow the utility to create a deferred account for a regulatory asset that would increase at a rate of $5,970 per day—the difference between the rates approved in the PSC's order on reconsideration and the rates originally requested in Blue Granite's application. Then, assuming Blue Granite prevailed on appeal, it would be able to recover the amount in the deferred account in a future ratemaking case.

Following oral arguments, the PSC maintained the stay on Blue Granite's ability to implement the higher rates under bond, but granted the utility's alternative request for the creation of a deferred account. Blue Granite moved for reconsideration, arguing:

> Establishment of the regulatory asset authorized by the Commission in the August 31, 2020 directive is an inadequate remedy. . . . [U]nlike implementing rates under bond, future recovery of a regulatory asset is not guaranteed, and it is therefore not a substitute for implementing rates under bond. . . . While the regulatory asset was necessary to protect the Company's potential ability to recover the revenues to which it is entitled, there is no adequate substitute for the Commission issuing final approval of the bond and permitting the Company to implement rates under bond.

The PSC denied the motion for reconsideration, noting "Blue Granite offered the accounting order as a[n] alternative to putting rates in effect under bond, while at the same time, waiving any objection to the continuing Stay."

b. Analysis

Blue Granite now raises a number of arguments as to why the PSC's decision to stay the bond was improper. However, we find the issue is moot and, therefore, decline to address the merits of the utility's arguments.

Blue Granite proposed two remedies that it originally contended would prevent an unconstitutional taking: (1) implement the rates under bond, or (2) grant the deferred accounting request. The PSC chose the second option. Blue Granite therefore received the relief it requested, and there is nothing further for the Court to decide as to the propriety of one remedy over the other. *See, e.g., State v. Parris*, 387 S.C. 460, 465, 466, 692 S.E.2d 207, 209, 210 (Ct. App. 2010) ("When the defendant receives the relief requested from the trial court, there is no issue for the appellate court to decide." (citing *State v. Sinclair*, 275 S.C. 608, 610, 274 S.E.2d 411, 412 (1981))). The fact that Blue Granite has now changed its mind and decided the deferred accounting option is an "inadequate remedy" is of no consequence. *Cf. McLeod v. Starnes*, 396 S.C. 647, 657, 723 S.E.2d 198, 204 (2012) ("A party may not argue one ground at trial and an alternate ground on appeal." (citation omitted)). We therefore affirm the PSC's decision as to this issue.

VII.

The Victory Tweet

As a final matter, Blue Granite discusses a social media post on the PSC's official Twitter account. Specifically, following the issuance of the PSC's final order, the Department posted a "victory tweet" on Twitter, sharing its excitement that Blue Granite failed to prevail on its request for a substantial rate increase, and that the decision was a win for consumers during the midst of the coronavirus pandemic. A gloating victory tweet by a prevailing party may be unbecoming, but it is understandable. Regrettably, the PSC then retweeted the victory tweet on its own official account, reveling in the defeat of Blue Granite's requested rate increase. As a quasi-judicial body, the PSC's retweet was inappropriate. The PSC must not only be fair and impartial, it must be diligent in its duty to avoid the appearance of impropriety. While we are confident that no commissioner of the PSC sanctioned the publication of the victory tweet, we trust the PSC will give more care and consideration to its social media posts in the future. Regardless, we have thoroughly reviewed the record and find the PSC's extensive questioning and diligence throughout Blue Granite's ratemaking proceeding reflects its commitment to fairly and impartially decide this application for a rate increase. When we consider the conscientious manner in which the PSC handled this complicated proceeding, together with its proper and detailed order, we commend the PSC. We therefore do not find the retweet a basis to reverse the PSC's entire final decision.

VIII.

In conclusion, we affirm the PSC's decision in part and reverse in part. Specifically, we affirm the PSC's decisions as to the ROE, storm costs, Greenville office upfit expenses, and stay of an appellate bond.[13] We reverse the PSC's decision to deny all rental expenses for Blue Granite's new headquarters and remand to the agency for further consideration of what a reasonable rental allowance should be.[14]

AFFIRMED IN PART, REVERSED IN PART, AND REMANDED.

BEATTY, C.J., HEARN, FEW and JAMES, JJ., concur.

---

[13] While Blue Granite also initially raised a question as to the PSC's treatment of the allowance for non-revenue water, the utility conceded the issue at oral argument. We therefore affirm the PSC's decision as to Blue Granite's non-revenue water allowance.

[14] Blue Granite challenges three additional issues that were not contested by either respondent before the PSC or on appeal: whether the PSC erred in (1) amortizing its annual water and wastewater service expenses that it purchased in the test year from third parties; (2) disallowing recovery of legal expenses incurred in prior cases filed and then later voluntarily withdrawn by Blue Granite; and (3) disallowing recovery of legal expenses related to administrative law court proceedings dealing with Blue Granite's I-20 system. The PSC's order does not contain sufficient findings of fact or analysis to allow us to evaluate the merits of these issues on appeal. As a result, we reverse and remand these issues as well.

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Ameren Illinois Company	**:**	
d/b/a Ameren Illinois	**:**	
	:	**21-0365**
Rate MAP-P Modernization Action Plan -	**:**	
Pricing Annual Update Filing.	**:**	

<u>ORDER</u>

December 13, 2021

TABLE OF CONTENTS

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Ameren Illinois Company	:	
d/b/a Ameren Illinois	:	
	:	**21-0365**
Rate MAP-P Modernization Action Plan -	:	
Pricing Annual Update Filing.	:	

ORDER

By the Commission:

I. INTRODUCTION

Section 16-108.5 of the Public Utilities Act ("Act"), the Energy Infrastructure Modernization Act ("EIMA"), provides that an electric utility or combination utility (providing electric service to more than one million customers in Illinois and gas service to at least 500,000 customers in Illinois) may elect to become a "participating utility" and voluntarily undertake an infrastructure investment program described in that section. 220 ILCS 5/16-108.5(b). A participating utility is allowed to recover its expenditures made under the infrastructure investment program through the ratemaking process, including, but not limited to, the performance-based formula rate and process set forth in Section 16-108.5. *Id*. The performance-based formula rate shall be implemented through a tariff that is consistent with the provisions of subsection (c) of the EIMA and with Commission practice and law. 220 ILCS 5/16-108.5 (c).

Section 16-108.5(d) of the Act requires a participating utility to file, on or before May 1 of each year, with the Chief Clerk of the Commission, its updated cost inputs to the performance-based formula rate for the applicable rate year and the corresponding new charges, based on final historical data reflected in the utility's most recently filed annual Federal Energy Regulatory Commission ("FERC") Form 1, plus projected plant additions and correspondingly updated depreciation reserve and expense for the calendar year in which the inputs are filed. 220 ILCS 5/16-108.5(d).

On January 3, 2012, Ameren Illinois Company d/b/a Ameren Illinois ("AIC", "Ameren Illinois," or "the Company") filed with the Commission its performance-based formula rate tariff, Rate MAP-P Modernization Action Plan—Pricing Tariff ("Rate MAP-P"), initiating Docket No. 12-0001. That docket established the terms of the formula.

On April 15, 2021, AIC filed its 10th annual update of cost inputs pursuant to Section 16-108.5(d) of the Act, initiating this docket. In this docket, the Commission will establish a new revenue requirement to take effect on the first billing day of January 2022, based on the historical FERC Form 1 reports for 2020 and projected plant additions for 2021, and reconcile the revenue requirement in effect for 2020 with actual costs for 2020. The reconciliation balance will be added to the new revenue requirement and collected in rates beginning on the first billing day of the January billing period following the date of the Final Order in this proceeding.

In addition to AIC, Staff of the Commission ("Staff"), the Office of the Illinois Attorney General ("AG"), and the Citizens Utility Board ("CUB") participated in this proceeding.

An evidentiary hearing was held before a duly-appointed Administrative Law Judge ("ALJ") in this matter on September 8, 2021. AIC, Staff, and the AG submitted testimony and other evidence at the evidentiary hearing. After the evidentiary hearing, the record was marked "Heard and Taken."

At the time of the evidentiary hearing, four issues remained contested among the parties: Cash Working Capital – Electric Distributions Tax ("EDT"), Cash Working Capital – Other Post-Employment Benefits ("OPEB") Expense, Amortization of Excess Deferred Income Tax ("EDIT"), and Capital Structure. On September 28, 2021, AIC, Staff, the AG, and CUB filed Initial Briefs on the contested issues, and on October 12, 2021, the same parties filed Reply Briefs. On October 13, 2021, AIC, Staff, the AG, and CUB had the option of filing Statements of Position and Suggested Conclusions on the contested issues, and jointly filed a Limited Agreed Draft Order on all other issues, for the ALJ's consideration.

A Proposed Order was served on the parties on November 4, 2021. Briefs on Exceptions were filed by all parties on November 18, 2021. The AG was the only party to request oral argument. Due to the deadline in this proceeding, the schedule did not allow for the filing of Reply Briefs on Exceptions.

II. LEGAL STANDARD

The provisions of EIMA, specifically Section 16-108.5 (c), provides in relevant part:

> The performance-based formula rate shall be implemented through a tariff filed with the Commission consistent with the provisions of this subsection (c) that shall be applicable to all delivery services customers. The Commission shall initiate and conduct an investigation of the tariff in a manner consistent with the provisions of this subsection (c) and the provisions of Article IX of this Act to the extent they do not conflict with this subsection (c). Except in the case where the Commission finds, after notice and hearing, that a participating utility is not satisfying its investment amount commitments under subsection (b) of this Section, the performance-based formula rate shall remain in effect at the discretion of the utility. The performance-based formula rate approved by the Commission shall do the following:
>
> (1) Provide for the recovery of the utility's actual costs of delivery services that are prudently incurred and reasonable in amount consistent with Commission practice and law. The sole fact that a cost differs from that incurred in a prior calendar year or that an investment is different from that made

> in a prior calendar year shall not imply the imprudence or unreasonableness of that cost or investment.

220 ILCS 5/16-108.5 (c).

Section 16-108.5(d), provides in relevant part:

> Subsequent to the Commission's issuance of an order approving the utility's performance-based formula rate structure and protocols, and initial rates under subsection (c) of this Section, the utility shall file, on or before May 1 of each year, with the Chief Clerk of the Commission its updated cost inputs to the performance-based formula rate for the applicable rate year and the corresponding new charges.

220 ILCS 5/16-108.5(d).

Section 16-108.5(d) further specifies the requirements for this annual filing as follows:

> Within 45 days after the utility files its annual update of cost inputs to the performance-based formula rate, the Commission shall have the authority, either upon complaint or its own initiative, but with reasonable notice, to enter upon a hearing concerning the prudence and reasonableness of the costs incurred by the utility to be recovered during the applicable rate year that are reflected in the inputs to the performance-based formula rate derived from the utility's FERC Form 1. During the course of the hearing, each objection shall be stated with particularity and evidence provided in support thereof, after which the utility shall have the opportunity to rebut the evidence. Discovery shall be allowed consistent with the Commission's Rules of Practice, which Rules shall be enforced by the Commission or the assigned hearing examiner. The Commission shall apply the same evidentiary standards, including, but not limited to, those concerning the prudence and reasonableness of the costs incurred by the utility, in the hearing as it would apply in a hearing to review a filing for a general increase in rates under Article IX of this Act.
>
> . . .
>
> In a proceeding under this subsection (d), the Commission shall enter its order no later than the earlier of 240 days after the utility's filing of its annual update of cost inputs to the performance-based formula rate or December 31.
>
> . . .
>
> A participating utility's first filing of the updated cost inputs, and any Commission investigation of such inputs pursuant to

> this subsection (d) shall proceed notwithstanding the fact that the Commission's investigation under subsection (c) of this Section is still pending and notwithstanding any other law, order, rule, or Commission practice to the contrary.

Id.

Section 16-108.5(d) further specifies the requirements for the reconciliation filing as follows:

> The filing shall also include a reconciliation of the revenue requirement that was in effect for the prior rate year (as set by the cost inputs for the prior rate year) with the actual revenue requirement for the prior rate year (determined using a year-end rate base) that uses amounts reflected in the applicable FERC Form 1 that reports the actual costs for the prior rate year. Any over-collection or under-collection indicated by such reconciliation shall be reflected as a credit against, or recovered as an additional charge to, respectively, with interest calculated at a rate equal to the utility's weighted average cost of capital approved by the Commission for the prior rate year, the charges for the applicable rate year. Provided, however, that the first such reconciliation shall be for the calendar year in which the utility files its performance-based formula rate tariff pursuant to subsection (c) of this Section and shall reconcile (i) the revenue requirement or requirements established by the rate order or orders in effect from time to time during such calendar year (weighted, as applicable) with (ii) the revenue requirement determined using a year-end rate base for that calendar year calculated pursuant to the performance-based formula rate using (A) actual costs for that year as reflected in the applicable FERC Form 1, and (B) for the first such reconciliation only, the cost of equity, which shall be calculated as the sum of 590 basis points plus the average for the applicable calendar year of the monthly average yields of 30-year U.S. Treasury bonds published by the Board of Governors of the Federal Reserve System in its weekly H.15 Statistical Release or successor publication. The first such reconciliation is not intended to provide for the recovery of costs previously excluded from rates based on a prior Commission order finding of imprudence or unreasonableness. Each reconciliation shall be certified by the participating utility in the same manner that FERC Form 1 is certified. The filing shall also include the charge or credit, if any, resulting from the calculation required by paragraph (6) of subsection (c) of this Section.

> Notwithstanding anything that may be to the contrary, the intent of the reconciliation is to ultimately reconcile the revenue requirement reflected in rates for each calendar year, beginning with the calendar year in which the utility files its performance-based formula rate tariff pursuant to subsection (c) of this Section, with what the revenue requirement determined using a year-end rate base for the applicable calendar year would have been had the actual cost information for the applicable calendar year been available at the filing date.

Id.

III. AIC'S PROPOSED REVENUE REQUIREMENT

AIC's proposed rebuttal net revenue requirement for AIC's electric formula rate (after consideration of the filing year and reconciliation year revenue requirements, with interest and the return on equity collar) is $1,021,411,000. AIC's proposed update to its formula rate delivery service revenue requirement results in an increase of $60,166,000 (6.23%) from the electric revenue requirement ordered by the Commission in Docket No. 20-0381 ("Ameren 2020 FRU"). The rebuttal net revenue requirement calculations use a rate of return ("ROR") of 5.850% for the filing year and 5.813% in the reconciliation year. The rebuttal net revenue requirement calculations reflect the revenue requirement for the filing year of $1,011,853,000, the reconciliation adjustment of ($22,447,000), and the return on equity ("ROE") adjustment of $31,675,000.

IV. RATE BASE

A. Uncontested or Resolved Issues

1. Asset Separation Program ("ASP") Corrections

Staff proposed an adjustment to reflect the correction to AIC's ASP for asset 399-IL-AIC-Electric Intangible, changing the allocator from E. Distribution to OMTD. The Company agreed to Staff's proposed adjustment and additional adjustments for revisions to the allocation of certain other items of general and intangible plant ("G&I Plant"). Collectively this has resulted in a modification to the G&I Plant allocator for Electric Distribution from 70.78% to 70.59%. AIC reflected these corrections in its rebuttal schedules, Ameren Exhibit 11.1, Sch FR A-2.

The Commission finds that the proposed corrections to the ASP are uncontested and therefore adopts the proposed corrections for use in this proceeding.

2. Cash Working Capital – Other than Electric Distribution Tax

The parties agree on the methodology to calculate Cash Working Capital ("CWC") for the final revenue requirements ordered by the Commission in the instant case, and for all leads and lags, except for the Electric Distribution Tax, which remains contested by Staff and the AG. On rebuttal, AIC agreed to Staff and the AG's correction to the calculation of lead days (except Electric Distribution Tax).

In testimony, Staff proposed to include OPEBs in revenues and expenses for the Filing Year and Reconciliation Year CWC calculations. In AIC's Surrebuttal Testimony, the Company noted that it accepted Staff's calculation of OPEB expense in CWC for purposes of narrowing issues in this matter. The AG previously contested the Company's position regarding OPEB expense in CWC; however, in its Initial Brief, the AG stated it does not object to Staff's CWC calculation for OPEB expense for purposes of narrowing the issues in this proceeding. Furthermore, in its Statement of Position, the AG indicated that it does not object to Staff witness Pearce's CWC calculation of OPEB expense in this proceeding, which the Company accepted in its surrebuttal testimony.

With the exception of the contested CWC EDT issue, no other party opposes the calculation of CWC.

Subject to its determination on the Electric Distribution Tax, the Commission finds that the agreed amount of CWC is reasonable and uncontested, and therefore adopts the parties' agreed amount of CWC.

3. Performance Share Unit Program ("PSUP") Adjustment – Correction of Ameren Service Company ("AMS") Expense/Capital Split

The AG proposed a correction to the Company's ratios for expense and capital for AMS costs. In response to data request AG 4.01, AIC provided the correction to the AMS ratios for expense and capital on Schedules B-2.6 and C-2.9 which is an increase to Rate Base of $138,000 and a decrease to operating expense of $220,000.

The Commission finds that the agreed-upon proposed corrections to the PSUP Adjustment are uncontested and therefore adopts the proposed corrections for use in this proceeding.

4. Tree Risk Management Program Deferral

Staff proposed certain adjustments to reflect the 2020 Tree Risk Management program costs as repairs and maintenance expense rather than as Rate Base deferred charge subject to amortization. AIC agreed and reflected these corrections in its surrebuttal schedules, Ameren Exhibits 13.3. Ameren Exhibit 13.2, page 9 presents an updated Part 285, Schedule B-10 with the regulatory assets approved by the Commission for deferral and the corresponding amortization periods.

The Commission finds that the agreed-upon proposed corrections to the 2020 Tree Risk Management program are uncontested and therefore adopts the proposed corrections for use in this proceeding.

B. Contested Issues

1. Cash Working Capital – Electric Distribution Tax

a. AIC's Position

AIC notes that in Ameren 2020 FRU, the Commission found that credit memoranda related to the EDT affect Ameren Illinois's cash flows and Ameren Illinois should include the impact of receipt of those credit memoranda in its CWC determination. AIC explains that by including the credit memoranda, the EDT lead/lag analysis more accurately reflects the Company's actual cash flow experience and provides a more accurate analysis of cash receipts and cash outflows." Ameren 2020 FRU, Order at 13 (December

9, 2020). AIC argues that consistent with that finding, it is proposing to include the impact of receipt of EDT credit memoranda in its CWC determination.

AIC notes that in Ameren 2020 FRU, the Commission adopted the methodology proposed by Staff, stating "The Commission agrees with Staff that since calendar year 2019 is the year that was used for purposes of the lead lag study, and the purpose of including the credit memorandum is to get a more accurate lead/lag analysis, it is appropriate to use the items that impacted payments during the period that was used as the basis of the study." Ameren 2020 FRU, Order at 12.

AIC notes that in this case, Ameren Illinois and Staff agree that Ameren Illinois' credit memoranda should be included in the determination of CWC, and so the 2019 credit memorandum is the proper credit memo to use for CWC analysis. According to AIC, the AG proposes a method that considers only the required estimated payment dates and does not reflect the EDT credit memoranda. AIC argues that as this method does not reflect the Commission's decision in Ameren 2020 FRU, it should be rejected.

AIC notes that the Company and Staff disagree, however, on the specific methodology to reflect the credit memo, and each propose modifications to the methodology approved by the Commission in Ameren 2020 FRU. In particular, Staff and Ameren Illinois disagree on the appropriate service period to reflect in the calculations. AIC contends that as explained below, the Commission should approve use of a service period that reflects the tax year that the credit memorandum was based upon (calendar year 2018). AIC argues that, as its evidence in this docket shows, approximately 11% of Ameren Illinois' EDT payments in the 2018 tax period represent a prepayment, which is later returned via the credit memorandum. Thus, AIC argues, its proposal most accurately reflects the cash flows associated with the credit memo process.

AIC witness Weiss testified that CWC represents the funds necessary to finance a utility's day-to-day operations. Mr. Weiss noted that CWC bridges the gap between the time when funds are provided to the Company by investors to allow the Company to provide service to customers, and the time revenues are received from customers as reimbursement for that service. Ameren Ex. 6.0 at 3. Mr. Weiss further explained that CWC is included in rate base to compensate those investors for the use of the funds required by the Company for daily operations. Mr. Weiss explained that in order to determine how much cash is necessary to meet operating expenses, the Company must understand the timing of its cash inflows and outflows. Mr. Weiss explained that AIC uses a "lead-lag" study to assess the differences between the revenue lags and expense leads. *Id*.

AIC witness Stafford testified that AIC's proposed treatment of EDT follows the Ameren 2020 FRU Order's methodology with respect to the year of the credit memorandum applied. Ameren Ex. 1.0 (Rev.) at 55. In addition to the four quarterly installment payments for EDT in 2020, the Company's lead lag study reflects the actual EDT credit memorandum received in December 2019 and applied in 2020. Mr. Stafford testified that by including the credit memorandum, the EDT lead/lag analysis more accurately reflects the Company's actual cash flow experience and thus provides a more accurate analysis of cash receipts and cash outflows. *Id*.

Mr. Stafford explained that EDT is a tax that Illinois law imposes on utilities, like Ameren Illinois, that distribute electricity in the state, based on the volume of kilowatt-hours ("kwh") the utility sells in a year. *Id.*; *see* 35 ILCS 620/1 *et seq*. Mr. Stafford testified that the tax is paid in four quarterly installments on the 15th of March, June, September, and December each year. 35 ILCS 620/2a.2. Mr. Stafford further explained that the first payment includes a true-up for the prior year. Mr. Stafford testified that although he is not an attorney, his understanding is that the law also provides for a credit if the state collects more than a cap set forth in the statute, which is set forth in a "credit memorandum." 35 ILCS 620/2a.1(c).

Mr. Stafford testified that in March of each year, the law requires the Company to file a return, Form ICT-4, Electricity Distribution and Invested Capital Tax Return, with the Illinois Department of Revenue ("IDOR") on which AIC states the number of kwh it distributed in the taxable period (the prior calendar year - Year 0). Ameren Ex. 1.0 (Rev.) at 55-56. Mr. Stafford explained that in the year the return is filed (Year 1), the utility makes quarterly payments equal to one-fourth the total number of kwh distributed in Year 0, multiplied by the tax rate in Year 0; and in March of the following year (Year 2), AIC will again file a return stating its actual total kwh distributed in the prior taxable period, Year 1. *Id*. at 56. Mr. Stafford testified that during Year 2, AIC will make quarterly payments based on the total Year 1 electricity distributed, and so forth. Thus, Mr. Stafford concluded, the EDT payments a utility makes during any year are estimated, based on the utility's electricity distributed in the prior taxable period, and since the payments are estimated based on kwh distributed, the payments made in any given year will not be equal to the tax liability generated by the kwh distributed during that year.

Mr. Stafford explained that since the EDT payments AIC makes in any given year will not be equal to the tax generated by the kwh distributed in that taxable period, when AIC submits its annual ICT-4 tax return to the ILDOR, AIC also compares the actual payments in Year 1 to the actual kwh distributed multiplied by the tax rate in Year 1. *Id*. Mr. Stafford stated that if there is an amount due, it is paid to IDOR by AIC with the annual tax return ICT-4, or, if a refund is due, it is applied to the next quarterly payment. 35 ILCS 620/2a.2.

Mr. Stafford explained that if the total amount received by IDOR from the EDT exceeds a statutory cap (approximately $145 million), the IDOR will issue credit memoranda. 35 ILCS 620/2a.1(c). Credit memoranda reduce EDT payments only when the next quarterly payment is due after receipt of the credit memoranda. AIC notes that, for example, a credit memorandum it received in December could not be applied by the Company to lower its cash outlay to IDOR until its next EDT payment, which occurs in March of any given year.

Mr. Stafford testified that the statute creates a cap in the total amount of tax for any "taxable period". Ameren Ex. 11.0 at 8. The credit memo returns a proportional amount of excess above the cap to each tax paying entity. So, Mr. Stafford explained, the amount of the credit memo changes for each taxable period as the proportion of the total EDT paid by a tax paying entity changes for that taxable period.

AIC argues that the Company has a long-standing and consistent history of receiving refunds for EDT. In every year from 2010-2020, AIC has received credit memoranda, ranging in amount from a low of $4,228,675 (2017 tax reporting period) to a high of $6,709,666 (2013 tax reporting period). *Id*. at 10. Thus, AIC concludes, it is well established that the Company receives credit memoranda each year for specific tax reporting periods.

Mr. Stafford explained that because the credit memo returns a proportional amount of excess EDT above the statutory cap to each tax paying entity, the credit memo is part of the ultimate determination of the tax bill, as it reduces the tax liability to meet the statutory cap. *Id*. at 8. Thus, Mr. Stafford stated, the statute requires Ameren Illinois to "prepay" a portion of its EDT obligation for a tax or reporting year period through estimated taxes in that year (here, 2018). Mr. Stafford explained that since a credit memo was issued for 2018, Ameren Illinois' payments during 2018 were too high: the amount of EDT Ameren Illinois paid in the 2018 reporting year period was greater than its actual EDT obligation for 2018. *Id*. Mr. Stafford testified that Ameren Illinois is not made whole for the overpayment until the credit memo is applied in 2020.

Mr. Stafford testified that Ameren Illinois analyzed the estimated taxes paid for the taxable periods 2016-2019 and the credit memorandum amount received the following December for the same taxable period each year. *Id*. at 10. Ameren Ex. 11.5 shows that the prepayment amount resulting from credit memoranda reimbursements to AIC for the 2016-2019 taxable period averaged approximately 11% of the estimated taxes paid. AIC argues that its proposed service lead for EDT reflects this reality – that the credit memo amount effectively represents a prepayment of taxes that are ultimately not owed.

AIC argues that its proposal in this proceeding properly reflects the prepayment in the lead lag study calculation, consistent with the statute and AIC's actual costs. AIC explains that this requires designating the service period as the EDT tax year, which in this case is tax year 2018.

As noted *supra*, Mr. Stafford explained that the credit memorandum is dependent on the tax year (period) and the statute creates a cap in the total amount of tax for any "taxable period". *Id*. at 8. 35 ILCS 620/2a.1. The credit memorandum returns a proportional amount of excess above the cap to each tax paying entity. 35 ILCS 620/2a.1(c). So, AIC argues, it follows that the credit memorandum reduces the tax liability for the taxable period to meet the statutory cap. In this case, the taxable period is 2018, and the credit memo for 2018, received in 2019 but not applied until March 2020, reflects the amount by which Ameren Illinois prepaid (or over-paid) its 2018 EDT tax obligation. Ameren Ex. 11.0 at 10; *see* Ameren Ex. 1.11.

AIC argues that the instructions for paying the EDT tax return confirm this. AIC notes that the Company is required to pay an estimate based on statutory tax rates applied to the utilities' kwh sold in the prior calendar year. AIC explains that IDOR Form ICT-1 Electricity Distribution and Invested Capital Tax Estimated Payment for calendar year 2020 required Ameren Illinois to pay each quarter 25% (Step 2: Line 15) of the prior year's actual kwh (kwh) distributed multiplied by statutory tax rates (Worksheet B). Ameren Ex. 11.4. AIC argues that the Company does not have the option to make lower estimated tax payments each quarter to reflect the likelihood that it is pre-paying that portion of its EDT obligation for a tax or reporting year period that will be returned later.

AIC further argues that the statutory language describing calculation of credit memoranda performed by IDOR pursuant to 35 ILCS 6320/2a.1(c) also makes this clear. *See* P.A. 90-561, eff. 1-1-98; 90-624, eff. 7-10-98; 91-357, eff. 7-29-99. Mr. Stafford testified that this statutory language confirms that: (1) IDOR shall issue credit memoranda to taxpayers if receipts are in excess of the amount allowed by statute for any taxable period; and (2) calculation of the amount of the credit memoranda shall be made as of December 1 of the year following the immediately preceding taxable period. Ameren Ex. 11.0 at 10. AIC argues that since Ameren Illinois has been receiving material credit memos for the last 10 years, Ameren Illinois is routinely paying more than its tax obligation for the taxable period (here, 2018), waiting until December the following year (2019) to receive the credit memo with the amount of the overpayment, and waiting until March the year after that (2020) until it can credit the overpayment against its estimated EDT payments. Essentially, AIC maintains, it has advanced funds to the taxing authority and does not receive the cash flow benefit of the return of those funds until two years later. AIC asserts that to properly reflect this prepayment in the lead lag study calculation, therefore, the EDT service period must be set at the 2018 taxable period.

Turning to Staff's proposed EDT calculation, AIC notes that Staff's proposal does not use 2018 as the service period, but instead uses the date the credit memorandum was applied to offset payment of the first quarter's EDT, March 15, 2020 (rather than the December 16, 2019 date the Company was notified of the credit memorandum amount, as was reflected in the Ameren 2020 FRU calculation of CWC). Staff Ex. 1.0 at 11-12. Staff argues that this more accurately reflects actual cash flow.

AIC argues that Staff's approach fails to recognize the fact that, as discussed above, Ameren Illinois prepays a portion of the EDT amount each year. Mr. Stafford testified that Ameren Exhibit 11.5 demonstrates that Ameren Illinois was required to remit, on average for calendar years 2016-2019, 11% more than its actual EDT statutory tax obligation. Ameren Ex. 13.0 at 9. Mr. Stafford further explained that the Company's calculation on Exhibit 11.5 recognizes actual cash EDT outlays and thus is representative of actual cash flows. AIC concludes that Staff's method fails to recognize the actual cash payments from AIC that triggered the EDT credit memorandum.

Mr. Stafford testified that Staff's proposal is inconsistent with other taxes within the lead-lag study that establish service periods based on tax years. Ameren Ex. 11.0 at 11. For example, the Company receives real estate tax bills from every county in Illinois with AIC taxable assets each year. Mr. Stafford explained that the lead lag study is calculated with a service period based on the tax year, not the date the tax bill is received. For example, within the lead lag study, taxes due for Champaign, Peoria, and St. Clair Counties reflect service period beginning and ending dates of November 1, 2019 and December 31, 2019 to depict a tax year of 2019. Mr. Stafford further explained that, for these real estate bills, the tax is due at various due dates in June and July of 2020. *Id*. Since the tax is due in the calendar year after the 2019 tax year, the result is an expense lead of 347.92, 355.92, and 406.92 days for the respective tax bills. Mr. Stafford testified that under Staff's approach for the EDT refunds, the service period beginning and ending dates for the tax bills would ignore the tax year and focus strictly on the date the Company applies the refund. Mr. Stafford further explained that if the same approach was applied to real estate taxes in the lead lag study, and the date the tax bill was due was substituted as the tax year service period, expense lead days would be measurably lower and CWC included in rate base would increase.

AIC notes that Staff raises two main concerns. The first is that Ameren Illinois' approach "is completely at odds with" the Commission's Order in Ameren 2020 FRU. AIC contends this is not entirely true. Ameren Illinois' proposed treatment of EDT follows the Ameren 2020 FRU Order's methodology with respect to the year of the credit memorandum applied (2020). Ameren Ex. 1 (Rev.) at 55. In addition to the four quarterly installment payments for EDT in 2020, the Company's lead lag study reflects the actual EDT credit memorandum received in December 2019 and applied in 2020.

Ameren Illinois does agree that with respect to the appropriate service period, it is proposing a change from the Ameren 2020 FRU Order – to set the service period at tax year 2018. (AIC notes that Staff also proposes a change to the Ameren 2020 FRU Order's service period methodology: rather than the December 16, 2019 date the Company was notified of the credit memorandum amount, as was reflected in the Ameren 2020 FRU calculation of CWC, Staff uses the date the credit memorandum was applied to offset payment of the first quarter's EDT, March 15, 2020. Staff Ex. 1.0 at 11-12.) Ameren Illinois asserts it is proposing this change based in part on a new analysis that confirms it prepays approximately 11% of its EDT each year.

AIC posits that the crux of Staff's argument is that the existence of credit memos in a given year cannot be guaranteed and so "AIC seeks to have the credit memorandum recognized for purposes of the lead-lag study before it even came into existence." Staff Init. Br. at 5-6. AIC responds that this argument relies on a technical read of the statute and ignores both the Ameren 2020 FRU Order and the record in this case. According to AIC, the Ameren 2020 FRU Order was clear that credit memos affect Ameren Illinois' cash flow. *See* Ameren 2020 FRU, Order at 12-13. Thus, AIC argues, to the extent that Staff's position on the service period is premised on the possibility there will not be a credit memo, the Commission has rejected that rationale.

AIC further argues that Staff's arguments ignore the record. According to AIC, Staff's own treatment of EDT in the CWC calculation reflects the existence of credit memo. Staff Ex. 1.0 at 12. AIC contends the record demonstrates that Ameren Illinois has received credit memos for every year for over ten years, and that those credit memos demonstrate that Ameren Illinois prepays approximately 11% of its EDT. Mr. Stafford explained that since AIC has been receiving material credit memos every year for more than the last 10 years, Ameren Illinois is routinely paying more than its tax obligation for the taxable period (here, 2018), and waiting until March two years after that until it can credit the overpayment against its estimated EDT payments. Ameren Ex. 13.0 at 7-8. AIC contends that its proposal in this proceeding is to properly reflect the prepayment in the lead lag study calculation, consistent with the statute and Ameren Illinois' actual costs. This requires designating the service period as the EDT tax year, which in this case is tax year 2018.

For these reasons, AIC argues that the Commission should reject Staff's proposal and adopt the Company's.

Turning to the AG's proposal, AIC notes that the AG asks the Commission to adopt the calculation of the lead days for EDT based upon the same methodology on which the weighted lead is determined for Commonwealth Edison Company ("ComEd"), considering only the four statutory EDT tax payment dates and not the impact of credit memos. AG Ex. 1.0 at 20-21. AIC notes that, as indicated above, this is contrary to the Commission decision in Ameren 2020 FRU to reflect the credit memoranda in the CWC calculation. AIC argues that for this reason alone, the AG's proposal should be rejected.

Mr. Stafford testified that adopting the ComEd method does not consider Ameren Illinois' actual costs. Ameren Ex. 11.0 at 13. By comparison, Mr. Stafford explained, AIC's method more accurately calculates the EDT CWC requirement than ComEd's because the AIC method includes the impact of annual EDT refunds and thus considers the utility's cash obligations of prepaying a portion of the EDT tax each year in calculating the EDT expense lead. Ameren Ex. 13.0 at 12.

AIC observes that in the AG's view, a negative expense lead for EDT improperly characterizes the total payment of EDT in the test year as being prepaid, and the Company's lead-lag study treats the payment of EDT tax differently than the payment of other estimated taxes, such as the payment of quarterly estimated federal and state income taxes. AG Ex. 1.0 at 19. AIC argues that both of these positions are incorrect.

AIC clarifies that it is not characterizing the total payment of EDT as prepaid. Mr. Stafford explained that when a credit memo is issued, it means AIC prepays a portion of the EDT tax obligation through estimated tax payments in the reporting year; that is, AIC has prepaid more than it owes. Ameren Ex. 11.0 at 12. Mr. Stafford testified that Ameren Illinois performs five separate calculations for the four quarterly payments and the 2018 credit memo applied to the March 15, 2020 quarterly payment. Ameren Ex. 13.0 at 10. Mr. Stafford explained that the calculation inputs include $48.520 million of quarterly payments offset in part by the $6.193 million credit memo. *Id*.

Further, AIC argues, the Company's lead-lag study does not treat the payment of EDT tax differently than the payment of other estimated taxes. Mr. Stafford testified that the lead-lag study reflects quarterly installment payments for EDT and federal and state income taxes and some other taxes. Ameren Ex. 11.0 at 12. Unlike these other taxes, Mr. Stafford explained, by statute the Company is required to pay more than 100% of its estimated EDT tax liability each year to comply with the tax return instructions issued by IDOR. Thus, Mr. Stafford concluded, the only difference in the methodology used for EDT vs. the other taxes is to recognize that a portion of the tax is prepaid for a given tax reporting period and will be refunded to AIC after the end of the tax reporting period. *Id*. at 13.

AIC notes that the AG's primary argument against Ameren Illinois' position on the CWC calculation for EDT is that Ameren Illinois "does not prepay its EDT obligation." AG Init. Br. At 4. AIC contends that this is not correct. As noted above, Ameren Illinois contends that it is not characterizing the total payment of EDT as prepaid. When a credit memo is issued, it means Ameren Illinois prepays a portion (11%) of the EDT tax obligation through estimated tax payments in the reporting year (to comply with the tax return instructions issued by IDOR); that is, Ameren Illinois has prepaid more than it owes. AIC argues the AG acknowledges as much when it says, "In other words, if IDOR determines that the State received more tax revenue than the statute allows after taking into account the tax paid by the other electric utilities, Ameren Illinois may apply the overpayment in that year as a credit for a subsequent year's EDT obligation." AG Init. Br. at 4.

The AG argues Ameren Illinois' proposal here is inconsistent with the methodology approved by the Commission for the determination of the EDT expense lead-days for ComEd. AIC contends this is contrary to the Commission's decision in Ameren 2020 FRU to reflect the credit memoranda in the CWC calculation. AIC further argues that adopting the ComEd method does not consider Ameren Illinois' actual costs. By comparison, Ameren Illinois argues its method more accurately calculates the EDT CWC requirement than ComEd because the Ameren Illinois method includes the impact of annual EDT refunds and thus considers the utility's cash obligations of prepaying a portion of the EDT tax each year in calculating the EDT expense lead.

AIC argues that for these reasons, the AG's position should be rejected.

b. Staff's Position

Staff proposes changes to AIC's lead lag study for the lag time associated with a credit memorandum related to the 2018 EDT year that was received/applied to the first quarterly installment of EDT paid March 15, 2020. Staff Ex. 1.0 at 10. Staff witness Pearce explained that AIC treated the credit memorandum as a return of prepaid 2018 EDT tax that was not received until it was applied against the first quarter 2020 EDT payment. Staff Ex. 5.0 at 5. Accordingly, Ms. Pearce explained, AIC utilized a mid-point of tax year 2018 to derive a service lead of negative 182.50 days, then added all of calendar year 2019 plus the period from January 1, 2020 through March 15, 2020 to calculate a total of negative 440 payment lead days for a sum total of 662.50 negative lead (or refund lag) days associated with the credit memo notification received on December 16, 2019 that was applied March 15, 2020 as an offset to that quarterly payment of EDT for 2020. This had the effect of changing the overall EDT expense lead to a lag time of 56.40 days. *Id.*

Staff argues, however, that AIC's approach is at odds with the Commission's Order in Ameren 2020 FRU. There, AIC proposed to use a 2019 credit memorandum for CWC analysis. Staff proposed to use a 2018 credit memorandum, since that memorandum, rather than the one issued in 2019, actually affected the 2019 cash flows at issue in AIC's 2020 formula rate update ("FRU") docket. Staff notes the Commission adopted Staff's position, finding that it was "appropriate and should be approved." Ameren 2020 FRU, Order at 15. In so finding, the Commission determined that "since calendar year 2019 is the year that was used for purposes of the lead lag study, and the purpose of including the credit memorandum is to get a more accurate lead/lag analysis, *it is appropriate to use the items that impacted payments during the period that was used as the basis of the [lead-lag] study*." *Id.* (emphasis added). The Commission further observed that:

> Staff correctly notes that the calculation of an EDT credit memorandum is determined by statute, which makes clear that rather than depending upon the tax period as the Company suggests, the amount of the credit memorandum is based on payments received by [IDOR] during a set time period as compared to a value set in the statute. *The Commission agrees with Staff that as such, it is not*

> *appropriate to use any specific tax period for the basis of lead days associated with the credit memorandum*.

Id. (emphasis added.)

Staff argues that the dispute here relates to the payment by AIC to IDOR of sums due and owing under the EDT. *See* 35 ILCS 620/2a.1, 2a.2 (tax created; terms and conditions of its assessment and collection outlined). An entity, such as AIC, required to remit the tax, pays its estimated indebtedness on a quarterly basis. 35 ILCS 620/2a.2. To the extent that a taxpayer overpays its indebtedness in a given year, IDOR issues a credit memorandum to be applied as a credit against future tax obligations. 35 ILCS 620/2a.1. Significantly, however – and as the Commission recognized in Ameren 2020 FRU – credit memoranda are issued only if IDOR collects through the tax a sum in excess of a statutorily-specified amount in the aggregate from all taxpayers, in which case each taxpayer receives a credit memorandum reflecting that taxpayer's proportional share of the entire aggregate overpayment. *Id.* By statute, IDOR makes this determination on December 1 of the year after which taxes were paid. *Id.*

Ms. Pearce testified:

> There is no guarantee of any credit memorandum for a given year because any subsequent credit memorandum related to payment of a specific year's EDT tax estimates is based not only on the payments of AIC's EDT, *but by the payments of EDT collected from all Illinois utilities that are subject to EDT.* In other words, the calculation and determination of AIC's pro-rata portion of any credit memorandum is a function of the entire amount paid by all these utilities, not just AIC. Accordingly, the statute indicates the amount of any credit memorandum for a certain tax year is not determined until December of the year following the tax year (e.g., the 2018 EDT credit memorandum was finalized by ILDOR in December 2019 in this case).
>
> Moreover, the statute generally requires that any credit may not be received in cash. Unless a utility does not plan to pay any future EDT, credit memoranda may only be used to offset quarterly estimated payments of EDT. For example, the earliest time AIC could have utilized the 2018 credit memorandum was through a reduction (or offset) to the 2020 first quarter's estimated EDT payment that was due March 15, 2020.

Staff Ex. 5.0 at 6 (emphasis added).

Ms. Pearce further testified that "[n]o credit memorandum is guaranteed [under 35 ILCS 620/2a.1] because the amount cannot be determined except by [IDOR] as a function of total EDT collected from all subject utilities as compared to an amount in the statute. The credit memorandum is not based simply on the amount of EDT paid by AIC for a given tax period." Staff Ex. 5.0 at 7. Rather, Staff argues, the credit memorandum is based on all EDT collected from all taxpayers who owe it, and credit memoranda are based on a "calculation … made [by IDOR] as of December 1 of the year following the immediately preceding taxable period[.]" 35 ILCS 620/2a.1(c).

Staff observes that Staff and the Company agree the EDT credit memorandum should be included in the calculation of CWC during the 2020 reconciliation period. The Company further noted that there is no disagreement with Staff regarding the legal requirements of the EDT and the timing in which receipt of any credit memorandum may be applied to offset quarterly estimated payments of EDT. With respect to this issue, Staff states that the remaining points in dispute between Staff and the Company are these:

i) Whether quarterly estimates of EDT constitute "prepayments" as the Company would have it, or estimated payments of legally owed taxes pursuant to statute, as Staff argues; and,

ii) Whether, in the calculation of lead/lag times for CWC, the service period for an EDT credit memorandum should be treated as a return of "prepaid" EDT related to the tax year in which the "prepayments" were made, as the Company would have it; or whether the credit memorandum is more accurately related to the tax year in which the offset is permitted to be used for reduction of current EDT estimated payments, as Staff would have it.

On the first point, Staff argues the Company itself has referred to quarterly payments of EDT as estimated payments rather than "prepayments" of EDT. *See, e.g., Ameren Ill. Co.,* Docket No. 15-0305, Ameren Illinois Initial Brief at 8 (October 6, 2015)(where Ameren Illinois refers to EDT as "estimated payments during the year."). Staff argues that the Company was correct in that proceeding but is wrong here; the quarterly payments of EDT are not "prepayments" regardless of how regularly AIC might receive credit memoranda. Staff points to the statute governing the collection and remittance of the tax, which describes payments as "estimated quarterly payments" of a portion of "*the tax liability for the immediately preceding taxable period*[.]" 35 ILCS 620/2a.2 (emphasis added). By the terms of the statute, Staff argues, [AIC] is not prepaying taxes; rather, it is paying taxes already due and owing from the "immediately preceding taxable period."

Staff further argues the receipt of past credit memoranda bears no relationship to the potential receipt of any future credit memoranda because the statute requires a new calculation each year by IDOR to determine whether any amount of credit memorandum is to be issued to a utility for a specific tax year and the amount is calculated according to the terms of the statute for each year. Staff contends the amount of the credit is not dependent on the estimated payments by AIC for a given tax year but instead is a function of the threshold set by the statute and the amount of EDT owed by all Illinois utilities that are subject to the EDT. *See* 35 ILCS 620/2a.1 (the statute establishes an amount to be collected in a given year and, to the extent that IDOR collects a greater sum in that year, directs that credit memoranda be issued to all remitting utilities on a proportional basis).

Staff argues that resolution of the second disputed issue between the Company and Staff is dependent on the outcome of the first, because if the Commission concludes – based on the specific terms of Section 2a.2 - that the credit memorandum is not the return of a "prepayment" of EDT for a prior tax year, there is no basis to calculate the service lead/lag time as a function of that prior year. Instead, Staff argues, the service period associated with the credit memorandum must be reflected in the calculation of CWC for what it is: a credit that may be applied to offset the first quarterly installment of EDT due March 15 in the year following notification by IDOR to a utility in the previous December of the existence and amount of a credit memorandum. Thus, Staff argues, the credit memorandum in the instant proceeding relates to estimated payments of EDT in the 2018 tax year, for which an annual return was filed in 2019 and notice of the credit memorandum was received by AIC in December 2019 for offset against the first quarterly estimated payment of EDT in March 2020. Regardless of how regularly it may have received credit memoranda in the past, Staff argues that AIC could not know if it would receive a credit memorandum for March 2020 until December 2019; likewise, it would not know the amount until the latter date. Furthermore, the only way in which AIC could receive the benefit of the credit memorandum is by offset against future estimated payments of EDT; by statute, IDOR cannot issue refunds for EDT credit memoranda to taxpayers that will incur future EDT liability. 35 ILCS 620/2a.1(c). Staff argues that Ameren Illinois will undoubtedly continue to accrue such liability, and thus cannot expect to receive a refund rather than a credit memorandum.

Staff notes that this is not the first time the issue has come before the Commission. In the prior year's FRU, Ameren 2020 FRU, Staff proposed to calculate the service period associated with the EDT credit memorandum from the December date of notification to the Company by IDOR. The Commission agreed with Staff that:

> Staff correctly notes that the calculation of an EDT credit memorandum is determined by statute, which makes clear that rather than depending upon the tax period as the Company suggests, the amount of the credit memorandum is based on payments received by [IDOR] during a set time period as compared to a value set in the statute. *The Commission agrees with Staff that as such, it is not appropriate to use any specific tax period for the basis of lead days associated with the credit memorandum*.

Ameren 2020 FRU, Order at 13 (emphasis added).

Staff argues that AIC's position cannot be reconciled with the Commission's prior Order. It is undisputed that AIC applied the credit memorandum on March 15, 2020, to offset its quarterly payment of EDT for 2020. Staff Ex. 1.0 at 11. Staff further argues that it is clear as a matter of law that AIC could not assume the existence of a credit memorandum until December 1, 2019. *See* 35 ILCS 620/2a.1 ("[t]h[e] calculation [which gives rise to credit memoranda] shall be made as of December 1 of the year following the immediately preceding taxable period[.]"). In other words, Staff argues, AIC seeks to have the credit memorandum recognized for purposes of the lead-lag study *before the credit memorandum even came into existence*. Staff argues the Commission clearly cannot endorse this, and, as noted above, has refused to do so in the past. For these reasons, Staff argues AIC's position should be rejected.

c. AG's Position

The AG requests that the Commission change the Company's number of lead days for the payment of the EDT from negative 56.40 days to positive 30.25 days. The AG maintains that AIC reached this negative expense lead by improperly characterizing the payment of EDT as a prepayment of future tax obligation.

The AG explains that the EDT is a tax that AIC pays to IDOR based on the number of kwh the Company distributes during a taxable period. 35 ILCS 620/2a.1(a). AIC makes quarterly estimated payments to IDOR based on a statutory formula and the utility's kwh sold in the prior year. *Id*. at 2a.2. The AG notes, however, that the tax has a cap that is determined by the statute and IDOR calculates the sum certain amount of tax due on December 1 of the year following the tax year. *Id*. at 2a.1(c). The AG further explains that IDOR issues a credit memoranda if, after it calculates the cap, it determines that any of the three electricity distribution utilities operating in Illinois paid tax in excess of the cap. The credit memoranda notes the overpayment for the tax year and allows utilities to apply the amount in excess to a future tax year's EDT obligation. *Id*. The AG recognizes that AIC has frequently received credit memoranda and applied them to the EDT obligation for subsequent tax years.

The AG notes the Company's assertion that this payment structure creates a cash flow issue for AIC. AIC maintains that IDOR requires AIC to overpay its EDT obligation in a tax year, thereby creating a prepayment of a future year tax obligation, and then does not credit that prepayment until two years after the original payment is made when IDOR applies the credit memoranda to a subsequent year's EDT obligation. Thus, AIC does not receive the cash flow benefit from its overpayment in the tax year until two years later. To the Company, this lag justifies a negative 56.40 lead days for EDT in its lead-lag study.

The AG argues that this characterization misrepresents the EDT payment process. The AG argues that AIC pays the EDT that is due each year, with IDOR calculating the sum certain amount of tax due on December 1 of the year following the tax year. 35 ILCS 620/2a.1(c). The AG maintains that while the Company has frequently received credit memoranda, AIC pays the tax each year as mandated by the statute, and it cannot prepay a tax where no party knows the ultimate amount of tax due until after payment. Further, the AG argues, there is no guarantee of a credit memorandum because the total kwh delivered statewide, which determines the credit, is unknown until the end of the year.

The AG therefore proposes that the Commission calculate the EDT expense lead by only examining the quarterly dates where IDOR requires AIC to pay its estimated EDT obligation. The AG maintains that its proposal properly frames the EDT as an estimated tax and fixes the lead day calculation to the dates where payment is due during the applicable tax year. The AG's proposed calculation results in a positive 30.25 lead days for AIC.

The Company maintains that the AG's position violates the Commission's prior Order in Ameren 2020 FRU, which allowed AIC to consider credit memoranda in the calculation of its EDT lead days, but adopted Staff's proposal regarding which credit memoranda the Company could use. Ameren 2020 FRU, Order at 12–13.

The AG responds by requesting that the Commission reconsider that Order. The AG notes that the Commission approved the AG's proposed treatment of EDT lead days, which does not consider credit memoranda at all, in prior ComEd cases. For example, AG witness Selvaggio testified that in Docket No. 20-0393, ComEd witness Hengtgen, in calculating the utility's lead days, did not consider any overpayment of EDT in the test year to be a prepayment of future EDT obligation, and only considered the required payment dates. AG Ex. 1.0 at 19–20 (quoting Commonwealth Edison Co., Docket No. 20-0393, ComEd Ex. 2.0 at 18–19). The AG notes the Commission approved ComEd's treatment of EDT lead days in that proceeding. *See* Docket No. 20-0393, Order at 7 (Dec. 9, 2020). The AG further notes that the proper treatment of EDT lead days has now been an issue in three AIC FRU dockets: this case, Ameren 2020 FRU, and Docket No. 15-0305. The AG urges the Commission to resolve the difference between ComEd and AIC's treatment of EDT lead days and limit future litigation by aligning the treatment of EDT lead days between the two electric delivery utilities with formula rates.

In the event that the Commission continues considering the issuance of credit memoranda in the calculation of AIC's EDT lead days, the AG requests that the Commission adopt Staff's proposal which calculates the lead day period by considering the credit memoranda applied on the due date of the quarterly payment reduced by the application of the credit memoranda. *See* Staff Ex. 5.0 at 5-6. Staff's proposal assigns a positive 30.36 lead days to the payment of EDT.

d. CUB's Position

CUB took no position on this issue.

e. Commission Analysis and Conclusion

The Commission recognizes that its Ameren 2020 FRU Order found that EDT credit memos affect Ameren Illinois' cash flow, stating "The Commission agrees with AIC and Staff that, based on this record, the evidence supports the conclusion that the credit memoranda have been affecting and are reasonably expected to continue to affect Ameren Illinois's cash flows. Accordingly, the Commission finds on this more robust record and with the agreement of Staff that the impact of receipt of those credit memoranda should be included in its CWC determination." Ameren 2020 FRU, Order at 12.

AIC and Staff now dispute the appropriate service period to reflect for EDT in the CWC calculation: the actual 2018 tax year in which payments were made (Ameren Illinois' position) or the date the credit memorandum was applied to offset payment of the first quarter's EDT, March 15, 2020 (Staff's position). The AG asks the Commission to reconsider its decision in Docket No. 20-0381 entirely and find that credit memoranda should not be considered at all in the CWC determination. In the alternative, the AG argues that if the Commission decides to continue considering the issuance of credit memoranda in the calculation of AIC's EDT lead days, the Commission should adopt Staff's proposal which calculates the lead day period by considering the credit memoranda applied on the due date of the quarterly payment reduced by the application of the credit memoranda.

Ameren Illinois contends its quarterly payments of EDT represent a prepayment of EDT tax, which is later returned to the Company via the credit memorandum. Using that analysis, AIC treated the credit memorandum as a return of prepaid 2018 EDT tax that was not received until it was applied against the first quarter 2020 EDT payment. Both Staff and the AG disagree with AIC's analysis and contend that these quarterly payments are not "prepayments" as the Company contends, but rather estimated payments calculated according to statute. Both the AG and Staff further stress that there is no guarantee of a credit memorandum because the total kwh delivered statewide, which determines the credit, is unknown until the end of the year. Moreover, the payment of a specific year's EDT tax estimates is based not only on the payments of AIC's EDT, but the payments of EDT collected from all Illinois utilities that are subject to EDT.

The Commission agrees with Staff and the AG on these points. AIC's quarterly EDT payments are not accurately characterized as prepayments of EDT; rather, they are "estimated quarterly payments" of a portion of "the tax liability for the immediately preceding taxable period." 35 ILCS 620/2a.2. As Staff correctly notes, Ameren Illinois is not prepaying taxes; rather, it is paying taxes already due and owing from the immediately preceding taxable period. It is a function of the statute that creates a possible return of these funds if a certain threshold of total EDT is collected from all taxpayers who owe it; this is categorically different than the prepayment scenario envisaged by AIC's characterization. The Commission further agrees with the AG and Staff that there is no guarantee in any given year that such a threshold will be met or a credit memorandum issued to AIC, regardless of how consistently AIC has received such credit memoranda in the past. As Staff correctly notes, the amount of the credit is not dependent upon the estimated payments by AIC for a given tax year, but instead is a function of the threshold set by the statute and the amount of EDT owed by all Illinois utilities that are subject to the EDT.

In accordance with and in light of the conclusion that the quarterly payments do not constitute prepayments of EDT, the Commission agrees with Staff that there is no basis to calculate the service lead/lag time as a function of that prior year. The Commission adopts Staff's reasoning and finds that the service period associated with the credit memorandum should be reflected in the calculation of CWC as a credit that may be applied to offset the first quarterly installment of EDT due March 15 in the year following notification by IDOR to a utility in the previous December of the existence and amount of a credit memorandum. The Commission accordingly rejects AIC's proposed methodology for reflecting EDT in the CWC calculation and adopts Staff's recommendation for doing so.

The AG's recommendation to adopt the ComEd methodology ignores the Commission's Order in Ameren 2020 FRU. The Commission finds that the record in this docket reflects no compelling reason to depart from the decision or methodology approved in Docket No. 20-0381 and rejects the AG's request that the Commission do so.

2. Amortization of Excess Deferred Income Tax

a. AIC's Position

AIC observes that on September 15, 2021, after the record in this case was closed, Public Act ("P.A.") 102-0662, was enacted. Ameren Illinois recognizes that P.A. 102-0662 will require a change to the amortization schedule for EDIT. But, AIC argues, the EDIT at issue in this proceeding is 2020 actual EDIT. AIC argues that P.A. 102-0662 does not, and cannot, operate to adjust the actual amortization amounts of prior year 2020 EDIT. Section 16-108.21(c) of P.A. 102-0662 requires amortization of EDIT be addressed in a separate docket, not here. AIC further argues that adjusting the 2020 EDIT amortization to comply with Section 16-108.21 would improperly give the new section retroactive effect (and, AIC continues, the AG's proposed accelerated amortization periods improperly adjust AIC's actual 2020 costs, contrary to EIMA requirements, in any event). According to AIC, even if Section 16-108.21 could apply retroactively, the record in this case does not support adjusting the amortization period to comply with the December 31, 2025 deadline. AIC maintains that until a new amortization schedule is established pursuant to P.A. 102-0662, its 2020 unprotected property-related EDIT amount is reasonable.

AIC contends that the AG's proposed alternative EDIT amortization approach, which is intended to offset the rate increase in this proceeding, is flawed for several additional reasons. AIC argues that the AG has not established that the acceleration is necessary, particularly because the alternative proposal will cause a rate spike in 2024. AIC argues that accelerating the amortization of EDIT to provide pandemic relief to customers also represents a collateral attack on the Stipulations in the Commission's Order in Docket No. 20-0309. Finally, AIC argues, the Baltimore Gas and Electric case the AG cites in testimony does not support its alternative approach here.

For these reasons, AIC argues, the AG's proposed accelerated amortization of unprotected property-related EDIT in this docket should be rejected, Ameren Illinois' existing amortization amount for 2020 should be approved, and the accelerated amortization of EDIT should be separately addressed in a new docket pursuant to Section 16-108.21.

Mr. Stafford testified that prior to 2017, when Ameren Illinois claimed certain tax deductions in excess of its corresponding book expenses – most particularly accelerated (including bonus) tax depreciation – it would defer its income tax liability by an amount determined using the corporate tax rate expected to be in effect when the deferred tax liability became due in the future. Ameren Ex. 11.0 at 20. Mr. Stafford explained that Ameren Illinois retained the benefit of the income tax deferral and recorded it as accumulated deferred income taxes ("ADIT"), which was reflected in ratemaking as an offset to rate base. *Id*. Mr. Stafford testified that it was expected that the amount of the deferred tax liability would eventually have to be paid back to the government in the form of higher income taxes when, later on in the life of the depreciable assets, book depreciation would exceed the available tax depreciation deductions.

Mr. Stafford testified that the enactment of the Tax Cut and Jobs Act ("TCJA") in 2017 reduced the income tax rate and altered the amount of Ameren Illinois' anticipated repayment liability – consequently, when the deferred tax liability becomes due it will be taxed at 21%, not the higher rates previously in effect (35% from 1994-2017, 34% from 1987-1993). *Id*. As a result, Mr. Stafford explained, a portion of Ameren Illinois' ADIT reserve that was recorded on the presumption that it would be taxed at the higher rate of 34% or 35% was rendered unnecessary and is considered EDIT. *Id*. This EDIT can be returned to customers over the appropriate amortization period.

Mr. Stafford testified that, as approved by the Commission in Docket Nos. 19-0436 and 20-0381 (and as affirmed by the Fourth District Appellate Court), and pursuant to the TCJA, Ameren Illinois has determined the EDIT amortization period using the average rate assumption method ("ARAM") for property-related excess deferred taxes where ARAM is required by law or where it is feasible to do so. (Property-related EDIT for which the amortization period is mandated by law is "protected" EDIT. Other property-related EDIT is referred to as "unprotected" EDIT.) Ameren Ex. 1.0 (Rev.) at 33. Mr. Stafford explained that ARAM aligns amortization of both protected and unprotected property-related EDIT with the useful life of the underlying assets, allowing customers to pay a smoother, more normalized cost over time. Mr. Stafford testified that AIC uses a 35-year amortization as a proxy for the remaining useful life of the assets for those property-related items where Ameren Illinois' tax systems cannot perform the necessary calculations for ARAM. *Id*. Mr. Stafford stated that other EDIT balances are amortized over 7 years.

Mr. Stafford stated that application of this Commission-approved amortization period for "unprotected" property-related EDIT resulted in an actual unprotected property EDIT amortization amount for Ameren Illinois in 2020 of $2,196,000 ($3,899,000 multiplied by 56.32% jurisdictional factor). AIC notes that AG witness Selvaggio proposed to shorten the amortization period for this "unprotected" property related EDIT to a 5-year amortization starting in 2020. As an alternative, she proposes an accelerated amortization of EDIT related to unprotected property to offset any rate increase resulting from this proceeding, which would increase 2020 unprotected" property related EDIT by $21 million, with the remainder of the EDIT balance to be returned pursuant to the timetable approved by the Commission.

AIC notes that Section 16-108.21 of the new P.A. 102-0662 states that "Notwithstanding the Commission Orders in Docket Nos. 19-0436, 19-0387, 20-0381, and 20-0382, the excess deferred income tax referenced in those dockets shall be fully refunded to ratepayers by the respective utilities no later than December 31, 2025." 220 ILCS 5/16-108.21(b). But AIC notes that Section 16-108.21 also specifies that "The Commission shall initiate a docket to provide for the refunding of these excess deferred income taxes to ratepayers of the utilities referenced in those dockets, and shall set forth any necessary provisions to accomplish the reimbursement on the schedule delineated in subsection (b)." 220 ILCS 5/16-108.21(c). Thus, AIC argues, the mechanism by which this subsection (b) "refunding" happens must be determined in a new, separate docket. Because a new, separate docket is required, AIC reasons, the Commission cannot adjust Ameren Illinois' actual 2020 unprotected property-related EDIT to meet the requirements of Section 16-108.21 in this proceeding (and, as explained below, to do so would be contrary to the "actual costs" requirement of the formula rate law). Moreover, AIC contends, any attempt to do so raises various legal and factual concerns.

AIC notes that P.A. 102-0662 went into effect on September 15, 2021. AIC observes that both the AG's proposed accelerated amortization proposals require increasing Ameren Illinois' reconciliation year 2020 actual unprotected property EDIT amortization amount of $2.196 million, either by approximately $5 million (AG's primary 5-year amortization proposal) or $21 million (AG's alternative proposal). AIC contends that such a change to recorded 2020 amounts would be an impermissible retroactive application of Section 16-108.21.

In Illinois, whether a statutory amendment will be deemed to have retroactive effect is analyzed under the framework established by the U.S. Supreme Court in *Landgraf v. USI Film Products*, 511 U.S. 244 (1994), as adopted by the Illinois Supreme Court in *Commonwealth Edison Co. v. Will County Collector*, 196 Ill. 2d 27 (2001) and further interpreted by subsequent decisions including *Caveney v. Bower*, 207 Ill. 2d 82 (2003). As applied in Illinois, the first step under this analysis is to determine "whether the legislature has clearly indicated the temporal reach of an amended statute. If so, then, absent a constitutional prohibition, that expression of legislative intent must be given effect." *Caveney*, 207 Ill. 2d at 91 (internal citations omitted).

AIC argues that here, the legislature has not clearly expressed an intent that Section 16-108.21 should apply retroactively or apply to a pending proceeding. Instead, the language of the new provision indicates prospective application, as subsection (c) requires the Commission to initiate a docket (a future action) and to "set forth [in that future action] any necessary provisions to accomplish the reimbursement on the schedule delineated in subsection (b)."

AIC contends that if the legislature has not clearly indicated an intent that the amended statute be effective retroactively, as it has not here with Section 16-108.21, then Section 4 of Illinois' Statute on Statutes (5 ILCS 70/4) controls. Section 4 "represents a clear legislative directive as to the temporal reach of statutory amendments and repeals: those that are procedural in nature may be applied retroactively, while those that are substantive may not." *Caveney*, 207 Ill. 2d at 92. Furthermore, AIC argues that "where the legislature has not expressly indicated its intent as to temporal reach, "a presumption arises that the amended statute is not to be applied retroactively." *Perry*, 2018 IL 122349 at ¶ 42. Here, AIC argues, the AG's proposed change to the amount of unprotected EDIT is clearly a substantive change. *See, e.g., Ill. Commerce Comm'n on Its Own Motion*, Docket No. 17-0267, Second Notice Order at 5-7 (Aug. 25, 2017) (applying *Caveny* and 5 ILCS 70/4 in finding that amendment to PUA that changed the definition of renewable energy resources did not apply retroactively to prevent utility from claiming renewable energy credits no longer allowed under amended statute for compliance years prior to amendment); *In re Res. Tech. Corp*., 721 F.3d 796, 800 (7th Cir. 2013) (applying *Caveney* and 5 ILCS 70/4 in finding that amendment to PUA did not apply retroactively to disallow tax credits claimed by utility for period prior to effective date of amendment that changed conditions for claiming those credits).

Thus, AIC concludes, P.A. 102-0662 cannot operate retroactively to adjust Ameren Illinois' 2020 actual EDIT amortization amounts. AIC asserts that even if it could, there is no record here to support such an amortization.

AIC notes that no witness testified regarding the "necessary provisions to accomplish the [EDIT] reimbursement on the schedule delineated in subsection (b)" of Section 16-108.21 – because the statute did not become law until after the hearing. AIC further notes that no witness testified regarding a specific proposal for unprotected EDIT to be fully refunded to ratepayers no later than December 31, 2025. AIC argues that in the absence of any witness testimony or evidence addressing the requirements of Section 16-108.21, there is no record basis for the Commission to adopt an amortization period for unprotected EDIT that purports to comply with that statute.

AIC contends that neither of the AG's proposals make full use of the statutory schedule for refunding EDIT, noting that the AG's primary proposal would complete the amortization in 2024 (AG Ex. 1.0 at 5) and the AG's alternate proposal would amortize over 50% of the balance of unprotected property-related EDIT in 2020 (Ameren Ex. 13.0 at 21). Mr. Stafford testified that if the AG's proposal is understood as a one-year only amortization adjustment, some new amortization schedule that is consistent with Section 16-108.21 would need to be determined, based on a record that does not yet exist, for the remaining $16 million of unprotected property-related EDIT. *Id*.

AIC argues that even if, as a technical matter, the AG's primary and alternate proposal could refund unprotected plant related EDIT by December 31, 2025, that does not mean that those proposals are the best options. AIC argues that its evidence shows that accelerated amortization has impacts on Ameren Illinois' cash flows and causes rate base to increase more rapidly (*Id*. at 24), as well as causing rates to significantly increase when the amortization ends. Thus, AIC argues, other amortization periods may better balance customer and utility interests. AIC contends that in any of these scenarios, the concerns regarding accelerated amortization's impacts on customers and the utility would have to be addressed, and that the record in this case does not do that.

AIC further notes that there are open questions about Section 16-108.21 that have not been, and cannot be, addressed in this case now that the evidence has closed. For example, the new section refers to "excess deferred income tax," without specifying "protected" or "unprotected," or "property-related", or "plant" or "non-plant." AIC argues that to the extent the Section 16-108.21 reference to "excess deferred income tax," is supposed to include protected EDIT, that raises normalization concerns and issues under Federal tax law. *See, e.g.*, Public Law No. 115-97, Section 130001(d), 131 Stat. 2054 (2017). To the extent the reference is to non-property EDIT, that EDIT is being amortized over 7 years, and so will be fully amortized prior to December 31, 2025. Ameren Ex. 1.0 (Rev.) at 33. AIC contends that no evidence in this proceeding addresses the question of whether the non-property EDIT amortization period should be revised as well to match the "schedule delineated" in Section 16-108.21(b).

AIC argues that a record would need to be developed to address these issues – something the procedural schedule does not permit here, but something that can be accomplished in a separate docket per Section 16-108.21(c).

AIC notes that the formula rate law requires that the filing year and annual reconciliation be based on the utility's actual costs (plus filing year projected plant). Section 16-108.5(c) provides that the formula must be "updated annually with transparent information that reflects the utility's *actual costs* to be recovered during the applicable rate year." EIMA provides for "an annual reconciliation…of the revenue requirement reflected in rates for each calendar year… with what the revenue requirement would have been had *the actual cost* information for the applicable calendar year been available at the filing date." 220 ILCS 16-108.5(c)(6) (emphasis added). The reconciliation reconciles "the revenue requirement that was in effect for the prior rate year (as set by the cost inputs for the prior rate year) with the *actual* revenue requirement for the prior rate year (determined using a year-end rate base) that uses amounts reflected in the applicable FERC Form 1 that reports *the actual costs for the prior rate year*." 220 ILCS 16-108.5(d)(1) (emphasis added).

AIC contends that the AG's primary proposal adjusts AIC's actual 2020 unprotected property-related EDIT by approximately $5 million (AG Ex. 2.1), and the alternate proposal adjusts AIC's actual 2020 unprotected property-related EDIT by $21 million. Ameren Ex. 13.0 at 21. AIC argues that the AG's proposed EDIT amortization levels do not reflect AIC's actual costs, which is contrary to the EIMA requirements. AIC argues that because these adjustments do not reflect AIC's actual costs, they are not proper adjustments to Ameren Illinois' formula rate and should be rejected.

AIC argues that it is reasonable to reflect Ameren Illinois' 2020 level of unprotected property-related EDIT in rates until the Commission opens a new docket to establish a new EDIT amortization schedule. AIC argues this value reflects the Commission's approved amortization approach, allocating the EDIT to all of the customers that will pay for and support the depreciable asset smoothly over its useful life. Ameren Ex. 11.0 at 23. AIC argues that to adopt either of the AG's proposals, by contrast, would require a reconciliation of 2020 costs with accelerated EDIT amortization that is inconsistent with Docket Nos. 18-0808, 19-0436, 19-0387, 20-0381 and 20-0393 and the related appellate court orders, before establishing the "necessary provisions to accomplish the reimbursement" by December 31, 2025 as required by Section 16-108.21(c).

AIC contends that the reasonableness of AIC's unprotected property-related EDIT amount has been repeatedly confirmed; in Docket No. 19-0436, the Commission considered and approved the application of a consistent amortization period for all property-related deferred taxes, both protected and unprotected. In that proceeding, the Commission concluded that use of the ARAM to arrive at a 35-year amortization period for unprotected property-related EDIT is reasonable, equitable, and balances the interest of all customers. *Ameren Ill. Co*., Docket No. 19-0436, Order at 34-36 (December 16, 2019). AIC notes that the Commission again approved this approach in Ameren Illinois' prior FRU, Ameren 2020 FRU. Further, the Commission approved the same proposals in ComEd Docket Nos. 18-0808, 19-0387, and 20-0393.

AIC further notes that the courts have affirmed that this approach is reasonable. On June 25, 2021, the First District Appellate Court issued an opinion affirming the Commission's decision in Docket No. 19-0387 to reject the AG's proposal to accelerate amortization of EDIT for ComEd. On August 19, 2021, the 4th District Appellate Court issued an order affirming the Commission's Docket No.19-0436 order approving AIC's ARAM amortization for unprotected EDIT, following the AG's appeal of that case. The court order stated that "Based on the evidence, we agree with the Commission and find the Attorney General failed to provide substantial evidence that ADIT and its related EDIT are ratepayer funded" and "The Commission's order adopting a 35-year amortization period based on the ARAM method for unprotected property-related EDIT was reasonable and supported by witness testimony." 2021 IL App (4th) 200105-U, ¶¶ 73 & 78. Thus, AIC concludes, its 2020 level of unprotected property-related EDIT represents an established, reasonable approach that can be used until a new amortization period is properly considered and approved in the new proceeding required by P.A. 102-0662.

AIC argues that adopting the AG's proposal for an accelerated amortization now, by contrast, presents a number of concerns.

AIC points to Mr. Stafford's testimony that the AG's primary proposal would produce a significant spike in rates when the amortization period ends in 2024, resulting in increased rates in either 2025 (i.e., Year 6) or whenever the next rate effective date after 2024 is. Ameren Ex. at 23; see Ameren Ex. 11.7. AIC argues that accelerating the amortization of EDIT beyond the new amortization deadline deprives the customers that pay for and support the depreciable asset of the benefits of that EDIT during those years between the end of amortization and December 31, 2025 – for the same reasons ARAM amortization better balances the interests of customers in the short and long term. Docket No. 19-0436, Order at 34-36.

Further, AIC argues, unamortized EDIT represents cost-free capital and is treated as a reduction to rate base from which customers derive an indirect, but important, benefit. Ameren Ex. 11.0 at 24. AIC argues that the AG's proposed accelerated amortization period thus causes a more rapid increase in rate base. In contrast, AIC argues, Ameren Illinois' Commission-approved amortization period best avoids sudden and drastic impacts to rate base and revenue requirement.

AIC further contends that the AG's acceleration proposal does not consider how the amortization period for EDIT affects AIC's cash flow. Mr. Stafford explained that all ADIT represents cost-free capital available to the Company to invest in productive assets. Ameren Ex. 11.0 at 23. The capital will be repaid to the government as the depreciation timing differences reverse, and the Company has this capital available to it for a predictable period of time – the regulatory life of the relevant asset. Mr. Stafford further explained that the difference between "regular" ADIT and EDIT is that the interest free government loan for "regular" ADIT will be repaid to the government but, because of the reduction in tax rates under the TCJA, the interest free government loan for EDIT will instead be paid to customers. In short, Mr. Stafford testified, all that has changed is the destination for the payment of the capital. *Id*. Mr. Stafford testified that flowing the benefit of EDIT to customers over a shorter period effectively truncates the period over which the Company has access to the capital and so decreases cash flow.

For these reasons, AIC asks the Commission to reject the AG's proposals and continue to approve Ameren Illinois' use of the ARAM methodology for all property-related excess deferred taxes, both protected and unprotected, or a 35-year proxy where ARAM is not feasible, until a proceeding to determine the new amortization period is complete.

The AG proposed, as an alternative, an accelerated amortization of EDIT related to unprotected property to offset the rate increase resulting from this proceeding. AG witness Selvaggio illustrated the effect of her alternative proposal as a one-time increase in amortization of $21 million, which is over 50% of the unprotected property EDIT balance as of December 2019. AG Ex. 2.0 at 10.

AIC argues this proposal should be rejected for at least four reasons: (1) the AG has not established that the alternative acceleration is necessary; (2) the alternative proposal will cause a rate spike in 2024; (3) accelerating the amortization of EDIT to provide relief to customers due to the pandemic represents a collateral attack on the Stipulations in Docket No. 20-0309; and (4) the Baltimore Gas and Electric case the AG cites in testimony does not support its alternative approach here.

AIC notes that the AG argues that in 2022: (1) there is a need to offset the increase in electric distribution rates as well as increases in several other rates, including commodity rate and gas rates; and (2) customers will also no longer have the protections established by the Commission's Covid disconnection moratorium. The AG's claims are based on monthly reports that the AG contends show a significant number of AIC customers are enrolling in deferred payment agreements ("DPAs") and incurring late payment fees or charges, and thus will still have difficulties paying their bills.

AIC contends that the AG's arguments lack context. Mr. Stafford testified that the monthly reporting data Ms. Selvaggio cites represents a single snapshot at July 2021, and so fails to account for month to month or year to year trends, or factors that may be specific to July 2021. Ameren 13.0 at 24. For example, Mr. Stafford testified, historical data related to DPAs that shows, based on a monthly review of customers on a DPA, there is actually a decrease in DPA enrollments over the 2017-2021 timeframe. *Id*. Further, Mr. Stafford noted, DPAs are a mechanism designed to help customers manage payments and ultimately pay their bills in full. Thus, Mr. Stafford concluded, it is simplistic to say that the number of customers on DPAs shows that customers are struggling to pay their AIC utility bills in 2021. AIC contends that because the data the AG cites in support of its position was both introduced late and lacks context, it is not a sufficient basis for the AG's alternative proposal.

Second, AIC contends that the AG's alternative proposal creates a specific rate spike in 2024. Mr. Stafford testified that in a 2022 reconciliation, there would be $21 million of amortization in rates coming from the Filing Year calculation in the current proceeding, but actual unprotected property-related amortization (for 2021) would only be $2 million. Ameren Ex. 13.0 at 21. Mr. Stafford testified that this would result in a significant increase to the revenue requirement in 2024 of $19 million from the 2022 reconciliation, prior to interest. In addition to interest on the additional Reconciliation balance, rate base would increase by $21 million as a result of the AG's one-time accelerated EDIT amortization, as discussed above, resulting in an additional rate increase impact in 2024 rates. *Id*.

Third, AIC argues, addressing the impacts of Covid-19 is beyond the scope of this proceeding, in light of the global settlements, stipulations and Commission orders by which Illinois public utilities "have agreed to various commitments and undertakings with regard to the continuation of utility services, the recovery of associated costs, customer assistance, and other pertinent matters related to the provision of essential utility services during the present public health emergency." *In the Matter of Moratorium on Disconnection of Util. Services during the Public Health Emergency Declared on March 9, 2020 pursuant to Sections 4 and 7 of the Ill. Emergency Management Agency Act*, Docket No. 20-0309, Order at 4 (June 18, 2020). In Docket No. 20-0309, Ameren Illinois entered into an initial settlement that included the AG. That settlement, AIC contends, and the subsequent Commission Order, established policies and procedures relating to utility credit and collections procedures, payment assistance, and recovery of costs incurred by those utilities as a result of the pandemic. *See* Docket No. 20-0309, Order at 2. On March 18, 2021, the Commission approved a second Stipulation, which extended certain customer protections and payment assistance programs, and which provided "The commitments reflected in the terms, including all paragraphs and subparagraphs, of this Stipulation are interdependent and therefore not severable. Thus, AIC concludes, if any terms are not adopted by the Commission in whole, are adopted by the Commission on an otherwise modified basis, are subsequently vacated by the Commission or a court, or are modified pursuant to or in response to a Commission order, directive, or request, the entire Stipulation is null and void." Docket No. 20-0389, Order on Reopening (Mar. 18, 2021), Appendix A – Enforceability Terms, para. 3.

AIC argues that to the extent the AG is now seeking to provide new pandemic-related payment assistance through accelerated amortization of EDIT in this docket, that would modify the terms agreed to in the Stipulations in Docket No. 20-0309 and render the Stipulations void. AIC notes that the AG participated in the extensive and comprehensive settlement discussions throughout the pendency of that proceeding, and so should be aware of the policies and procedures arising out of that proceeding. *See* Docket No. 20-0389, Order on Reopening, Appendix A. To the extent that the AG suggests that the Commission now adopt an accelerated amortization period in order to provide additional pandemic-related relief to customers, AIC contends that this is not the appropriate docket for that concern.

The AG cites a Maryland Commission order in support of its alternate proposal. AIC argues that the Commission is under no obligation to follow this case. *N. Shore Gas Co./Peoples Gas Light & Coke*, Docket No. 07-0241, Order at 152 (Feb. 5, 2008); *see Downtown Disposal Services, Inc. v. City of Chicago*, 2012 IL 112040, *50 (2012) (internal citations omitted) ("…although decisions from other jurisdictions can provide guidance where precedent from Illinois is lacking, Illinois courts do not look to the law of other states when there is relevant Illinois case law available.")

In the case Ms. Selvaggio cited, *Application of Baltimore Gas and Elec. Co. for an Electric and Gas Multi-Year Plan*, Case No. 9645, Order No. 89678 at 1 (Dec. 16, 2020), the utility proposed to accelerate amortization of excess deferred taxes as part of a multi-year rate plan. AIC notes that the Maryland Commission expressed exactly the same concerns about future rate impacts that led this Commission to reject accelerated amortization five times.

AIC notes that Staff agrees that the Commission should reject the AG's EDIT amortization adjustment because it is "clear that the General Assembly intended that the impact of the new section 16-108.21 is to be addressed" in a separate docket. Staff Init. Br. at 9-10. However, both the AG and CUB in their Initial Briefs argue that the Commission should begin the acceleration of unprotected excess deferred taxes in this docket. AG Init. Br. at 6; CUB Init. Br. at 5. AIC notes that CUB proposes that the Commission adopt either of the two proposals by AG witness Selvaggio (5-year amortization or, alternatively, a one-time amortization to offset Ameren Illinois' rate increase) (CUB Init. Br. at 5), while the AG now appears to recommend only the alternative, one-time acceleration (AG Init. Br. at 6).

AIC notes that the AG and CUB rely on the findings of the General Assembly in Section 16-108.21(a) as the basis for their conclusion that amortization should be accelerated in this docket. CUB Init. Br. at 5; AG Init. Br. at 19. The AG claims "the section leaves no doubt that it is in the State's interest to *prevent rate increases* when possible…" AG Init. Br. at 19. But, AIC responds, nothing in Section 16-108.21 actually says this. Rather, Section 16-108.21(a)(5) makes clear that the "State's interest" is an accelerated timetable for amortization, not "preventing rate increases." 220 ILCS 5/16-108.21(a)(5). AIC contends the general Assembly's findings in Section 16-108.21(a) do not specify what this accelerated timetable should be. But, AIC continues, Sections 16-108.21(b) and (c) do specify both the timetable and the docket – a separate docket initiated by the Commission. Thus, AIC contends, the General Assembly's findings cannot be used to override the plain requirements of Section 16-108.21(c).

CUB also argues that adopting one of the AG's acceleration proposals is a "reasonable way to start the accelerated amortization process without prejudging the outcome of a pending proceeding that has no statutory timeline for completion." But according to AIC, the opposite is true, as increasing the unprotected property-related EDIT amortization amount for 2020 would reduce the remaining balance of unprotected property-related EDIT significantly. This, AIC argues, would necessarily affect the amount and timing of any accelerated amortization ordered pursuant to Section 16-108.21(c) – and so prejudge the outcome.

For these reasons, AIC argues, the AG's proposed accelerated amortization of unprotected property-related EDIT in this docket should be rejected, Ameren Illinois' existing amortization amount for 2020 should be approved, and the accelerated amortization of EDIT should be separately addressed in a new docket pursuant to Section 16-108.21.

b. Staff's Position

Staff notes the AG's request that the Commission order AIC to refund the December 31, 2019 balance of EDIT for non-protected property using a shorter timeframe of five years instead of the 35-year amortization period that is currently being used by the Company pursuant to the ARAM method, as approved by the Commission in prior AIC FRU Docket Nos. 19-0436 and 20-0381. AG Ex. 1.0 at 4-10. Staff asks the Commission to decline to do so in this proceeding.

Staff observes this issue has come before the Commission in the last two AIC FRU dockets and the proper amortization period for EDIT related to non-protected property has been a vigorously disputed issue in those proceedings, including oral arguments. Staff Ex. 5.0 at 14. Staff argues that no evidence was provided in this case sufficient to support a departure from the Commission's two prior orders. *Id*. In fact, in its June 25, 2021 Opinion in *People ex rel. Raoul v. Ill. Commerce Comm'n*, 2021 IL App (1st) 200366, the Appellate Court for the First Appellate District affirmed the Commission's decision to allow amortization by a utility of unprotected EDIT over a period of 39.47 years, rejecting the AG's assertion that this period was unreasonable. 2021 IL App (1st) 200366, ¶¶64-71.

Staff notes that Public Act 102-0662 requires the Commission to "initiate a docket to provide for the refunding of [ ] excess deferred income taxes to ratepayers of the utilities referenced in [ ] dockets [19-0436, 19-0387, 20-0381, and 20-0393], and shall set forth any necessary provisions to accomplish the reimbursement on the schedule delineated in subsection (b)." 220 ILCS 5/16-108.21(c). Staff observes that, at the time of filing, no such proceeding has yet been initiated and argues that it is clear that the General Assembly intended that the impact of the new Section 16-108.21 is to be addressed in that proceeding. Under subsection (b) of Section 16-108.21, [EDIT] in dockets 19-0436, 19-0387, 20-0381, and 20-0393 is to be "fully refunded to ratepayers by the respective utilities no later than December 31, 2025." Staff argues that Section 16-108.21 does not specifically identify Docket No. 21-0365; therefore, it does not prescribe a timeline for the Commission to follow for EDIT to be refunded in Docket No. 21-0365. However, the Commission order arising from the subsection (c) proceeding required by Section 16-108.21 will have the effect of superseding the Commission ruling on the EDIT issue reached in this proceeding. Based upon the above, Staff argues that the Commission should decline to adopt the AG's recommendation.

Staff further observes that the Commission's approval of a 35-year amortization period was recently affirmed by the Appellate Court. *People ex rel. Raoul v. Ill. Commerce Comm'n*, 2021 IL App (4th) 200105-U. Staff contends the AG has failed to present any evidence of changed circumstances that would warrant departing from the approach the Commission has taken in the last two Ameren Illinois FRUs and the approach upheld by the Appellate Court. Staff observes that the AG cites to P.A. 102-0662, enacted on September 15, 2021 (after the evidentiary hearing in this docket), as a reason why the Commission should depart from its past decisions on EDIT. AG Init. Br. at 9-11. However, Staff argues, P.A. 102-0662 does not apply retroactively to the Company's 2020 EDIT, and Section 16-108.21(c) of P.A. 102-0662 requires amortization of EDIT to be addressed in a separate docket. For these reasons, Staff argues the AG's proposal should be rejected and the Company's existing amortization amount for 2020 should be approved.

c. AG's Position

The AG requests that the Commission accelerate amortization of the unprotected property EDIT such that the acceleration offsets any increase resulting from this proceeding only. *Id.* at 9–10; *see* AIC Ex. 13.0 at 20–21, ref. AIC Ex. 13.5. Of the total $438.020 million EDIT, AG witness Mary Selvaggio identified that only 9% or $39.253 million is allocated to distribution (or delivery service) and is unprotected property EDIT. (The total unprotected property related EDIT is $69.697, including distribution and non-distribution. *See* AG Ex. 2.0 at 8 (AIC net plant allocator is 56.32%)). The AG argues that it is this amount, $39.253 million, that is subject to a shorter amortization period. The AG's recommendation does not impact 84.1% of the total electric EDIT. AG Ex. 2.0 at 7, 8. The AG argues that its request would apply an incremental amortization of $21 million of this unprotected property EDIT to offset the rate increases that Ameren Illinois requests in this proceeding. *Id*. According to the AG, its recommendation is squarely aimed at providing customers both relief and protection from Ameren Illinois's rising costs when they need it most, which it argues is right now.

The AG argues its recommendation would reduce the net revenue requirement increase to approximately zero because it "results in an incremental reduction in revenue requirement of approximately $30 million for the Filing Year calculation and another $30 million for the Reconciliation Year calculation, with Interest, such that the proposed additional $21 million of amortization reduces revenue requirement by about $60 million in the current proceeding." *Id*. at 10; AIC Ex. 13.5. The AG does not ask the Commission to determine the refund period here for the entire EDIT balance at issue. The AG argues its recommendation would not exhaust the unprotected property EDIT; the remainder ($16.057 million) would be left to be amortized later.

With the recent enactment of P.A. 102-0662, the AG argues that its recommendation is most consistent with the legislature's clear and unambiguous intent to deliver monetary relief now to help ameliorate the economic harms and ongoing pandemic threat that the State's ratepayers face. The AG contends that the relevant section of the new act, Section 16-108.21, supports its recommendation. In applying the cardinal rule of statutory construction, the "primary goal … is to ascertain and give effect to the intent of the legislature," and "[t]he most reliable indicator of legislative intent is the language of the statute, which is to be given its plain, ordinary and popularly understood meaning," and "[w]here the language of the statute is clear and unambiguous, courts may not resort to aids of statutory construction." *In re Powell*, 217 Ill. 2d 123, 135 (2005) (internal citations omitted).

The AG argues that the plain language of Section 16-108.21 expresses the immediacy and urgency of the monetary stresses that Illinois ratepayers face; specifically, the statute references the ongoing COVID-19 pandemic which "has harmed many customers of all rate classes in the State," and for which the Commission has "adopt[ed] a number of measures to provide relief for customers." 220 ILCS 5/16-108.21(a)(4). The AG contends that the section leaves no doubt that it is in the State's interest to prevent rate increases when possible, and that its prescription is to provide repayment of EDIT "on a timetable *greatly accelerated*." *Id*. at 16-108.21(a)(5) (emphasis added). The urgent need for immediate ratepayer relief is clear and unambiguous from the statutory language.

The AG further argues that statutory construction shows why Ameren Illinois's proposal to keep its 35-year amortization period for the EDIT at issue is untenable. The AG argues that the plain language of Section 16-108.21(a)–(b) leaves no doubt that the legislature's intent is to overturn Ameren Illinois's 35-year amortization period. The AG points out that subparagraphs (a)(1)–(3) not only identify the EDIT discussed in this proceeding, but that subparagraphs (a)(5) and (b) also reference specific AIC formula rate dockets (i.e., Docket Nos. 19-0436, 20-0381), and prescribe an accelerated return to ratepayers "[n]otwithstanding the Commission orders" in those dockets. 220 ILCS 5/16-108.21(a)–(b). As such, the AG argues that AIC's insistence that the Commission maintain its 35-year amortization period for unprotected property EDIT cannot square with the plain intent of Section 16-108.21 that the EDIT refund is to be "greatly accelerated" despite clearly disapproved prior Commission orders. *See Id*. According to the AG, AIC's request thus leads to an absurd result, and "[s]tatutes should be interpreted to avoid impractical or absurd results." *Commonwealth Edison Co. v. Ill. Commerce Comm'n*, 2014 IL App (1st) 132011, ¶ 26. The AG contends that if the Commission were to adopt AIC's proposal, it would continue an approach that the General Assembly has expressly denounced.

The AG stresses that nothing in the statutory language of Section 16-108.21 precludes this Commission from adopting its recommendation. The AG argues that the Commission's adoption of its recommendation would be entirely logical and consistent with the statutory language, and "in the interest of the State" to repay the EDIT "on a timetable greatly accelerated" to provide relief for customers "harmed" by the ongoing COVID-19 pandemic. 220 ILCS 5/16-108.21(a)(4)–(5). The AG argues that while Section 16-108.21(c) may instruct the Commission to "initiate a docket" to order that refunds are made by no later than December 31, 2025, this language in no way precludes this Commission from beginning the refund process in this docket to provide AIC ratepayers with needed relief now. *Id*. at 16-108.21(c). The AG argues that read together with Section 16-108.21(a), the unambiguous intent of the language counsels against the Commission waiting to provide relief until that later proceeding. *In re Shelby R*., 2013 IL 114994, ¶ 32 (internal citation omitted) ("[T]he fundamental principle that statutes must be read as a whole and not as isolated provisions.") The AG argues there is no timetable for the Commission to initiate this other docket, nor is there any statutory timetable for its completion (other than that the refund be completed by December 31, 2025). The AG contends that starting the process of refunding the EDIT at issue now will smooth out the refund over four years and avoid procedural delays that may require an accelerated refund over fewer years, potentially causing unnecessary rate fluctuations.

In response to the Company's claim that Section 16-108.21 does not allow for the AG's recommendation, the AG argues that the statutory construction of the law is clear: The General Assembly mandated the refund of unprotected property related EDIT within four years, and has expressly rejected Commission orders that had accepted Ameren Illinois's 35-year amortization. The AG argues that Ameren Illinois asks the Commission to wrongly defy the General Assembly's intent. The AG dismisses as hyperbole the Company's claims that the AG's recommendation could harm the Company's cash flow and access to cost-free capital. Ms. Selvaggio testified that "[i]n six of the years between 2012 and 2021, AIC's net revenue requirement increased or decreased by significantly more than $30 million …" (AG Ex. 2.0 at 11) and the AG stresses that the total unprotected property EDIT subject to shorter amortization of $39.253 million represents just 9% of the Company's total electric EDIT. *Id*. at 7, 8.

The Company claims Section 16-108.21 should not apply to this proceeding under a retroactive analysis prescribed in *Landgraf v. USI Film Prod*., 511 U.S. 244, 269–70 (1994). The AG argues that the Landgraf test is irrelevant and does not apply. According to the AG, the *Landgraf* test is used only when courts are called to determine whether an amended statute may be applied retroactively to events that occurred before the law was enacted. *See, e.g., Commonwealth Edison Co. v. Will County Collector*, 196 Ill. 2d 27, 36–37 (2001). But in this docket, the AG argues that no one is asking that rates in effect before the law was enacted be changed; the new law only affects prospective rates, making *Landgraf* irrelevant. The AG cites the well-established rule that Illinois courts "must decide the case in accordance with the law *as it now exists* unless the law affects the vested rights of the parties." *McGinley v. Madison*, 366 Ill. App. 3d 974, 981 (2006) (emphasis added) (citations omitted). The AG argues there are no vested rights at issue in this proceeding, and that no parties dispute that the EDIT at issue in this proceeding (and prior proceedings) is that EDIT relating to unprotected property not subject to the average rate assumption method ("ARAM") only. The AG further notes that there is no dispute that the Commission maintains its authority to refund this amount over a time period of its choosing. The AG argues there is no justification for the Commission to depart from the general rule and asks the Commission to apply the law as it stands, which rejects AIC's proposal and supports adoption of its recommendation.

The AG dismisses AIC's contention that the AG's proposal violates the EIMA because it does not reflect the Company's actual costs from the previous year. The AG argues this mischaracterizes EDIT amortization because it is not an annual cost, and that it represents the repayment of money to consumers of the difference between the current and higher federal income tax rate, which no longer applies – and that the Commission has the authority to set it in this proceeding.

The AG further refutes the Company's argument that the record is insufficient to support the AG's recommendation, arguing the record is replete with support for its necessity. The AG cites the numerous rate increases Ameren Illinois's ratepayers face, and that will be compounded should the Commission approve AIC's requested increase here without adopting the AG's recommendations. Ms. Selvaggio highlighted the Company's numerous requests for increased rider charges, from Rider EE by $11.092 million to Rider UEA and PER by $8.71 million to Rider SPC by another $2.5 million. AG Ex. 2.0 at 12–13. The AG argues that ratepayers are also grappling with escalating electricity and gas supply costs, which are leading to higher bills. Ms. Selvaggio testified that more customers "facing substantial increased costs at the same time that the COVID-19 pandemic is returning in the form of the Delta variant." *Id*. at 14–15. Ms. Selvaggio testified that electricity supply rates have increased, noting that between the summer of 2020 and June 2021, electricity rates rose from 4.396¢ to 4.821¢, respectively – an increase of 9.67%. *Id*. at 13. Ms. Selvaggio further testified that the Company's gas customers are also seeing higher bills as a result of the Company's increase of $76.129 million (or 17.7%) revenue requirement in Docket No. 20-0308. *Id*. at 13. The AG argues that these upward cost pressures on consumers are likely to occur after the Commission's consumer protections from Docket No. 20-0309 have expired, meaning that consumers have fewer options to help address all of these escalating costs. *Id*. at 15. According to the AG, AIC's request to increase distribution rates by another $59.115 million (or 5.97%) over its 2021 net revenue requirement will only heighten financial concerns. Ameren Ex. 13.0 at 3. The AG contends these reasons are more than ample to demand the Commission adopt its recommendation.

The AG argues its recommendation is not novel and directs the Commission to a recent decision by the Public Service Commission of Maryland, which adopted a similar proposal. The Maryland Commission ordered the accelerated return of unprotected property to its state's customers more quickly "to blunt the impact" of the utility's rate increase. AG Ex. 1.0 at 8–10, quoting Application of Baltimore Gas & Electric Co. for an Electric & Gas Multi-Year Plan, Case No. 9645, Order No. 89678 at 2, 7–13 (Md. Pub. Serv. Comm'n Dec. 16, 2020). Like the AG's recommendation and the General Assembly's intention in the new Section 16-108.21, the Maryland Commission cited "… the profound impacts of COVID-19 on the [s]tate's and the nation's economy and the welfare of Maryland's ratepayer …" in wanting to ensure " … customers see no net increase in their bills … ." *Id*.; *see also* AG Ex. 2.0 at 11–12. The AG argues this decision demonstrates that – in addition to the mandate of Section 16-108.21 – economic difficulties, such as those that continue to burden Illinois families, schools, and businesses due to the ongoing pandemic, are valid reasons to support the urgency and necessity of the AG's recommendation.

The Company argues that the Maryland Commission's decision does not support the AG's recommendation merely because the Commission mentioned that the funds used to offset rate impacts will be unavailable to offset rates in future years. Ameren Init. Br. at 31. The AG contends that this is not an argument; it is basic math, and that no one disputes that faster reimbursement of funds now will result in less funds to reimburse later. The AG argues that what matters are the reasons for hastening that reimbursement, which the record handily supports.

The Company also argues that the AG's recommendation is a collateral attack on payment assistance terms stipulated between the parties in Docket No. 20-0309. The AG rejects this accusation as meritless, noting that the stipulation does not preclude the AG, Staff, or any party, from proposing adjustments in this or another docket whose effects include providing rate relief to consumers. The AG further argues that Docket No. 20-0309 did not address rates, nor did it monopolize or close the door on such critical proposals.

Next, the AG rejects the Company's argument that the AG's recommendation would result in a rate spike in 2024. The AG argues this is irrelevant, speculative, and exaggerated, because the EDIT amount at issue ($39.253 million) represents just 9% of the Company's electric EDIT. AG Ex. 2.0 at 7–8. In rejecting AIC's suggestion that there will be a specific rate spike, the AG argues that the rate increase or decrease in each of these changes have exceeded the effect of its proposal. AG Ex. 2.0 at 11.

Staff declined to support the AG's recommendation on two grounds, both of which the AG argues are groundless. Staff first argues that the Commission should proceed with Ameren Illinois's 35-year amortization period based on the Commission's orders "in the last two AIC FRU dockets" and related appellate opinion. The AG argues that the formula rate dockets are specifically identified in Section 16-108.21(a)(5) and (b), which collectively make clear that "[n]otwithstanding the[se] Commission orders," it is "in the interest of the State for repayment of the [EDIT] … to be paid back to ratepayers on a timetable greatly accelerated from that set forth in the dockets," and to "fully refund[ ]" the EDIT "to ratepayers by … no later than December 31, 2025." 220 ILCS 5/16-108.21(a)(5), (b). The AG contends that the language of the statute and its intent could not be clearer that the General Assembly does not support a 35-year amortization period for unprotected property related EDIT.

Staff then posits that the exclusion of this formula rate proceeding in the statute must mean that the General Assembly did not prescribe a timeline for the Commission to follow here on refunding the EDIT. In response, the AG notes that the EDIT provision is in Section 16-108, which is the same general section as formula rates, which are established in Section 16-108.5. *See* 220 ILCS 5/16-108, 16-108.5. The AG argues that this statutory interpretation violates the fundamental principle that statutes be read as a whole and not as isolated provisions (*see In re Shelby R*., 2013 IL 114994 at ¶ 32), and that Staff's interpretation leads to an absurd result, where the Commission approves an order that the General Assembly expressly prohibited (*see Commonwealth Edison Co*., 2014 IL App (1st) at ¶ 26 ("[s]tatutes should be interpreted to avoid impractical or absurd results")). The AG argues that Staff commits the same errors as the Company, and these errors constitute defiance of the General Assembly's will.

The AG contends that its recommendation aligns with the legislative intent of Section 16-108.21, which demands the Commission provide relief and protection to ratepayers right now. The AG argues that the Commission has the authority, the opportunity, and the record necessary to implement the AG's recommendation. The AG demands that the Commission take action by adopting its recommendation in this proceeding.

d. CUB's Position

CUB notes the amortization timeline for EDIT pertaining to unprotected property has been the subject of debate in every post-TCJA Ameren Illinois FRU proceeding. Federal tax law requires that the refund of EDIT for protected property be amortized according to the Average Rage Assumption Method's projection of the remaining useful life of the underlying assets. Pub. L. No. 115-97, 131 Stat. 2054 § 13001(d)(1) (2017). However, CUB contends that no such legal requirement applies to the 9.0% of Ameren Illinois's EDIT balance that pertains to unprotected property allocated to electric distribution. *See* AG Ex. 2.0 at 7-8 (calculating the percentage). Nonetheless, CUB notes, the Commission has determined in past Ameren Illinois FRUs to extend the ARAM EDIT amortization period for protected property to unprotected property as well, spreading the refund across the next 34 years. Docket No. 18-0808, Order 57-58 (Dec. 4, 2018); Docket No. 19-0436, Order at 37 (Dec. 4, 2019); Ameren 2020 FRU, Order at 27-28 (Dec. 9, 2020).

CUB observes that P.A. 102-0662, which was signed into law in September 2021, departs from the Commission's previous decisions on the amortization of Ameren Illinois's EDIT for unprotected property and mandates it be refunded in full to ratepayers by "no later than December 31, 2025." 220 ILCS 5/16-108.21(b). P.A. 102-0662 orders the Commission to initiate a separate docket to execute this accelerated amortization. *See* § 16-108.21(c). However, CUB notes, no applicable law precludes the Commission from recognizing that the amortization period has been shortened by statute and determining the amortized portion of EDIT to be deducted from the revenue requirement determined in this FRU accordingly. CUB also points out that P.A. 102-0662 expressly recognizes that the COVID-19 pandemic has imposed economic hardship on ratepayers and that the accelerated refund of EDIT for unprotected property to ratepayers therefore would serve the public interest. 220 ILCS 5/16-108.21(a)(4)-(5).

AG witness Selvaggio makes two proposals, either of which CUB maintains would address the need to begin the acceleration of the refund of unprotected property EDIT that P.A. 102-0662 requires. Ms. Selvaggio's primary proposal is to calculate this rate year's unprotected property EDIT amortization based on a 5-year amortization period. AG Ex. 1.0 at 4-5. In other words, AIC would refund 20% its unprotected property EDIT balance to its customer next year. AG Ex. 2.0 at 9. This adjustment would increase the EDIT refund for the rate case year by $5.655 million. *Id*. at 4; AG Ex. 2.1. CUB observes that P.A. 102-0662 requires a refund of the full amount by the end of 2025, which translates to a 4-year amortization period. 220 ILCS 5/16-108.21(b). However, CUB observes that at the time of filing, the docket mandated by P.A. 102-0662 to finalize this amortization schedule has not yet begun. CUB posits that this FRU proceeding will conclude before that docket's outcome is known. Therefore, CUB argues, Ms. Selvaggio's proposed 5-year amortization period is a reasonable way to start the accelerated amortization process without prejudging the outcome of a pending proceeding that has no statutory timeline for completion.

Ms. Selvaggio's alternative proposal is to accelerate amortization of EDIT related to unprotected property to offset any rate increase resulting from this proceeding. AG Ex. 1.0 at 7-8. In support of this proposal, Ms. Selvaggio references the same financial impacts on ratepayers imposed by the COVID-19 pandemic that P.A. 102-0662 recognizes in its findings supporting accelerated EDIT amortization. *Id*. at 8; 220 ILCS 5/16-108.21(a)(4)-(5). While not directly applicable to this FRU proceeding, P.A. 102-0662's additional provisions regarding amortization of charges or credits reference the public interest in determining amortization periods so as to mitigate customer bill impacts. 220 ILCS 5/6-105.6(a). CUB argues this speaks to the reasonableness of Ms. Selvaggio's alternative proposal to calculate the amortized portion of unprotected property EDIT to be returned to customers in the next rate year so as to exactly offset any rate increase that otherwise would have gone into effect.

CUB supports Ms. Selvaggio's proposals and asks that the Commission adopt either her proposed 5-year amortization or her rate increase offset proposal. The latter would provide ratepayers the greatest relief right now, and therefore is CUB's preference, given the ongoing economic hardships facing Ameren Illinois's customers amid the COVID-19 pandemic.

e. Commission Analysis and Conclusion

Section 16-108.21 of the new P.A. 102-0662 requires that the amortization of EDIT be accelerated, but specifies "[t]he Commission shall initiate a docket to provide for the refunding of [EDIT] to ratepayers of the utilities referenced in those dockets, and shall set forth any necessary provisions to accomplish the reimbursement on the schedule delineated in subsection (b)." 220 ILCS 5/16-108.21(c) (emphasis added). Thus, as Staff and AIC agree, the method by which a refund or reimbursement of EDIT is accomplished is meant to be determined in a new, separate docket. Because a new, separate docket is specifically required in the statute, the Commission finds that the legislature clearly intended that this new docket is the appropriate forum to adjudicate how this accelerated amortization is to be effectuated. Until a new amortization schedule is established in Docket No. 21-0738 pursuant to P.A. 102-0662, the Commission finds Ameren Illinois' 2020 unprotected property-related EDIT amount is reasonable, consistent with prior dockets and the Appellate Court's decision in *People ex rel. Raoul v. Ill. Commerce Comm'n*, 2021 IL App (1st) 200366.

Both the AG and CUB argue that the Commission should begin the acceleration of unprotected EDIT in this docket, arguing the clear language of P.A. 102-0662 requires the return of EDIT to taxpayers by 2025. The Commission recognizes that the clear language of the statute requires the amortization of EDIT to be complete by 2025, but finds the statute to be equally clear that the correct forum for that process to be adjudicated is the new docket specifically required by the statute. The Commission further finds there is nothing in the statutory language that requires, directs, or implies that the Commission should attempt to effectuate this accelerated amortization of EDIT sooner in any other pending dockets. The Commission takes judicial notice of the fact that the new docket required by the P.A. 102-0662 is already underway in Docket No. 21-0738, and Direct Testimony is due to be filed by November 4, 2021. The Commission further recognizes that the Order arising from Docket No. 21-0738 will have the effect of superseding the Commission ruling in this case.

For these reasons, the Commission finds the AG and CUB proposals to accelerate amortization of unprotected property-related EDIT in this docket should be rejected and the accelerated amortization of EDIT should be separately addressed in a new docket pursuant to Section 16-108.21. The Commission further finds that Ameren Illinois' existing amortization amount for 2020 is supported by this record and should be approved. As noted by AIC and Staff, the Commission has repeatedly found the application of a consistent amortization period for all property-related deferred taxes to be reasonable and this approach has recently been affirmed by the Appellate Court. The Commission finds that neither the AG nor CUB have created a record in this docket which justifies departure from past practice in this docket when the legislature so clearly intends that the accelerated amortization process be adjudicated and effectuated in a separate docket.

C. Original Cost Determination

Staff witness Siebert recommended the Commission approve $8,162,525,000 as the original cost of plant in service as of December 31, 2020. Staff and AIC agree that the Commission's Order should state the following with respect to the Original Cost Determination:

> (x) the Commission, based on Ameren Illinois's proposed original cost of plant in service as December 31, 2020, before adjustments, of $8,162,387,000 and reflecting the Commission's determination adjusting that figure, approves $8,162,525,000 as the composite original cost of jurisdictional distribution services plant in service as of December 31, 2020.

The Commission finds that Staff and AIC are in agreement on this issue and approves the agreed-upon original cost determination in this Order.

D. Incremental EIMA Plant Investments

AIC provided the actual and projected incremental plant investment that is included in the revenue requirement in compliance with Section 16-108.5(b)(2) of the Act, as ordered by the Commission in Docket No. 12-0292, to which Staff agrees. The Commission will therefore adopt the following agreed conclusion for use in this proceeding:

> The Commission is setting a revenue requirement in this proceeding for the recovery of $39.8 Million in actual 2020 plant additions and $15.6 Million of projected 2021 plant additions in compliance with Section 16-

108.5(b) of the Act. The details of these actual and projected plant additions by categories as required by Section 16-108.5(b) are as follows:

	Category	Actual 2012-2019 (In Millions)	Actual 2020 (In Millions)	Projected 2021 (In Millions)	Cumulative 2020 (In Millions)
(A)(i)	Distribution Infrastructure Improvements	$215.3	$20.4	$12.7	$235.7
(A)(ii)	Training Facility Construction or Upgrade Projects	$7.4	$0.0	$0.0	$7.4
(A)(iii)	Wood Pole Inspection, Treatment, and Replacement	$0.0	$0.0	$0.0	$0.0
	Total Electric System Upgrades, Modernization Projects, and Training Facilities	**$222.7**	**$20.4**	**$12.7**	**$243.1**
(B)(i)	Additional Smart Meters	$295.0	$10.0	$0.1	$305.0
(B)(ii)	Distribution Automation	$104.4	$9.1	$2.7	$113.5
(B)(iii)	Associated Cyber Secure Data Communications Network	$10.5	$0.3	$0.1	$10.8
(B)(iv)	Substation Micro- processor Relay Upgrades	$6.7	$0	$0.0	$6.7
	Total Upgrade and Modernization of Transmission and Distribution Infrastructure and Smart Grid Electric System Upgrades	**$416.6**	**$19.4**	**$2.9**	**$436.0**
	Total Plant Additions in Compliance with Section 16-108.5(b)(2) of the Act	**$639.3**	**$39.8**	**$15.6**	**$679.1**

E. Recommended Rate Base

1. Filing Year

The Commission finds, based on the decisions presented earlier on the various issues, that a reasonable rate base for the filing year is shown on Appendix A, Schedule 3.

2. Reconciliation Year

The Commission finds, based on the decisions presented earlier on the various issues, that a reasonable rate base for the reconciliation year is shown on Appendix B, Schedule 3.

V. OPERATING REVENUES AND EXPENSES

A. Uncontested or Resolved Issues

1. Injuries & Damages ("I&D") Expenses

Staff and the AG proposed an adjustment to remove from both the filing year and reconciliation year revenue requirements expenses related to Injuries and Damages ("I&D"). On rebuttal, AIC agreed with the adjustment and removed $1.223 million from I&D expenses: after applying the jurisdictional allocation factor applicable to A&G expenses this results in a net adjustment of $1.105 million I&D for the electric distribution portion. Ameren Ex. 11.2 at 56.

The Commission finds that the proposed adjustment removing I&D expenses are reasonable and uncontested, and therefore approves its use in this proceeding.

2. Industry Associated Dues

In response to data request BAP 1.07, AIC provided an adjustment to increase its dues expense by $6,068 as shown on Ameren Ex. 11.3.

The Commission finds that the proposed adjustment to dues expense is reasonable and uncontested, and therefore approves its use in this proceeding.

3. PSUP Adjustment – Correction of AMS Expense/Capital Split

The AG proposed a correction to the Company's ratios for expense and capital for AMS costs. In response to data request AG 4.01, AIC provided the correction to the AMS ratios for expense and capital on Schedules B-2.6 and C-2.9 which is an increase to rate base of $138,000 and a decrease to operating expense of $220,000.

The Commission finds that the agreed-upon proposed corrections to the PSUP Adjustment are uncontested and therefore adopts the proposed corrections for use in this proceeding.

4. Non-Plant Related Excess Deferred Tax Amortization

In response to data request AG 4.03, AIC provided an adjustment to decrease deferred tax expense by $255,289 as shown on Ameren Ex. 11.3 to reflect a correction for its 2020 Deferred Tax Expense.

The Commission finds that the correction is reasonable and uncontested, and therefore approves its use in this proceeding.

5. Rate Case Expense

Section 9-229 of the Act requires the Commission to assess the justness and reasonableness of AIC's rate case expenses. 220 ILCS 5/9-229. Part 288 of the Commission's rules is intended to guide that assessment. 83 Ill. Adm. Code 288. AIC explains that consistent with that authority, it supplied for the Commission's review extensive documentation supporting the justness and reasonableness of its 2019 formula rate case expenses. Staff and AIC agree that the Commission's Order should state the following with respect to those expenses:

> The Commission has considered the costs expended by the Company during 2020 to compensate attorneys and technical experts to prepare and litigate rate case proceedings and assesses that the amount included as rate case expense in the revenue requirements of $599,842 is just and reasonable. This amount includes the following costs: (1) $22,869 associated with Docket No 19-0436; (2) $576,973 associated with Docket No. 20-0381; and (3) $0 associated with Docket No. 21-0365.

No other party opposes AIC's proposed level of rate case expense.

The Commission finds that the total rate case expense that AIC incurred to litigate its formula rate cases in 2020 is supported by the evidence and is just and reasonable. The Commission, therefore, adopts Staff and AIC's suggested language in this Order.

6. Tree Risk Management Program Deferral

Staff proposed certain adjustments to reflect the 2020 Tree Risk Management program costs as repairs and maintenance expense rather than as a rate base deferred charge subject to amortization. AIC agreed and reflected these corrections in its surrebuttal schedules, Ameren Exhibit 13.3. Ameren Exhibit 13.2, page 9 presents an updated Part 285, Schedule B-10 with the regulatory assets approved by the Commission for deferral and the corresponding amortization periods.

The Commission finds that the agreed-upon proposed corrections to the 2020 Tree Risk Management program are uncontested and therefore adopts the proposed corrections for use in this proceeding.

B. Contested Issues

1. Amortization of Excess Deferred Income Tax ("EDIT")

See Section IV.B.2 above.

C. Recommended Operating Revenues and Expenses

1. Filing Year

The Commission finds based on the decisions presented earlier on the various issues, that a reasonable amount for AIC's jurisdictional operating revenues and expenses for the filing year is shown on Appendix A, Schedule 1.

2. Reconciliation Year

The Commission finds, based on the decisions presented earlier on the various issues, that a reasonable amount for AIC's jurisdictional operating revenues and expenses for the reconciliation year is shown on Appendix B, Schedule 1.

VI. COST OF CAPITAL AND RATE OF RETURN

A. Uncontested or Resolved Issues

1. Cost of Capital and Overall Rate of Return of Rate Base

As shown in the table below, Staff and AIC agree that a cost of long-term debt of 4.092% and a cost of preferred stock of 4.979% are reasonable for both the 2022 rate setting and the 2020 reconciliation. In addition, Staff agrees that AIC's bank facility costs add 1.7 basis points to AIC's weighted average cost of capital. Finally, Staff and AIC agree that the cost of equity is 7.360% which equals the 1.560% average of the twelve monthly 30-year U.S. Treasury bond yield averages in 2019, plus 580 basis points, as required under Section 16-108.5 of the Act. 220 ILCS 5/16-108.5(c)(3). The cost of equity for the 2022 revenue requirement is 7.360%. Further, Staff and AIC agree the cost of equity for the 2020 reconciliation year revenue requirement must be adjusted by 0.070% for performance metrics penalty. Thus, the cost of equity for the 2020 reconciliation year revenue requirement is 7.290% (7.360% minus the 0.07% performance metric penalty).

a. Filing Year

The Commission finds that the agreed-upon costs of debt and equity are reasonable and uncontested and therefore adopts them for use in this proceeding.

Component	Weight	Cost	Weighted Cost
Long Term Debt	48.285%	4.092%	1.976%
Short Term Debt	0.000%	0.080%	0.000%
Preferred Stock	0.715%	4.979%	0.036%
Common Stock	51.000%	7.360%	3.754%
Bank Facility Costs			0.017%
Total Capital	100.000%		5.783%

b. Reconciliation Year

Component	Weight	Cost	Weighted Cost
Long Term Debt	48.285%	4.092%	1.976%
Short Term Debt	0.000%	0.080%	0.000%
Preferred Stock	0.715 %	4.979%	0.036%
Common Stock	51.000%	7.290%	3.718%
Bank Facility Costs			0.017%
Total Capital	100.000%		5.747%

B. Contested Issues

1. Capital Structure

a. AIC's Position

AIC and Staff agreed to capital structures for the Filing Year and the Reconciliation Year. AIC asserts that for the following reasons, those capital structures should be approved and used by the Commission in its Final Order in this proceeding.

Darryl Sagel, Vice President and Treasurer for Ameren Services Company, presented the Company's proposed capital structure. Ameren Ex. 5.0 at 9. Mr. Sagel explained that the Company proposed to use its year-end 2020 capital structure, which consisted of no short-term debt, 46.208% long-term debt, 0.715% preferred stock, and 53.077% common equity, excluding goodwill and the effects of purchase accounting.

Mr. Sagel explained that AIC's 2020 year-end actual capital structure is reasonable and prudent for the FRU since the actual capital structure was managed and maintained in a manner consistent with sound financial practice. *Id*. Importantly, he noted, the Company's actual year-end 2020 capital structure will continue to support Ameren Illinois' infrastructure investments to enhance customer service and reliability (with affiliated job creation benefits), while maintaining the strong financial position and credit ratings that Ameren Illinois has preserved for a number of years. *Id*. Mr. Sagel testified that the structure prudently balances the relative costs and benefits of debt and equity financing and establishes financial strength and stability at a reasonable weighted average capital cost. Mr. Sagel explained that AIC's capital structure and the credit metrics that are derived in part from it also support Ameren Illinois' current investment grade issuer credit ratings, ratings that should enable Ameren Illinois to execute debt financing at reasonable rates.

AIC acknowledges that the common equity component of the Company's initially proposed capital structure exceeds the 50% "safe harbor" under the EIMA. 220 ILCS 5/16-108.5(c)(2). Accordingly, Ameren Illinois was required to provide additional evidence that the capital structure is prudent and reasonable.

Mr. Sagel testified that the Company requires a common equity ratio in excess of 50% to maintain its current credit ratings. Mr. Sagel testified that the Company's operations have experienced cash flow reductions from the change in the federal corporate tax rate in the TCJA, which became effective on January 1, 2018. *Id*. at 10. Mr. Sagel stated that the TCJA brought significant benefits to AIC's electric customers in the form of reductions in current taxes and excess deferred taxes that they received and are continuing to receive through new base rates established in the Company's subsequent formula ratemaking cases. However, Mr. Sagel asserted, realization of these benefits by customers carries with it certain potentially significant adverse financial impacts to Ameren Illinois. *Id*. at 11. Mr. Sagel explained that on June 18, 2018, Moody's cited the TCJA changes and the resulting increase in financial risk for utilities as the driver for changing its outlook on the U.S. regulated electric and gas utility sector from "stable" to "negative". While Moody's did subsequently change its outlook for the utility industry back to "stable" from "negative" on November 9, 2019, it did so as a result of the implementation of more proactive regulatory and financial actions to address sector cash flows following passage of the TCJA, with such regulatory actions including increased authorized equity layers. *Id.* Mr. Sagel explained that approving Ameren Illinois' actual year-end 2020 capital structure, which includes increased equity content relative to recent years, can help ensure that the Company maintains its current strong credit ratings.

AIC observes that Staff witness Freetly opposed the Company's proposed capital structure and recommended that the common equity ratio be set at 50%. Ms. Freetly testified that the performance-based formula rate plan under EIMA has had a positive impact on the Company's credit ratings. Staff Ex. 4.0 at 5. Ms. Freetly also testified that the Company's proposed common equity ratio exceeds the mean common equity ratio for electric distribution utilities for 2021. *Id*. at 8. She further testified that a 50% common equity ratio would be adequate to support the Company's current credit ratings. *Id*. at 9.

In response, AIC witness Sagel testified that the median authorized effective common equity ratio, rather than the mean, is the appropriate measure to use because the mean is influenced by aberrantly low equity ratios in Texas. Ameren Ex. 12.0 at 15. Mr. Sagel explained that the median equity ratio for 2021 is 50.53%, with a high of 54.51%. Mr. Sagel further explained that the Company's proposed equity ratio was above the mean, toward the higher end, but reasonable and justified based on the Company's declining credit metrics.

Mr. Sagel also explained that the Company's equity ratio is justified by its equity-weighted ROE, which is the product of a company's authorized ROE multiplied by its equity ratio. It effectively measures a company's practical equity return. *Id*. at 16. Mr. Sagel explained that at its proposed common equity ratio, the Company's 2021 equity-weighted ROE for electric distribution was projected to 3.91%. Mr. Sagel stated that this compares to an industry median of 4.79%. *Id*. at 15.

Thereafter, the Company and the Staff entered into a Partial Stipulation on Capital Structure ("Partial Stipulation"), in which they stipulated to capital structures for the Filing Year and the Reconciliation Year that reflect common equity ratios of 51.000%. AIC noted that no party opposed the filing of the Partial Stipulation, and it was admitted into evidence.

A settlement agreement not agreed to by all of the parties may be considered by the Commission as a decision on the merits as long as the provisions of the settlement are "supported by substantial evidence in the whole record." *Bus. and Prof'l People for the Pub. Int.*, 136 Ill.2d 192, 216-217 (1989) ("*BPI*"). AIC contends that the Partial Stipulation meets that standard. AIC argues that the evidence provided by Mr. Sagel justifies a higher common equity ratio than that reflected in the Partial Stipulation. Moreover, AIC argues, the stipulated common equity ratio of 51.000% is not meaningfully in excess of the 2021 median common equity ratio for electric distribution utilities and is well below the higher end of the range. Ameren Ex. 12.0 at 15. AIC maintains that, together with the lack of any evidence regarding the appropriate capital structure from any party other than the Company and Staff, the record fully and adequately supports the adoption of the capital structures reflected on Attachment A to the Partial Stipulation.

AIC notes that the AG and CUB oppose the 51% common equity ratio endorsed by the Company and Staff in their Partial Stipulation. The intervenors argue that the 51% ratio is per se illegal; that the 51% ratio was not specifically supported by record evidence;

and that acceptance of the 51% ratio from the Partial Stipulation would violate the Supreme Court's holding in *BPI*. AIC argues that none of these objections to the 51% common equity ratio is valid.

In short, AIC argues, the 51% common equity ratio should be approved because it was expressly supported by the testimony of Ms. Freetly; it is within the range of common equity ratios recommended by the parties in their evidence; and the Commission can approve a 51% ratio if it wishes without need for the Partial Stipulation. Moreover, AIC contends that the Partial Stipulation does not violate *BPI*.

First, AIC notes the AG's argument that FEJA's amendment to Section 16-108.5(c)(2) of the Act bars any common equity ratio in excess of 50% and responds that to the contrary, that amendment created a "safe harbor" by insulating a common equity ratio up to 50% from attack:

> To enable the financing of the incremental capital expenditures, including regulatory assets, for electric utilities that serve less than 3,000,000 retail customers but more than 500,000 retail customers in the State, a participating electric utility's actual year- end capital structure that includes a common equity ratio, excluding goodwill, of up to and including 50% of the total capital structure shall be deemed reasonable and used to set rates.

220 ILCS 5/16-108(c)(2).

AIC argues that it is clear from this language that the provision is a safe harbor and not an absolute limit, because: 1) the provision does not expressly bar common equity ratios in excess of 50%; 2) the provision that a "common equity ratio… of up to and including 50% of the total capital structure shall be deemed reasonable" does not preclude finding a higher common equity ratio reasonable; and 3) the provision's stated purpose is "to enable . . . financing." The section enables financing by allowing the utility to represent to lenders and equity investors that a common equity ratio less than 50% cannot be imposed on it. AIC argues that an absolute cap on the common equity ratio would not "enable financing."

The AG places great weight on its observation that Ameren Illinois "has not received a common equity ratio greater than 50% since the passage of FEJA." AIC contends that this makes it sound like the Commission has enforced this provision to bar common equity ratios above 50%. However, AIC points out, there is no case in which the Commission has denied the Company a common equity ratio greater than 50% since FEJA was adopted because the Company has not requested one.

Secondly, AIC notes the AG and CUB's argument that the Commission cannot approve a 51% common equity ratio because that precise figure was not expressly supported by any party before the Partial Stipulation was filed. AIC claims that contention is simply wrong, for two reasons: 1) Ms. Freetly testified in support of the 51% figure, and 2) the Commission frequently approves components of the ROR that no party has proposed, typically arriving at its result through an averaging of some or all of the components of the analysis of some or all of the parties submitting evidence on the topic—and the courts have upheld that practice.

AIC observes that the Commission is frequently faced with a situation in which the parties present disparate recommendations and identify what they believe to be significant flaws in the analysis of the others. The Commission has in the recent past averaged the parties' recommendations in such instances. *See, e.g., Ameren Ill. Co.*, Docket No. 20-0308, Order at 168-69 (Jan. 13, 2021) "Averaging is a reasonable approach that has been traditionally both used by the Commission and upheld by the courts." *Nicor Gas Co.*, Docket No. 18-1775, Order at 120, *citing Ill.-Am. Water Co.*, Docket No. 16-0093, Order at 66-67 (Dec. 13, 2016); *Aqua Ill., Inc.*, Docket No. 14-0419, Order at 43 (Mar. 25, 2015); *Citizens Util. Bd. v. Ill. Commerce Comm'n*, 2018 IL App (1st) 170527, ¶ 33.

AIC argues that in *Citizens Util. Bd.*, the Appellate Court expressly rejected the argument that CUB and the AG are making here. In the case below, the Commission averaged ROE recommendations to arrive at an ROE of 9.87%. The intervenors in the case appealed. The court stated:

> Essentially, the intervenors suggest that in order for substantial evidence to have supported the ROE approved by the Commission, the record would need to show that (1) a witness recommended a 9.87% ROE, (2) that witness supported his testimony with additional evidence showing a ROE of 9.87% was appropriate, and/or (3) a witness testified that a ROE falling outside the range suggested by the witnesses would be proper. The intervenors contend that the varying expert opinions did not permit the Commission "to cobble together" an authorized ROE. Contrary to the intervenors' position, that is precisely what the Act permits the Commission to do.

Citizens Util. Bd., ¶ 31.

AIC argues that like the intervenors in *Citizens Util. Bd.*, the intervenors in this case are arguing that Ms. Freetly not only had to testify that 51% was reasonable (which she did), but she also had to provide additional evidence showing that exactly 51% was reasonable, or the Commission cannot approve the 51% common equity ratio. To the contrary, AIC argues, as in *Citizens Util. Bd.*, that is exactly what the Commission can do, with or without the Partial Stipulation: it can approve a common equity ratio of 51% as long as it has substantial evidence for its decision. It does not require "conclusive evidence." *Id.* ¶ 36.

AIC further notes the court's observation that ratemaking by its nature is imprecise:

> Ideally, one expert would have presented flawless analysis suggesting impeccable accuracy in determining what ROE is appropriate in this instance, thereby allowing the Commission to categorically adopt the conclusion of one witness. Unfortunately, this is not the nature of ratemaking. *See Amax*

> *Zinc Co. v. [Ill.] Commerce Comm'n*, 124 Ill. App. 3d 4, 11 (1984) (stating that ratemaking is not an exact science and lacks precision). Indeed, the Commission was within its authority to find that neither [expert] provided a nonpareil opinion.

Id. ¶ 35. Accordingly, AIC argues, the Commission does not require the testimony of either Ms. Freetly or Mr. Sagel, nor any additional evidence from either of them, to approve a 51% common equity ratio. AIC contends the intervenors' argument that it does should be rejected.

Third, AIC argues that the Commission has approved a capital structure that none of the parties proposed. Earlier this year in *Ameren Ill. Co*., the Commission approved a 52% common equity ratio for Ameren Illinois' gas operations, even though no party had submitted an analysis expressly supporting that result. *Ameren Ill. Co*., Docket No. 20-0308, Order at 130 (Jan. 13, 2021). Ameren Illinois submitted evidence supporting 54.1% (*Id*. at 121); Staff submitted evidence supporting 50.43% (*Id*. at 122); and intervenors submitted evidence supporting 50% (*Id*. at 124). AIC noted that the Commission concluded that the record did not support the utility's proposed 54.1% common equity ratio, but that it did support a finding that the utility required a stronger capital structure than the previously approved 50%. *Id*. at 130. The Commission averaged the utility's common equity ratios at prefiling year-end and mid-year to reach a result of approximately 52%--a figure no party had proposed or supported. (*Id*.)

Fourth, AIC contends that the Commission could reach a 51% common equity ratio without relying on the Partial Stipulation by averaging the three proposals before it: the Company's detailed analysis supporting 53.077%; the Staff's detailed analysis supporting 50%; and the intervenors' unsupported advocacy for 50%. The average of these three figures is 51.03%.

Finally, AIC argues that the Commission can and should give effect to the Partial Stipulation. AIC maintains that the record in this proceeding supports a range of common equity ratios from 50% to 53.077%. *See* Staff Init. Br. at 12-23. Ms. Freetly expressly testified on rebuttal that a 51% common equity ratio was reasonable. Staff Ex. 8.0 at 2. Ms. Freetly further testified that a 51% common equity ratio is reasonably comparable to the 50.46% median authorized effective equity ratio for electric distribution companies. *Id*.

The AG dismisses Ms. Freetly's rebuttal testimony as being unsupported by "capital structure analyses," but AIC argues that is precisely what supports her testimony. AIC contends that the capital structure analyses in the record support a range from 50% to 53.077%. The median common equity ratio is 50.46%. AIC argues that if the AG or CUB believed that Ms. Freetly's rebuttal testimony lacked justification, they could have taken discovery and cross-examined her. AIC notes that they did not—instead, they waived cross-examination.

AIC contends that there is a preliminary question as to whether the intervenors, without their own evidence, can simply adopt Staff's initial evidence as their own. The court in *Citizens Util. Bd*. addressed a similar situation, where intervenors tried to rely on Staff's opinion:

> The intervenors assert that the Commission's decision was not supported by substantial evidence and sufficient findings. Before addressing their specific contentions, however, we find it inappropriate at this juncture for the intervenors to rely on the expert opinion of . . . the expert for the Staff. A party must assert his own legal interests and rights, not those of third parties. *Powell v. Dean Foods Co*., 2012 IL 111714, ¶ 36. The intervenors have not developed a cohesive argument explaining why they should be permitted to rely on another party's evidence. *See Enbridge Pipeline (Illinois), LLC v. Monarch Farms, LLC*, 2017 IL App (4th) 150807, ¶¶ 79-80 (finding that failure to develop a cohesive argument results in forfeiture).

Citizens Util. Bd. ¶ 30.

AIC argues that the situation here is even more egregious because the intervenors are adopting only part of Ms. Freetly's testimony. AIC contends that the AG and CUB are trying in their briefs, in effect, to impeach Ms. Freetly's rebuttal testimony supporting a 51% common equity ratio with her earlier testimony supporting a 50% ratio. AIC argues that the time to attempt that was at hearing—there is nothing in her direct testimony that per se trumps her rebuttal testimony. AIC argues that without some admission from Ms. Freetly that her direct testimony fully cancels out her subsequent endorsement of the Partial Stipulation, the AG and CUB have no basis for their claims. AIC notes that their position relies completely on Ms. Freetly's direct testimony, which she herself superseded by testifying that a 51% common equity ratio was reasonable.

Further, AIC argues, this proceeding is unlike the situation in *BPI*, where the utility and the Staff agreed to a complex, two-step rate increase, with numerous other conditions stretching out over a five-year period that overrode the test year rules and did not give parties who did not agree to the stipulation in that case adequate opportunity to submit evidence regarding the settlement. *BPI*, 136 Ill.2d at 240. AIC argues that here there is no violation of test year rules, and the Company and the Staff are asking the Commission to act consistently with its established practice. Furthermore, unlike *BPI*, AIC maintains, the intervenors had an opportunity to submit testimony, but elected instead not to submit any evidence regarding the capital structure at all. The only two parties who submitted evidence have agreed to a specific point within the range of reasonableness that their evidence establishes.

Accordingly, AIC asks the Commission to reject the intervenors' opposition to a 51% common equity ratio and to approve the capital structure reflected in the Partial Stipulation.

b. Staff's Position

Staff witness Freetly explained that an optimal capital structure minimizes the cost of capital and will maintain a utility's financial integrity. Staff Ex. 4.0 at 2. Unfortunately, determining whether a capital structure is optimal remains problematic because: (1) the cost of capital is a continuous function of the capital structure, rendering its precise measurement along each segment of the range of possible capital structures problematic;

(2) the optimal capital structure is a function of operating risk, which is dynamic; and (3) the relative costs of the different types of capital vary with dynamic market conditions. *Id.* at 3. Consequently, Ms. Freetly explained, one should determine whether the capital structure is consistent with the financial strength necessary to access the capital markets under most economic conditions, and if so, whether the cost of that financial strength is reasonable.

In direct testimony, Ms. Freetly recommended imputing a capital structure for AIC containing 50% equity, which resulted in a ROR on rate base for AIC's electric delivery service operations of 5.749% for the filing year, and 5.714% for the reconciliation year, as shown on Staff Ex. 4.0 PUBLIC, Schedule 4.01.

After the filing of Staff's direct testimony and the Company's rebuttal testimony, Staff entered a Partial Stipulation on Capital Structure with the Company. AIC-Staff Joint Ex. 1. AIC and Staff stipulated that the overall ROR for the filing year is 5.783% and 5.747% for the reconciliation year. Both stipulated RORs reflect a capital structure containing 51% common equity, .715% preferred stock, and 48.285% long-term debt for setting formula rates for the Company's electric distribution operations, as shown below.

AIC - Staff Stipulated Proposal

Filing Year

Type of Capital	Ratio	Cost	Weighted Cost
Long Term Debt	48.285%	4.092%	1.976%
Short Term Debt	0.000%	0.080%	0.000%
Preferred Stock	0.715%	4.979%	0.036%
Common Stock	51.000%	7.360%	3.754%
Bank Facility Costs			0.017%
TOTAL	100.000%		5.783%

Reconciliation Year

Type of Capital	Ratio	Cost	Weighted Cost
Long Term Debt	48.285%	4.092%	1.976%
Short Term Debt	0.000%	0.080%	0.000%
Preferred Stock	0.715%	4.979%	0.036%
Common Stock	51.000%	7.290%	3.718%
Bank Facility Costs			0.017%
TOTAL	100.000%		5.747%

AIC-Staff Joint Ex. 1 - Partial Stipulation on Capital Structure.

Ms. Freetly supported the stipulated capital structure in her rebuttal testimony. *See* Staff Ex. 8.0. While higher than the equity ratio that Staff recommended in direct testimony, Ms. Freetly testified that the 51% common equity ratio reflected in the stipulated ROR lies within the range of equity ratios recommended by parties in this proceeding, and is reasonably comparable to the 50.46% median authorized effective equity ratio for electric distribution companies. Staff Ex. 8.0 at 2 (*citing* Ameren Ex. 12.0 at 15). Further, Ms. Freetly testified that based on the record in this proceeding, the resulting ROR is reasonable to support AIC's financial strength and maintain its investment grade rating and the stipulated capital structure appears consistent with the requirements of Sections 9-230 and 16-108.5(c)(2) of the Act. *Id*.

Ms. Freetly agreed with the Company's costs for the components of the capital structure for December 31, 2020, including bank facility costs of 0.017%, an embedded cost of long-term debt of 4.092%, and an embedded cost of preferred stock of 4.979%. Staff Ex. 4.0 at 18-19. Ms. Freetly further agreed that the ROE set by the formula in EIMA was 7.36% for the filing year, which was reduced by seven basis points as a consequence of AIC not achieving its performance metric for electric service reliability, resulting in an ROE of 7.29% for the reconciliation year. *Id*.

Staff notes that AIC witness Sagel proposed using the Company's December 31, 2020 capital structure, which was comprised of 46.208% long-term debt, 0.715% preferred stock and 53.077% common equity. AIC Exs. 5.0 and 12.0. Ms. Freetly testified that the Company's proposed capital structure contained an excessive amount of common equity and did not comply with Section 16-108.5(c)(2). Staff Ex. 4.0 PUBLIC at 3. Hence, Staff proposed to impute a capital structure for AIC containing 50% equity in accordance with the threshold established in Section 16-108.5(c)(2). *Id*.

Staff notes that AIC has maintained approximately 50% equity in its capital structure for setting formula rates since 2014. As Ms. Freetly explained, the Company's financial health and ability to attract capital has been supported under formula rate plans that reflect a common equity ratio of 50%, with no negative credit rating actions. Staff Ex. 4.0 PUBLIC at 4. Ms. Freetly testified that AIC has operated its electric distribution business under a performance-based formula rate plan since 2011, when the rate plan was originally established as part of EIMA.

Ms. Freetly testified that in AIC's initial performance-based formula rate plan proceeding, Docket No. 12-0001, the Commission concluded that AIC had lower operating risk than its parent company, Ameren Corporation ("Ameren Corp."), and that the regulatory environment was more favorable under the performance-based formula rate plan, which warranted lowering AIC's common equity ratio to 51.49% from AIC's 2010 common equity ratio of 54.28%, consistent with Section 9-230 of the Act, which requires that a regulated utility's ROR cannot reflect incremental risk resulting from affiliation with an unregulated entity. *Ameren Ill. Co.*, Docket No. 12-0001, Order at 128 (Sept. 19, 2012). Subsequently, Ms. Freetly explained, AIC's authorized capital structure contained 51% common equity through 2014, and then in 2015 an equity ratio of 50% was authorized for AIC's formula rates through 2019. Staff Ex. 4.0 PUBLIC at 5.

Ms. Freetly testified that the performance-based formula rate plan has had a positive impact on AIC's credit ratings. *Id*. At the direction of the Commission, AIC filed a Report Pursuant to the Final Order in Docket No. 12-0001, which stated that the credit rating agencies noted that the passage of EIMA had improved the qualitative components of the Company's ratings. *Id*., *citing Ameren Ill. Co.*, Docket No. 14-0317, Ameren Ex.

5.1 at 19 (AIC Report Pursuant to the Final Order in Docket No. 12-0001"). This is evidenced by the fact that AIC's credit ratings from Moody's Investors Service ("Moody's") and Standard & Poor's ("S&P") have been upgraded several times since the implementation of formula rates. Staff Ex. 4.0 PUBLIC at 5-6.

Ms. Freetly testified that at the time AIC agreed to the 50% common equity threshold for determining a revenue requirement under formula rates, AIC was rated Baa1 by Moody's and BBB+ by S&P. *Id*. at 6. Currently, AIC is rated A3 (one notch higher) by Moody's and BBB+ by S&P. Ms. Freetly testified that AIC's credit rating from Moody's improved three notches since formula rates began, while AIC's S&P rating improved two notches. *Id*.

Ms. Freetly further explained that both Moody's and S&P have viewed the performance-based formula rate plan positively, as shown by the rating upgrades that have occurred. *Id*. Specifically, Ms. Freetly testified that Moody's noted "The [performance-based formula rate plan] has operated smoothly for the past ten years with Ameren Illinois' earnings closely tracking authorized levels. From a business risk perspective, having formula rate regulation is a strong credit positive because it provides a high level of cash flow transparency and predictability." *Id*. According to Ms. Freetly's testimony, Moody's also noted the downside of the performance-based formula rate plan is that the existing formula ties the utility's authorized ROE to the 30-year U.S. Treasury rate, which has fallen by 200 basis points or more since 2011. *Id*. at 7, *citing* Moody's Investors Service, "Credit Opinion: Ameren Illinois Company Update to Credit Analysis," May 10, 2021 at 4. Ms. Freetly testified that Moody's outlook for AIC's A3 credit rating is stable. Staff Ex. 4.0 PUBLIC at 7. Ms. Freetly also testified that Ameren Corp. is rated Baa1 by Moody's, one notch lower, indicating higher risk at the utility's parent company. *Id*., *citing* Moody's Investors Service, *Ameren Corporation – Update to credit analysis*, April 3, 2020.

Ms. Freetly explained that S&P's BBB+ rating for AIC includes business risk considered excellent and states that AIC's low level of business risk is bolstered by its constructive regulatory framework that provides more certainty and timeliness of cost recovery compared to peers, which includes, in part, formula ratemaking that contributes to annual relief. Staff Ex. 4.0 PUBLIC at 7, *citing S&P Global, Ratings Direct – Ameren Illinois Co*., April 30, 2021. Ms. Freetly further testified that while AIC's financial risk is considered significant by S&P, S&P's outlook for AIC's BBB+ rating is stable. *Id*. at 7. Under S&P's group rating methodology, Ms. Freetly explained, the issuer credit rating on AIC is in line with Ameren Corp.'s group credit profile of bbb+ because there are no significant insulation measures in place that protect AIC's assets or profits from its parent company. *Id*.

Ms. Freetly compared the Company's proposed equity ratio of 53.077% to the authorized equity ratios for electric distribution utilities over the last three years, as reported by S&P Global Market Intelligence ("MI"). *Id*. at 8. Ms. Freetly computed the average authorized equity ratio for the electric distribution-only utilities for each year from 2018 through 2020. Ms. Freetly also calculated the average equity ratio requested by electric distribution-only utilities reported by MI for 2021. *Id*. She then compared these annual averages with the equity ratio authorized for AIC in each year, and the requested 53.077% equity ratio that AIC requests in this proceeding. Ms. Freetly included the authorized and requested equity ratios for ComEd in each of the respective years in the graph on page 9 of Staff Ex. 4.0. Ms. Freetly explained this is a relevant comparison since ComEd is the only other Illinois electric utility operating under the same performance-based formula rate plan as AIC. AIC's 50% equity ratio was consistent with the average authorized equity ratio for the electric distribution utilities for each year from 2018 through 2020. While ComEd continues to stay below the 50% equity ratio threshold and consistent with the average equity ratio requested by electric distribution utilities reported by MI for 2021, Ameren Illinois significantly raised its 2020 equity ratio to over 53%. *See* Staff Ex. 4.0, PUBLIC at 9.

Ms. Freetly compared the level of financial strength implied by the financial ratios of the Company to Moody's Benchmark Ratios for regulated electric and gas utilities. Staff Ex. 4.0 PUBLIC at 9. Moody's currently assigns AIC an issuer rating of A3, which Moody's considers upper-medium grade and subject to low credit risk. *Id., citing* Moodys' Investors Service, "Moody's Rating Symbols & Definitions," January 26, 2021 at 6. Ms. Freetly testified that the current Moody's issuer rating for Ameren Corp. is Baa1, which Moody's considers medium-grade and subject to moderate credit risk. *Id., citing* Moody's Investors Service, *Ameren Corporation – Update to credit analysis*, April 3, 2020.

Ms. Freetly explained that although Moody's does not rigidly adhere to a formula for assigning credit ratings, Moody's publishes ratio ranges that may generally be seen at different rating levels for regulated electric utilities. *Id*. She testified that Moody's focuses on the following four ratios to assess the financial strength of low risk gas and electric utilities: (1) Cash Flow from Operations Before Changes in Working Capital ("CFO pre-WC") interest coverage; (2) CFO pre-WC to total debt; (3) CFO pre-WC less dividends to total debt coverage; and (4) debt to capitalization. Staff Ex. 4.0 PUBLIC at 10. Staff calculated each ratio for AIC for 2020 and as a three-year average from 2018 through 2020, as shown in Table 2 of Staff Ex. 4.0 PUBLIC. The 2020 and three-year average Moody's financial ratios both implied a credit rating of A1 for the Company, which suggests a level of financial strength consistent with a credit rating that is higher than the Company's actual rating. *Id*.

In addition, Ms. Freetly compared the financial strength implicit in the Company's and Staff's proposed capital structures using the Company's test year rate base. *Id*. Staff presented the ratios produced by the Company's and Ms. Freetly's proposed capital structures, along with the credit ratings implied by those ratios. *Id*. at 11. Those ratios, presented in Table 3 of Staff Ex. 4.0, indicate that the Company's proposed capital structure contains a higher common equity ratio than is necessary to maintain its current A3 Moody's credit rating. Under *Hope* and *Bluefield*, Staff argues the Company is entitled only to a return sufficient to maintain its financial integrity and attract capital on reasonable terms. *See Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of West Virginia*, 262 U.S. (1923)("*Bluefield*"); *see also Federal Power Commission v. Hope Nat. Gas Co.*, 320 U.S. 591 (1994)("*Hope*"). Ms. Freetly testified that AIC has maintained an authorized capital structure at the 50% common equity threshold level since the performance-based formula rate plan has been in effect, with an improving credit position. Staff Ex. 4.0 PUBLIC at 12. Staff argues the Commission should approve no higher equity ratio than is necessary and reasonable to support AIC's financial strength and maintain its investment grade rating.

Staff notes the current Moody's issuer rating for Ameren Corp. is Baa1, which is, notably, one notch lower than AIC's A3 Moody's rating. *Id*. Thus, Ms. Freetly testified, Moody's considers Ameren Corp. to have higher risk than the regulated electric utility. As a diversified parent holding company, Ameren Corp. has higher operating risk than AIC's electric distribution operations due to its inclusion of AIC's gas distribution operations, Ameren Missouri's vertically integrated electric and gas utility operations, and the operations of its FERC-regulated transmission subsidiary, Ameren Transmission Company of Illinois ("ATXI"). *Id*. Ms. Freetly testified that AIC's 2020 common equity ratio of 53.077% is much higher than its riskier parent company's common equity ratio of 42.10%; she further explained that this is a very common arrangement in the relationships between holding companies and their operating company subsidiaries. Ms. Freetly explained that non-rate regulated corporations have an economic incentive to maintain relatively low equity ratios (i.e., high debt levels) at the holding company level while maintaining relatively high equity ratios at the utility operating company level, because they can borrow at low rates at the holding company and, in turn, invest that capital in the utility, where it will earn relatively high equity returns. *Id*. at 12-13. The utility in such scenarios, despite being very low risk based solely on its own operating and financial risk, may face a higher level of risk because of its parent's debt requirements. *Id*. at 13. To service its parent's obligations, Ms. Freetly explained, the utility subsidiary will often maintain a higher equity ratio than it otherwise would have needed, thereby increasing the utility's cost of capital. In Illinois, if that increased cost of capital is reflected in the utility's rates, it is a violation of Section 9-230 of the Act. *Id*.

Section 9-230 of the Act states, "[i]n determining a reasonable rate of return upon which investment for any public utility in any proceeding to establish rates or charges, the Commission shall not include any … incremental risk, … [or] increased cost of capital … which is the direct or indirect result of the public utility's affiliation with unregulated or nonutility companies." 220 ILCS 5/9-230.

Staff argues that using AIC's actual 2020 capital structure for setting formula rates would violate Section 9-230 of the Act. *Id*. at 13. As the Appellate Court found, when a larger corporation owns a utility, the corporation is generally not motivated to establish the optimal, lowest-cost capital structure for the utility, but to instead use a capital structure with a greater percentage of equity than is optimal, thereby allowing the parent corporation to realize a greater return. *Id., citing Citizens Util. Bd. v. Ill. Commerce Comm'n*, 276 Ill. App. 3d 730, 744 (1st Dist. 1995). In other words, Ms. Freetly explained, the capital structure of the regulated utility can be manipulated to include excessive equity to inflate the ROR. When AIC's capital structure carries an excessive amount of equity, it benefits its parent to the detriment of AIC ratepayers, who would pay for the excessive amount of equity. *Id*. at 14.

Ms. Freetly testified that AIC's equity balance has increased mostly due to capital infusions from AIC's parent company, Ameren Corp. Staff Ex. 4.0 CONF at 14. Mr. Sagel stated that Company management took action to manage a higher equity ratio over the course of 2020 to prevent its credit position from weakening. Ameren Ex. 5.0 at 14. However, as discussed above, there was no threat to the Company's credit position to justify AIC's increase to a 53.077% equity ratio and the corresponding costs to ratepayers. Staff Ex. 4.0 PUBLIC at 14.

The Commission authorized AIC to use an equity ratio of 52.0% for its gas distribution operations in its recent gas rate case, Docket No. 20-0308. Ms. Freetly explained several reasons that the authorized equity ratio for AIC's gas distribution operations should not be considered here. Staff Ex. 4.0 PUBLIC at 14. First, the Company used a future test year in its recent gas rate case. The Commission found the 52% common equity ratio for AIC's gas distribution operations "reasonable because it conforms with its recent decision to use actual, or historical common equity components while balancing the need for fiscal strength in light of current market conditions." The Commission also declared that its decision in that case "should not be seen as an abandonment of prior practices of adopting projected capital structures, when reasonable in light of all factors, nor is it an invitation for utilities to infuse equity into their capital structure for the sole purpose of justifying their proposed common equity." Docket No. 20-0308, Order at 129-130.

The RRA Regulatory Focus for 2020 presents the average authorized equity ratios for electric and gas utilities for 2017 through 2020, which Ms. Freetly presented in Table 4 on page 15 of Staff Ex. 4.0. Table 4 and the graph below it illustrates that the authorized equity ratios reported by RRA for gas utilities have exceeded the equity ratios authorized for electric utilities since 2017.

Staff notes that the Company's gas operations are not subject to a formula rate regime, which provides for more timely and certain cost recovery than traditional ratemaking. Hence, the equity ratio of the gas distribution operations should not be considered when evaluating the equity ratio needed to support AIC's electric delivery service operations, for which rates are being set in this proceeding. Staff Ex. 4.0 PUBLIC at 16.

The Company believes that certain fundamental financial conditions have changed, which have resulted in an adverse impact on the financial condition of AIC that consequently justifies a higher common equity ratio than the 50% deemed reasonable by the EIMA. Ameren Ex. 5.0 at 10. AIC witness Sagel cites reduced cash flows from the 2018 change in the federal corporate tax rate in the TCJA as having had negative credit quality implications for AIC. Ms. Freetly responded that while AIC's CFO Pre-WC / Debt did decline to 21.2% in 2018, Moody's shows that it increased back to 25.3% in 2019, while AIC maintained a 50% equity ratio. Staff Ex. 4.0 PUBLIC at 16-17. Ms. Freetly testified that Moody's notes that a CFO Pre-WC / Debt ratio below 19% on a sustained basis could lead to a credit rating downgrade for AIC, whereas a CFO Pre-WC / Debt ratio above 22% on a sustained basis could lead to a rating upgrade for AIC. *Id*. at 17. Moody's stable outlook for the AIC's A3 rating reflects the expectation that AIC's CFO Pre-WC / Debt ratio will remain solid in the A benchmark range. *Id*.

Mr. Sagel also cited the historically low interest rate environment in which the Company has operated in recent years as another factor that has impacted AIC's financial health and credit position. Ameren Ex. 5.0 at 12. While the Company has benefitted from low interest rates when issuing debt securities, Ms. Freetly testified that the allowed ROE has decreased for the electric distribution utilities operating under formula rates because the ROE is tied directly to the 30-year U.S. Treasury yield. Staff Ex. 4.0 PUBLIC at 17. Ms. Freetly noted that Moody's specifies an industry average ROE of 9.40% for 2020 in comparison to the Company's 8.91% electric distribution authorized in 2020. *Id*. While the ROE allowed under the performance-based formula rate plan has declined, the financial ratios have remained strong and AIC's credit ratings have maintained a stable outlook. *Id*.

Ms. Freetly recommended that the Commission impute AIC's capital structure to the 50% common equity ratio threshold established for the performance-based formula rate plan in Section 16-108(c)(2) of the Act and in accordance with Section 9-230 of the Act. Staff Ex. 4.0 PUBLIC at 18. In her direct testimony, Ms. Freetly testified that the Company's actual capital structure as of December 31, 2020 is unreasonable and unfairly burdensome on consumers. *Id*. Ms. Freetly further testified that the Company has maintained an equity ratio of approximately 50% for its electric operations since 2014. AIC's credit position has only improved under this rate paradigm, as the Company's higher credit ratings reflect lower risk. Staff Ex. 4.0 PUBLIC at 18. Yet, Ms. Freetly observed, instead of increasing leverage as allowed by the improved credit ratings at the utility, AIC requests an unjustified increase in the common equity ratio to more than 53%. Hence, Staff recommended in direct testimony that the Commission approve the imputed capital structure for AIC containing 50% common equity for 2020. *Id*.

In order to impute AIC's common equity ratio at 50%, Ms. Freetly subtracted 3.077% from the Company's proposed common equity ratio of 53.077% and added the 3.077% to the Company's proposed long-term debt ratio of 46.208%. *Id*. at 19. Based on Ms. Freetly's direct testimony proposed capital structure for AIC, consisting of 49.285% debt, 0.715% preferred stock, and 50.000% common equity, and the costs of the individual components discussed above, Ms. Freetly's direct testimony recommended ROR on rate base for AIC's electric delivery service operations was 5.749% for the filing year, and 5.714% for the reconciliation year. Staff Ex. 4.0 PUBLIC at 19-20, Schedule 4.01.

As set forth in the Partial Stipulation on Capital Structure, Staff and AIC stipulated that the overall ROR for the filing year is 5.783% and 5.747% for the reconciliation year. Ameren-Staff Joint Ex. 1. Both stipulated RORs reflect a capital structure containing 51% common equity, .715% preferred stock, and 48.285% long-term debt for setting formula rates for the Company's electric distribution operations. The stipulation was supported by Staff in rebuttal testimony (Staff Ex. 8.0) and by the Company in surrebuttal testimony (AIC Ex. 13.0 at 4).

Staff notes that throughout the evidentiary phase of this proceeding, neither the AG nor CUB offered testimony on the issue of common equity. Nor were either CUB or the AG in any way excluded from the discussions that led to the Partial Stipulation. However, both the AG and CUB urge the Commission not to adopt the Partial Stipulation on Capital Structure entered into by the Company and Staff in their initial briefs. Specifically, the AG and CUB argue that Section 16-108.5(c)(2) requires that the Commission reduce the Company's common equity ratio to 50%. The AG and CUB further argue that, even if their interpretation of Section 16-108.5(c)(2) is wrong, the record does not support a common equity ratio greater than 50%.

Staff argues that the AG and CUB incorrectly interpret Section 16-108.5(c)(2). It is established that a settlement agreement not agreed to by all of the parties may be considered by the Commission as a decision on the merits as long as the provisions of the settlement are supported by substantial evidence in the whole record. *BPI* at 216-217. Here, Staff argues, the Partial Stipulation is supported by substantial evidence in the record. *See* Staff Ex. 8.0 at 1-2; Ameren Ex. 12.0 at 15-16.

The AG and CUB argue that Section 16-108.5(c)(2) serves as an upper limit of 50% for the Company's equity ratio under formula rates – that the equity ratio cannot exceed 50%. Staff disagrees with this interpretation. Staff argues the current language of Section 16-108.5(c)(2) states that a Company's common equity ratio in a formula-rate case shall:

> (2) . . . To enable the financing of the incremental capital expenditures, . . . a participating electric utility's actual year-end capital structure that includes a *common equity ratio, excluding goodwill, of up to and including 50% of the total capital structure shall be deemed reasonable and used to set rates*.

220 ILCS 5/16-108.5(c)(2). (Emphasis added.)

Staff notes that the AG and CUB are both correct that FEJA, enacted in 2017, amended Section 108.5(c)(2) to add the emphasized language above. However, they argue that this language was added to serve as an absolute cap to the common equity ratio the Commission may approve in a FRU. Staff contends that this fundamentally misconstrues the provision; the language referring to a 50% common equity ratio is not an upper limit. Instead, Staff contends it is an evidentiary presumption (indeed, likely a conclusive one) that any capital structure with 50% or less common equity is "deemed" reasonable, which is to say "h[e]ld, consider[ed], adjudge[d], … determine[d], treat[ed] as if, [or] construe[d]" as reasonable and used to set rates. 374 H. C. Black, Black's Law Dictionary (5th ed. 1979). In contrast, Staff points out that the statute does not explicitly refer to what the Commission should determine when a common equity ratio greater than 50% is proposed. Particularly, it does not prohibit the Commission from considering and adopting a proposed common equity ratio in excess of 50%. Staff argues this is true for several reasons.

First, the Illinois Appellate Court has held that the plain language of Section 16-108.5 affords the Commission discretion to determine whether AICs proposed actual capital structure is prudent and reasonable. *Ameren Ill. Co. v. Ill. Commerce Comm'n*, 2013 IL App (4th) 121008, ¶¶22-32. There, AIC argued that the Commission violated Section 16-108.5(c)(2) by not imputing AIC's own capital structure, and instead approving a lower capital structure based on AIC's parent. *Id*. at ¶27. The Appellate court rejected this argument, stating that it "disagree[d] with [AIC's] contention that the statutory language creates a presumption of reasonableness when read in conjunction with provisions of the Utilities Act." *Id*. at ¶29. While this case was decided before the passage of FEJA, it demonstrates that the statute vests the Commission with substantial discretion to establish a capital structure for formula rate purposes. *See Id*. (court finds that "[t]he plain language of the statute provides the Commission with the discretion to determine whether [AIC's] proposed actual capital structure is prudent and reasonable.") While this decision was issued before the passage of FEJA, Staff argues that the language added by FEJA merely places a limit on Commission discretion such that the Commission may no longer decline to approve an actual capital structure that contains 50% or less common equity; the statute continues to afford the Commission discretion to approve, where appropriate and supported by the record, a common equity ratio greater than 50%. Thus, Staff contends, because FEJA does not explicitly address common equity ratios greater than 50%, the Appellate Court's 2013 holding still applies in formula rate proceedings where the Company proposes a common equity ratio higher than 50%.

Second, Staff argues it is undoubtedly the case that the General Assembly knows how to impose a cap or upper limit on some rate, figure, or input in utilities law. The Act is replete with examples of this. For example, Section 9-220.3 provides that increases in rates resulting from qualifying infrastructure plant investments by gas companies "shall not exceed" a specific percentage. 220 ILCS 5/9-220.3(g). Indeed, the General Assembly uses the phrase "shall not exceed" throughout the Act. *See, e.g.*, 220 ILCS 5/5-202; 220 ILCS 5/9-210.5(d); 220 ILCS 5/13-506.2(e)(2); 220 ILCS 5/16-108(j). Staff argues that it has not done so in Section 16-108.5(c)(2), and the AG / CUB assertion that such a cap exists must accordingly fail. For these reasons, the Commission should reject the AG and CUB's interpretation of Section 16-108.5(c)(2) as an "absolute cap" on common equity ratios greater than 50% in formula rate proceedings.

The AG and CUB argue that the Partial Stipulation is not supported by the record. Staff contends that this is not the case. As an initial matter, Staff argues that neither the AG nor CUB have offered a scintilla of evidence regarding the common equity ratio. Instead, CUB and the AG latch onto Staff witness Freetly's recommendations made in her direct testimony, which she ceased herself to support upon the execution of the Partial Stipulation. However, Staff insists that CUB's and the AG's reliance on Staff testimony is completely improper in this context. In *Citizens Util. Bd. v. Ill. Commerce Comm'n*, 2018 IL App (1st) 170527, CUB and another intervenor, in arguing that the Commission authorized an excessively high ROR in a rate case, attempted to rely on appeal on the testimony of Staff witness Kight-Garlisch on that issue. 2018 IL App (1st) 170527 at ¶30. The Appellate Court rejected this as improper, stating that "[a] party must assert his own legal interests and rights, not those of third parties. [citation omitted]. The intervenors have not developed a cohesive argument explaining why they should be permitted to rely on another party's evidence." *Id.* (citation omitted). Staff argues that CUB and the AG attempt to do here exactly what the Appellate Court forbade – rely on the evidence of another party to mount a challenge regarding an issue upon which they offered no evidence.

Staff contends that the AG and CUB's recommendations that some common equity ratio lower than the 51% agreed to should be adopted are the only recommendations which have no support whatever in the record. Staff points out that no witness offered any evidence in the record to rebut the Company's and Staff's arguments in support of a 51% common equity ratio. In fact, the only evidence the AG and CUB can rely on was used by Staff in support of the Partial Stipulation the AG and CUB seek the Commission to invalidate. Staff contends that the AG and CUB cannot rely solely on another party's witness' recommendation to support a lower common equity ratio, and the record evidence in this proceeding does not support the AG and CUB's recommendation.

Staff contends that there is ample record evidence supporting the Company's and Staff's stipulated 51% common equity ratio. Ms. Freetly, as noted, offered testimony in support of the Stipulation, giving her opinion that "the 51% common equity ratio reflected in the stipulated ROR lies within the range of equity ratios recommended by parties in this proceeding, and is reasonably comparable to the 50.46% median authorized effective equity ratio for electric distribution companies[,]" and characterizing the "resulting ROR [a]s reasonable to support AIC's financial strength and maintain its investment grade rating[.]" Staff Ex. 8.0 at 2. Likewise, Ameren Illinois witness Sagel testified that the Company requires a common equity ratio in excess of 50% to maintain its current credit ratings due to cash flow reductions stemming from the change in federal corporate tax rate in the federal TCJA, which became effective in 2018. Ameren Ex. 5.0 at 10. Mr. Sagel offered evidence why the median authorized effective common equity ratio should be used rather than Staff's mean authorized effective common equity ratio. Ameren Ex. 12.0 at 15. Mr. Sagel explained that the proposed equity ratio is justified by its equity-weighted ROE. *Id*. at 16. A 51% common equity ratio is not meaningfully in excess of the 2021 median common equity ratio for electric distribution utilities and is well below the higher end of the range. *Id*. at 15. Furthermore, a 51% common equity ratio is not outside the range that has been previously ordered by the Commission and upheld by the Appellate Court. *Ameren Ill. Co*., 2013 IL App (4th) 121008, ¶31. For these reasons, Staff requests the Commission approve the Partial Stipulation and adopt its proposed 51% common equity ratio.

c. AG's Position

The AG asks the Commission to reduce the Company's common equity ratio to 50%, down from the 51% proposed by AIC and Staff in their Partial Stipulation to comply with the Act. The AG maintains that Section 16-108.5(c)(2) of the Act, which was amended in 2017 through the enactment of FEJA, controls the Company's capital structure sought under formula rates. The AG contends that the section is amenable to two readings, both of which bar the Company from recovering a 51% common equity ratio in this proceeding. First, Section 16-108.5(c)(2) can be read to say that 50% is an absolute cap on AIC's common equity ratio. Thus, the Commission would violate the Act if it approved a common equity ratio above 50%. The second interpretation advanced by the AG is that Section 16-108.5(c)(2) acts as a limited safe harbor, and the Commission must presume (absent evidence of fraud) that a party's capital structure (in this case, AIC's) with up to 50% common equity is reasonable. However, if the Company requests a capital structure with more than 50% common equity, the Commission must conduct its normal evaluation of the reasonableness and prudency of the Company's proposed capital structure, like the Commission does in traditional rate cases. The AG notes that the Commission has not approved a common equity ratio greater than 50% for AIC since FEJA's enactment.

The AG argues that for the Commission to approve the 51% common equity ratio proposed by the Company and Staff in the Stipulation then it must adopt the second interpretation and the Company and Staff must support the stipulated common equity ratio. The AG maintains that the Commission cannot reach this conclusion because the Company and Staff did not support the 51% common equity ratio in the record. The AG contends that no expert offered any capital structure analysis in this proceeding that supports a finding that a 51% common equity ratio is reasonable for the Company. Staff witness Freetly initially proposed a 50% common equity ratio that she arrived at through a full capital structure analysis, whereas AIC witness Sagel proposed a 53.077% common equity ratio using his own capital structure study. *See* Staff Ex. 4.0 at 3-18; Ameren Ex. 5.0 at 9-15; Ameren Ex. 12.0 at 2–22. The AG argues that after Staff and AIC submitted the Stipulation into the record, both had the opportunity to submit capital structure analyses justifying the 51% common equity ratio, but neither did.

The AG argues that the evidence cited by the Company and Staff to support the 51% common equity ratio cannot support a finding that the figure is reasonable because none of the cited evidence examines AIC's financial needs. For example, the AG rejects AIC and Staff's argument that the median common equity ratios for other electric distribution companies support granting the Company a 51% common equity ratio. The AG argues that these other companies do not have the benefit of FRUs, like AIC, and that the median ratios say nothing about what the Company needs at this time. The AG contends that the evidence cited by the Company and Staff cannot point to any examination of AIC's finances which would support a finding that a 51% common equity ratio is reasonable because neither party ever conducted such an analysis, even though both had the opportunity to do so after they submitted the Stipulation into the record.

The AG characterizes the Stipulation as a non-unanimous settlement, and an attempt by the Company and Staff to reduce the items litigated in this proceeding. The AG notes that the Illinois Supreme Court declared in *BPI*, 136 Ill.2d 192, 217 (1989) that the Commission can only adopt a non-unanimous settlement "if the [Commission] makes an independent finding, supported by substantial evidence in the record as a whole, that the proposal would establish just and reasonable rates." The AG maintains that the parties present no evidence to support a finding that a 51% common equity ratio is reasonable for the Company and thus the Commission must reject this proposed ratio.

The AG requests that the Commission adopt a 50% common equity ratio, which it maintains is presumptively reasonable under Section 16-108.5(c)(2) and supported in the record by Ms. Freetly. She stated in her testimony that "the Company's financial health and ability to attract capital has been supported under formula rate plans that reflect a common equity ratio of 50%, with no negative credit rating actions." Staff Ex. 4.0 at 4.

d. CUB's Position

CUB requests that the Commission adopt Staff witness Freetly's recommendation to maintain Ameren Illinois' 50% equity ratio, which the Commission has approved in each of the Company's last several FRUs. *See* Staff Ex. 4.0. CUB contends Ms. Freetly's proposed equity ratio is the only one in the proceeding that falls within the range of equity ratios that the Act states "shall be deemed reasonable used to set rates," subject to "prudence and reasonableness" review. 220 ILCS 16-108.5(c)(2). Further, CUB argues that, unlike the Partial Stipulation's 51%, Ms. Freetly's 50% recommendation is supported by record evidence.

Equity is the most expensive component of Ameren Illinois's capital structure. The higher the equity ratio, the more the Company's customers pay. CUB maintains adopting Ameren Illinois's requested equity ratio would result in a ROR that exceeds what is reasonably required to attract capital, and therefore the Company's customers would pay inflated rates. In *Citizens Util. Bd. v. Ill. Commerce Comm'n*, the Illinois Appellate Court found, "the Act requires the Commission to establish rates which are just and reasonable for both the investors and the consumers." 276 Ill. App. 3d 730, 737 (1995). Accordingly, CUB urges the Commission to adopt Ms. Freetly's recommendation and approve Ameren Illinois's currently authorized 50% common equity ratio. CUB contends this ratio appropriately balances the Company's debt and equity capital, is the only equity ratio proposed in this proceeding that falls within the Act's prescribed range, and will not cost customers more than is needed to support the Company's financial integrity and access to capital markets. *See generally* Staff Ex. 4.0 at 2-19. The Illinois Appellate Court found that, through Section 9-230:

> The legislature has directed the Commission to protect against the increased cost of capital sought by a utility with such an inflated level of equity. … The Commission should disallow recovery of any cost of capital in excess of that reasonably necessary for the provision of services. If a utility has included excessive equity in its capital structure, it has inflated the rate of return and its capital cost.

Citizens Util. Bd. v. Ill. Commerce Comm'n, 276 Ill. App. 3d at 745-746. The court's decision preceded the formula rates law, but the Article IX "just and reasonable" standard the court cited, and the court's interpretation of this standard, remain in effect today. The only change to the language of Section 9-230 since the court's order was to add a provision regarding telephone directory operations, which is not relevant to this proceeding. *See* 220 ILCS 5/9-230. Thus, CUB contends, the Illinois Appellate Court has been clear that the Act requires an equity ratio that is no higher than is necessary to assure the Company's financial integrity. *Id.* at 737-746.

CUB argues that a 50% equity ratio would secure Ameren Illinois's credit rating and ability to attract capital. CUB further argues an equity ratio higher than the 50% would exceed both what record evidence demonstrates is necessary and the Act's stated upper bound for equity ratios under formula rates. Put simply, CUB's position is both the law and the record support adopting Ms. Freetly's recommendation and maintaining the 50% equity ratio that has been in effect since 2014 and has supported Ameren Illinois's financial health, ability to attract capital, and several credit rating upgrades.

Here, CUB contends, the Act establishes an upper limit of 50% for the Company's equity ratio under formula rates, subject to prudence and reasonableness review. In other words, CUB's interpretation is the equity ratio cannot exceed 50% unless prudence and reasonableness requires that it be higher. CUB maintains the record provides no basis for the conclusion that an equity ratio any higher than 50% is necessary.

CUB argues that consistent with CUB's interpretation of the Act, AIC's authorized equity ratio has remained at or below 50% since 2014. Staff Ex. 4.0 at 4. CUB notes the Company has enjoyed stable financial health, effectively attracted capital, and experienced no negative credit rating action during this period. *Id.* at 4.

The Commission concluded in AIC's initial formula rate plan proceeding that the Company had a lower operating risk than its parent company, and that the favorable regulatory environment under formula rates would support an equity ratio at or below 50%. *Id.* (*citing* Docket No. 12-0001). CUB contends AIC's financial record since then has confirmed the Commission's expectations, as the Company has received several credit ratings upgrades and no downgrades in the decade since then. *Id.* at 5-6. Credit rating agencies have cited AIC's electric distribution operations in particular as presenting low risk and high cash flow, transparency, and predictability under the same formula rate structure that includes the 50% equity ratio limit. *Id.* at 6-7. CUB concludes the Company has demonstrated every year since 2014, and certainly since FEJA instituted the 50% limit in 2017, that 50% is sufficient for AIC's financial health to thrive. There is no reason to set aside this standard now.

CUB argues to warrant its request for the Commission to make an exception to the Act's 50% equity ratio limit, AIC would need to establish that 50% is an imprudently and unreasonably low equity component. 220 ILCS 5/16-108.5(c)(2). CUB argues the Company has made no such showing. The Company initially sought a 53.077% equity ratio, seeking to lock in the Company's actual year-end 2020 equity ratio that exceeded the Commission-authorized 50% equity ratio. AIC Ex. 5.0 at 9-15; AIC Ex. 12.0. CUB argues AIC failed to support this figure with evidence of prudence and reasonableness, let alone to demonstrate that 50% was insufficient. Rather, CUB posits, AIC relies heavily on the fact that 53.077% represents an actual value, from 2020 year-end.

Ms. Freetly testified, "the Commission should not determine the overall rate of return from a utility's actual capital structure if that capital structure adversely affects the overall cost of capital." Staff Ex. 4.0 at 2. Increasing the equity component would increase the overall cost of capital, unless it is necessary to prevent an even costlier outcome like a credit downgrade. AIC repeatedly claims adhering to its authorized 50% equity ratio would have harmed the Company's financial standing, but CUB contends AIC's attempts to substantiate this assertion with evidence fall short. *See* AIC Ex. 5.0 at 10-15; AIC Ex. 12.0 at 3, 4-5.

AIC alleges a need for a higher equity ratio to offset reduced cash flow resulting from TCJA. AIC Ex. 5.0 at 10-11. As Company witness Sagel noted, TCJA went into effect on January 1, 2018. *Id.* at 10. The Commission authorized the same 50% equity ratio that was in effect before TCJA, the same 50% equity ratio that Ms. Freetly proposed and CUB supports in this proceeding, in each of the Company's annual FRU proceedings since TCJA went into effect. Staff Ex. 4.0 at 4. CUB contends AIC has maintained stable financial health, attracted capital, and experienced no negative credit rating action during this period. *Id.* at 4. The Company points to a decline in its funds from operation ("FFO") to debt ratio compared to pre-TCJA (2017), but CUB argues the Company's own data shows this metric has stabilized. AIC Ex. 5.0 at 13. Mr. Sagel testified that the Company's FFO to debt ratio was 21.2% in the wake of TCJA going into effect in 2018, and he estimated it would be 21.1% for 2020. *Id.* at 13. After three years of both TCJA and a 50% authorized equity ratio being in place, the FFO to debt ratio has moved 0.1% by AIC's own estimation. *Id.* CUB considers this a stable FFO to debt ratio that does not support increasing the authorized equity ratio.

AIC estimates that had it not managed its capital structure to exceed its authorized 50%, its FFO to debt ratio would have been 19.5%, but the Company admits the metric still would have exceeded Moody's 19.0% threshold for considering a negative determination. *Id.* at 13. As Mr. Sagel testified, a credit downgrade from Moody's based on FFO to debt ratio would enter the realm of possibility only "if AIC's FFO debt ratio *remained below 19% on a sustained basis*." AIC Ex. 12.0 at 5 (emphasis added). The Company's calculations demonstrate that a 50% equity ratio supports an FFO to debt ratio above the threshold. Further, even if the metric were to drop significantly below AIC's expectations and manage to dip below the Moody's 19% threshold, CUB notes the Commission would be able to revisit the issue in the Company's next annual FRU, before it could be considered to be have been below the threshold "on a sustained basis."

Finally, CUB contends that AIC attempts to liken apples to oranges by referencing AIC's separately regulated and financed gas distribution operation. The Company attempts to support a higher equity ratio for the electric division by referencing the gas division's higher equity ratio and the legal standard that applies to its approval. AIC Ex. 5.0 at 14-15. CUB argues this comparison does not hold up because these are separate businesses subject to different financial and legal frameworks. CUB emphasizes that the electric division operates under formula rates and the gas division does not. As noted above, the Commission has recognized before that the formula rate structure supports a lower equity ratio than otherwise would be necessary. Docket No. 12-0001, Order at 128. For all these reasons, CUB contends considerations of post-TCJA cashflow, FFO to debt ratio, and AIC's separate gas division's finances do not support an equity ratio any higher than 50%.

AIC came down from its original equity ratio request, agreeing in the Partial Stipulation with Staff to request a 51% equity ratio instead. Staff Ex. 8.0, Sch. 8.1. As stated above, CUB argues 51% exceeds the Act's 50% limit. 220 ILCS 5/16-108.5(c)(2). Further, CUB argues the Company's requested 51% equity ratio finds no more support in the record. In fact, there is no record evidence, in testimony or otherwise, supporting a 51% equity ratio. Staff had the opportunity to file testimony providing record evidence in support of the reasonableness of adopting a 51% equity ratio. Staff did not. Instead CUB argues, the only testimony nominally supporting the Partial Stipulation is Staff Exhibit 8.0, which simply states the agreement's terms, provides a paragraph asserting that applicable standards are met, and indicates that Staff and AIC have agreed to support the stipulated positions in this proceeding. Staff Ex. 8.0. The only other party to the Partial Stipulation, AIC, had the opportunity to provide evidence supporting a 51% equity ratio in its surrebuttal testimony. The Company provided no such support. In fact, the surrebuttal testimony's only reference to the Partial Stipulation is to note that it accepted Ms. Freetly's adjustments that are based on its terms. AIC Ex. 13.0 at 72-73, 79-81. CUB argues that rather than support their proposal on the merits, AIC and Staff treat the equity ratio issue as if a Partial Stipulation between two parties resolved it. As a matter of law, CUB maintains this is simply not true.

Illinois caselaw states that "In order for the [C]ommission to dispose of a case by settlement . . . all of the parties and intervenors must agree to the settlement." *BPI*, 136 Ill. 2d 192, 209 (1989). Neither CUB nor the AG is a signatory to the Partial Stipulation, which binds only AIC and Staff. Without a unanimous agreement, the Company still must satisfy its burden of proof. The Commission must make "an independent finding, supported by substantial evidence in the record as a whole, that the proposal would establish just and reasonable rates." *Id.* at 217. The Commission retains its duty to review the record, apply the formula rate law (including what CUB considers a 50% equity ratio limit), and determine for itself a prudent and reasonable capital structure for AIC.

CUB contends the formula rates law and the record evidence do not support saddling AIC electric customers with the cost of an equity ratio above 50%. Accordingly, CUB argues, Ms. Freetly recommended a 50% equity ratio, which equals both AIC's current authorized equity ratio and the threshold limit established in the Act. *Id.* at 3. CUB contends the Commission should set aside the Partial Stipulation and adopt the 50% equity ratio, which CUB maintains is the only proposal in the record that complies with the Act and finds support in the record.

e. Commission Analysis and Conclusion

The Commission finds that the 51% common equity ratio proposed in the Partial Stipulation between AIC and the Staff is reasonable and should be approved. It is reasonably comparable to the median common equity ratio of electric distribution utilities, it is within the range of recommendations in this proceeding, and contrary to the AG's and CUB's assertions, Ms. Freetly expressly testified that it is reasonable.

The Commission rejects the AG and CUB argument that the statutory language of the Act bars common equity ratios in excess of 50%. As noted by parties, the relevant portion of the statute states: ". . . a participating electric utility's actual year-end capital structure that includes a common equity ratio, excluding goodwill, of up to and including 50% of the total capital structure shall be deemed reasonable and used to set rates." The clear language of this passage states only that common equity ratios, excluding goodwill, of up to and including 50% of the total capital structure shall be deemed reasonable; it is utterly silent as to common equity ratios that are above 50%. In order for the AG and CUB's interpretation of this passage to be correct, and for this passage to act as a statutory cap, the legislature would have had to insert limiting language, such as "only a capital structure that includes a common equity ratio . . . of up to and including 50% . . . shall be deemed reasonable . . ." The legislature did not do so. The Commission finds that, rather than acting as a cap, this provision requires that any common equity ratio exceeding the 50% safe harbor be supported by substantial evidence. AIC and Staff argue that the 51% common equity ratio here is supported by substantial evidence in the record; the AG and CUB disagree. The Commission agrees with AIC and Staff.

The AG and CUB cite *BPI* for the proposition that the Commission can only adopt a non-unanimous settlement "if the [Commission] makes an independent finding, supported by substantial evidence in the record as a whole, that the proposal would establish just and reasonable rates." *BPI* at 217. The AG and CUB both urge the Commission to find that the record in this docket contains no evidence to support a 51% common equity ratio. However, their argument appears to ignore that Ms. Freetly's rebuttal testimony specifically supported this. Staff Ex. 8.0 at 2. Moreover, the record contains further support for 51% common equity ratio in the Company's direct testimony (Ameren Ex. 5.0 at 10) in which Ameren Illinois witness Sagel testified that the Company requires a common equity ratio in excess of 50% to maintain its current credit ratings due to cash flow reductions and its rebuttal testimony (Ameren Ex. 12 at 15-16) in which Ameren Illinois witness Sagel testified that the median authorized effective common equity ratio should be used rather than Staff's mean authorized effective common equity ratio and that the proposed equity ratio is justified by its equity-weighted ROE. In light of the clearly cited support in the record of the 51% common equity ratio, the AG and CUB seem to argue that in order for a Partial Stipulation to be properly supported by substantial evidence in the record, a party must have specifically advanced it as an initial position in their testimony. The Commission finds this clearly goes beyond the principle articulated in *BPI*, and the Commission further finds that such an extension of this principle finds no support in either the record in this docket or in legal authority. Accordingly, the Commission rejects the AG's and CUB's arguments on this matter and finds that AIC's ratio of 51% is supported by substantial evidence in the record and sufficient to maintain its financial integrity and attract capital on reasonable terms.

VII. RECOMMENDED REVENUE REQUIREMENT

The Commission finds, based on the determinations presented above on the various uncontested issues, that the agreed-upon net revenue requirement, which includes the revenue requirement for the filing year, the reconciliation adjustment with interest, and the ROE collar adjustment, as shown on Appendix A, should be adopted for use in the proceeding. The new delivery services charges, effective beginning with the January 2022 billing period, will reflect this agreed-upon net revenue requirement, as well as the cost allocation, and rate design methods approved by the Commission in Docket No. 19-0877.

VIII. COST OF SERVICE/REVENUE ALLOCATION/RATE DESIGN

AIC submitted direct testimony and exhibits that indicated that updated Rate MAP-P pricing is based on the updated net revenue requirement and consistent with the cost allocation, revenue allocation, and rate design methodologies approved by the Commission in Docket No. 19-0877. No party took issue with AIC's proposal.

Therefore, the Commission finds that AIC's proposal is reasonable and uncontested, and therefore approves its use in this proceeding. Additionally, Schedule E-1 tariffs should be filed with the compliance filing Informational Sheets for Rate MAP-P.

IX. OTHER ISSUES

A. Uncontested or Resolved Issues

1. Riders PER, HSS, and HMAC

Staff and AIC agree on the updated Supply Costs Adjustment factors and the costs to be recovered through Supply Procurement Adjustment, power supply portion of CWC and the power supply portion of uncollectibles, through Rider PER and Rider HSS. Additionally, Staff and AIC agree on AIC's calculation of the Rider HMAC base amount. No other party opposes these determinations.

X. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having considered the entire record herein and being fully advised in the premises, is of the opinion and finds that:

(1) Ameren Illinois Company d/b/a Ameren Illinois is an Illinois corporation engaged in the distribution and sale of electricity and natural gas to the public in Illinois, and is a public utility as defined in Section 3-105 of the Act;

(2) the Commission has jurisdiction over the parties hereto and the subject matter herein;

(3) the recitals of fact and conclusions of law reached in the Commission conclusions of this Order are supported by the evidence of record, and are hereby adopted as findings of fact and conclusions of law; the Appendices attached hereto provide supporting calculations for the approved rates;

(4) AIC's proposed update to its Rate MAP-P should be approved, subject to the conclusions contained herein;

(5) the rates herein found to be consistent with Public Acts 97-0616, 97-0646, and 98-0015 are based on AIC's FERC Form 1 for 2019;

(6) for purposes of this proceeding, the net original cost rate base for AIC's electric delivery service operations is $3,451,497 for the 2020 reconciliation year and $3,676,453 for the 2021 filing year;

(7) the rate of return that AIC should be allowed to earn on its net original cost rate base is 5.747% for the 2020 reconciliation year; this rate of return incorporates a return on common equity of 7.290%;

(8) the rate of return that AIC should be allowed to earn on its net original cost rate base is 5.783% for the 2021 filing year; this rate of return incorporates a return on common equity of 7.360%;

(9) the rates of return set forth in Findings (7) and (8) result in base rate electric delivery service operating revenues of $1,018,854,000 (reflecting the reconciliation and ROE Collar adjustments) and net annual operating income of $212,609,000 as shown on Appendix A;

(10) AIC's electric delivery service rates presently in effect are insufficient to generate the operating income necessary to permit AIC the opportunity to earn a fair and reasonable return on net original cost rate base consistent with Public Acts 97-0616, 97-0646, and 98-0015; these rates should be permanently canceled and annulled;

(11) the specific rates proposed by AIC in its initial filing do not reflect various determinations made in this Order regarding revenue requirement;

(12) AIC should be authorized to place into effect amended Rate MAP-P Informational Sheets and tariff pages based on changes in Docket No. 19-0877, consistent with the findings of this Order;

(13) AIC should be authorized to place into effect the Rate MAP-P tariff Informational Sheets designed to produce annual base rate electric delivery service revenues of $1,018,854,000 which represents an increase of $57,609,000 (5.99%); such revenues, in addition to other tariffed revenues, will provide AIC with an opportunity to earn the rates of return set forth in Findings (7) and (8) above; based on the record in this proceeding, this return is consistent with Public Acts 97-0616, 97-0646, 98-0015, and 99-0906;

(14) the new charges authorized by this Order shall take effect beginning on the first billing day of the January billing period following the date of the Final Order in this proceeding; the tariff sheets with the new charges,

however, shall be filed no later than December 10, 2021, with the tariff sheets to be corrected thereafter, if necessary;

(15) the Commission, based on AIC's proposed original cost of plant in service as of December 31, 2020, before adjustments, of $8,162,387,000 and reflecting the Commission's determination adjusting that figure, unconditionally approves $8,162,525,000 as the composite original jurisdictional distribution services plant in service as of December 31, 2020;

(16) the Commission has considered the costs expended by the Company during 2020 to compensate attorneys and technical experts to prepare and litigate rate case proceedings and assesses that the amount included as rate case expense in the revenue requirements of $599,842 is just and reasonable; this amount includes the following costs: (1) $22,869 associated with Docket No. 19-0436; and (2) $576,973 associated with Docket No. 20-0381; and (3) $0 associated with Docket No. 21-0365; and

(17) all motions, petitions, objections, and other matters in this proceeding which remain unresolved should be disposed of consistent with the conclusions herein.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the tariff sheets at issue and presently in effect for electric delivery service rendered by Ameren Illinois Company d/b/a Ameren Illinois are hereby permanently canceled and annulled effective at such time as the new electric delivery service tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that Ameren Illinois Company d/b/a Ameren Illinois is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (12) and (13) of this Order, applicable to electric delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Ameren Illinois Company d/b/a Ameren Illinois shall update its formula rate in accordance with this Order.

IT IS FURTHER ORDERED that all motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that pursuant to Section 10-113(a) of the Public Utilities Act and 83 Ill. Adm. Code 200.880, any application for rehearing shall be filed within 30 days after service of the Order on the party.

IT IS FURTHER ORDERED that subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By Order of the Commission this 13th day of December, 2021.

(SIGNED) CARRIE ZALEWSKI

Chairman

Chairman Zalewski dissents.

RRA REGULATORY FOCUS

Lowest equity return on record to be used in Ameren Illinois' newest rate case

Friday, April 16, 2021 10:58 AM CT

By Russell Ernst
Market Intelligence

The lowest ROE known by Regulatory Research Associates, a group within S&P Global Market Intelligence, to be used in an electric or natural gas utility rate case is integral to Ameren Corp. subsidiary Ameren Illinois Co.'s latest formula rate plan request for its electric distribution operations.

The calculation of the ROE in formula rate plan, or FRP, cases is formulaic, as required by FRP statute. As such, ROE is not expected to be a contested issue in the case. In Docket No. 21-0365, Ameren Illinois proposes a 7.36% ROE for the "filing year" that is significantly below the 9.44% average ROE authorized electric utilities nationwide in cases decided in 2020, according to RRA. For electric distribution utilities such as Ameren Illinois, the average authorized ROE in 2020 was 9.10%.

Ameren Illinois, authorized filing year ROEs for electric distribution business (2012-2020)

Date approved	Authorized ROE (%)	Relative to national average at time authorized[1]
12/09/20	8.38	Below
12/16/19	8.91	Below
11/01/18	8.69	Below
12/06/17	8.40	Below
12/06/16	8.64	Below
12/09/15	9.14	Below
12/10/14	9.25	Below
12/09/13	8.72	Below
12/05/12	9.71	Below
09/19/12	10.05	Below

As of April 15, 2021.
[1]Relative to prevailing nationwide average return on equity for electric utilities, included in RRA's Major Rate Case Decisions quarterly report.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Ameren Illinois seeks to implement a $49.3 million revenue requirement increase that includes a $17.2 million filing year increase premised upon a 7.36% return on equity (53.08% of capital) and a 5.85% return on a $3.693 billion rate base and a $20.4 million downward "reconciliation" adjustment calculated using a 7.29% return on equity (53.08% of capital) and a 5.81% return on a $3.468 billion rate base to reconcile the company's actual 2020 revenues with the level that would have been approved had actual data been available at the time rates were established. Because the $20.4 million downward reconciliation adjustment for 2020 was less than the $14.8 million downward adjustment approved for 2019, the downward reconciliation adjustment proposed in the instant case is, effectively, $5.6 million.

The company also proposes a $31.7 million upward ROE adjustment as the company's earned ROE calculated for 2020 was below the 7.29% ROE established for the year under the FRP provisions, which reflects a 7-basis-point downward "performance metrics penalty." The company's previous case used a downward ROE adjustment of $6 million.

The FRP calculations reflect an ROE that is the result of applying a 580-basis-point premium to the 12-month average 30-year Treasury Bond yield. However, as contemplated in pending legislation, beginning with the 2022 FRP rate filing, the ROE calculation would be modified to reflect a "national average" equity return.

The FRP was established by 2011 legislation applicable to the state's large electric utilities to facilitate recovery of certain costs associated with infrastructure expansion projects. The current filing reflects actual results for 2020 and estimated net plant additions through 2021.

The Illinois Commerce Commission, or ICC, is expected to issue a decision in December, and new rates are to take effect in January 2022.

Since Illinois' FRP statute was enacted in 2011, Ameren Illinois has implemented roughly $215 million of net revenue requirement increases.

Previous proceeding

In a Dec. 9, 2020, order in Docket No. 20-0381, the ICC ordered Ameren Illinois to place into effect a $35 million revenue requirement reduction. The approved reduction included a $4 million filing year increase premised upon an 8.38% return on equity (50% of capital) and a 6.39% return on a $3.413 billion rate base and a $14.8 million downward reconciliation adjustment calculated using an 8.31% return on equity (50% of capital) and a 6.36% return on a $3.195 billion rate base. Because the $14.8 million downward reconciliation adjustment adopted for 2019 was less than the $37 million upward adjustment approved for 2018, the downward reconciliation adjustment adopted in the 2020 case was effectively $51.8 million.

The ICC also adopted a $6 million downward ROE adjustment as the company's 8.58% earned ROE calculated for 2019 was above the 8.31% ROE established for the year. The company's previous case used a downward ROE adjustment of $18.7 million.

Regulatory Research Associates is a group within S&P Global Market Intelligence.

For a full listing of past and pending rate cases, rate case statistics and upcoming events, visit the S&P Global Market Intelligence Energy Research Home Page.

For a complete, searchable listing of RRA's in-depth research and analysis, visit the S&P Global Market Intelligence Energy Research Library.

This article was published by S&P Global Market Intelligence and not by S&P Global Ratings, which is a separately managed division of S&P Global.

STATE OF CALIFORNIA EDMUND G... R., *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

FILED
02/06/18
01:55 PM

February 6, 2018

Agenda ID #16274
Ratesetting

TO PARTIES OF RECORD IN APPLICATION 17-04-001 ET AL.:

This is the proposed decision of Administrative Law Judge Bemesderfer. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's March 22, 2018, Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, ex parte communications are prohibited pursuant to Rule 8.3(c)(4)(B).

/s/ ANNE E. SIMON
Anne E. Simon
Acting Chief Administrative Law Judge

AES:jt2

Attachment

ALJ/KJB/lil **PROPOSED DECISION** Agenda ID #16274
Ratesetting

Decision **PROPOSED DECISION OF ALJ BEMESDERFER**
(Mailed February 6, 2018)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SAN JOSE WATER COMPANY (U168W) for Authority to Adjust Its Cost of Capital and to Reflect That Cost of Capital in Its Rates for the Period from January 1, 2018 through December 31, 2020.	Application 17-04-001
And Related Matters.	Application 17-04-002 Application 17-04-003 Application 17-04-006

DECISION FIXING COST OF CAPITAL FOR CALENDAR YEARS 2018, 2019 AND 2020 FOR CALIFORNIA WATER SERVICE COMPANY, CALIFORNIA-AMERICAN WATER COMPANY, GOLDEN STATE WATER COMPANY AND SAN JOSE WATER COMPANY

Table of Contents

DECISION FIXING COST OF CAPITAL FOR CALENDAR YEARS 2018, 2019 AND 2020 FOR CALIFORNIA WATER SERVICE COMPANY, CALIFORNIA-AMERICAN WATER COMPANY, GOLDEN STATE WATER COMPANY AND SAN JOSE WATER COMPANY

Summary

We adopt the ratemaking capital structures, costs of equity, costs of debt and overall rates of return for the three-year period commencing January 1, 2018 through December 31, 2020 for all four applicants (Applicants). We also continue the Water Cost of Capital Mechanism for the same period.

The figures shown in Table I represent each Applicant's authorized return on equity, costs of debt, debt/equity ratio and overall rate of return on rate base. In each case, we have adopted the capital structure, costs of debt and return on equity proposed by the Office of Ratepayer Advocates. Overall rate of return has been calculated in each case by multiplying the cost of debt times the debt percentage in the capital structure and adding that product to the product of authorized return on equity times the equity percentage in the capital structure.

Table 1
Authorized Capital Structures, Costs of Equity, Costs of Debt and Overall Rate of Return for All Applicants

Company	Return on Equity	Cost of Debt	Debt/Equity Ratio	Overall Rate of Return
California Water Service Company	8.22%	5.51%	45.46%/54.44%	6.99%
California-American Water Company	8.23%	5.22%	45.82%/54.18%	6.85%
Golden State Water Company	8.23%	6.40%	45.87%/54.13%	7.39%
San Jose Water Company	8/30%	5.96%	47.42%/52.58%	7.19%

1. Background

In Decision (D.) 12-07-009, the Commission approved a settlement between Applicants and the Division of Ratepayer Advocates, predecessor to the Office of Ratepayer Advocates, (ORA) that fixed the return on equity (ROE) for all Applicants for the three-year period beginning January 1, 2012 at 9.99%. The terms of the settlement were extended to include the years 2015, 2016 and 2017 by annual letters to the Applicants from the Commission's Executive Director granting the requested extensions. On December 2, 2016, Applicants wrote to Executive Director Tim Sullivan proposing an additional year's extension. On February 16, 2017 Executive Director Sullivan responded to Applicants, rejecting their proposal and directing them to file cost of capital applications for the three-year period beginning January 1, 2018 on or before April 1, 2017.

The 9.99% ROE adopted for all Applicants in D.12-07-009 was adjusted downward by the operation of the Water Cost of Capital Mechanism (WCCM) for California Water Service Company (CWS), Golden State Water Company (GSW) and San Jose Water company (SJW) to its current authorized 9.43% ROE.

On April 3, 2017, Applicants CWS, California-American Water Company (CAW), GSW and SJW filed simultaneous applications for approval of their respective proposed costs of capital for the three-year period beginning January 1, 2018. On May 8, 2017, the assigned Administrative Law Judge (ALJ) issued a ruling consolidating the proceedings. On May 10, 2017, ORA filed a protest to all four applications.

Pursuant to the Scoping Memo of the assigned Commissioner issued on June 22, 2017, Applicants and ORA prepared and submitted extensive direct and rebuttal testimony addressing the methodology of determining costs of capital and their contrasting recommendations regarding those costs. Evidentiary hearings were held September 13-15, 2017, following which the parties filed opening and reply briefs on September 28, 2017 and October 9, 2017, respectively.

In addition to the evidentiary hearings, the Commission held a series of public participation hearings (PPHs) in Los Angeles, Monterey and San Jose on October 30, November 1, and November 6, 2017. At the PPHs, members of the public made their views regarding the specific applications known and questioned representatives of the water companies and ORA regarding their positions on various issues in the proceeding. In total more than 400 ratepayers appeared at these meetings and more than 100 of them provided comments.

On December 15, 2017, ORA filed a motion to require Applicants to establish memorandum accounts to track the difference between water rates currently in effect and water rates that will go into effect upon resolution of this proceeding. With no opposition to the motion, the ALJ granted ORA's motion on December 27, 2017 and required Applicants to establish their memorandum accounts effective January 1, 2018.

2. Discussion

Fixing costs of capital for the next three years is an exercise in economic and financial forecasting. In estimating such things as the future path of inflation, we rely on the opinions of experts. Different experts, employing different forecasting techniques, typically present different views of the future, leaving it to us to choose among the views presented.

In these cases, the great majority of the difference between Applicants' experts and ORA's experts results from a disagreement about what should be the authorized ROE. Underlying the clash of expert opinions on this topic are two rather different views of the justification for ROE. Applicants' experts take the position that the authorized ROE should be not less than the average ROE of similar securities issued by comparable regulated private water companies in other states. Underlying this position is the assumption that if Applicants choose to raise money by selling stock, these are the kinds of returns that investors in water company stocks would insist on receiving. If we approve ROEs significantly lower than those allowed to similar companies by other regulatory commissions, the argument goes, investors will choose to purchase the stock of those other companies rather than the stock of Applicants.

ORA does not disagree that such comparisons are relevant. But ORA also argues that the risk-hedging and risk-spreading mechanisms adopted by this Commission over the years have effectively guaranteed that the Applicants will earn their allowed returns on rate base, making investment in their common equity nearly risk-free and their ROEs should be adjusted downward to reflect this fact. Such mechanisms include the Water Rate Adjustment Mechanism (WRAM), which authorizes rate increases to offset declines in water use; the WCCM, which automatically adjusts authorized ROE up or down depending on changes in the capital markets; various 'balancing accounts' which permit applicants to earn back in the future certain expenses incurred in the present; an attrition or escalation adjustment mechanism which provides protection against inflation in years between general rate cases; and various specific advice letters relating to particular rates and charges which, if not the subject of timely protests, typically become effective 30 days after filing.

After reviewing the expert testimony, we adopt ORA's recommended ROEs, costs of debt (or CD) and capital structures. As the more detailed discussion below will demonstrate, ORA's recommended ROEs, CDs and capital structures are reasonable and find ample support in the evidentiary record.

Applicants' request to continue employing the WCCM authorized by the Commission pursuant to D.09-07-051 and D.12-07-009 for the years 2019 and 2020, using the base year 2018 that will be adopted in this proceeding, is unopposed and should be adopted.

3. Return on Equity

The legal standard for setting the fair rate of return has been established by the United States Supreme Court in the *Bluefield*, *Hope* and *Duquesne* cases.[1] *Bluefield* stands for the proposition that a utility's overall return should be comparable to the overall return earned at the same time and in the same general part of the country on investments in other business undertakings attended by corresponding risks and uncertainties. *Hope* states that authorized rates will not be judged invalid as long as they enable a utility to maintain financial integrity, to attract capital, and to compensate investors for the risks they assume. In *Duquesne*, the Court concludes that rates must not be so low as to be confiscatory. However, in applying these parameters, we must not lose sight of our duty to utility ratepayers to protect them from unreasonable risks including risks of imprudent management.

Hence, our basic objective in a cost of capital proceeding is to set the equity return at the lowest level that meets the test of reasonableness.[2] At the same

[1] *The Federal Power Commission v. Hope Natural Gas Company,* 320 U.S. 591 (1944), *Bluefield Water Works & Improvement Company v. Public Service Commission of the State of Virginia*, 262 U.S. 679 (1923); *Duquesne Light Co. v. Barasch,* 488 U.S. 299 (1989).

[2] 46 CPUC2d 319 at 369 (1992).

time, the adopted equity return should be sufficient to provide a margin of safety to pay interest, pay reasonable common dividends, and allow for some money to be kept in the business as retained earnings.[3] To accomplish this objective, we have consistently evaluated analytical financial models as a starting point to arrive at a range of fair equity returns.

The financial models commonly used in equity return proceedings are the Capital Asset Pricing Model (CAPM),[4] Risk Premium Model (RPM),[5] and Discounted Cash Flow Analysis (DCF).[6] An additional method utilizing a comparable earnings approach[7] was used by SJW and GSW. A Proxy Group comprised of companies with characteristics and risks comparable to those of Applicants is used for the DCF and CAPM financial models. The parties selected their Proxy Groups from the water utilities group listed in Value Line.[8] Screens used by the parties in selecting their comparable Proxy Group included: (1) publicly traded water utility; (2) investment grade bond rating; (3) high percentage of revenue from regulated activities; and (4) no significant merger activity in the previous five years.

---

[3] 78 CPUC at 723 (1975).

[4] The CAPM is a risk premium approach that gauges an entity's cost of equity based on the sum of an interest rate on a risk-free bond and a risk premium.

[5] Similar to the CAPM, the RPM measures a company's cost of equity capital by adding a risk premium to a risk-free long-term treasury or utility bond yield.

[6] The DCF model is used to estimate an equity return from a Proxy Group by adding estimated dividend yields to investors' expected long-term dividend growth rate.

[7] The Comparable Earnings Approach uses a proxy of non-utility companies to estimate a comparable utility ROE.

[8] Value Line is an independent financial and research publishing firm.

CAW, CWS, SJW and ORA used the same eight water companies in their Proxy Group analysis, as identified in the following table by utility, annual revenue, market capitalization and current bond rating. GSW added Artesian Resources to the companies in Table 2 to form its Proxy Group.

Table 2
Water Proxy Group Financial Data

Company	Annual Revenue[9] (Millions)	Market Capitalization[10] (Millions)	Standard & Poors' 2016 Credit Rating
American States Water	$439	$1,446	A+
American Water Works	$3,283	$13,661	A
Aqua America	$820	$5,449	A-
Connecticut Water Services	$98	$556	A
Middlesex Water	$132	$571	A
SJW Corporation	$348	$898	BBB+
York Water Co.	$47	$380	A-

Applicants used the CAPM, RPM and DCF financial models as a basis to derive their requested ROEs, ranging from a low of 10.75% by CWS to a high of 11.00% by GSW. ORA used the CAPM and a variation of the DCF as its basis to recommend ROEs for Applicants ranging from a low of 8.20% for CWS to a high of 8.30% for SJW.

Applicants assert that ORA's results and recommendations are too low given that the national average ROEs granted water utilities were 9.68% in 2016 and 9.43% for the first five months of 2017 and (2) major California energy

[9] As of December 31, 2016.

[10] As of September 1, 2016.

utilities have ROEs of 10.05% to 10.30%.[11] Conversely, the 10.75% to 11.00% ROEs being requested by Applicants are more than 100 basis points[12] higher than the national average ROEs granted water utilities and approximately 70 basis points higher than the California energy utilities' ROEs.

Applicants did not provide any evidence to substantiate that their businesses are riskier than either the national water utilities or the major California energy utilities. Consequently, we have no reason to consider either the national water utilities' average ROEs or the California energy utilities' ROEs as benchmark in this proceeding; instead we address the parties' financial model results.

4. Financial Modeling Adjustments

Applicants included upward adjustments in their financial modeling results for: (1) flotation costs; (2) non-regulated comparable earnings approach (Non-Reg. Comp.); (3) after tax weighted average cost of capital (ATWACC); (4) financial leverage; and (5) small size. ORA did not propose any adjustments to its 7.26% to 8.63% DCF and 5.27% to 10.43% CAPM financial model results.[13] Applicants applied the results of these financial model adjustments differently, as summarized in the following table:

[11] *See* for example Exhibit GSW 7 at 2-3.

[12] One basis point equals 0.01%.

[13] Exhibit ORA 20 at 62 and 68.

Table 3
Applicants' Proposed Returns on Equity
by Financial Models Employed and Related Adjustments

	CAW[14]	**CWS**[15]	**GSW**[16]	**SJW**[17]
DCF Base	6.80% - 9.00%	6.80% - 9.00%	8.80%	8.50%
ATWACC Adj.	2.70% - 2.00%	1.70% - 2.40%	n.a.[18]	n.a.
Leverage Adj.	n.a.	n.a.	1.33%	n.a.
Flotation Adj.	n.a.	n.a.	.25%	n.a.
Total DCF	**9.50% - 11.00%**	**8.50% - 11.40%**	**10.38%**	**8.50%**
RPM Base	10.10% - 10.20%	n.a.	11.50%	11.19%
Flotation Adj.	n.a.	n.a.	.25%	n.a.
Total RPM	**10.10% - 10.20%**	**combined**[19]	**11.75%**	**11.19%**
CAPM Base	9.00% - 9.70%	9.00% - 9.90%	10.40%	9.41%
ATWAC Adj.	1.00% - 1.20%	.60% - 1.50%	n.a.	n.a.
Size Adj.	n.a.	n.a.	1.00%	n.a.
Flotation Adj.	n.a.	n.a.	.25%	n.a.
Total CAPM	**10.00% - 10.90%**	**9.60% - 11.40%**	**11.65%**	**9.41%**
Separate Adjustments				
Non-Reg. Comp.	n.a.	n.a.	12.30%[20]	10.39%[21]
Size Adj.	n.a.	.20%	n.a.	.10%
Flotation Adj.	n.a.	n.a.	n.a.	.17%

14 Exhibit CAW 1 at 2 and Exhibit BV-4 at 23-25 and 35-36.

15 Exhibit CWS 1 at 54, Exhibit E pp. 23-24 and pp. 35-36, and Exhibit CWS 3.

16 Exhibit GSW 3 at 4 and 30-40.

17 Exhibit SJW 4 at 5.

18 Not applicable (n.a.).

19 CWS combined its RPM and CAPM results.

20 Exhibit GSW 3 at 43, represents average of 12.2% historical and 12.4% forecast.

21 Exhibit SJW 4 at 56-57 represents average of 11.42% DCF, 10.30% RPM, and 9.68% CAPM.

4.1. Flotation Cost

Flotation costs are those costs associated with the sale of new issuances of common stock. They include the essential costs of issuance such as underwriting fees, printing, legal, and registration.[22] This is not a new issue. Although CWS, GSW and SJW contend that it is appropriate to recover their flotation costs, only GSW and SJW reflected a flotation adjustment in their overall ROE recommendations. GSW included a 0.25% upward flotation costs adjustment to its CAPM, RPM, and DCF analysis to arrive at an 11.65% CAPM 11.75% RPM and 10.38 DCF.[23] SJW included a 0.17% upward flotation costs adjustment to the average of its DCF, RPM, CAPM, and Non-Reg. Comp. financial model results.[24]

We have previously disallowed energy utilities from including flotation cost impacts in similar financial models.[25] CWS, GSW and SJW testimony did not provide any new information for the Commission to reevaluate the appropriateness of allowing water utilities to include a flotation costs adjustment in their financial models. Accordingly, we reject GSW's and SJW's proposed flotation costs adjustments.

4.2. Non-Regulated Comparable Earnings Approach

The non-regulated comparable earnings approach estimates a fair ROE by comparing returns realized by non-regulated companies to returns that a public utility with similar risk characteristics would need to realize in order to compete

22 Exhibit SJW 4 at 59.

23 Exhibit GSW 3 at 4.

24 Exhibit SJW 4 at 5.

25 *See* for example D.12-12-034 at 23 (2012), D.02-11-027 at 30 (2002), D.00-12-062 at 16 (2000) and 46 CPUC2d. 319 at 361 (1992).

for capital. Both SJW and GSW included a non-regulated comparable earnings approach to compare relative risk, not a particular business activity or degree of regulation.

SJW selected 15 companies from Value Line for its non-regulated Proxy Group[26] which included AutoZone Inc., Kroger Co., Lilly (Eli) and Co., and Reynolds American. SJW's non-regulated Proxy Group resulted in an 11.42% non-comparable earnings factor using the DCF method, a 10.30% non-regulated comparable earnings factor using the RPM, and a 9.69% non-regulated comparable earnings factor using CAPM.[27] SJW took the average mean and median of these results to arrive at an overall 10.39% non-regulated comparable earnings factor.

GSW selected 17 companies for its non-regulated Proxy Group[28] which included Campbell Soup Co., Cheesecake Factory Inc., Erie Indemnity, and O'Reilly Automotive Inc. GSW's non-regulated Proxy Group averaged a 12.20% non-regulated comparable earnings factor based on five historical years and a 12.40% non-comparable earnings factor based on five future years, resulting in a 12.30% combined past and future average non-comparable earnings factor.[29]

We find that non-utility Proxy Groups are not comparable to utility Proxy Groups for purposes of risk comparison. Non-utility earnings are dependent on a company's ability to price products or services at rates a buyer is willing to pay in a competitive market. Utility earnings are limited by a regulatory return on

---

[26] Exhibit SJW 4 at 55.

[27] Exhibit SJW 4 at 57.

[28] Exhibit GSW 3 at 1 of Schedule 13.

[29] Exhibit GSW 3 at 42-43.

rate base in a monopolistic market. While a non-regulated company faces the possibility of loss of business (or bankruptcy) to any number of competitors, a regulated utility in a monopolistic market faces the possibility of under-earning its allowed return but regulatory mechanism largely insulates it from factors beyond its control. This difference in the nature of the risks faced by regulated and non-regulated companies leads us to reject financial modeling results from SJW's and GSW's non-utility Proxy Groups. Accordingly, we reject SJW's and GSW's non-regulated comparable earnings adjust.

4.3. After Tax Weighted Average Cost of Capital

The ATWACC is calculated using a weighted-average of the after-tax cost of equity and the market CD. This method differs from the traditional WACC (weighted average cost of capital) which is calculated using a weighted-average of after-tax cost of equity and the pre-tax CD.

Both CWS and CAW used the ATWACC method in calculating their respective DCF and CAPM. The following table compares CAW and CWS respective CD forecast to the market CD.

Table 4
CAW and CWS Forecasted Cost of Debt vs. Market Cost of Debt

	Market Cost of Debt[30]	Utility Forecasted Debt[31]
CAW	4.1%	5.63%
CWS	4.1%	5.51%

CWS acknowledged in its testimony that the Commission has not adopted the ATWACC method.[32] By way of background, the ATWACC method was

[30] Exhibit CAW 1, Tab 4 at 37 and Exhibit CWS 1, Ex E at 37.

[31] CAW Application at 2 and CWS Application at 2.

first brought before the Commission in an energy 1998 cost of capital proceeding[33] and was represented in several subsequent energy cost of capital proceedings. Each time the ATWACC method was presented to the Commission, the Commission declined to adopt it. Neither CWS nor CAW provided convincing testimony that the ATWACC method should be adopted in this proceeding. Therefore, CWS and CAW's ATWACC calculations carry no weight in this proceeding.

4.4. Financial Leverage Adjustment

GSW includes a leverage adjustment in its DCF results to reflect a financial risk difference between a book value and market value capital structure.

GSW adjusted its 8.80% DCF result upward by a 1.33%[34] leverage adjustment to arrive at a 10.13% DCF.[35] In defense of this adjustment, GSW argues that investors expect to earn returns that reflect the fact that the company is not capitalized with 100% equity but has a balanced capital structure instead. The presence of debt on the company's balance sheet adds an element of risk to investment in its common stock that should be compensated for by an adjustment in ROE.[36]

We decline to adopt GSW's leverage adjustment. While such an approach might be appropriate in evaluating the risk of investment in a non-utility whose success or failure reflects its ability to compete in the marketplace, it is

---

32 Exhibit CWS 1 at 2.

33 *See* D.99-06-057.

34 Exhibit GSW 3 at 30.

35 GSW further imputes a 25 flotation adjustment to arrive at its 10.38% DCF.

36 Exhibit GSW 3 at Schedule 9.

inappropriate in the context of investing in a regulated utility whose returns are effectively insulated from market fluctuations. While it is true that a water utility is guaranteed only the right to earn a certain return on its rate base, the risk reduction mechanisms that we apply to water utilities[37] effectively mitigate most, if not all, of the risk associated with the existence of leverage in the capital structure.

4.5. Small Size Adjustment

Three of the four Applicants seek an upward adjustment to their ROEs for the small size of their operations. SJW added a 0.10% business risk to its total financial model results so that it may be compensated for its small size in comparison to the average market capitalization of its water Proxy Group.[38] CWS added a 20 basis points size adjustment to its overall ROE to compensate it for risks and challenges involved in operating a series of smaller districts that are not present for larger districts.[39] GSW added a 1.00% adjustment in its CAPM to account for its smaller size in comparison to the market-based average equity capitalization of the Water Proxy Group as a whole.[40]

We reject Applicants' small size adjustments because the impact of small size districts and operations is already reflected in the financial models of their Proxy Group. Applicants have included their own operations as part of their Proxy Groups. Given the Proxy Group members' substantial spread of annual revenue and market capitalization as shown in Table 3, and inclusion of

---

[37] *See* footnote 4, *supra.*

[38] Exhibit SJW 4 at 63.

[39] Exhibit CWS 3 at 15.

[40] Exhibit GSW 3 at 39-40 and GSW 7 at 22.

Applicants' own operations as part of the Water Proxy Group, further small size adjustments are unnecessary.

We note that a related issue, whether the Commission should identify opportunities for consolidation of troubled systems within or adjacent to utilities' service territories that are not able to provide safe, reliable and affordable drinking water, and to what extent such issues should be addressed outside the water utility's general rate case, is being addressed in Rulemaking (R.) 17-06-024. This specific issue was not raised by the parties in this proceeding, but to the extent such consolidation or acquisitions are in the public interest, they may justify a troubled system adjustment. Parties may revisit this issue in R.17-06-024 consistent with the scope set forth in the January 9, 2018 Scoping Memo issued in that proceeding. Any future adjustments in this area whether addressed in R.17-06-024 or future applications for adjustments in cost of capital will need to be supported by the record in the respective proceedings.

5. Financial Model Results

Applicants and ORA derived an ROE range from the results of their financial models and used that range to recommend a specific ROE. The parties were not consistent in selecting their respective ROE range. CAW, GSW and SJW took a simple average of their individual financial model results.[41] CWS selected the lowest point and highest point from all of its financial model results. ORA used the results of its CAPM financial model.

The DCF financial model is investor related and assesses the equity returns based on dividend yields and growth. Unlike the DCF financial model both the

---

41 Although SJW applied a simple average of its financial model results it gave very limited weigh to its DCF result. Exhibit SJW 4 at 5.

RPM and CAPM financial models are risk premium related. Applicants have included several variations of the CAPM financial model in arriving at their CAPM result.[42] Because both the RPM and CAPM financial models are risk premium related, we have given their results equal weight. Hence, we apply a simple weighted average of these three models consisting of 1/2.

DCF, 1/4 RPM and 1/4 CAPM to compare Applicants' and ORA's ranges of ROE. The following table summarizes the simple weighted averages of the individual financial models used by the parties, excluding the flotation cost, Non-Reg. Comp., ATWACC, financial leverage and small size adjustments we have determined are not appropriate in this proceeding.

Table 5
Applicants' and ORA's Adjusted ROE Ranges

	CAW	CWS	GSW	SJW	ORA[43]
DCF	6.80% - 9.00%	6.80% - 9.00%	8.80%	8.50%	7.26% - 8.63%
RPM	10.10% - 10.20%	n.a.	11.50%	11.19%	n.a.
CAPM	9.00% - 9.70%	9.00% - 9.90%	10.40%	9.41%	5.27% - 10.43%
Weighted Average	8.18% - 9.48%	7.90% - 9.45%	9.88%	9.40%	6.27% - 9.53%

6. Return on Equity Summary

The results of these financial models are used to establish a range to which parties apply risk factors and individual judgment to determine a proposed equity return. Although the parties agree that the models are objective, the results are dependent on subjective inputs. In the final analysis it is the

[42] Exhibit CAW 1 at 26.

[43] ORA's DCF range is based on is constant growth and non-constant growth DCF results.

application of judgment, not the precision of these models, which is the key to selecting a specific equity return within the range produced by financial model analysis.

As summarized in the following table, the financial models employed by Applicants and ORA, depending on the methods of calculation used and the assumptions made, produce average ROEs ranging from 6.27% to 9.88%. The table also compares the average of ROE ranges from the financial models to Applicants' requested and ORA's proposed ROEs. In all cases, the ROEs requested by Applicants exceed the ceiling of their adjusted financial model results by more than 100 basis points.

Table 6
Comparison of the Parties' Weighted Average Return of Equity Ranges to Applicants' Requested and ORA's Proposed Return on Equity

	Adjusted ROE Ranges		Requested/Proposed ROE	
	Utility	**ORA**	**Utility**	**ORA**
CAW	8.18% - 9.48%	6.27% - 9.53%	10.80%	8.23%
CWS	7.90% - 9.45%	6.27% - 9.53%	10.75%	8.22%
GSW	9.88%	6.27% - 9.53%	11.00%	8.22%
SJW	9.40%	6.27% - 9.53%	10.80%	8.30%

After considering all the evidence which includes the financial model results, adjustments to financial models, interest rate forecast, CD forecast, and applying informed judgement we arrive at a base ROE range of 7.40% to 9.40%. From that ROE range we consider the appropriate ROE for each of the Applicants.

ORA's expert Rothschild developed his ROE recommendations using a constant growth DCF method to derive a cost of equity range between 7.48% and

8.63% for the Water Proxy Group.[44] Based on this method, he calculated an unadjusted ROE for the Water Proxy Group of 8.25%. Rothschild's use of this methodology was criticized by CWS expert Vilbert, but on cross-examination Vilbert admitted that Rothschild's use of the method was "reasonable"[45] and that Rothschild had "implemented the methodology correctly"[46] in arriving at his Water Proxy Group ROE of 8.25%.

To determine the ROE of individual Applicants, Rothschild began with the 8.25% ROE of the Water Proxy Group and then asked if that ROE should be further modified to take account of firm-specific risks. Rothschild testified that in order for firm-specific risks to modify the Proxy Group's ROE, they have to meet two criteria. First, the "risks must be risks not faced by the other companies in the Proxy Group and/or the risks are relatively higher than for the Proxy Group on average" and second the "risks must not be the type that can be diversified by investors buying a portfolio of stocks."[47] Rothschild's explanation of non-diversifiable risks was not disputed by Applicants' experts.

Although Applicants' experts listed a variety of risks allegedly faced by the specific firms, including operating leverage from high capital expenditures, a "small firm effect," regulatory uncertainty, and water supply issues,[48] they failed in each case to demonstrate that these firm-specific risks were non-diversifiable,

---

[44] Exhibit ORA 20 at 62. Although Rothschild used 7.48% to 8.63% based on a constant growth DCF, the overall result adopted in this opinion includes all results within a specific model, resulting in a lower bound of 7.26% in the DCF calculation.

[45] Transcript Vol.1 at 71, lines 14-17.

[46] *Ibid*. at 73, lines 18-20.

[47] Exhibit ORA 20 at 46.

[48] Exhibit ORA 20 at 77.

a fact admitted by Vilbert in his rebuttal testimony.[49] Since only non-diversifiable risks can potentially affect a specific company's ROE, we conclude that there is no basis for adjusting the Water Proxy Group ROE based on such risks.

Consistent with our above risk discussion, the adopted ROE should be set near the middle of the 7.40% to 9.40% ROE range found reasonable for this consolidated proceeding. ORA's recommended 8.23% ROE for CAW, 8.22% ROE for CWAS, 8.22% ROE for GSW, and 8.30% ROE for SJW, representing the Proxy Group ROE as modified by Rothschild to reflect the relative riskiness of each company's capital structure, are well within that middle range and are adopted.

7. Cost of Debt

We adopt ORA's proposed costs of debt, which are shown on Table 7, below.

Table 7
Comparison of ORA's and Applicants' Proposed Cost of Debt

	ORA Recommended Cost of Debt	Utility Proposed Cost of Debt
SJW	5.96%	6.20%
GSW	6.40%	6.60%
CAW	5.22%	5.63%
CWS	5.51%	5.51%

ORA calculates the annual CD percentage by dividing total annual debt cost amount (both annual interest amount and annual amortization of debt cost,

[49] Exhibit CWS 5 at 37.

including redemption premium) by the existing net proceeds amount. In calculating total annual debt cost for the test year, ORA also incorporates Applicants' proposed future debt cost. ORA calculates its recommended CD percentage by taking the average of the debt cost percentages from 2018 to 2020.[50]

Applicants calculate the annual CD percentage by dividing the total annual debt cost amount (both annual interest amount and annual amortization of debt cost, including redemption premium) by the existing net proceeds amount less unamortized amounts (of debt and redemption premium) associated with the debt that is already paid.[51] In calculating total annual debt cost, Applicants also incorporate future debt cost.[52] Applicants, except CAW, calculate the recommended CD percentage by taking the average of the debt cost percentages from 2018 to 2020. CAW recommends 2018 debt percentage be applied for 2019 and 2020.[53]

Where differences exist, we reject Applicants' proposed CD estimates because of a combination of double-counted issuance costs and, in the case of GSW, the inclusion of unsubstantiated redemption premiums. In developing its recommendation, ORA removed double-counted issuance costs of

[50] ORA Exhibit 28.

[51] CAW Exhibit 3 at 10 and Application, Attachment A, Chapter 3 – Table 2; SJW Exhibit 1 Schedule 4; GSW Exhibit 2, Tables 1 and 2.

[52] CAW Exhibit 3 at 11; GSW Exhibit 2 at 5, and 6; SJW Exhibit 1 at 5; CWS Exhibit 2 at 10, lines 6-7.

[53] GSW Exhibit 2, Table 2; SJW Exhibit 1, Schedule 4.

approximately $3.49 million, $420,900 and $1.18 million from the calculation of debt costs proposed by SJW, GSW and CAW, respectively.[54]

We concur with ORA that the double counted unamortized issuance costs and redemption premium costs associated with the loans that have already been paid as reflected in the Applicants' calculation of CD in the instant proceeding should be removed.[55]

The Applicants' proposed calculation of the effective cost of existing debt adds unamortized issuance costs to the annual cost of existing debt while also subtracting these unamortized issuance costs from net proceeds. Since the effective CD is calculated by dividing the annual CD by net proceeds, increasing both the annual cost amount (numerator) and decreasing the net proceeds amount (denominator) by the same amount for the same cost is essentially double-counting and results in a CD greater than the actual effective cost of outstanding debt.

SJW contends that since both the Bond redemption premium and debt issuance costs reduce borrowing proceeds, they should be treated consistently (as a reduction of Net Proceeds) for purposes of determining the weighted average effective interest rate GSW claims that financing charges associated with redeeming an old debt should be treated no differently than any other debt issuance related cost and should be deducted from net proceeds. Both SJW and GSW are incorrect. There is a fundamental difference between the two types of unamortized debt costs that should not be conflated. One type of unamortized debt cost is attached to existing debt, which may have been issued in order to

[54] ORA Exhibit 22 at 11.

[55] ORA Exhibit 22 at 12.

retire higher-cost debt early, thereby generating unamortized costs and possible early redemption premiums that have not been amortized in rates. The second type of costs that these Applicants propose to recover are not associated with any particular existing issuance but rather have been attached to an existing issuance out of convenience. We reject the inclusion of this second type of cost in current cost of debt.

8. Capital Structure

ORA witness Dawadi arrived at his recommended capital structures by calculating the weighted average capital structures of the Applicants' regulated operations as shown in their annual reports. His recommended capital structures are not materially different from those proposed by the Applicants; however, Dawadi's approach has the advantage of being based on the actual capital structure of the companies' regulated operations and as such it provides the most accurate capital risk profile on which to base adjustments to recommended ROE. Consequently, we conclude that Dawadi's method of establishing regulatory capital structures is reasonable and appropriate. We adopt the capital structures proposed by ORA for all Applicants.

9. Conclusion

Through the testimony of its expert witnesses, ORA has demonstrated that its recommended capital structures, returns on equity and CD for the Applicants are reasonable and should be adopted by this Commission. Accordingly, we adopt ORA's proposed capital structure, CD and ROE for each of the applicants, resulting in the authorized overall rates of return shown on Table 1, above.

10. Comments on Proposed Decision

The proposed decision of ALJ in this matter was mailed to the parties in accordance with Section 311 of the Pub. Util. Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on _____, and reply comments were filed on _____ by _____.

11. Assignment of Proceeding

Martha Guzman Aceves is the assigned Commissioner for this proceeding and Karl J. Bemesderfer is the assigned ALJ.

Findings of Fact

1. More than 400 ratepayers appeared at the PPHs and more than 100 of them provided comments.
2. Applicants seek Commission authorization to continue with their WCCM for the years 2019 and 2020 using the base year 2018 that will be adopted in this proceeding.
3. The legal standards for setting a fair rate of return have been established by the *Bluefield*, *Hope* and *Duquesne* cases. Such a rate of return should be similar to that generally being made at the same time and in the same general part of the country on investments in other business undertakings attended by corresponding risks and uncertainties, should enable a utility to maintain financial integrity, to attract capital, and to compensate investors for the risks they assume and should not be confiscatory.
4. The national average ROEs granted water utilities were 9.68% in 2016 and 9.43% for the first five months of 2017.
5. The major California energy utilities' ROEs are 10.05% to 10.30%.
6. The 10.75% to 11.00% ROEs requested by Applicants are more than 100 basis points higher than the national average ROEs granted water utilities and approximately 70 basis points higher than the major California energy utilities' ROEs.

7. The parties used the same eight water companies in their Proxy Group. In addition, GSW added Artesian Resources to its Proxy Group.

8. The parties used variations of the CAPM, RPM and DCF financial models to support their respective ROE recommendations.

9. GSW and SJW included a flotation cost adjustment in their financial model results, which the Commission has previously disallowed other utilities from using in similar financial models.

10. GSW and SJW included the impact of a non-regulated comparable earnings approach in their financial model results.

11. CWS and CAW included an ATWACC adjustment in their financial model results, which the Commission has previously disallowed other utilities from using in similar models.

12. GSW included a leverage adjustment in its DCF results.

13. CWS, GSW and SJW included a small size adjustment in their financial model results.

14. CWS's and SJW's operations are included in Proxy Group companies California Water Service Group and SJW Corp., respectively.

15. The RPM and CAPM financial models are both risk premium related.

16. The DCF financial model assesses equity returns based on dividend yields and growth.

17. ORA's recommended returns on equity range from 8.22% to 8.30%.

18. Applicants' costs of debt as calculated by ORA range from 5.22% to 5.40%.

19. After elimination of double-counted costs, ORA's calculated costs of debt are not materially different from those proposed by Applicants.

20. ORA's recommended capital structures are not materially different from those proposed by Applicants.

Conclusions of Law

1. The consolidation of these applications does not mean that a uniform ROE should be applied to each of the Applicants.

2. Applicants' requests to continue with their Water Cost of Capital Mechanisms are unopposed and should be adopted.

3. Applicants provided no reason to consider the average ROE of the national water utilities or major California energy utilities as an ROE benchmark in this proceeding.

4. The flotation cost and ATWACC adjustments proposed in this proceeding should be disallowed because the Commission has previously disallowed other utilities from using those adjustments in similar financial models and Applicants provided no reasons for changing this approach.

5. Non-regulated comparable earnings financial modeling results should not be considered in this proceeding for the reasons set forth in the body of this decision.

6. GSW's financial leverage adjustment in its DCF results should be disallowed for the reasons set forth in the body of this decision.

7. The small size adjustment should not be considered in this proceeding for the reasons set forth in the body of this decision.

8. A simple weighted average of financial modeling results consisting of 1/2 DCF, 1/4 RPM and 1/4 CAPM should be applied.

9. Applicants did not provide any evidence to substantiate that they are riskier than either the national water utilities or the major California energy utilities.

10. A 2018, 2019 and 2020 ROE range from 7.40% to 9.40% is just and reasonable for CAW, CWS, GSW and SJW.

11. An 8.23% ROE for the 2018, 2019 and 2020 calendar year is just and reasonable for CAW.

12. An 8.22% ROE for the 2018, 2019 and 2020 calendar year is just and reasonable for CWS.

13. An 8.22% ROE for the 2018, 2019 and 2020 calendar year is just and reasonable for GSW.

14. An 8.30% ROE for the 2018, 2019 and 2020 calendar year is just and reasonable for SJW.

15. ORA's recommended costs of debt for CAW, CWS, GSW and SJW are reasonable and should be adopted.

16. ORA's recommended capital structures for CAW, CWS, GSW and SJW are reasonable and should be adopted.

17. Applicants should amortize and close their memorandum accounts that track the difference between water rates currently in effect and water rates that will go into effect due to a change in their ROE authorized by this decision as part of their next general rate adjustment.

18. The water utilities' ROE applications should be granted to the extent provided for in the following order.

ORDER

1. California Water Service Company is authorized an 8.22% return on equity and a 5.51% cost of debt with a 45.56% debt to 54.44% equity ratio resulting in a 6.99% return on rate base for the calendar years 2018, 2019 and 2020.

2. California-American Water Company is authorized an 8.23% return on equity and a 5.22% cost of debt with a 45.82% debt to 54.18% equity ratio

resulting in a 6.85% return on rate base for the calendar years 2018, 2019 and 2020.

3. Golden State Water Company is authorized an 8.22% return on equity and a 6.40% cost of debt with a 45.87% debt to 54.13% equity ratio resulting in a 7.39% return on rate base for the calendar years 2018, 2019 and 2020.

4. San Jose Water Company is authorized an 8.30% return on equity and a 5.96% cost of debt with a 47.42% debt to 52.58% equity ratio resulting in a 7.19% return on rate base for the calendar years 2018, 2019 and 2020.

5. California Water Service Company, California-American Water Company, Golden State Water Company and San Jose Water Company shall continue with their Water Cost of Capital Mechanism for the years 2019 and 2020, using the base year 2018 adopted in this decision.

6. California Water Service Company, California-American Water Company, Golden State Water Company and San Jose Water Company shall amortize and close their memorandum accounts that track the difference between water rates currently in effect and water rates that will go into effect due to a change in their return on equity authorized by this decision as part of their next general rate adjustment.

7. Application (A.) 17-04-001, A.17-04-002, A.17-04-003, and A.17-04-006 are closed.

This order is effective immediately.

Dated ________________, at San Francisco, California.

2022 U.S. Stock Market Outlook

MORNINGSTAR®

Markets Face Strong Headwinds in 2022

January 2022

Dave Sekera, CFA Chief U.S. Market Strategist, Morningstar Research Services LLC
Preston Caldwell Head of U.S. Economics, Morningstar Research Services LLC

Agenda

- 2021 U.S. Stock Market Review
- 2022 U.S. Stock Market Outlook
- 2022 U.S. Economic Outlook
- Questions

2021 U.S. Stock Market Review

2021 U.S. Market Action

- Economic normalization versus the pandemic
  - Investors entered 2021 with high hopes as pandemic was on downtrend
  - Value & small-caps outperformed early, but lagged as variants emerged
    - Delta drove investors back to their 2020 pandemic playbook
    - Omicron less of an impact than prior variants
  - Interest rates followed pandemic progression, but ended year higher
  - Energy, real estate, & technology outperformed
  - Communications, utilities, & consumer defensive lagged

Market Returns

	2019	2020	1Q2021	2Q2021	3Q2021	4Q2021	2021
Morningstar US Market Index	**31.22**	**20.90**	*6.01*	*8.37*	*0.03*	*9.46*	**25.78**
Morningstar Wide Moat Focus	**35.65**	**15.09**	*12.33*	*7.45*	*(0.87)*	*5.11*	**24.81**
Morningstar US Growth Index	**34.90**	**44.65**	*0.61*	*13.90*	*1.50*	*7.29*	**24.79**
Morningstar US Core Index	**33.07**	**18.15**	*5.55*	*7.20*	*(0.13)*	*13.88*	**28.68**
Morningstar US Value Index	**25.09**	**(1.31)**	*12.49*	*4.03*	*(1.36)*	*7.40*	**23.98**
Morningstar US Large Cap Index	**21.72**	**21.72**	*4.83*	*9.20*	*0.51*	*10.54*	**27.19**
Large Cap Growth	33.81	38.86	*(1.66)*	*15.42*	*2.35*	*3.59*	21.47
Large Cap Core	33.05	19.66	*4.93*	*7.86*	*(0.11)*	*14.62*	29.32
Large Cap Value	25.70	(0.62)	*10.99*	*3.82*	*(1.26)*	*7.62*	21.49
Morningstar US Mid Cap Index	**31.10**	**18.41**	*8.01*	*7.17*	*(0.48)*	*7.36*	**23.68**
Mid Cap Growth	36.01	46.17	*(2.37)*	*11.33*	*0.20*	*4.76*	14.97
Mid Cap Core	31.92	13.53	*9.29*	*6.75*	*(0.13)*	*10.18*	27.81
Mid Cap Value	24.81	(3.76)	*18.31*	*4.19*	*(1.49)*	*7.25*	29.02
Morningstar US Small Cap Index	**25.96**	**16.41**	*11.62*	*4.23*	*(3.67)*	*3.73*	**16.25**
Small Cap Growth	27.60	43.52	*(1.23)*	*4.79*	*(4.50)*	*(0.65)*	(1.00)
Small Cap Core	29.63	6.18	*15.79*	*2.52*	*(3.97)*	*7.25*	21.17
Small Cap Value	19.96	1.01	*21.99*	*5.41*	*(2.06)*	*5.13*	31.79

Source: Morningstar. Data as of December 31, 2021. Past performance is not a reliable indicator of future results and data is presented for illustrative purposes.

2021 U.S. Market Action

- Morningstar Core Index driven by some of the largest holdings in index

Company Name	Ticker	% Core Index	Star Rating 12/31/20	Star Rating 12/31/21	Stock Price 12/31/20	Stock Price 12/31/21	Change (%)	Fair Value 12/31/20	Fair Value 12/31/21	Change (%)
Apple	AAPL	17.0%	★	★★	132.69	177.57	**33.8%**	85.00	124.00	45.9%
Berkshire Hathaway	BRK.A	3.3%	★★★★	★★★	347,815	450,662	**29.6%**	380,000	480,000	26.3%
The Home Depot	HD	2.7%	★★	★	265.62	415.01	**56.2%**	210.00	244.00	16.2%
Broadcom	AVGO	1.7%	★★	★★	437.85	665.41	**52.0%**	350.00	500.00	42.9%
Accenture	ACN	1.6%	★★	★	261.21	414.55	**58.7%**	200.00	258.00	29.0%
Costco Wholesale	COST	1.5%	★★	★★	376.78	567.70	**50.7%**	332.00	447.00	34.6%
Eli Lilly	LLY	1.3%	★★★	★★	168.84	276.22	**63.6%**	169.00	235.00	39.1%
Lowe's Companies	LOW	1.1%	★★	★	160.51	258.48	**61.0%**	145.00	185.00	27.6%
Linde	LIN	1.1%	★★★	★★★	263.51	346.43	**31.5%**	275.00	316.00	14.9%
Oracle	ORCL	0.9%	★★	★	64.69	87.21	**34.8%**	53.00	63.00	18.9%
Charles Schwab & Co.	SCHW	0.9%	★★★	★★	53.04	84.10	**58.6%**	47.00	70.00	48.9%
Applied Materials	AMAT	0.9%	★★	★★★	86.30	157.36	**82.3%**	74.00	142.00	91.9%
		34.0%								

Source: Morningstar. Data as of December 31, 2021. Past performance is not a reliable indicator of future results and data is presented for illustrative purposes.

MORNINGSTAR

Market Returns

	2019	2020	*1Q2021*	*2Q2021*	*3Q2021*	*4Q2021*	2021
Morningstar US Market Index	**31.22**	**20.90**	*6.01*	*8.37*	*0.03*	*9.46*	**25.78**
Morningstar US Market Sector Returns							
Basic Materials	26.44	19.34	*11.27*	*4.95*	*(3.82)*	*16.03*	30.33
Consumer Cyclical	27.25	49.07	*5.16*	*5.79*	*(0.13)*	*11.19*	23.54
Consumer Defensive	27.51	14.28	*2.43*	*4.24*	*(1.22)*	*11.64*	17.74
Communication Services	33.56	26.11	*7.01*	*11.03*	*(0.63)*	*(1.98)*	15.72
Energy	10.03	(33.05)	*30.77*	*11.91*	*(1.06)*	*7.21*	55.23
Financial Services	33.37	4.02	*13.01*	*8.46*	*1.21*	*2.73*	27.45
Healthcare	21.77	17.41	*2.47*	*8.48*	*0.37*	*8.45*	21.01
Industrials	31.40	11.44	*11.19*	*4.41*	*(4.01)*	*9.18*	21.66
Real Estate	28.53	(4.20)	*7.50*	*11.21*	*0.69*	*14.86*	38.28
Technology	46.66	48.04	*1.94*	*11.33*	*1.95*	*16.17*	34.42
Utilities	25.12	(0.59)	*2.80*	*(0.44)*	*1.17*	*13.27*	17.28

Source: Morningstar. Data as of December 31, 2021. Past performance is not a reliable indicator of future results and data is presented for illustrative purposes.

2022 U.S. Stock Market Outlook

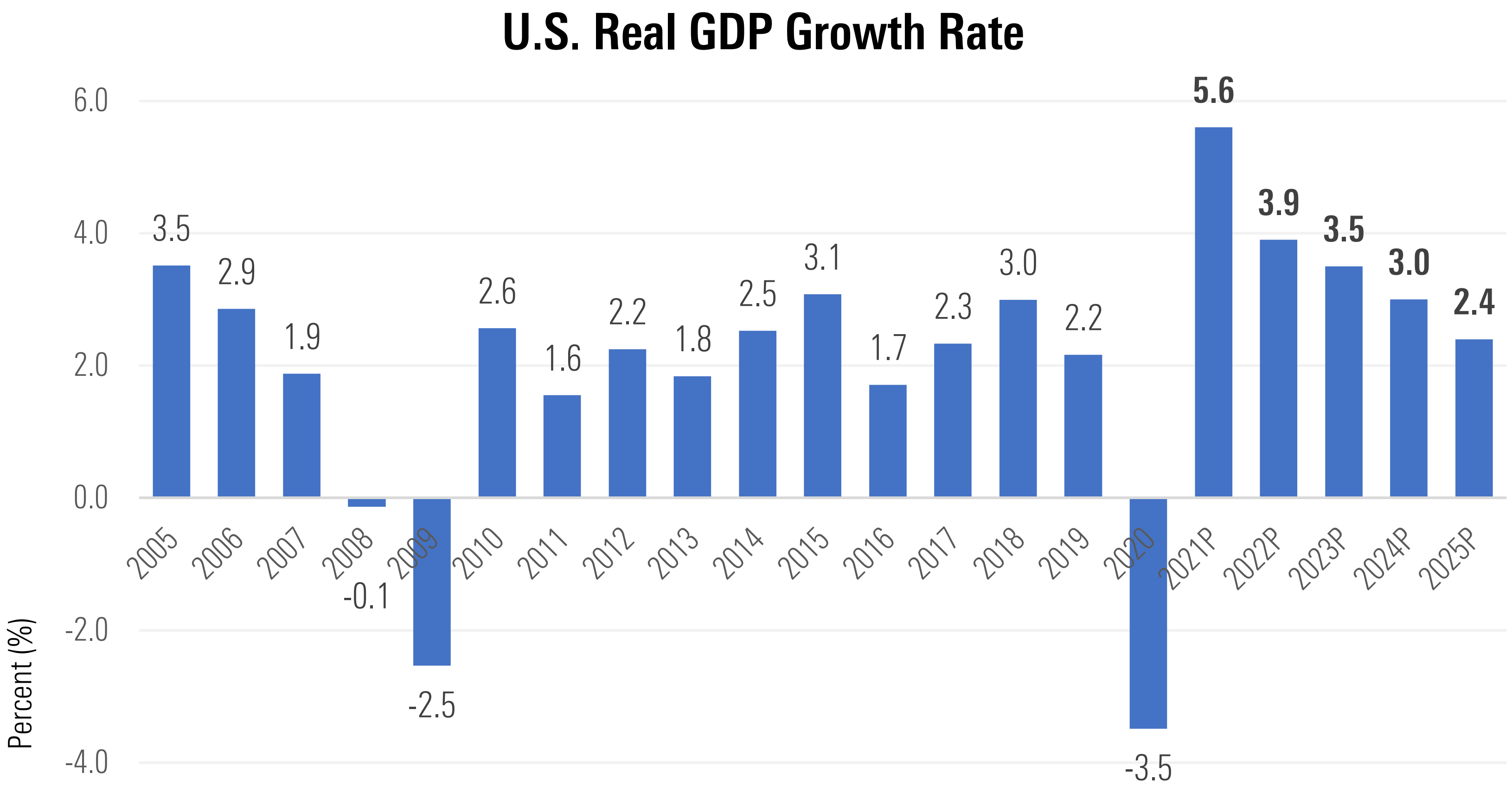
Our Market Outlook

- 2022 starting on a much different footing than the beginning of 2021
  - Slowing economic growth
  - Federal Reserve tightening monetary policy
  - Inflation running hot / rising interest rates

Source: Morningstar. Data as of December 23, 2021. Estimates/forecasts are indicative and for illustrative purposes only.

Our Market Outlook

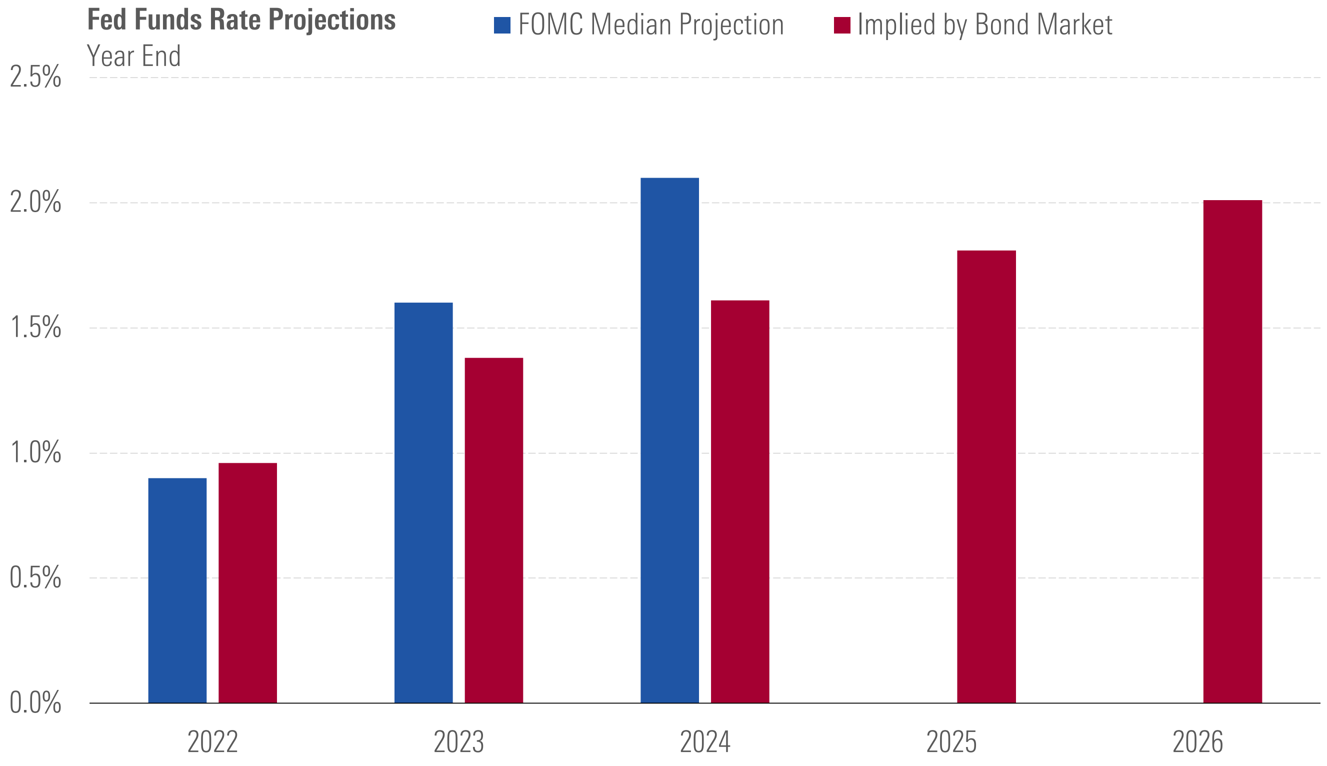
- Economic growth slowing, but remains high compared to past



Source: Morningstar. Data as of December 28, 2021. Estimates/forecasts are indicative and for illustrative purposes only.

Our Market Outlook

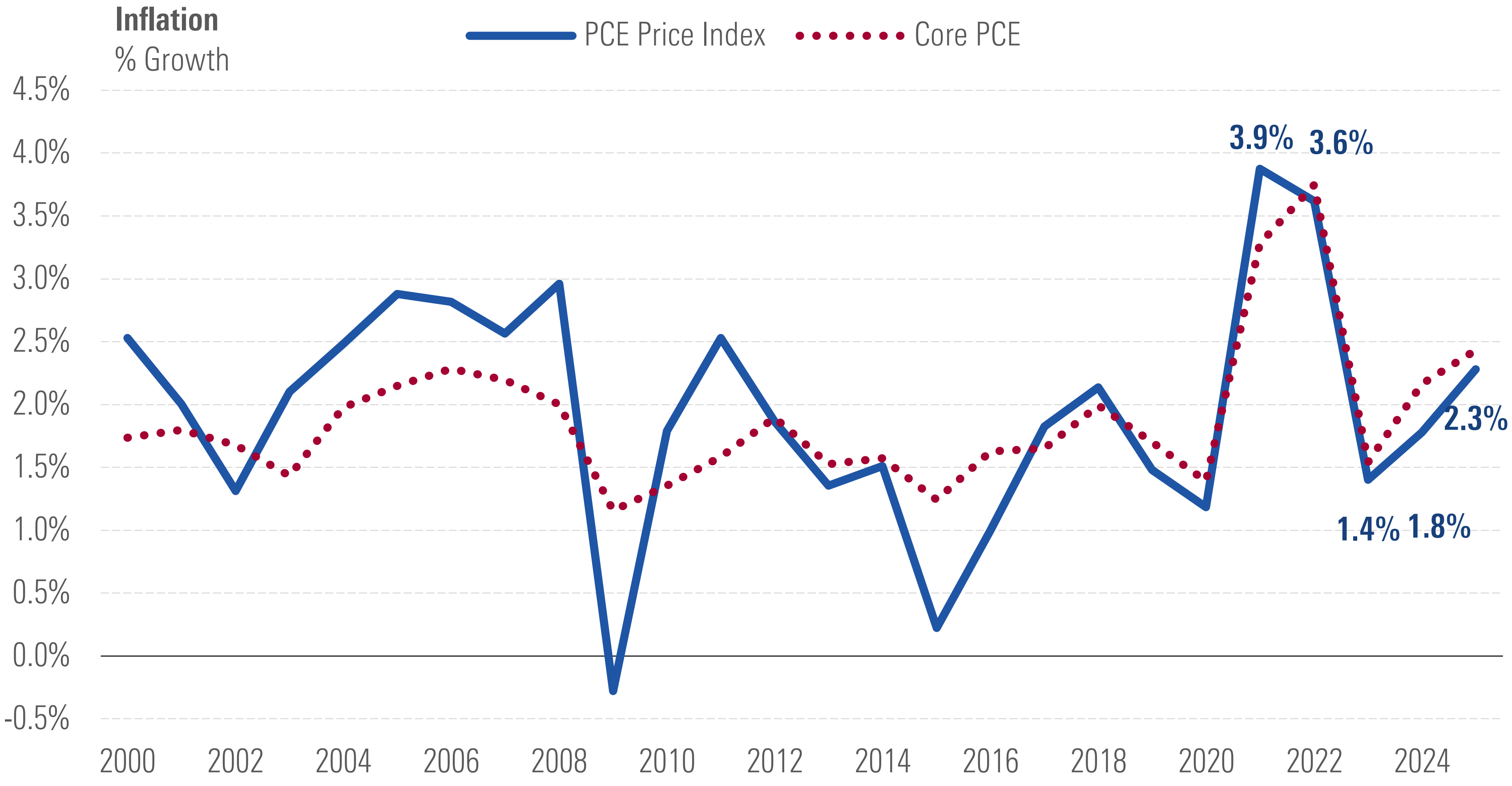
- Tapering quantitative easing, purchases to be completed in March
- Federal funds rate projected to head higher
  - 3 rate hikes forecast in 2022
  - 3 rate hikes forecast in 2023



Sources: U.S. Bureau of Labor Statistics, Morningstar (As of 1/1/2022)

Our Market Outlook

- Inflation running hot, but expected to moderate



Source: Morningstar. Data as of December 30, 2021. Estimates/forecasts are indicative and for illustrative purposes only.

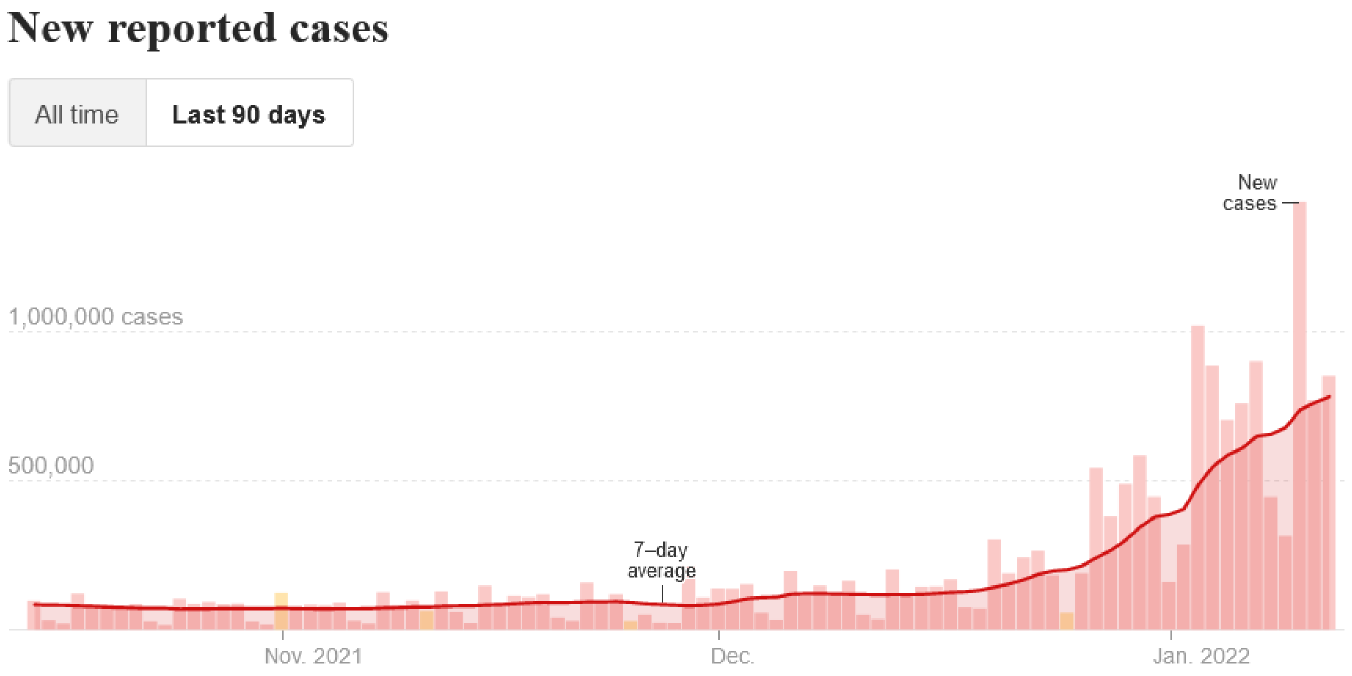
Our Market Outlook

- Broad U.S. equity market is trading at a 5% premium to our intrinsic valuations
  - Small-capitalization stocks most undervalued; especially Value
  - Value category undervalued and has economic tailwinds behind it
  - Energy sector still most undervalued, Communications close behind
  - Financials, Utilities, Consumer Cyclical, and Industrials least overvalued
  - Real Estate, Tech, Basic Materials, and Healthcare most overvalued

Source: Morningstar. Data as of December 23, 2021. Estimates/forecasts are indicative and for illustrative purposes only.

Our Market Outlook

- Unknown as to when Omicron cases may peak
- Is pandemic evolving to being endemic?
- Trend to additional economic normalization to continue in 2022



Source: https://www.nytimes.com/interactive/2021/us/covid-cases.html as of January 12, 2022. and Morningstar.

U.S. Equity Market 5% Overvalued

Morningstar U.S Price to Intrinsic Value (P/FV Metric) Heatmap

	All Coverage	Value	Core	Growth
All	**1.05**	**0.96**	**1.14**	**1.05**
Large	**1.05**	0.97	1.15	1.05
Mid	**1.05**	0.95	1.10	1.12
Small	**0.94**	0.88	1.02	0.99

Source: Morningstar. Data shown is the price to fair value metric as of December 23, 2021. Past performance is not a reliable indicator of future results and data is presented for illustrative purposes.

U.S. Equity Market: U.S Price to Intrinsic Value (P/FV Metric) Heatmap

9/24/21

	All Coverage	Value	Core	Growth
All	1.04	0.94	1.06	1.08
Large	1.03	0.95	1.05	1.07
Mid	1.04	0.92	1.10	1.15
Small	0.95	0.91	1.04	0.89

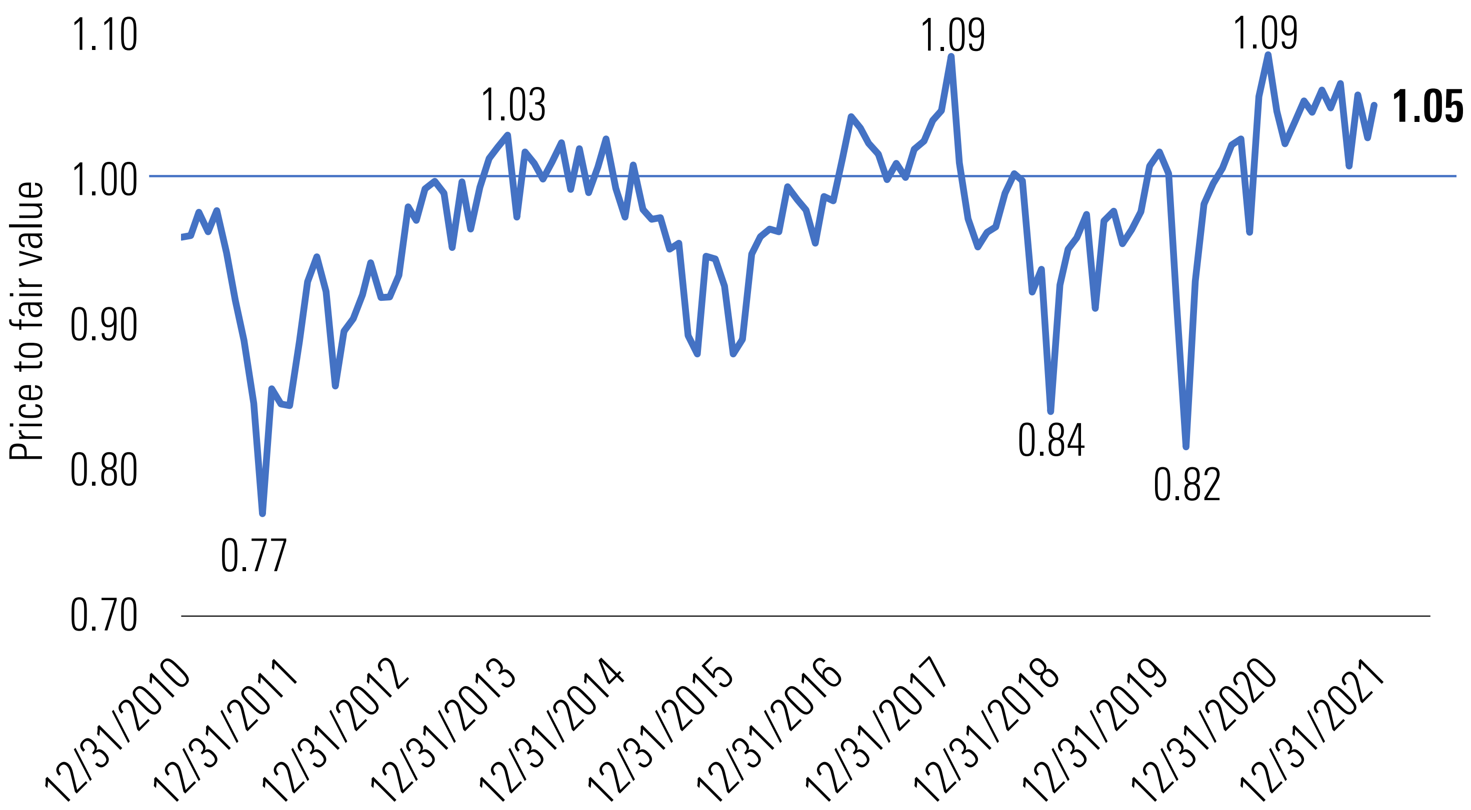
12/23/21

	All Coverage	Value	Core	Growth
All	1.05	0.96	1.14	1.05
Large	1.05	0.97	1.15	1.05
Mid	1.05	0.95	1.10	1.12
Small	0.94	0.88	1.02	0.99

Source: Morningstar. Data shown is the price to fair value metric as labeled. Past performance is not a reliable indicator of future results and data is presented for illustrative purposes.

U.S. Equity Market 5% Overvalued

Morningstar U.S Capitalization-Weighted Price to Intrinsic Value Metric



Source: Morningstar. Data shown is the price to fair value metric as of December 23, 2021. Past performance is not a reliable indicator of future results and data is presented for illustrative purposes.

Most Overvalued Mega-Caps ID'd at YE2020 Down or Lagged in 2021

Company Name	Ticker	Star Rating 12/31/20	Star Rating 12/31/21	Stock Price 12/31/20	Stock Price 12/31/21	Change (%)	Fair Value 12/31/20	Fair Value 12/31/21	Change (%)	Price/Fair Value 12/31/20	Price/Fair Value 12/31/21
Apple	AAPL	★	★★	132.69	177.57	33.8%	85.00	124.00	45.9%	1.56	1.43
Tesla	TSLA	★	★★	705.67	1,056.78	49.8%	306.00	680.00	122.2%	2.31	1.55
Nvidia	NVDA	★★	★★	130.55	294.11	125.3%	85.00	194.00	128.2%	1.54	1.52
Visa	V	★★	★★★	218.73	216.71	**-0.9%**	186.00	221.00	18.8%	1.18	0.98
The Home Depot	HD	★★	★	265.62	415.01	56.2%	210.00	244.00	16.2%	1.26	1.70
Procter & Gamble	PG	★★	★	139.14	163.58	**17.6%**	113.00	118.00	4.4%	1.23	1.39
Walmart	WMT	★★	★★★	144.15	144.69	**0.4%**	124.00	145.00	16.9%	1.16	1.00
MasterCard	MA	★★	★★★	356.94	359.32	**0.7%**	291.00	352.00	21.0%	1.23	1.02
The Walt Disney Company	DIS	★★	★★★	181.18	154.89	**-14.5%**	140.00	170.00	21.4%	1.29	0.91
Netflix	NFLX	★	★	540.73	602.44	**11.4%**	200.00	275.00	37.5%	2.70	2.19
Nike	NKE	★★	★★	141.47	166.67	**17.8%**	107.00	128.00	19.6%	1.32	1.30
PayPal Holdings	PYPL	★	★★	234.20	188.58	**-19.5%**	124.00	151.00	21.8%	1.89	1.25
Morningstar US Market Index						**25.8%**					

Source: Morningstar. Latest prices, fair values and ratings shown are current as of December 31, 2021 and subject to change. Further information including analyst names, the dates and times ratings were published and historical ratings, is available on request from your local Morningstar office. Data presented is indicative and past performance is not a reliable indicator of future results.

MORNINGSTAR®

Updated List of Overvalued Mega-Caps

- List expands to 15 from 10: 2 drop off, 7 new names

Company Name	Ticker	Star Rating	Price/Fair Value	Market Cap ($B)	Moat	Style Box	Sector
Apple	AAPL	★★	1.43	2,913	Narrow	Large Core	Technology
Tesla	TSLA	★★	1.55	1,061	Narrow	Large Growth	Consumer Cyclical
Nvidia	NVDA	★★	1.52	735	Wide	Large Growth	Technology
UnitedHealth Group	UNH	★★	1.31	473	Narrow	Large Core	Healthcare
The Home Depot	HD	★	1.70	433	Wide	Large Core	Consumer Cyclical
Procter & Gamble	PG	★	1.39	396	Wide	Large Core	Consumer Defensive
Bank of America	BAC	★★	1.17	364	Wide	Large Value	Financial Services
Pfizer	PFE	★	1.30	331	Wide	Large Value	Healthcare
Broadcom	AVGO	★★	1.33	275	Narrow	Large Core	Technology
Netflix	NFLX	★	2.19	267	Narrow	Large Growth	Communication Services
Cisco Systems	CSCO	★★	1.17	267	Narrow	Large Value	Technology
Nike	NKE	★★	1.30	264	Wide	Large Growth	Consumer Cyclical
Eli Lilly	LLY	★★	1.18	264	Wide	Large Growth	Healthcare
Thermo Fisher Scientif	TMO	★★	1.28	263	Wide	Large Core	Healthcare
Accenture	ACN	★	1.61	262	Wide	Large Core	Technology

Source: Morningstar. Latest prices, fair values and ratings shown are current as of December 31, 2021 and subject to change. Further information including analyst names, the dates and times ratings were published and historical ratings, is available on request from your local Morningstar office. Data presented is indicative and past performance is not a reliable indicator of future results.

MORNINGSTAR®

Trade Up In Quality: Wide Moat Remains Attractive on Relative Basis

- Wide-Moat Stocks undervalued relative to No Moat and Narrow Moat

9/24/21

	All	Large	Mid	Small	Value	Core	Growth
None	1.06	1.07	1.04	0.94	0.93	1.07	1.41
Narrow	1.11	1.14	1.04	0.96	0.93	1.12	1.26
Wide	0.98	0.98	1.08	0.97	0.96	1.02	0.96

12/23/21

	All	Large	Mid	Small	Value	Core	Growth
None	1.05	1.07	1.05	0.98	0.98	1.08	1.18
Narrow	1.14	1.18	1.04	0.92	0.94	1.14	1.31
Wide	1.00	0.99	1.08	0.95	0.97	1.14	0.94

Source: Morningstar. Data shown is the price to fair value metric as labeled.

MORNINGSTAR®

Selected Stocks: Undervalued Wide Moat

Company Name	Ticker	Star Rating	Stock Price	Fair Value	Price/Fair Value	Moat	Style Box	Sector
Core Laboratories	CLB	★★★★★	22.31	43.00	0.52	Wide	Small Growth	Energy
Yum China	YUMC	★★★★★	49.84	86.00	0.58	Wide	Large Core	Consumer Cyclical
Compass Minerals	CMP	★★★★	51.08	85.00	0.60	Wide	Small Growth	Basic Materials
Polaris Industries	PII	★★★★	109.91	172.00	0.64	Wide	Small Value	Consumer Cyclical
Zimmer Biomet	ZBH	★★★★★	127.04	192.00	0.66	Wide	Mid Core	Healthcare
Biogen	BIIB	★★★★	239.92	361.00	0.66	Wide	Mid Value	Healthcare
Western Union	WU	★★★★	17.84	26.00	0.69	Wide	Small Value	Financial Services
Kellogg's	K	★★★★	64.42	85.00	0.76	Wide	Mid Value	Consumer Defensive
MercadoLibre	MELI	★★★★	1,348.40	1,760.00	0.77	Wide	Large Growth	Consumer Cyclical
Intel	INTC	★★★★	51.50	65.00	0.79	Wide	Large Value	Technology
Salesforce.com	CRM	★★★★	254.13	320.00	0.79	Wide	Large Growth	Technology
Medtronic	MDT	★★★★	103.45	129.00	0.80	Wide	Large Value	Healthcare
Boeing	BA	★★★★	201.32	249.00	0.81	Wide	Large Growth	Industrials
Amazon.com	AMZN	★★★★	3,334.34	4,100.00	0.81	Wide	Large Growth	Consumer Cyclical
Merck & Co.	MRK	★★★★	76.64	94.00	0.82	Wide	Large Value	Healthcare
Meta Platforms	FB	★★★★	336.35	404.00	0.83	Wide	Large Growth	Communication Services
Alphabet	GOOGL	★★★★	2,897.04	3,470.00	0.83	Wide	Large Growth	Communication Services

Source: Morningstar. Latest prices, fair values and ratings shown are current as of December 31, 2021 and subject to change. Further information including analyst names, the dates and times ratings were published and historical ratings, is available on request from your local Morningstar office. Data presented is indicative and past performance is not a reliable indicator of future results.

Selected Stocks: FAANGMT

- Still a number of attractive opportunities across the famous FAANGs

Company Name	Ticker	Star Rating	Stock Price	Fair Value	Price/Fair Value	Market Cap ($B)	Moat	Style Box	Sector
Meta Platforms	FB	★★★★	336.35	404.00	0.83	936	Wide	Large Growth	Communication Services
Amazon.com	AMZN	★★★★	3,334.34	4,100.00	0.81	1,691	Wide	Large Growth	Consumer Cyclical
Apple	AAPL	★★	177.57	124.00	1.43	2,913	Narrow	Large Core	Technology
Netflix	NFLX	★	602.44	275.00	2.19	267	Narrow	Large Growth	Communication Services
Alphabet	GOOGL	★★★★	2,897.04	3,470.00	0.83	1,922	Wide	Large Growth	Communication Services
Microsoft	MSFT	★★★	336.32	345.00	0.97	2,525	Wide	Large Growth	Technology
Tesla	TSLA	★★	1,056.78	680.00	1.55	1,061	Narrow	Large Growth	Consumer Cyclical

Source: Morningstar. Latest prices, fair values and ratings shown are current as of December 31, 2021 and subject to change. Further information including analyst names, the dates and times ratings were published and historical ratings, is available on request from your local Morningstar office. Data presented is indicative and past performance is not a reliable indicator of future results.

Undervalued Chinese ADRs

- Uncertainty about further policy actions remains, but we think margin of safety in these Chinese ADRs compensates investors for added risks

Company Name	Ticker	Star Rating	Stock Price	Fair Value	Price/Fair Value	Moat	Style Box	Sector
I-Mab Biopharma	IMAB	★★★★	46.93	95.00	0.49	None	Not Rated	Healthcare
Yum China	YUMC	★★★★★	48.24	86.00	0.56	Wide	Large Core	Consumer Cyclical
Tencent Holdings	TCEHY	★★★★★	60.26	100.00	0.60	Wide	Large Core	Communication Services
JD.com	JD	★★★★	68.65	113.00	0.61	Wide	Large Core	Consumer Cyclical
Trip.com Group	TCOM	★★★★★	23.79	39.00	0.61	Narrow	Large Value	Consumer Cyclical
Sinopec	SNP	★★★★	47.23	75.00	0.63	None	Large Value	Energy
Alibaba Group	BABA	★★★★	118.66	188.00	0.63	Wide	Large Core	Consumer Cyclical
NetEase	NTES	★★★★	97.84	139.00	0.70	Narrow	Large Core	Communication Services
Baidu	BIDU	★★★★	144.12	183.00	0.79	Wide	Large Value	Communication Services
Sands	LVS	★★★★	38.59	52.00	0.74	Narrow	Mid Value	Consumer Cyclical
Wynn Resorts	WYNN	★★★★	88.88	111.00	0.80	Narrow	Mid Value	Consumer Cyclical

Source: Morningstar. Latest prices, fair values and ratings shown are current as of December 23, 2021, and subject to change. Further information including analyst names, the dates and times ratings were published and historical ratings, is available on request from your local Morningstar office. Data presented is indicative and past performance is not a reliable indicator of future results.

MORNINGSTAR

Key Themes in 2022

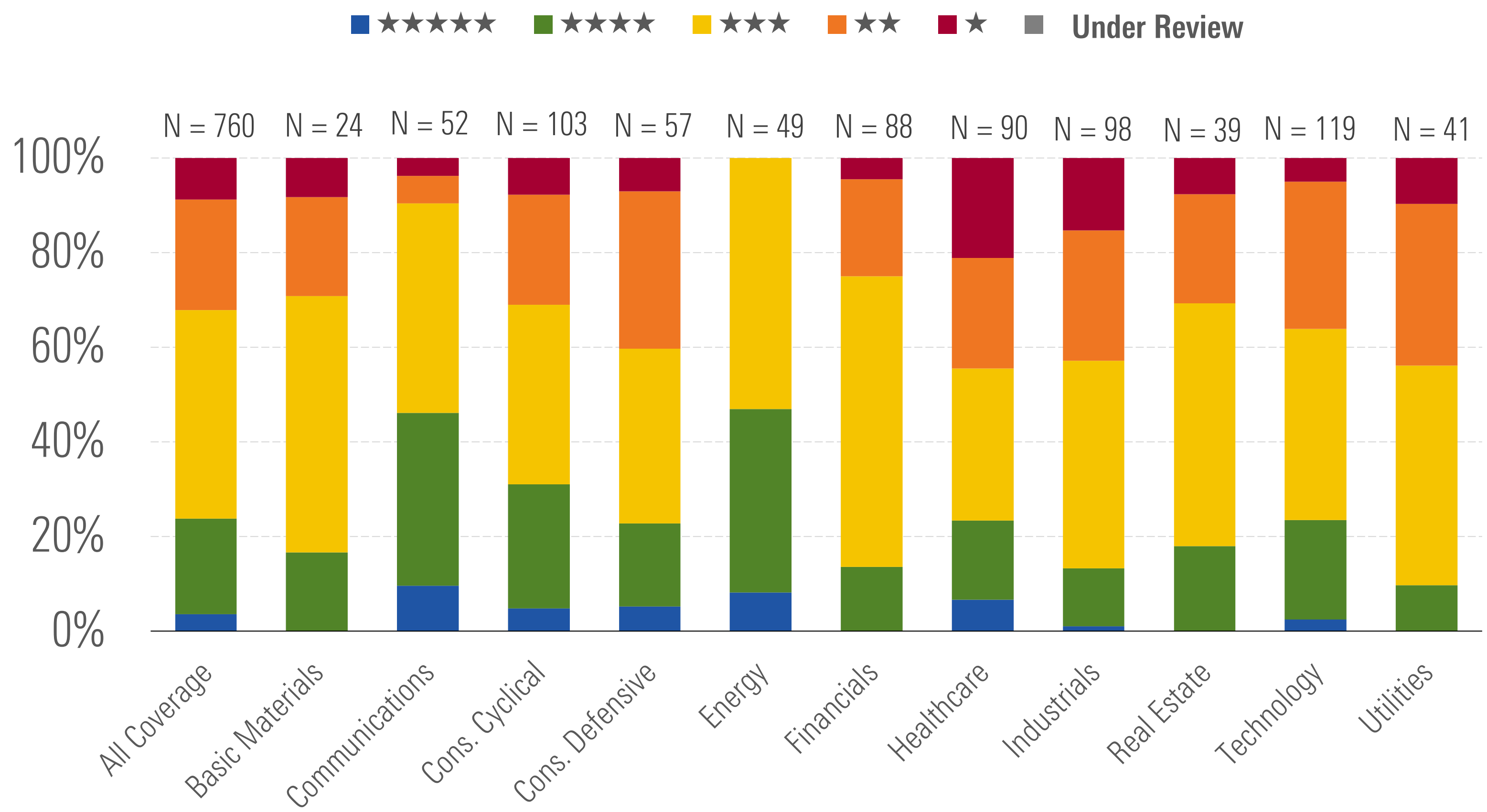
- Pandemic evolving to endemic
- Economic normalization
- Inflation & interest rates
- Earnings guidance
- Capital allocation
- ESG

Risks to Our Outlooks 2022

- Pandemic / new variants
- Inflation
- Interest rates
- Stretched equity valuations
- Geopolitical
- Regulatory environment

Rising Stocks Prices Leave Even Fewer Opportunities Behind

- Number of undervalued stocks increase within Communications
- Economic normalization opportunities span several sectors



Source: Morningstar. Latest prices, fair values and ratings shown are current as of December 27, 2021, and subject to change. Further information including analyst names, the dates and times ratings were published and historical ratings, is available on request from your local Morningstar office. Data presented is indicative and past performance is not a reliable indicator of future results.

MORNINGSTAR®

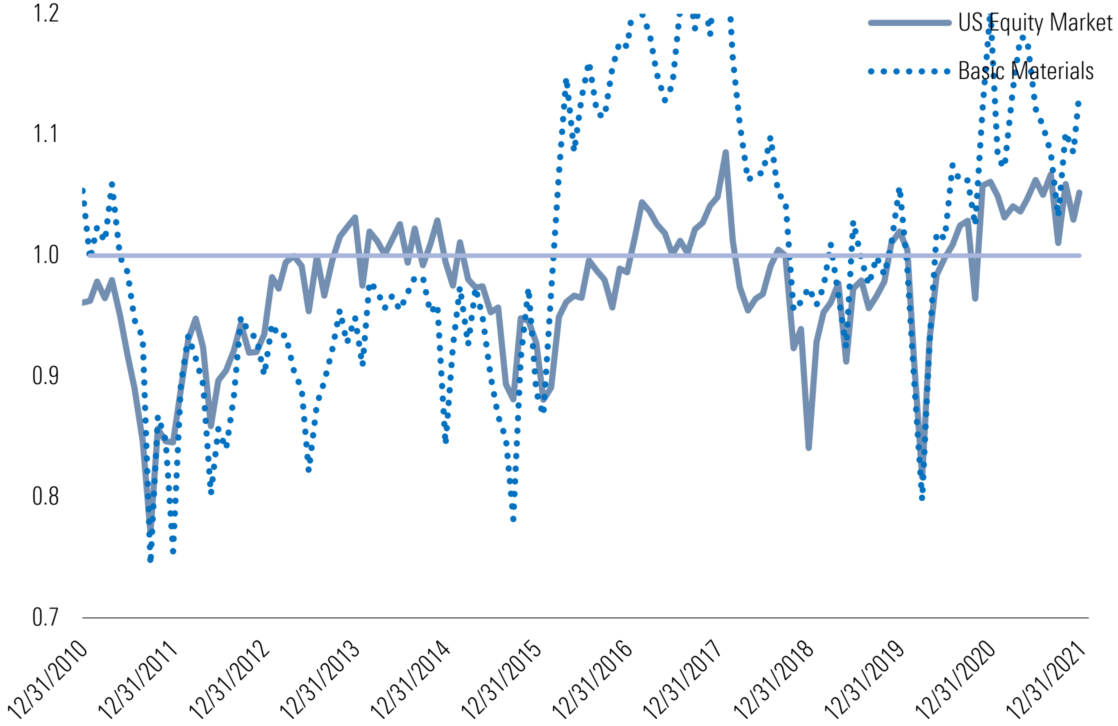
Valuation Heatmap by Sector

- At a P/FV of 0.86, Energy remains the most undervalued; Communications close behind
- Financials, Utilities, Consumer Cyclical, and Industrials least overvalued
- Remaining sectors at lofty valuations

	Sector	Value	Core	Growth	Large	Mid	Small
Basic Materials	1.13	0.95	1.23	1.07	1.18	1.09	1.14
Communications	0.87	0.79	0.86	0.88	0.87	0.87	0.99
Consumer Cyclical	1.08	0.90	1.22	1.06	1.09	1.05	0.92
Consumer Defensive	1.10	0.95	1.19	1.26	1.10	1.08	0.93
Energy	0.86	0.88	0.72	0.72	0.88	0.85	0.72
Financial Services	1.04	1.03	1.07	1.04	1.04	1.08	0.92
Healthcare	1.13	1.01	1.15	1.40	1.14	1.10	1.04
Industrials	1.08	0.90	1.17	1.21	1.08	1.11	1.04
Real Estate	1.20	0.98	1.16	1.43	1.36	1.07	0.94
Technology	1.13	1.00	1.14	1.14	1.14	1.07	0.96
Utilities	1.07	1.02	1.18	NA	1.06	1.09	1.06

Source: Morningstar. Data shown is the price to fair value metric as of December 23, 2021. Past performance is not a reliable indicator of future results and data is presented for illustrative purposes.

Basic Materials



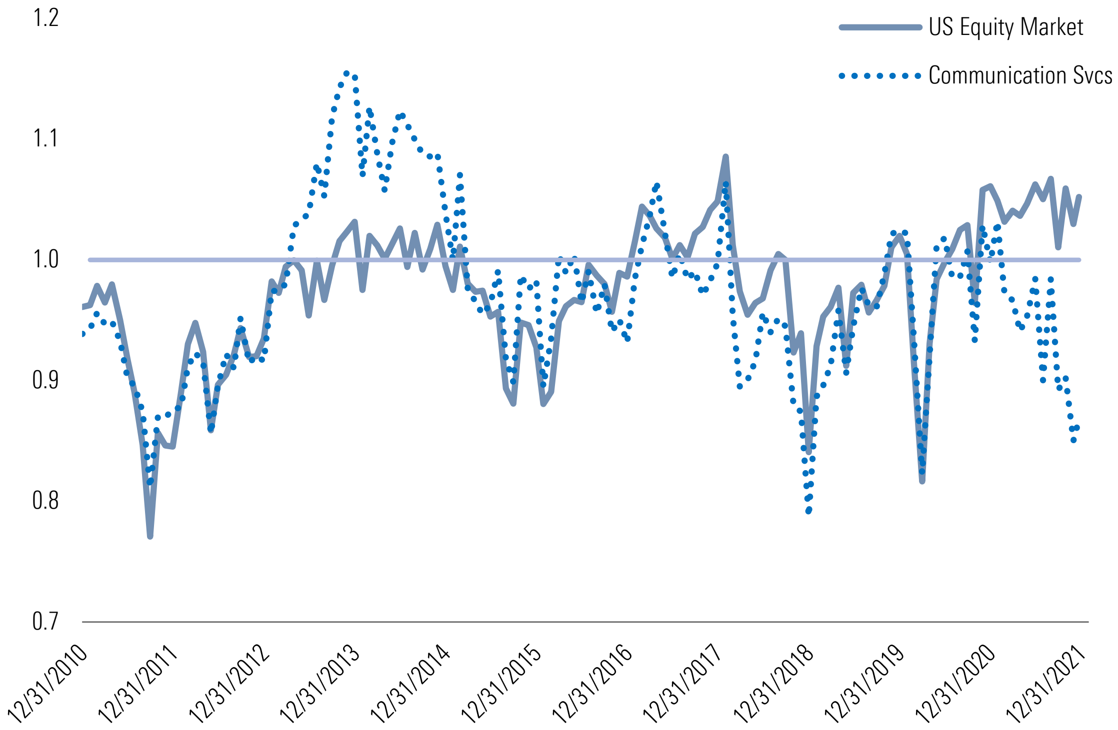
- Industrial gas: long-term agreements, take-or-pay clauses, indexed to inflation, & energy cost pass-throughs
- Specialty chemicals leveraged to electric vehicles

Company Name	Ticker	Star Rating	Stock Price	Fair Value	Price/Fair Value	Market Cap ($B)	Moat	Moat Trend	Style Box
Compass Minerals	CMP	★★★★	51.80	85.00	0.61	2	Wide	Stable	Small Growth
DuPont de Nemours	DD	★★★★	78.54	96.00	0.82	41	Narrow	Stable	Mid Value
Air Products and Chemicals	APD	★★★★	299.48	340.00	0.88	66	Narrow	Positive	Large Core
Corteva Agriscience	CTVA	★★★	46.44	50.00	0.93	34	Wide	Stable	Mid Core
Eastman Chemical Company	EMN	★★★	117.39	125.00	0.94	16	Narrow	Stable	Mid Value

Source: Morningstar. Latest prices, fair values and ratings shown are current as of December 23, 2021 and subject to change. Further information including analyst names, the dates and times ratings were published and historical ratings, is available on request from your local Morningstar office. Data presented is indicative and for illustrative purposes.

MORNINGSTAR

Communications

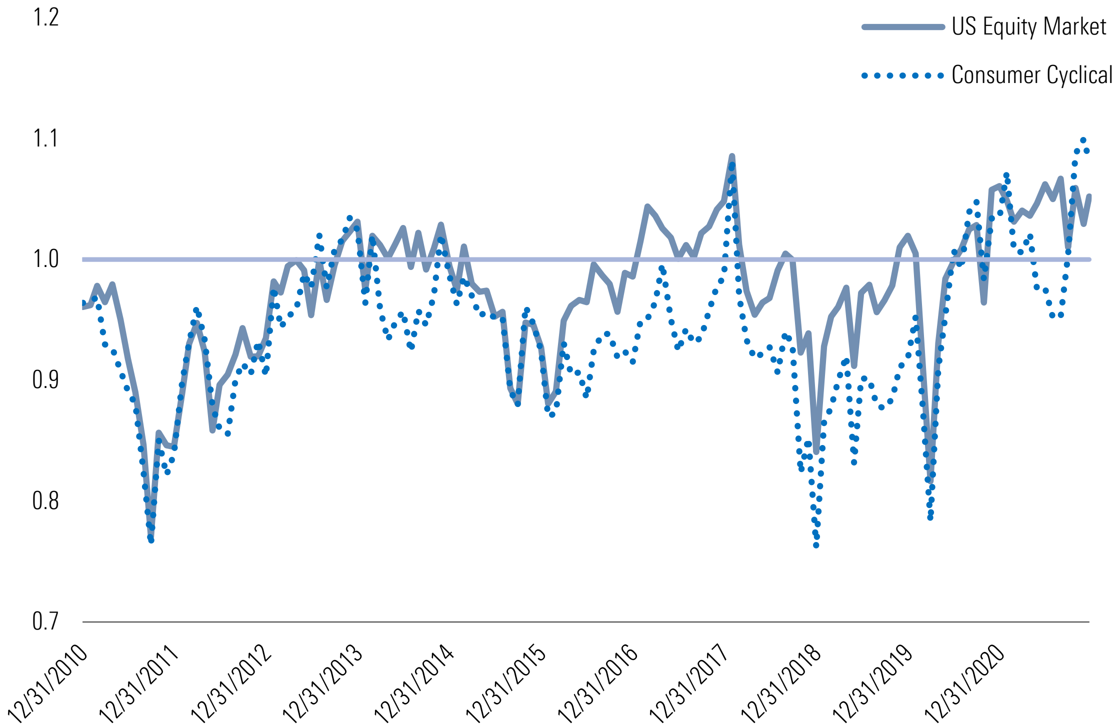


- GOOGL and FB account for 55% of sector weighting
  - GOOGL ★★★★ p/fv = 0.80
  - FB ★★★★ p/fv = 0.81
- AT&T: new management refocusing corporate strategy

Company Name	Ticker	Star Rating	Stock Price	Fair Value	Price/Fair Value	Market Cap ($B)	Moat	Moat Trend	Style Box
ViacomCBS	VIAC	★★★★★	30.58	61.00	0.50	20	Narrow	Negative	Mid Value
Pinterest	PINS	★★★★	37.42	67.00	0.56	24	Narrow	Stable	Mid Growth
Discovery	DISCA	★★★★★	24.42	42.00	0.58	12	Narrow	Stable	Mid Value
Snap Group	SNAP	★★★★	48.68	70.00	0.70	78	None	Stable	Large Growth
AT&T	T	★★★★	24.87	36.00	0.69	178	Narrow	Stable	Large Value

Source: Morningstar. Latest prices, fair values and ratings shown are current as of December 23, 2021, and subject to change. Further information including analyst names, the dates and times ratings were published and historical ratings, is available on request from your local Morningstar office. Data presented is indicative and for illustrative purposes.

Consumer Cyclical



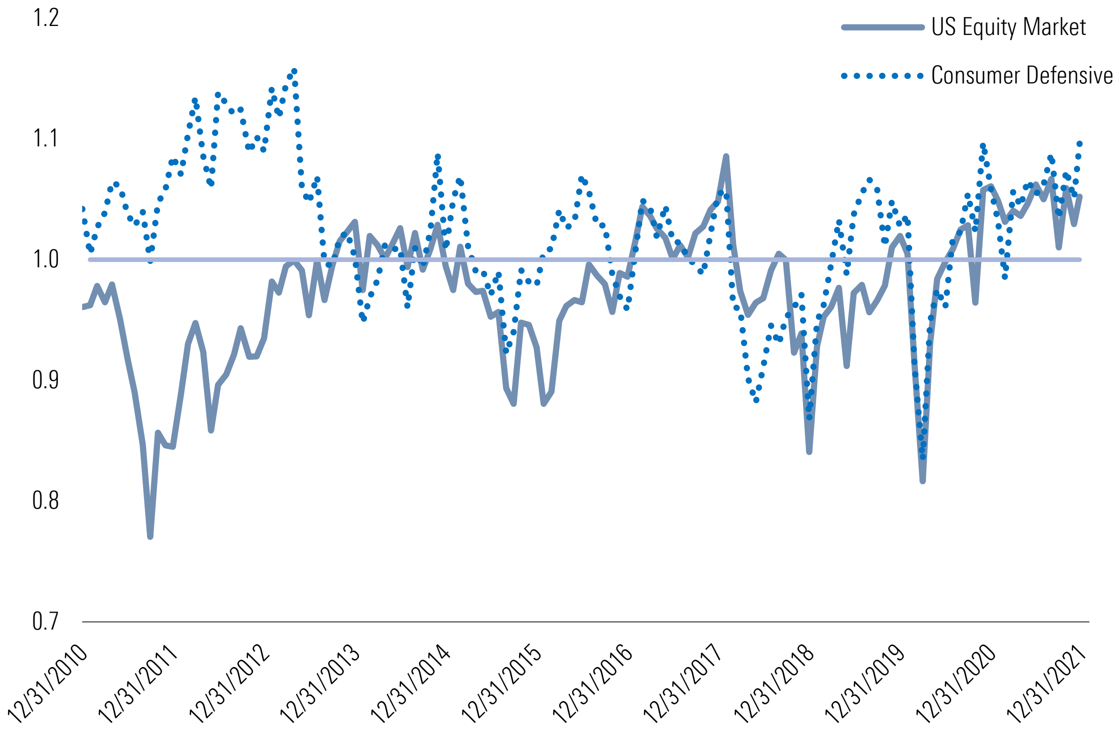
- AMZN ★★★★ p/fv = 0.79 accounts for 20% of sector index
- Travel forecast to return to pre-pandemic levels by 2023
- Long term structural shift to electric vehicles

Company Name	Ticker	Star Rating	Stock Price	Fair Value	Price/Fair Value	Market Cap ($B)	Moat	Moat Trend	Style Box
Polaris Industries	PII	★★★★	106.27	172.00	0.62	6	Wide	Stable	Small Value
BorgWarner	BWA	★★★★	43.62	69.00	0.63	10	Narrow	Stable	Mid Value
Norwegian Cruise Line Holdin	NCLH	★★★★	22.72	31.00	0.73	9	None	Stable	Mid Value
Wynn Resorts	WYNN	★★★★	88.88	111.00	0.80	10	Narrow	Stable	Mid Value
TripAdvisor	TRIP	★★★★	27.26	33.50	0.81	4	Narrow	Stable	Small Value

Source: Morningstar. Latest prices, fair values and ratings shown are current as of December 23, 2021 and subject to change. Further information including analyst names, the dates and times ratings were published and historical ratings, is available on request from your local Morningstar office. Data presented is indicative and for illustrative purposes.

MORNINGSTAR

Consumer Defensive

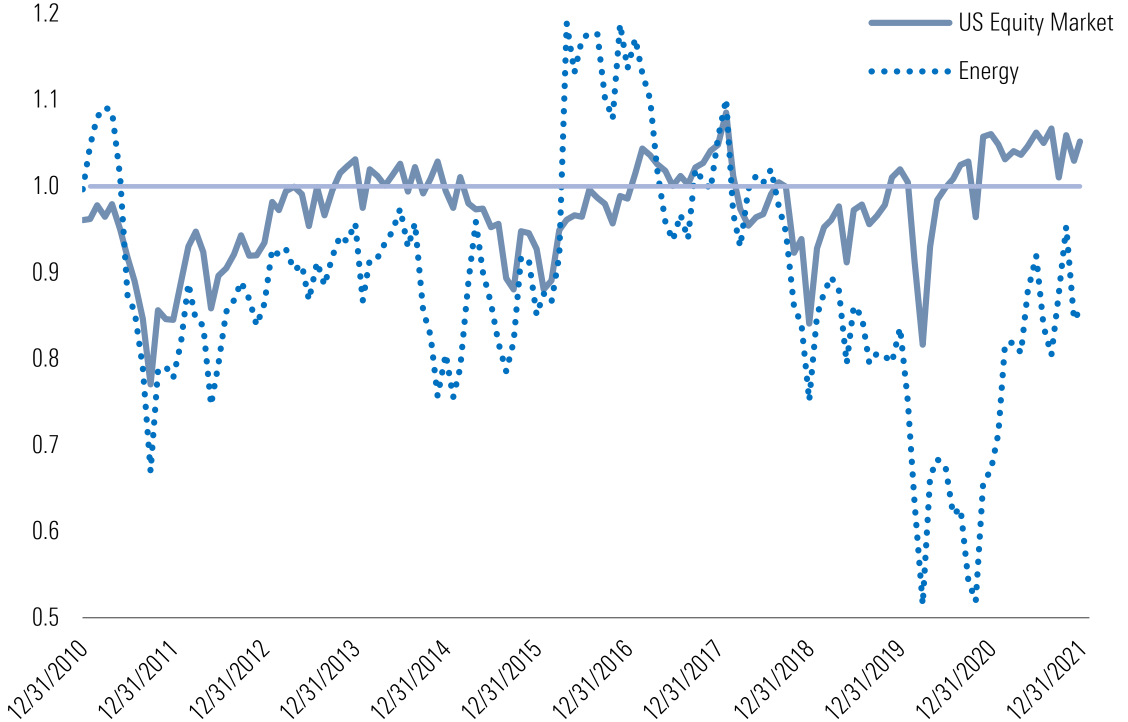


- Cost inflation picking up, focus on pricing power
- Economic normalization tailwind for resumption of on-premise alcoholic beverage consumption

Company Name	Ticker	Star Rating	Stock Price	Fair Value	Price/Fair Value	Market Cap ($B)	Moat	Moat Trend	Style Box
Anheuser-Busch InBev	BUD	★★★★★	60.77	90.00	0.68	106	Wide	Stable	Large Core
Molson Coors Beverage Co.	TAP	★★★★★	45.59	66.00	0.69	10	None	Negative	Mid Value
Boston Beer Co	SAM	★★★★★	524.87	750.00	0.70	6	Narrow	Stable	Small Growth
Kellogg's	K	★★★★	62.87	85.00	0.74	21	Wide	Negative	Mid Value
Treehouse Foods	THS	★★★★	39.53	53.00	0.75	2	None	Stable	Small Value

Source: Morningstar. Latest prices, fair values and ratings shown are current as of December 23, 2021, and subject to change. Further information including analyst names, the dates and times ratings were published and historical ratings, is available on request from your local Morningstar office. Data presented is indicative and for illustrative purposes.

Energy

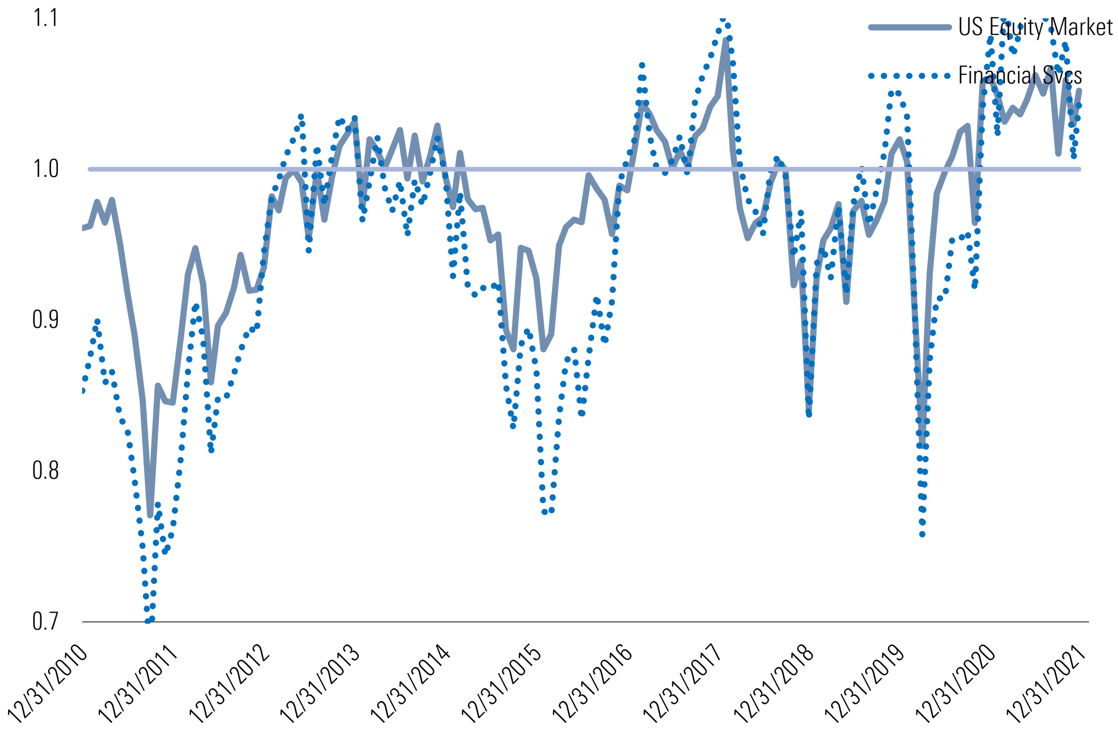


- Market overly-pessimistic about long-term rate of decline for oil demand
- Our oil demand forecast to peak around 2030, demand decreasing gradually to an 11% decline through 2050

Company Name	Ticker	Star Rating	Stock Price	Fair Value	Price/Fair Value	Market Cap ($B)	Moat	Moat Trend	Style Box
National Oilwell Varco	NOV	★★★★★	13.52	28.00	0.48	5	None	Stable	Small Core
Energy Transfer	ET	★★★★★	8.22	16.50	0.50	26	None	Stable	Mid Value
Schlumberger	SLB	★★★★	29.57	49.00	0.60	41	Narrow	Stable	Mid Core
Occidental Petroleum	OXY	★★★★	28.85	44.00	0.66	27	None	Stable	Mid Core
ExxonMobil	XOM	★★★★	61.02	76.00	0.80	258	Narrow	Stable	Large Value

Source: Morningstar. Latest prices, fair values and ratings shown are current as of December 23, 2021, and subject to change. Further information including analyst names, the dates and times ratings were published and historical ratings, is available on request from your local Morningstar office. Data presented is indicative and for illustrative purposes.

Financials

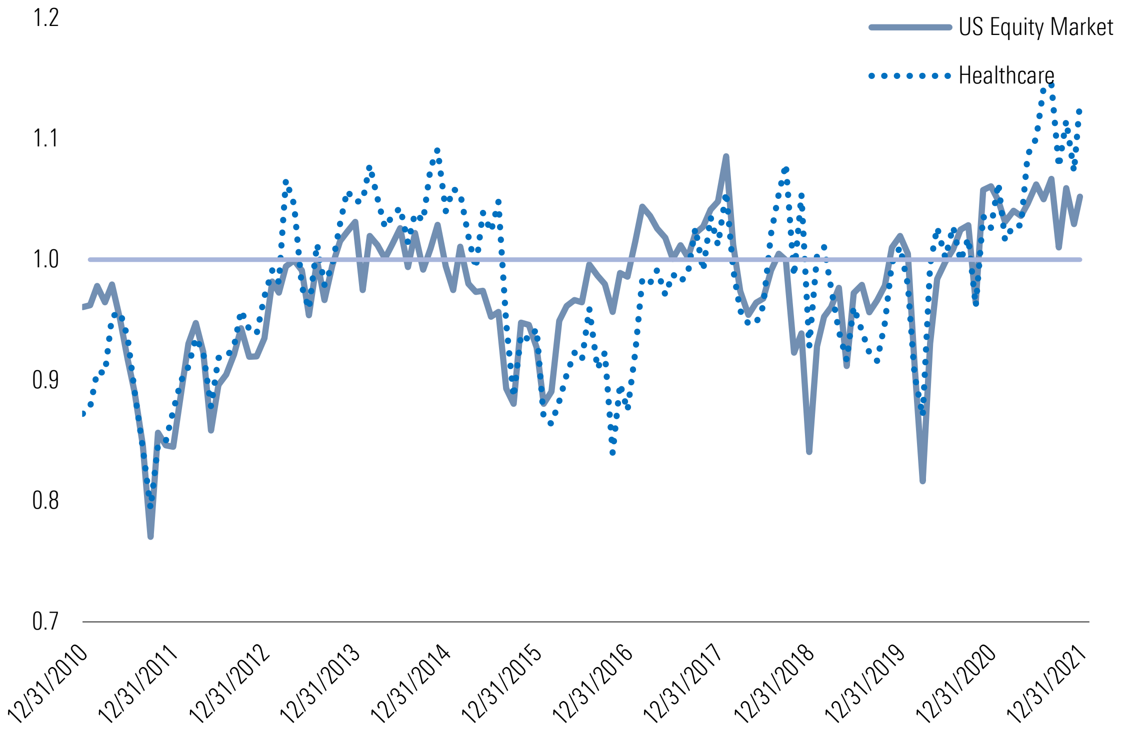


- Primary drivers of earnings trending positively
- Robust economic growth will help to maintain low default rate and minimize charge-offs

Company Name	Ticker	Star Rating	Stock Price	Fair Value	Price/Fair Value	Market Cap ($B)	Moat	Moat Trend	Style Box
Citigroup	C	★★★★	60	83	0.73	119	Narrow	Stable	Large Value
Invesco	IVZ	★★★★	23.34	28.00	0.83	11	Narrow	Negative	Mid Value
Huntington National Bank	HBAN	★★★★	15.26	18.00	0.85	22	Narrow	Stable	Mid Value
Wells Fargo	WFC	★★★★	48.36	55.00	0.88	193	Wide	Stable	Large Value
Truist	TFC	★★★	57.77	63.00	0.92	77	Narrow	Stable	Large Value

Source: Morningstar. Latest prices, fair values and ratings shown are current as of December 23, 2021, and subject to change. Further information including analyst names, the dates and times ratings were published and historical ratings, is available on request from your local Morningstar office. Data presented is indicative and for illustrative purposes.

Healthcare



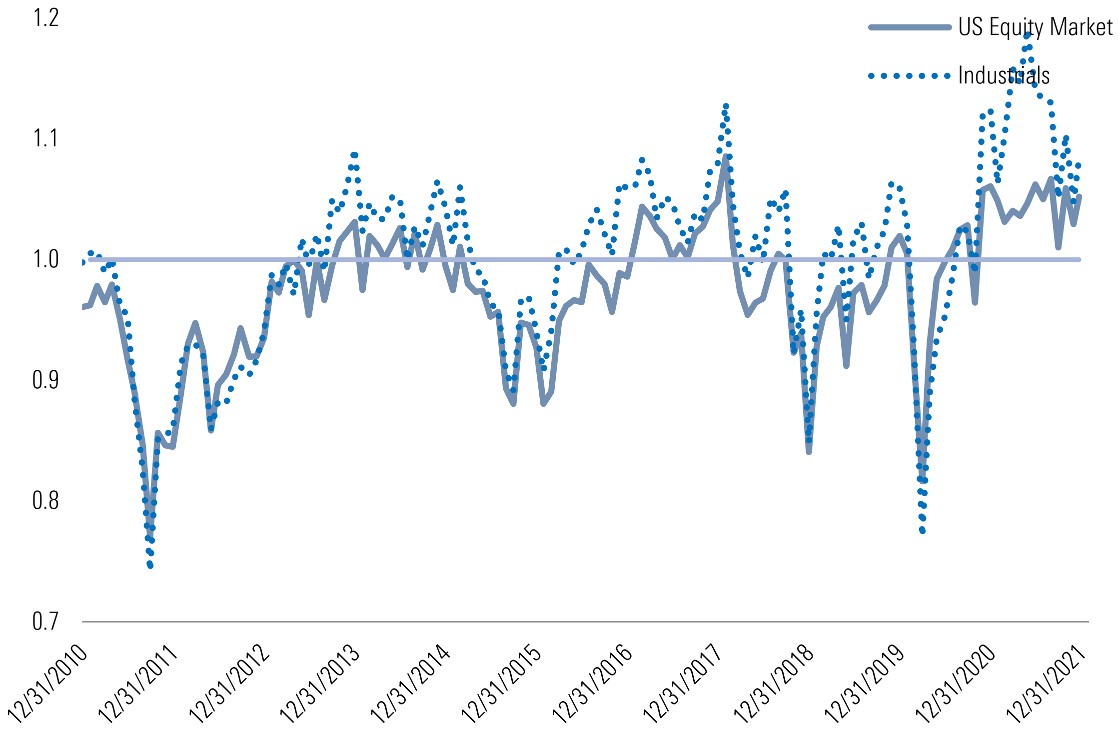
- Valuation in the sector split between a general undervaluation in the larger biopharma group and an overvaluation in the device and diagnostics industries comment

Company Name	Ticker	Star Rating	Stock Price	Fair Value	Price/Fair Value	Market Cap ($B)	Moat	Moat Trend	Style Box
Ionis Pharmaceuticals	IONS	★★★★★	32.71	62.00	0.53	5	Narrow	Positive	Small Core
Biogen	BIIB	★★★★	235.41	361.00	0.65	35	Wide	Stable	Mid Value
Zimmer Biomet	ZBH	★★★★★	126.99	192.00	0.66	27	Wide	Stable	Mid Core
Merck & Co.	MRK	★★★★	75.73	94.00	0.81	191	Wide	Stable	Large Value
BioMarin Pharmaceutical	BMRN	★★★★	91.16	105.00	0.87	17	Narrow	Positive	Mid Growth

Source: Morningstar. Latest prices, fair values and ratings shown are current as of December 23, 2021, and subject to change. Further information including analyst names, the dates and times ratings were published and historical ratings, is available on request from your local Morningstar office. Data presented is indicative and for illustrative purposes.

MORNINGSTAR

Industrials



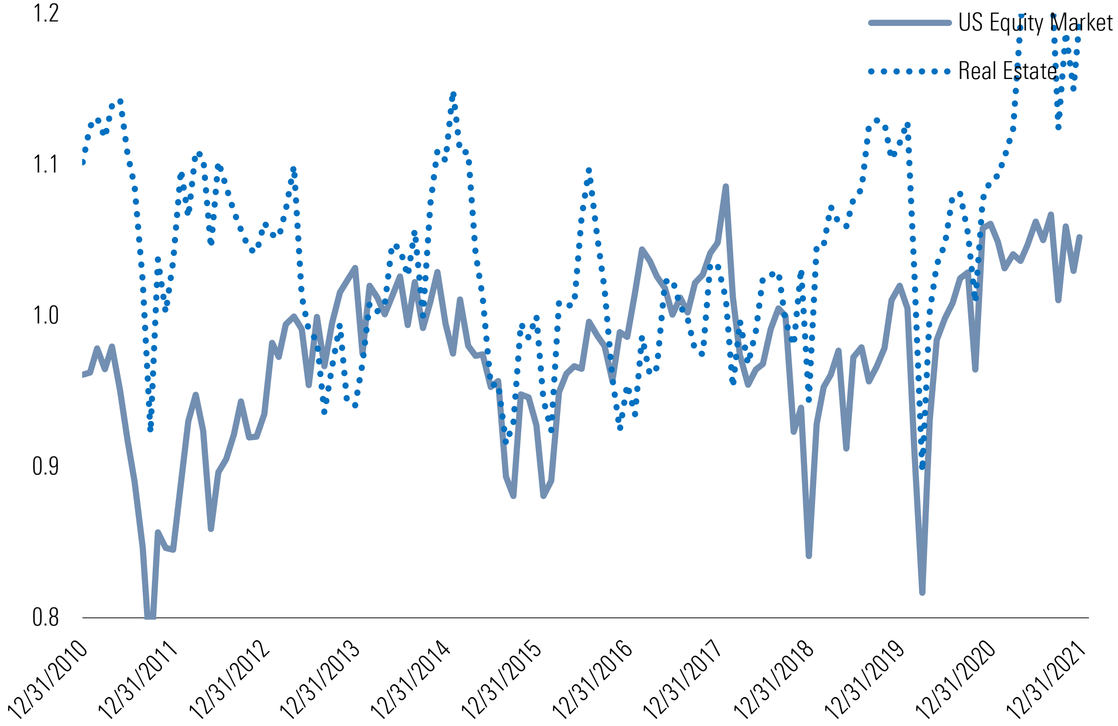
- Rebound in air travel will provide a tailwind for each of the airlines
- GE undergoing split-up to help unlock shareholder value
- We expect several years of positive organic growth at Emerson

Company Name	Ticker	Star Rating	Stock Price	Fair Value	Price/Fair Value	Market Cap ($B)	Moat	Moat Trend	Style Box
Southwest Airlines	LUV	★★★★	41.87	63.00	0.66	25	None	Stable	Mid Value
General Electric	GE	★★★★	94.00	131.00	0.72	103	Narrow	Stable	Large Value
Boeing	BA	★★★★	204.22	249.00	0.82	120	Wide	Stable	Large Value
Emerson	EMR	★★★★	91.28	107.00	0.85	54	Wide	Stable	Large Value
Crane Company	CR	★★★★	99.68	115.00	0.87	6	Narrow	Stable	Small Core

Source: Morningstar. Latest prices, fair values and ratings shown are current as of December 23, 2021, and subject to change. Further information including analyst names, the dates and times ratings were published and historical ratings, is available on request from your local Morningstar office. Data presented is indicative and for illustrative purposes.

MORNINGSTAR

Real Estate

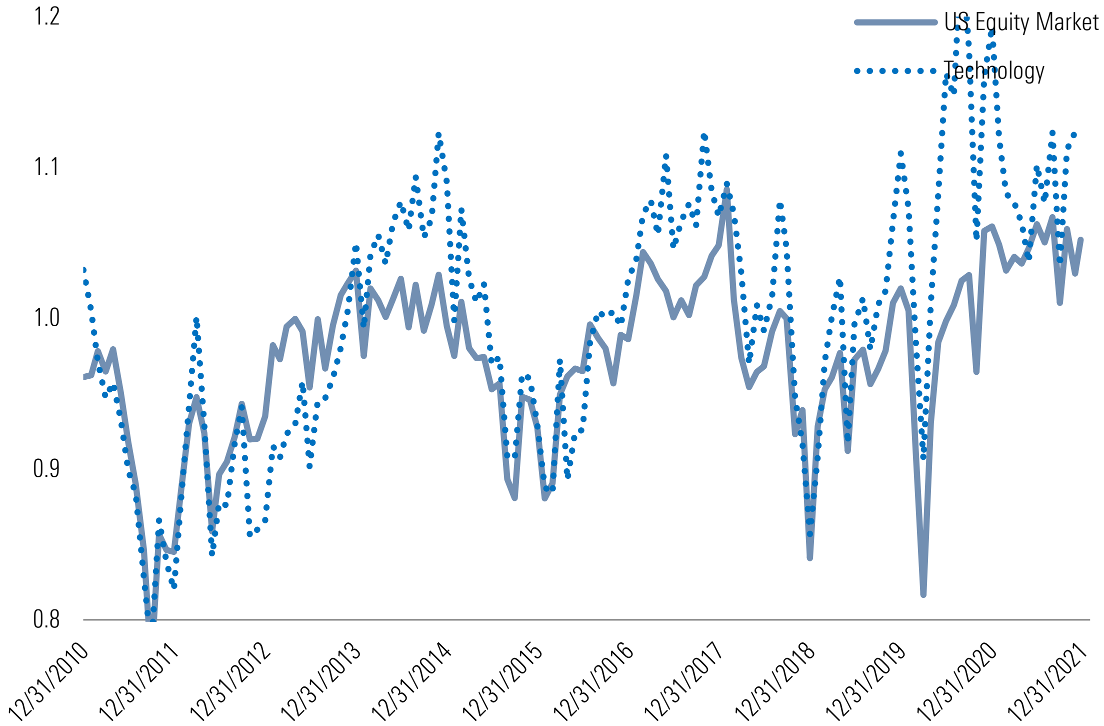


- Vaccine deployment in early 2021 led to faster than expected recovery in fundamentals for many real estate sectors
- Economic normalization to benefit travel related REITs and mall REITs

Company Name	Ticker	Star Rating	Stock Price	Fair Value	Price/Fair Value	Market Cap ($B)	Moat	Moat Trend	Style Box
Macerich	MAC	★★★★	17.03	30.00	0.57	4	None	Negative	Small Value
Ventas	VTR	★★★★	49.20	69.00	0.71	20	None	Stable	Mid Core
Empire State Realty Trust	ESRT	★★★★	9.03	12.00	0.75	2	None	Stable	Small Core
Park Hotels & Resorts	PK	★★★★	19.29	24.50	0.79	5	None	Negative	Small Value
Pebblebrook Hotel Trust	PEB	★★★★	22.28	27.50	0.81	3	None	Negative	Small Core

Source: Morningstar. Latest prices, fair values and ratings shown are current as of December 23, 2021, and subject to change. Further information including analyst names, the dates and times ratings were published and historical ratings, is available on request from your local Morningstar office. Data presented is indicative and for illustrative purposes.

Technology

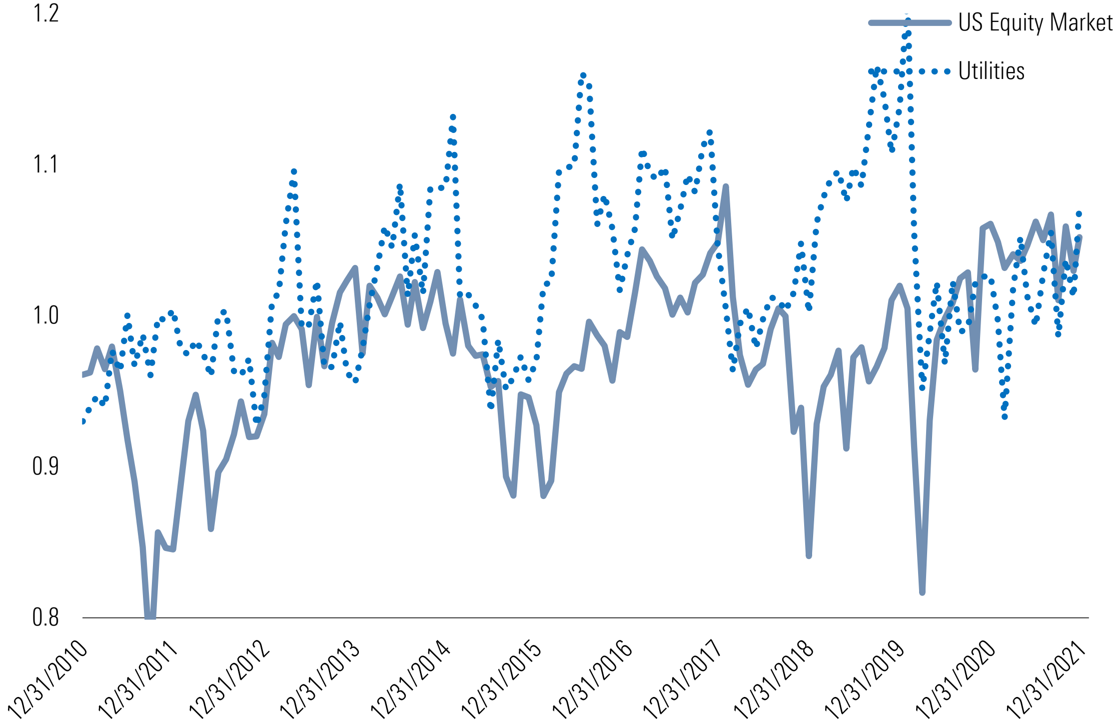


- Tech providers to travel related sectors to benefit from normalization
- After selling off since last February, many disruptive tech names now undervalued

Company Name	Ticker	Star Rating	Stock Price	Fair Value	Price/Fair Value	Market Cap ($B)	Moat	Moat Trend	Style Box
Sabre Corporation	SABR	★★★★★	8.91	15.00	0.59	3	Narrow	Negative	Small Value
Palantir Technologies	PLTR	★★★★	18.93	31.00	0.61	38	Narrow	Positive	Large Growth
Uber	UBER	★★★★	43.91	69.00	0.64	85	Narrow	Stable	Large Growth
DocuSign	DOCU	★★★★	157.01	244.00	0.64	31	Narrow	Stable	Large Growth
Splunk	SPLK	★★★★	115.92	175.00	0.66	18	Narrow	Positive	Mid Value

Source: Morningstar. Latest prices, fair values and ratings shown are current as of December 23, 2021, and subject to change. Further information including analyst names, the dates and times ratings were published and historical ratings, is available on request from your local Morningstar office. Data presented is indicative and for illustrative purposes.

Utilities



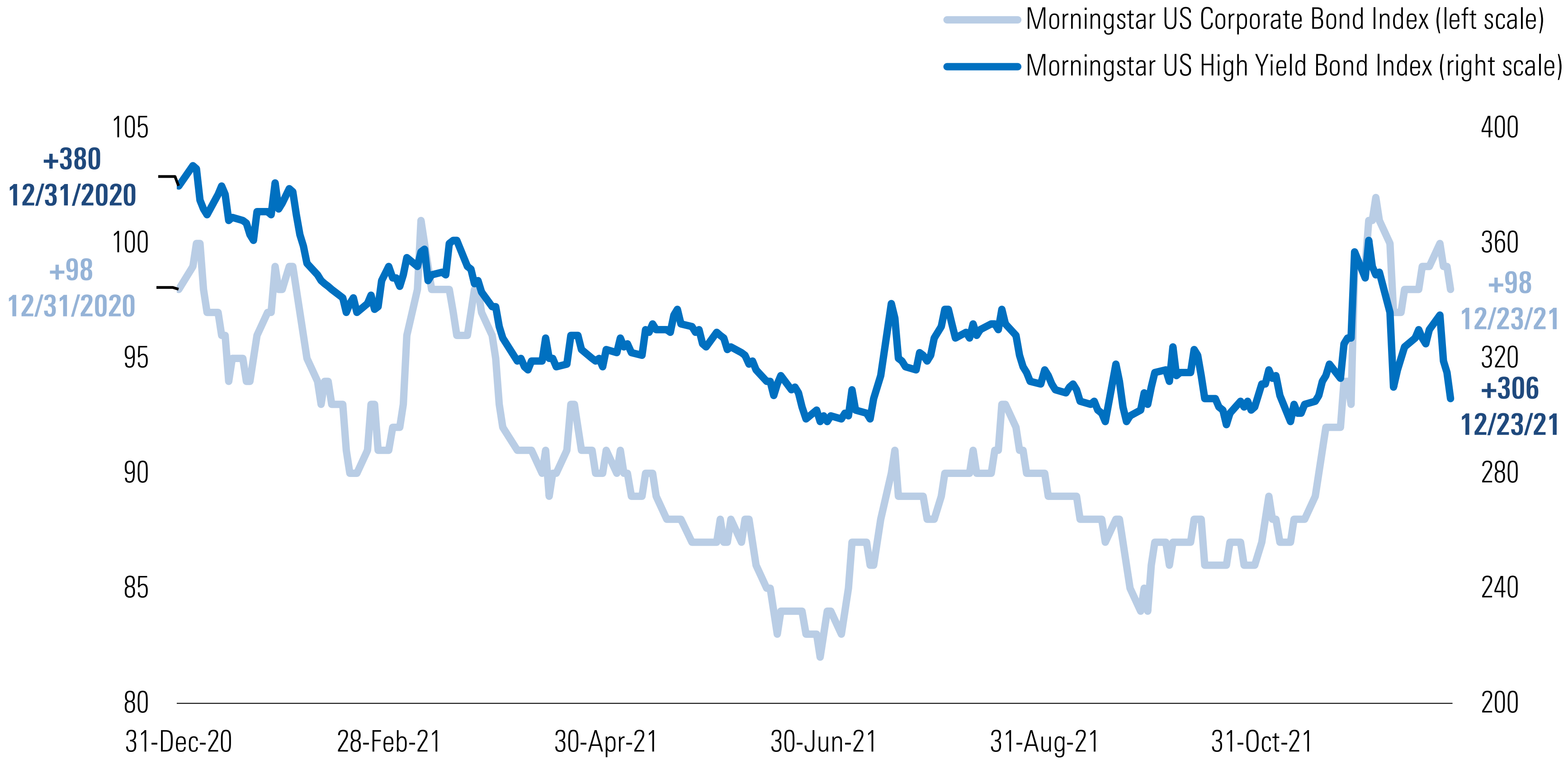
- Utility stocks appear poised for steady, but underwhelming, returns in 2022
- Look for: clean energy infrastructure growth, higher dividend yields, and constructive relationships with regulators

Company Name	Ticker	Star Rating	Stock Price	Fair Value	Price/Fair Value	Market Cap ($B)	Moat	Moat Trend	Style Box
Pinnacle West Capital	PNW	★★★★	68.91	77.00	0.89	8	Narrow	Stable	Small Value
NiSource	NI	★★★★	26.87	30.00	0.90	11	Narrow	Stable	Mid Value
AES	AES	★★★	23.55	25.00	0.94	16	None	Stable	Mid Value
Edison International	EIX	★★★	67.67	71.00	0.95	26	Narrow	Stable	Mid Value
Dominion Energy	D	★★★★	77.34	81.00	0.95	63	Wide	Stable	Large Value

Source: Morningstar. Latest prices, fair values and ratings shown are current as of December 23, 2021, and subject to change. Further information including analyst names, the dates and times ratings were published and historical ratings, is available on request from your local Morningstar office. Data presented is indicative and for illustrative purposes.

Corporate Credit Spreads Remain Tight

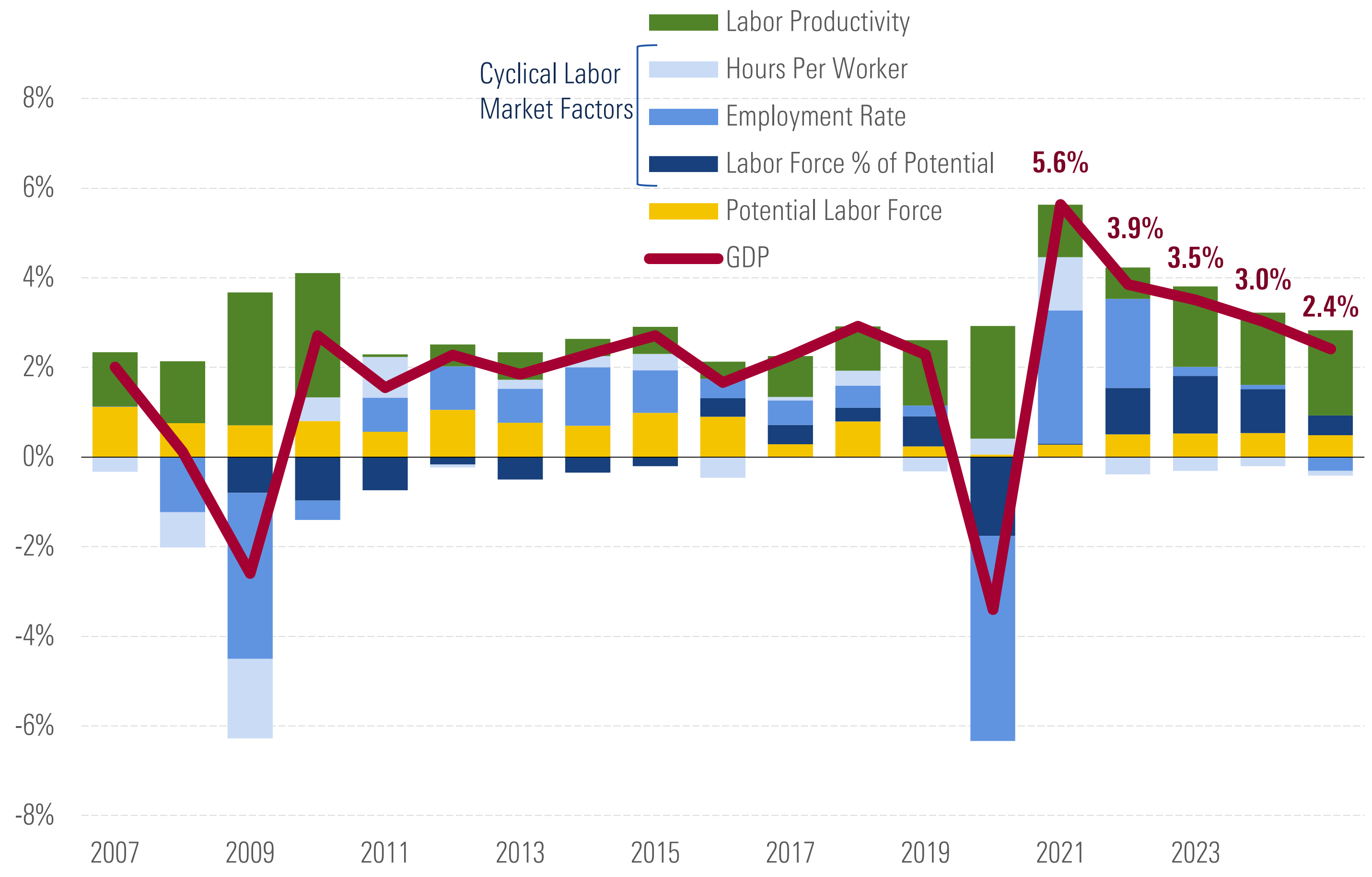
- Strong economy: limit defaults, constrain downgrades, and prompt upgrades



Source: Morningstar. Data as of December 23, 2021. Past performance is not a reliable indicator of future results and data is presented for illustrative purposes.

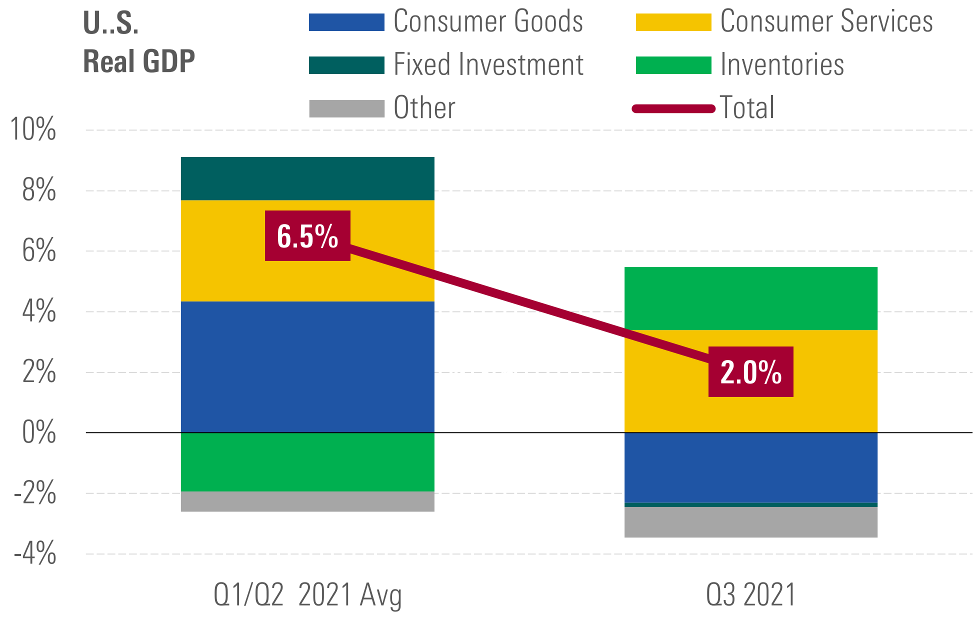
Our U.S. Economic Outlook

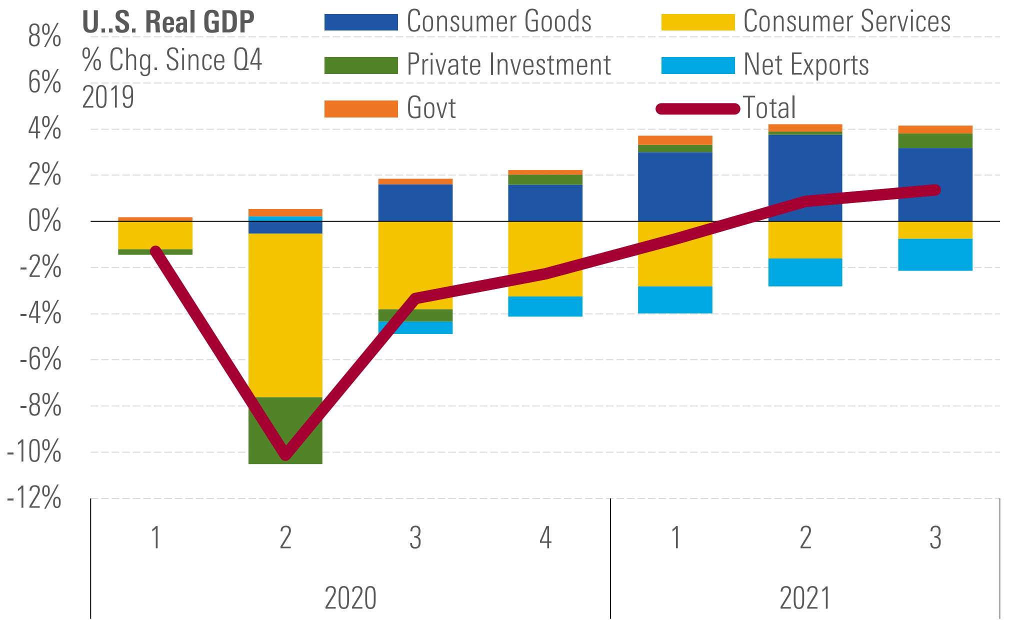
We're Above Consensus on GDP Growth Through 2025



Sources: U.S. Bureau of Economic Analysis, Morningstar (As of 1/1/2022)

GDP Growth Slowed Sharply in the Third Quarter

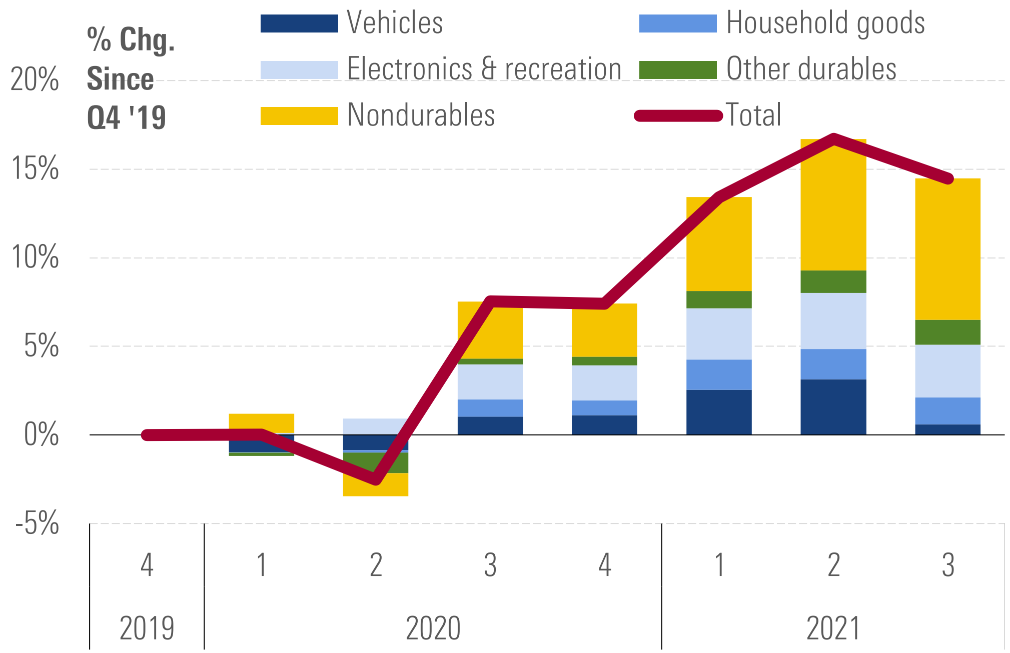


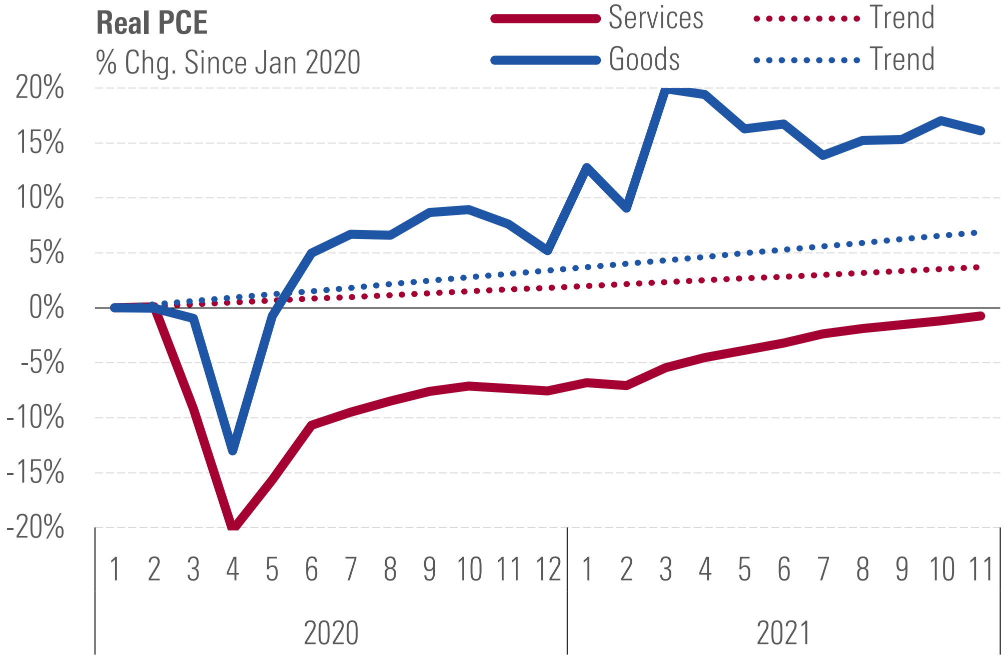


Sources: U.S. Bureau of Economic Analysis, Morningstar (As of 1/1/2022)

MORNINGSTAR

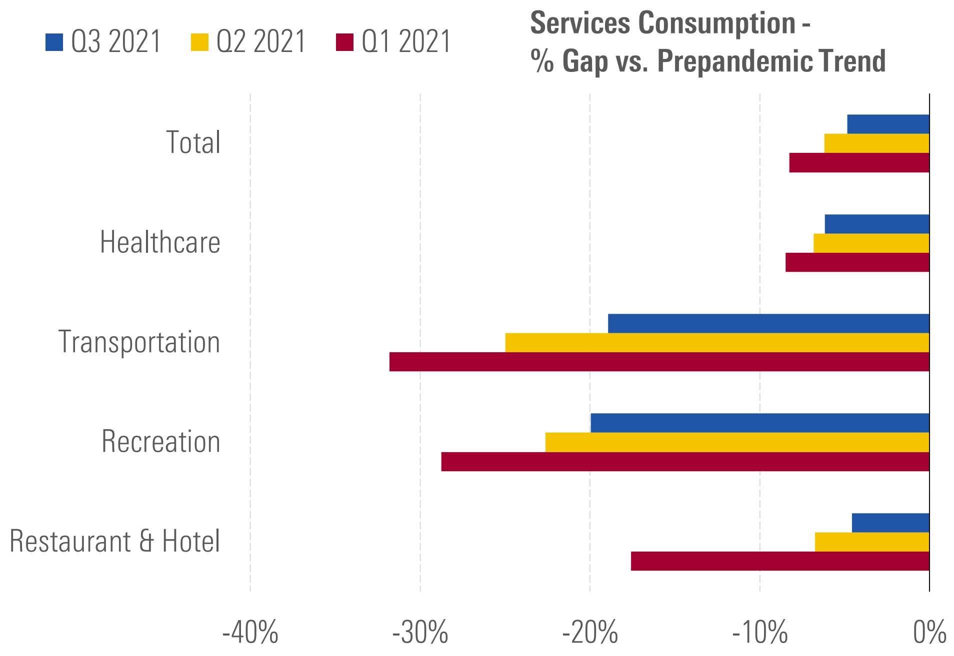
Goods Consumption Slowed Sharply in Q3 Owing to Vehicle Shortage

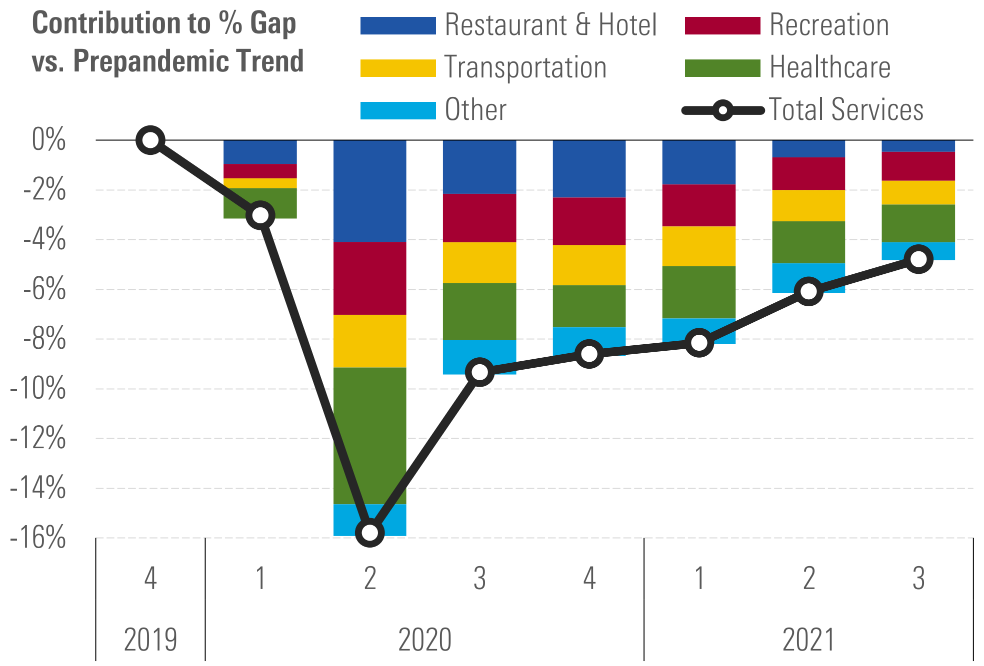




Sources: U.S. Bureau of Economic Analysis, Morningstar (As of 1/1/2022)

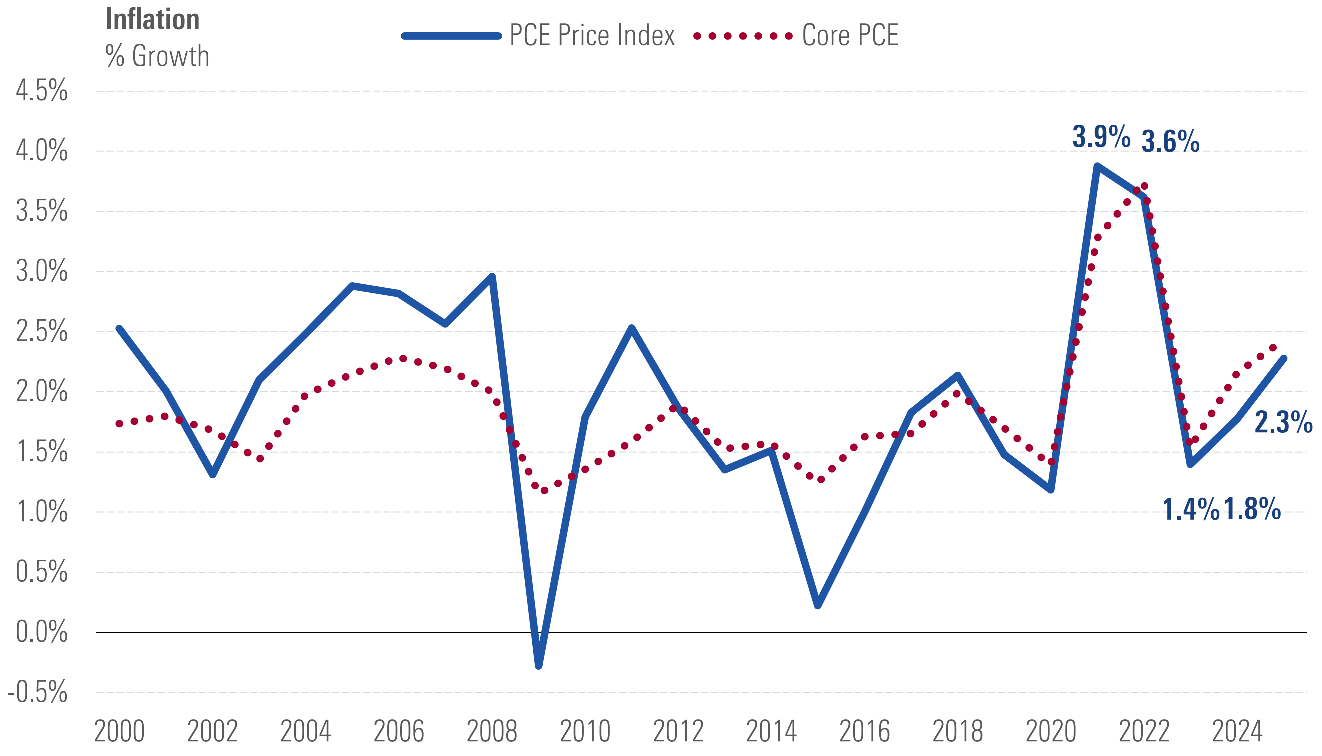
Breakdown of Shortfall in Consumption Services Spending





Sources: U.S. Bureau of Economic Analysis, Morningstar (As of 1/1/2022)

Inflation Should Cool Down After Hot 2021

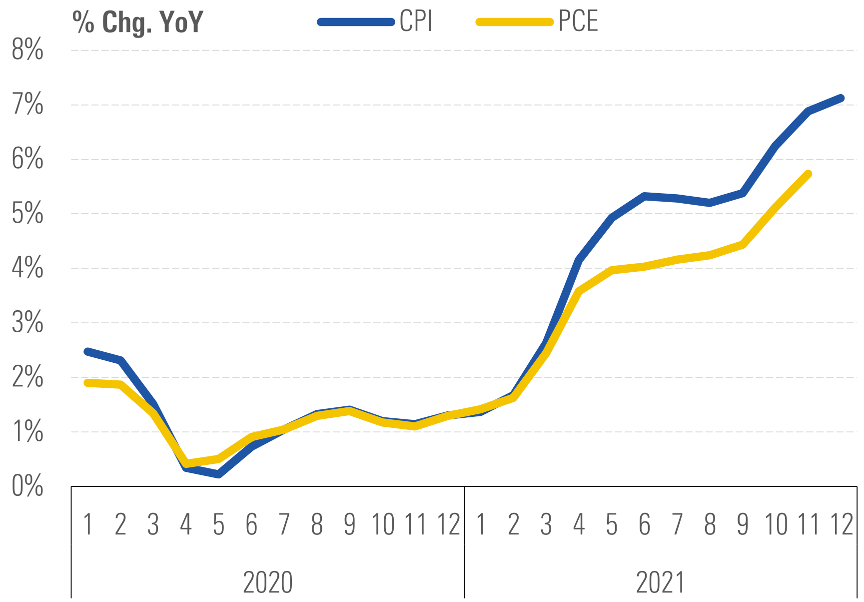


- We expect 3.8% inflation (PCE Index) in 2021.
- Over 2022-25, we expect inflation to moderate to 2.2% on average.

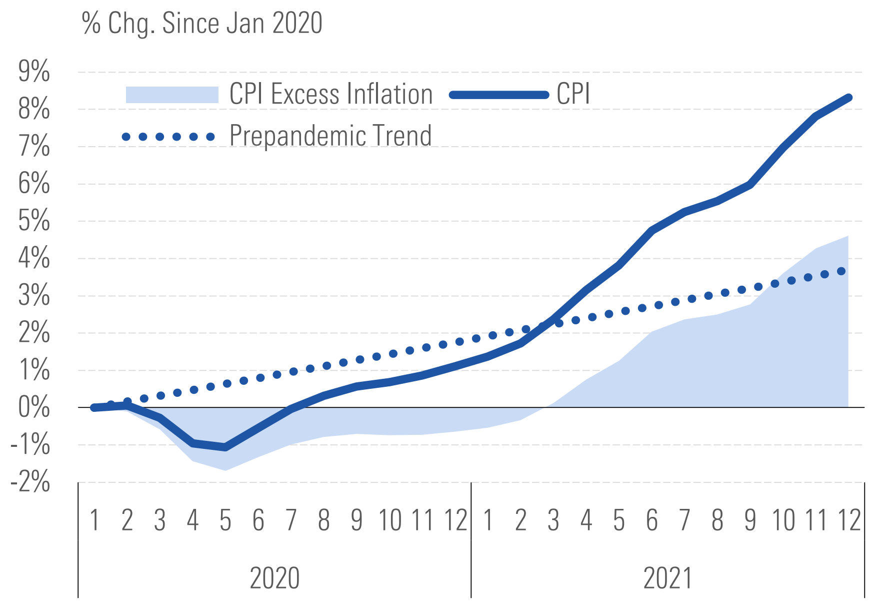
Sources: U.S. Bureau of Economic Analysis, Morningstar (As of 1/1/2022)

At First Glance, Near-Term Inflation Does Offer Room for Concern

Year-over-year inflation is somewhat misleading due to base effects…



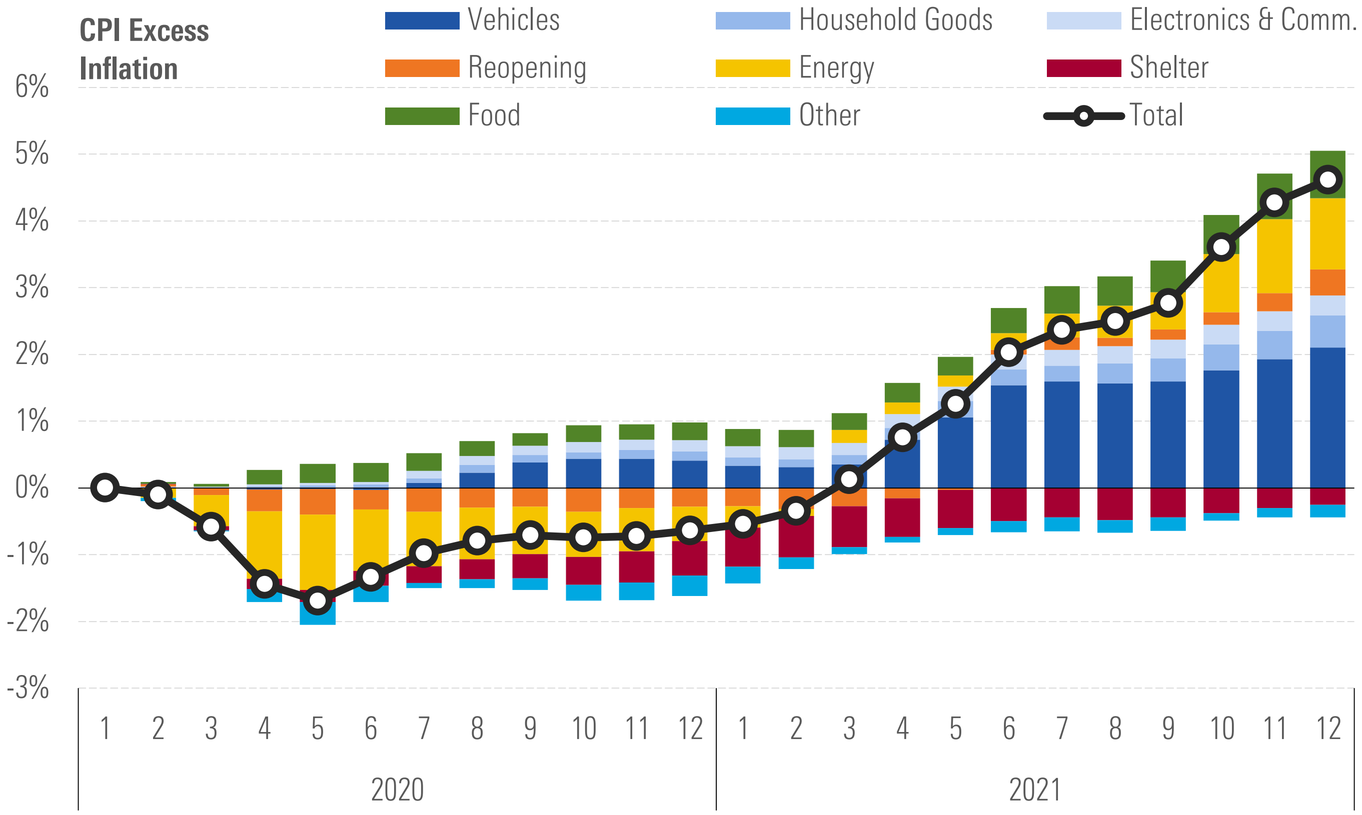
…comparing inflation index gap with trend is more illuminating



Sources: U.S. Federal Reserve, Morningstar (As of 1/1/2022)

MORNINGSTAR®

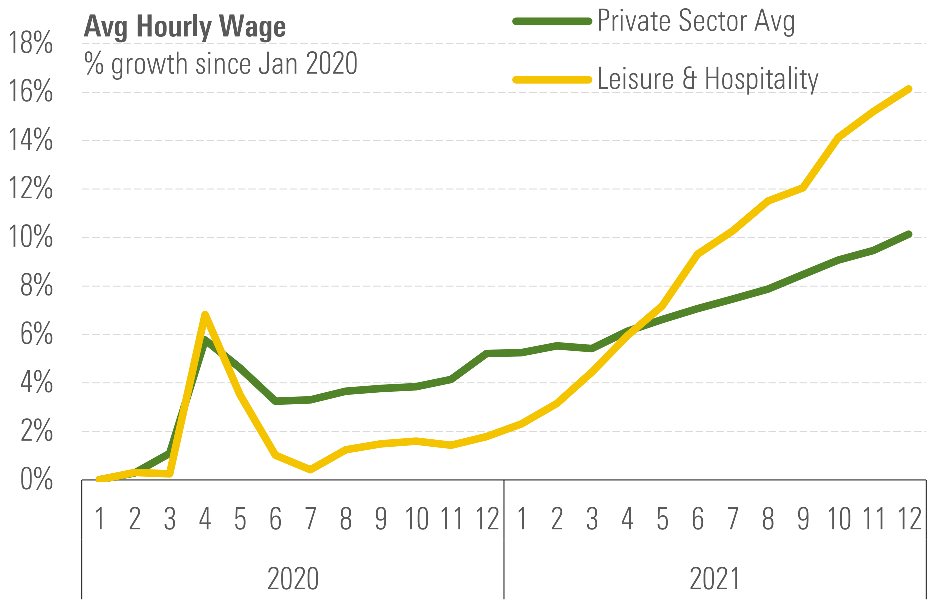
Auto Shortage and Related Areas Are Driving Bulk of Excess Inflation

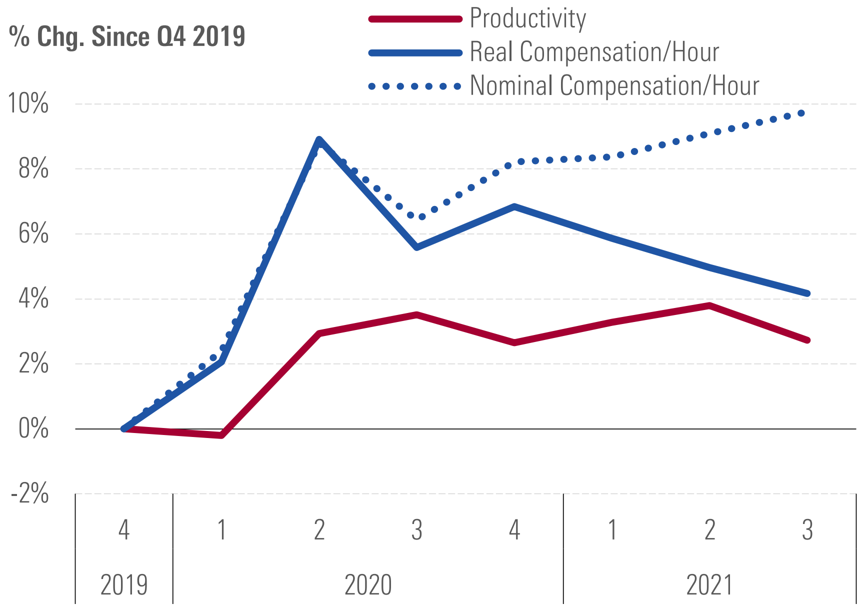


- Vehicles account for bulk of excess inflation.

Sources: U.S. Bureau of Economic Analysis, Morningstar (As of 1/1/2022)

Wage Growth Is Picking Up, But Is Far from Out of Control



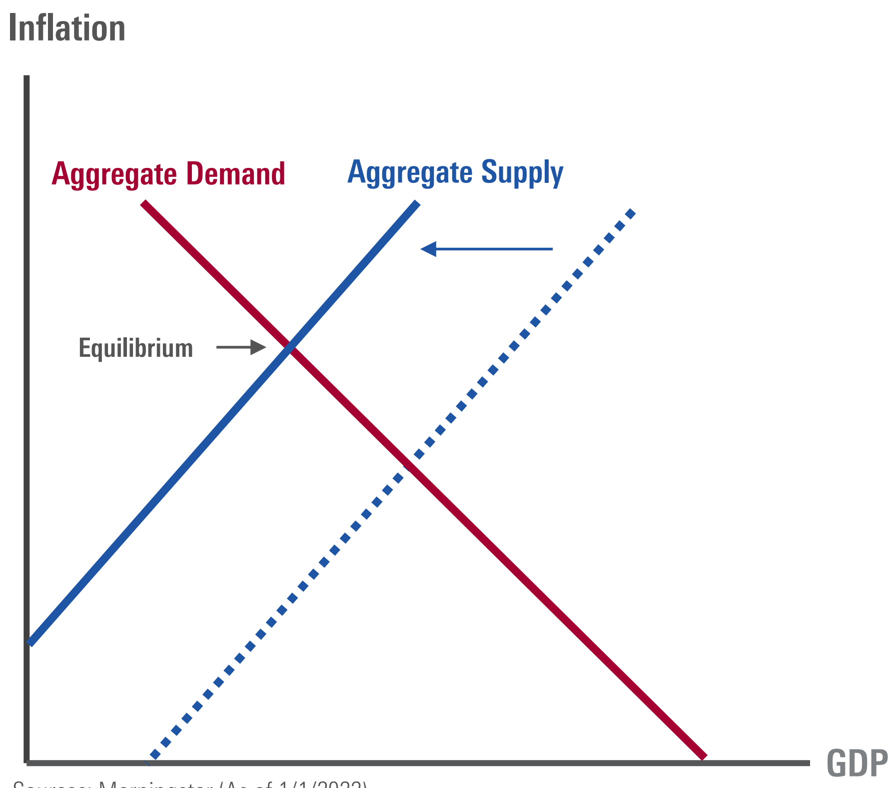


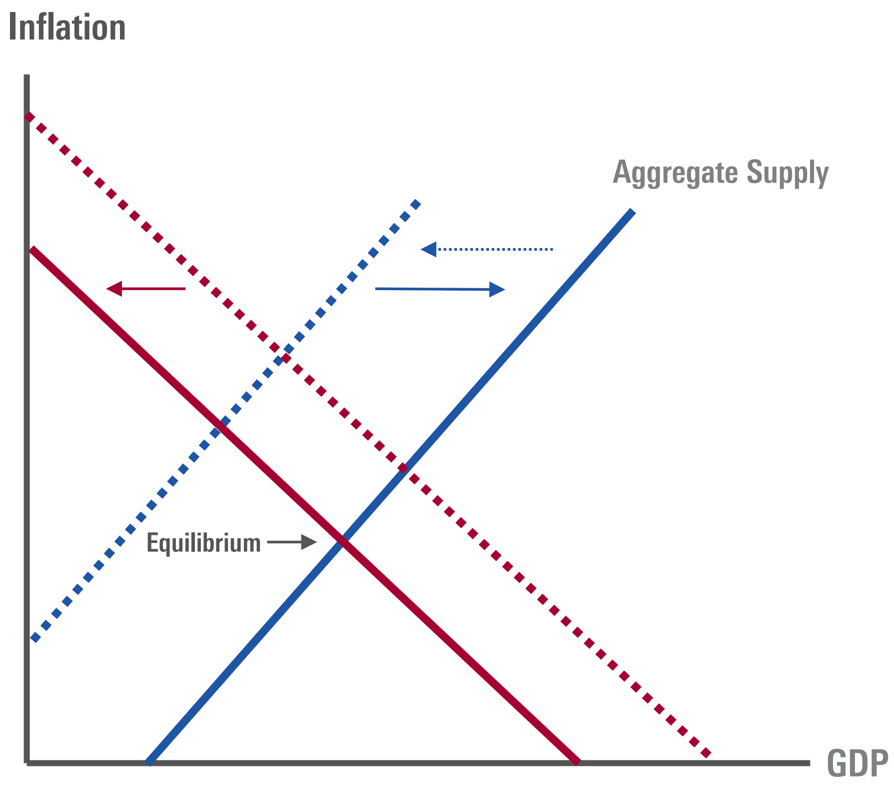
Sources: U.S. Bureau of Labor Statistics, Morningstar (As of 1/1/2022)

Why Is The Fed Not Tightening More Now?

The Fed might like to tighten monetary policy in order to offset an inflation shock…

…but if tightening doesn't take effect until *after* the shock has passed, then GDP will fall for no good reason

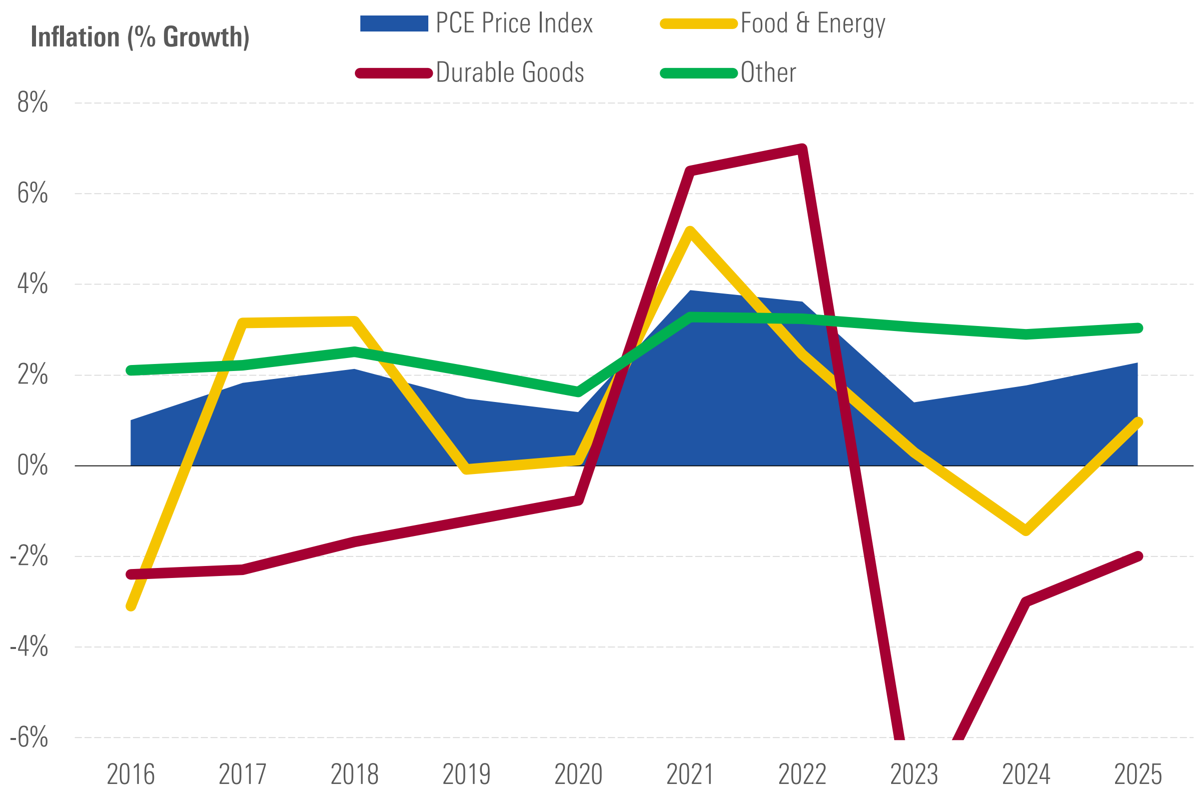




Sources: Morningstar (As of 1/1/2022)

MORNINGSTAR

Unwinding of Durable Goods Price Spike Will Ease Inflation

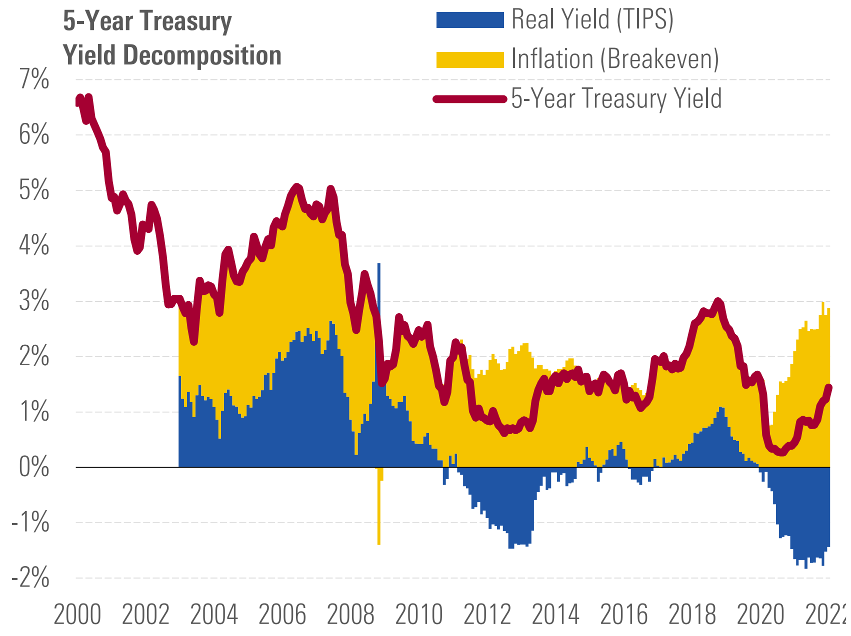


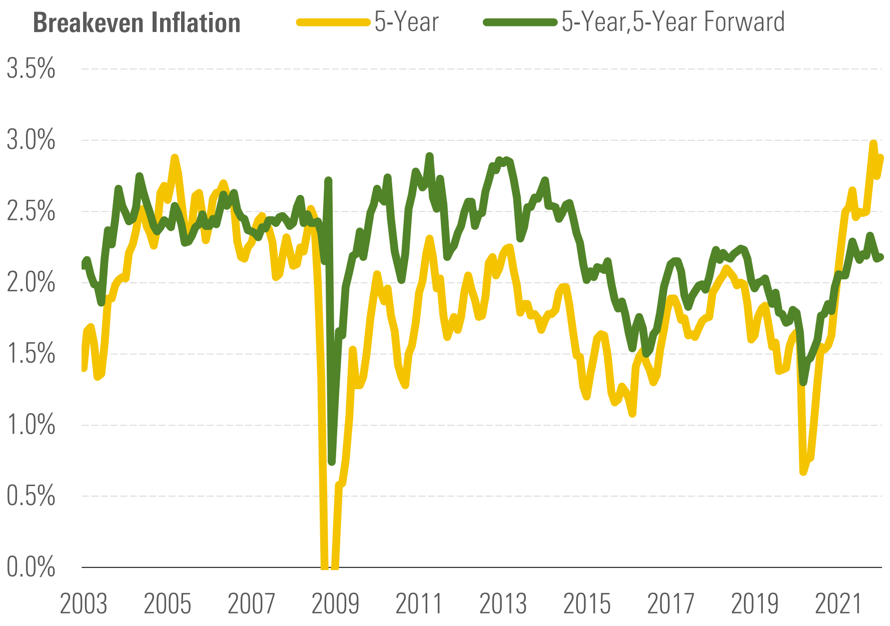
- We project 8% drop in durables prices in 2023.

Sources: U.S. Bureau of Economic Analysis, Morningstar (As of 1/1/2022)

Inflation Expectations Aren't Out of Control

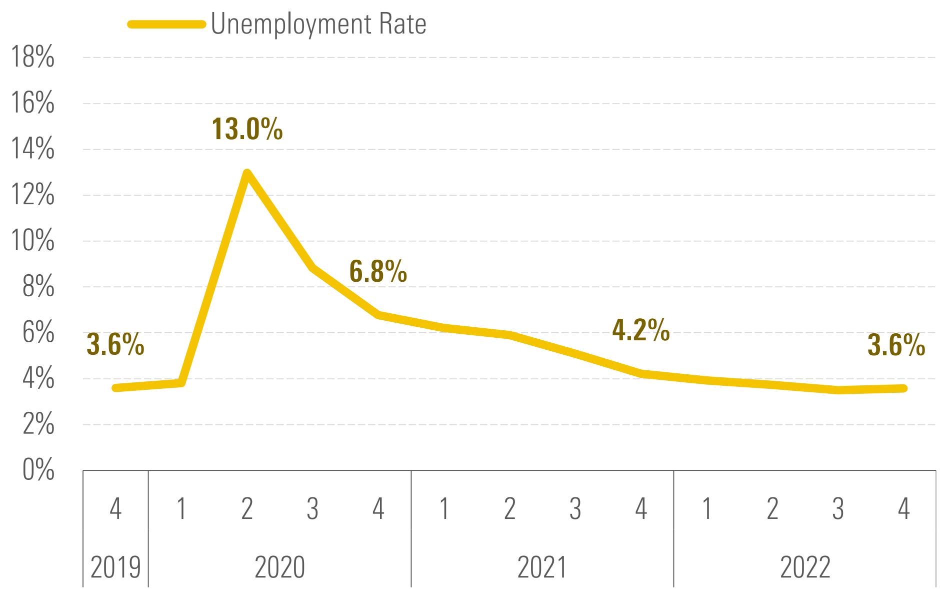
- 5-Year, 5-Year forward breakevens show that long-run inflation expectations are still muted

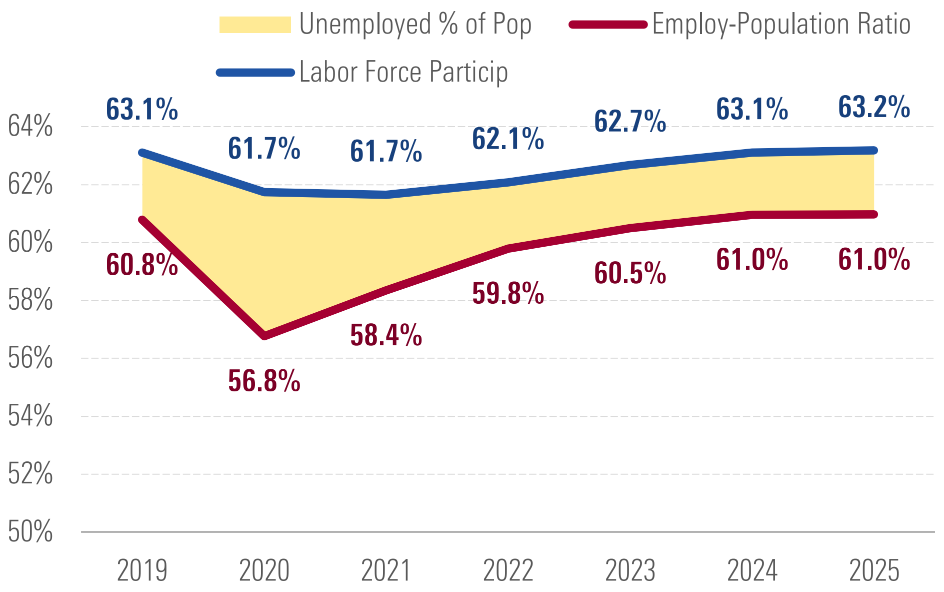




Sources: U.S. Federal Reserve, Morningstar (As of 1/1/2022)

We Expect the Labor Market to Continue Its Recovery



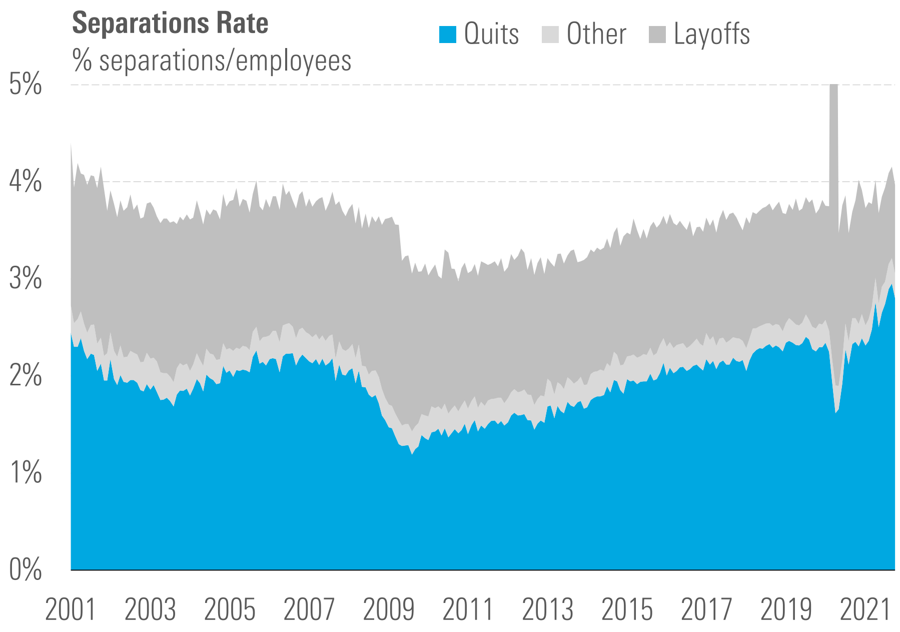


Sources: U.S. Bureau of Labor Statistics, Morningstar (As of 1/1/2022)

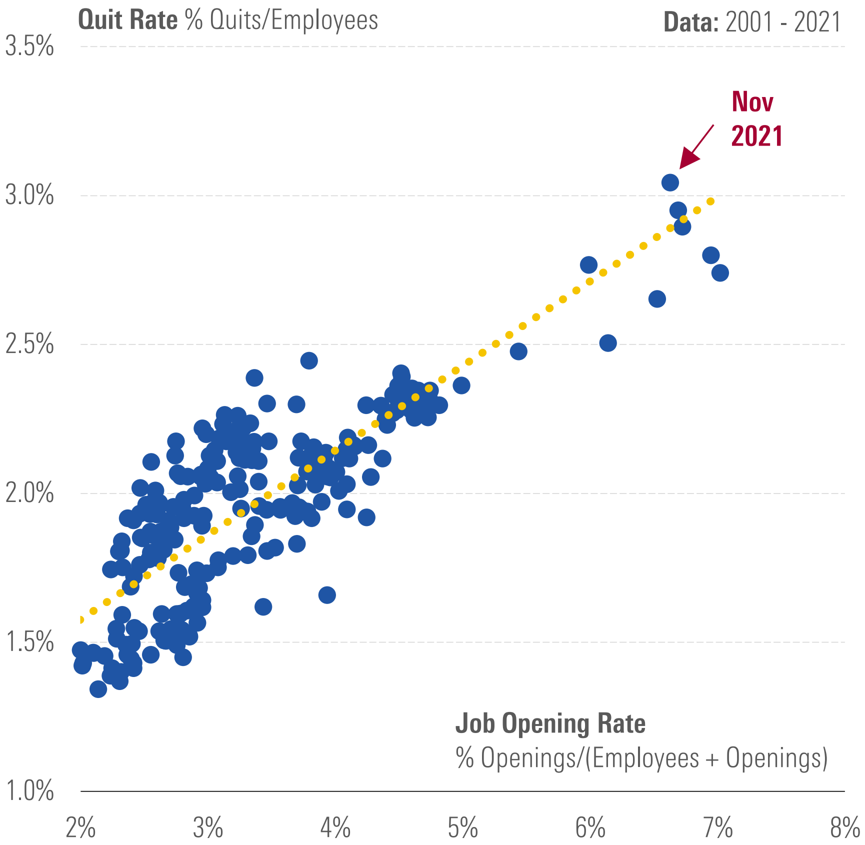
MORNINGSTAR

There is No Great Resignation, But Instead a Great Reshuffling

Quits rate has soared to record levels

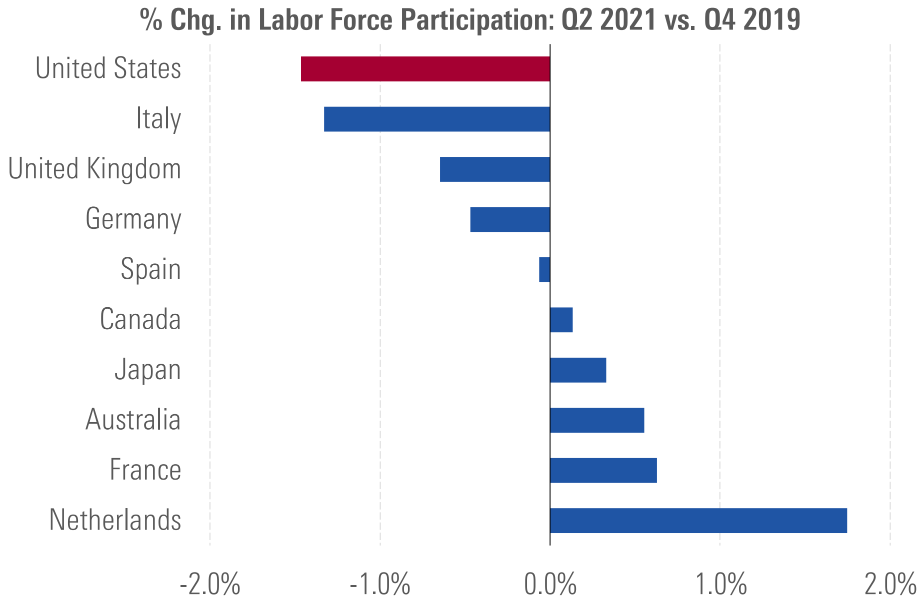


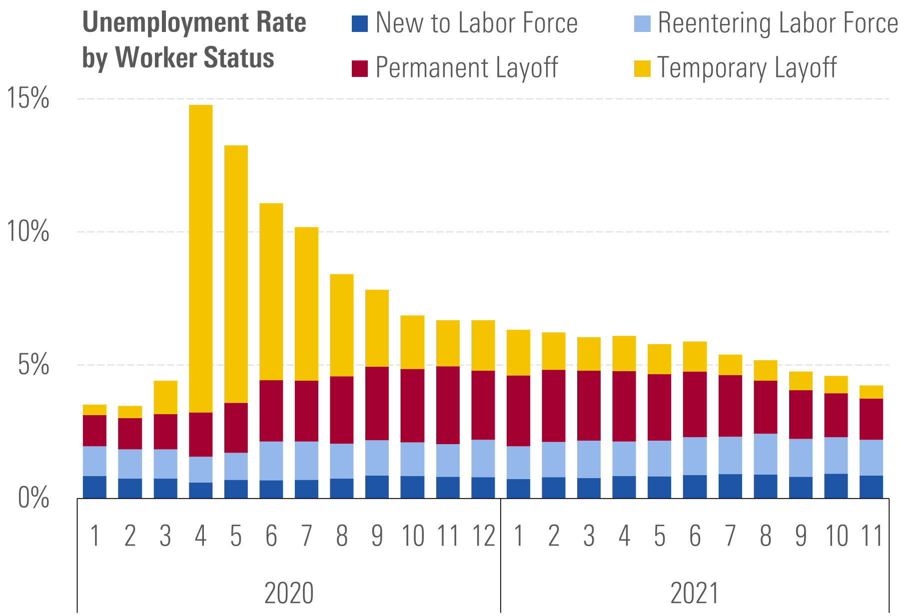
Given job openings, high quit rate isn't surprising…



Source: U.S. Bureau of Labor Statistics, Morningstar (as of 1/1/2022)

International Comparisons Suggest Labor Force Hit Is Temporary





Sources: U.S. Bureau of Labor Statistics, Morningstar (As of 1/1/2022)

Questions?

Disclosures

Important information

- **This presentation is for the intended institutional investor recipient only and is not for onward distribution/public dissemination**
- The analyst(s) identified on the cover page is/are employed by Morningstar Research Services LLC, a wholly-owned subsidiary of Morningstar, Inc.
- The conduct of Morningstar's analysts is governed by Morningstar's Code of Ethics and Investment Research Integrity Policy. For more information and for information on ratings and the methodologies used by the analysts, please click http://global.morningstar.com/equitydisclosures

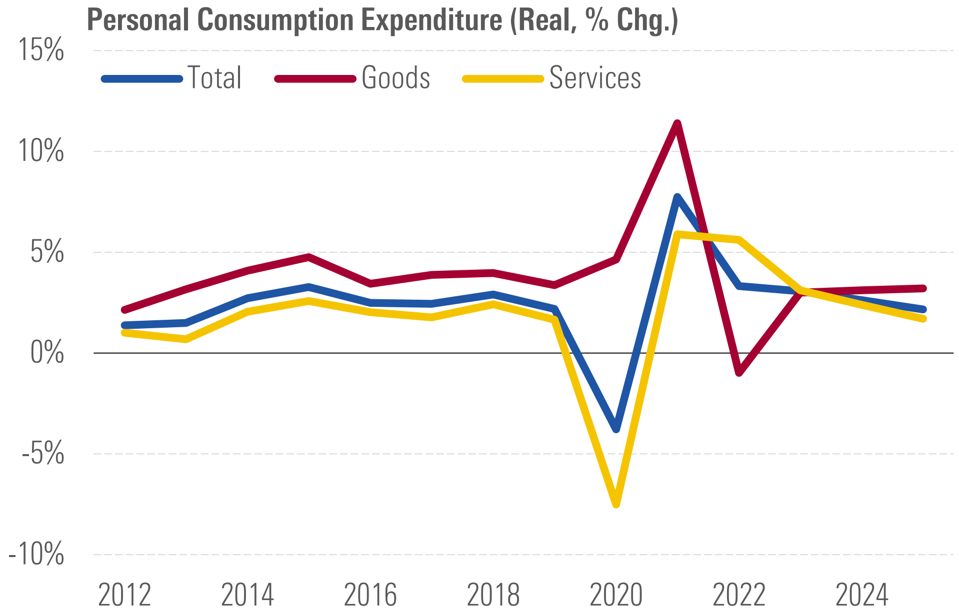
Conflicts of Interest

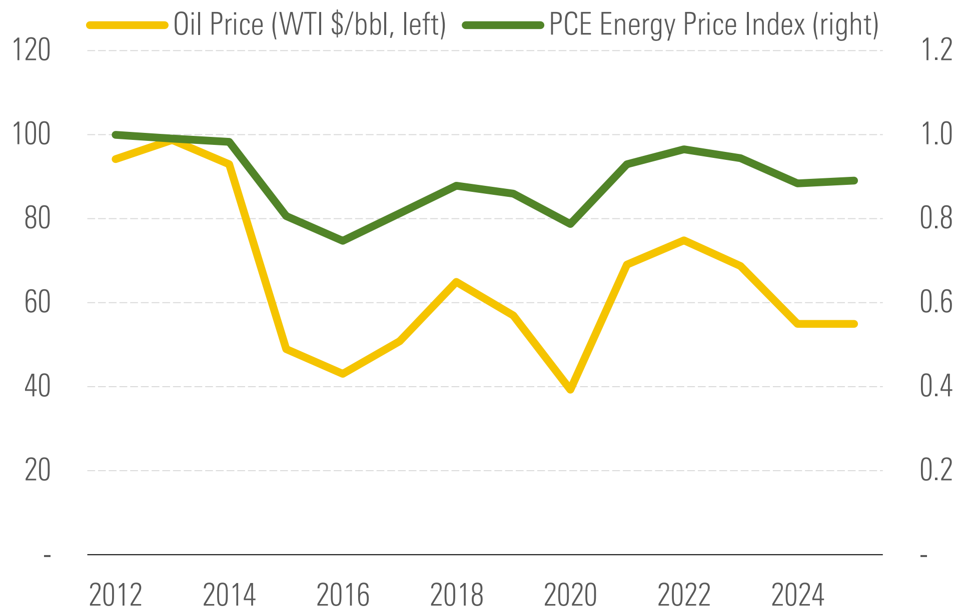
- The analyst and their immediate family are prohibited from owning directly the security or securities noted herein and the securities of those issuers close competitors. However, the analyst and/or their immediate family may invest in an investable product (e.g., mutual fund, ETF) sponsored by an unaffiliated party the underlying holdings of which includes the security or securities noted herein.
- Analysts' compensation is derived from Morningstar's overall earnings and consists of salary, bonus and in some cases restricted stock. Analysts' receive no compensation or material benefits from product issuers or third parties in connection with the presentation.
- Morningstar does not receive commissions for providing research and does not charge financial product issuers to be rated. Morningstar recommendations are not disclosed to the issuer to which the recommendation, directly or indirectly relates. Analysts may not pursue business and employment opportunities outside Morningstar within the investment industry (including but not limited to, working as a financial planner, an investment adviser or investment adviser representative, a broker-dealer or broker-dealer agent, a financial writer, reporter, or analyst). Morningstar may provide the financial product issuer or its related entities with services or products for a fee and on an arms' length basis including software products and licenses, research and consulting services, data services, licenses to republish our ratings and research in their promotional material, event sponsorship and website advertising. Morningstar affiliates (i.e., its investment management group) may have arrangements with a fund company's affiliate to provide investment consulting advice some of which an analyst may issue an investment research reports on one or more of the fund company's funds. However, analysts do not have authority over Morningstar's investment management group's business arrangements nor allow employees from the investment management group to participate or influence the analysis or opinion prepared by them. Analysts do not have any other material conflicts of interest at the time of publication. Neither Morningstar, Inc. nor any of its affiliates are market-makers or liquidity providers for any of the securities noted herein. Users wishing to obtain further information should contact their local Morningstar office.
- Further information on Morningstar, Inc.'s conflict of interest policies is available from http://global.morningstar.com/equitydisclosures. Also, please note analysts are subject to the CFA Institute's Code of Ethics and Standards of Professional Conduct.

General disclosure

- This presentation does not constitute investment, legal, tax or other advice. Reference to any specific security is not a recommendation to buy or sell that security. Except as otherwise required by law, Morningstar shall not be responsible for any trading decisions, damages or other losses resulting from, or related to, the information, data, analyses or opinions or their use. Past performance is not a guide to future returns. The value of investments may go down as well as up and an investor may not get back the amount invested. Investment in certain sectors offer the possibility of higher returns but may also involve a higher degree of risk.
- Morningstar Star Ratings for stocks are subjective in nature and should not be used as the sole basis for investment decisions. Morningstar Star Ratings for stocks are based on Morningstar analysts' current expectations about future events and therefore involve unknown risks and uncertainties that may cause Morningstar's expectations not to occur or to differ significantly from what was expected. Morningstar does not represent its Morningstar Star Ratings for stocks to be guarantees and does not accept any responsibility or liability whatsoever for any loss howsoever arising from the use of the Morningstar Star Ratings for stocks.
-
- The information, data, and opinions presented herein are provided solely for informational purposes and are not warranted to be correct, complete or accurate. The opinions expressed within are given in good faith, are as of the date of the presentation, are not statements of fact, and are subject to change. Data from third parties used herein are believed to be reliable sources. Except as otherwise required by law, Morningstar shall not be responsible for any trading decisions, damages or other losses resulting from, or related to, the information, data, analyses or opinions or their use. The information contained herein is the property of Morningstar and may not be reproduced, in whole or in part, or used in any manner, without the prior written consent of Morningstar.
- This presentation contains certain forward-looking statements. We use words such as "expects", "anticipates", "believes", "estimates", "forecasts", and similar expressions to identify forward-looking statements. Such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause the actual results to differ materially and/or substantially from any future results, performance or achievements expressed or implied by those projected in the forward-looking statements for any reason.

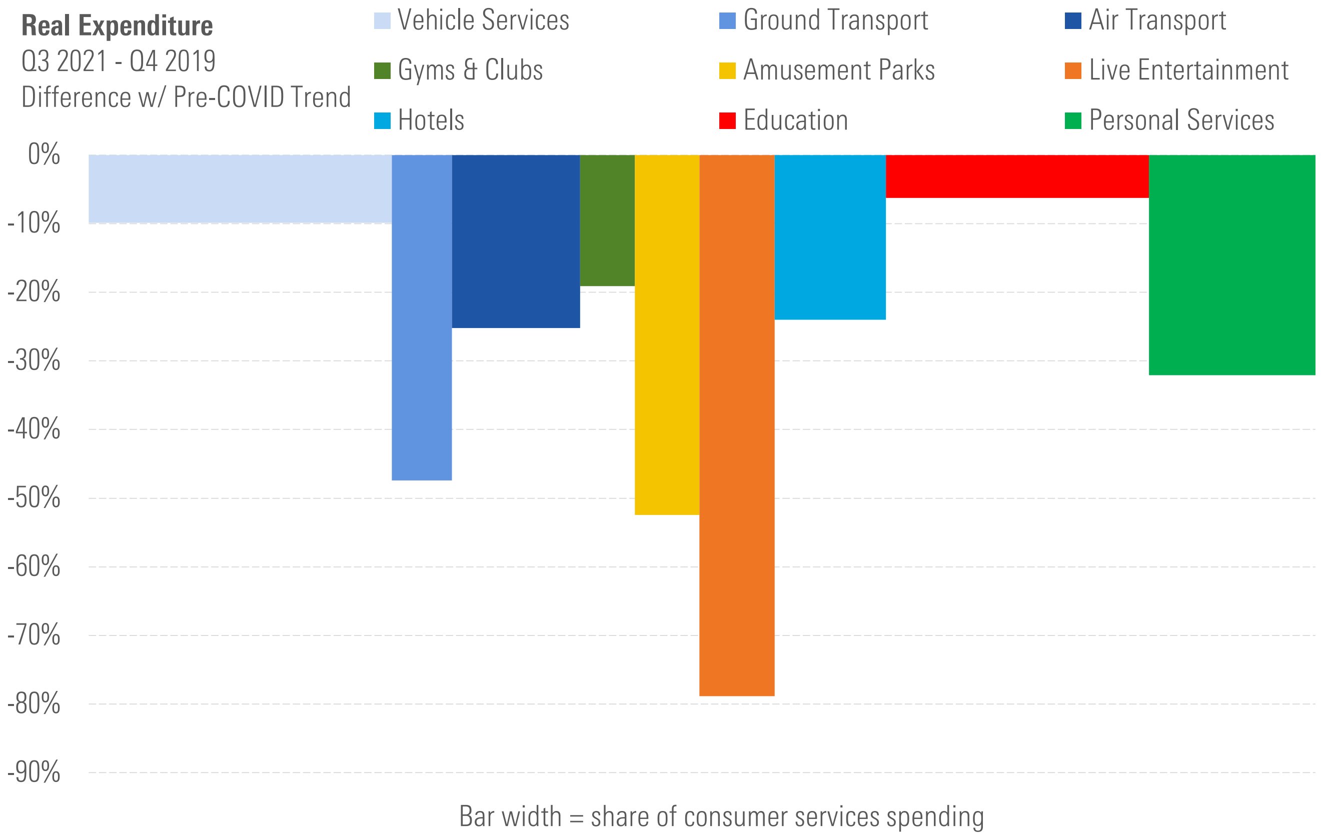
Lower Demand Will Help Cool Off Durables Prices, While Falling Oil Prices Should Do the Same for Energy





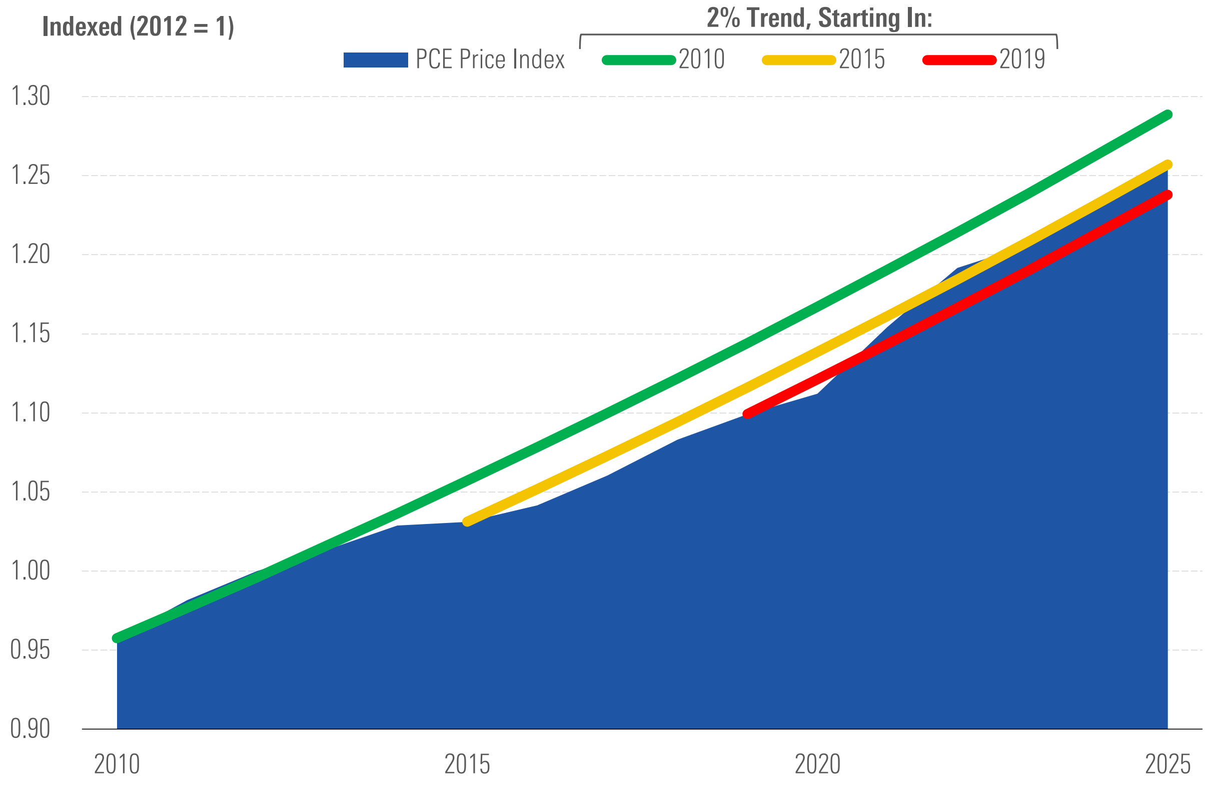
Source: U.S. Bureau of Economic Analysis, Morningstar (As of 1/1/2022)

Which Consumer Activities Have Yet to Return to Normal?



Sources: U.S. Bureau of Economic Analysis, Morningstar (As of 1/1/2022)

The Fed is Targeting 2% Average Inflation Over Time



- Our forecast is consistent with 2% average inflation from 2015-2025.

Sources: U.S. Bureau of Economic Analysis, Morningstar (As of 1/1/2022)