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July 19, 2023

VIA ELECTRONIC FILING

Ms. Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4300

RE: Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation (Docket No. E-7. Sub 1276)

Dear Ms. Dunston:

Pursuant to Ordering Paragraph 14 of the Commission's March 16, 2023, Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Testimony, enclosed for filing are the direct testimony and exhibits of the following witnesses:

- Mark E. Ellis;
- Genelle Wilson; and,
- David Hill and Jake Duncan

on behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Southern Alliance for Clean Energy, Natural Resources Defense Council, and Vote Solar.

We are forwarding a copy of this letter to all parties of record by electronic delivery. Please do not hesitate to contact us should any questions arise in connection with this filing.

Sincerely,

David L. Neal
Senior Attorney
Southern Environmental Law Center

On behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Southern Alliance for Clean Energy, Natural Resources Defense Council, and Vote Solar

Enclosures
cc: Parties of Record

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
	)	
	)	
Application of Duke Energy Carolinas, LLC, for and Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina and Performance-Based Regulation	)))))))	**Docket No. E-7, Sub 1276**

DIRECT TESTIMONY AND EXHIBITS OF

MARK E. ELLIS

ON BEHALF OF

NORTH CAROLINA JUSTICE CENTER, NORTH CAROLINA HOUSING COALITION, SOUTHERN ALLIANCE FOR CLEAN ENERGY, NATURAL RESOURCES DEFENSE COUNCIL, AND VOTE SOLAR

July 19, 2023

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EXHIBITS

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Exhibit MEE-2. Karl Dunkle Werner and Stephen Jarvis, *Rate of Return Regulation Revisited*, Energy Institute at Haas Working Paper 329 (2022)

Exhibit MEE-3. David C. Rode & Paul S. Fishchbeck, *Regulated equity returns: A puzzle*, 133 Energy Pol'y 1, 16 (2019)

Exhibit MEE-4. E-mail correspondence with Value Line

Exhibit MEE-5. E-mail correspondence with S&P Global Market Intelligence

Exhibit MEE-6. Richard A. Michelfelder & Panayiotis Theodossiou, *Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings*, 26:9 The Electricity J. (2013)

Exhibit MEE-7. Valeriy Zakamulin, *Secular Mean Reversion and Long-Run Predictability of the Stock Market*, 69:4 Bulletin of Economic Research (2017)

Exhibit MEE-8. Duke Energy Carolinas response to NCJC et al. Data Request 5.2

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND PROFESSIONAL AFFILIATION.

A. My name is Mark E. Ellis. I am an economic and financial consultant. My business address is 8595 Nottingham Place, La Jolla, CA 92037.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Southern Alliance for Clean Energy, Natural Resources Defense Council, and Vote Solar (NC Justice Center et al.).

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL WORK EXPERIENCE.

A. I graduated from Harvard University with a Bachelor of Science in Mechanical and Materials Sciences and Engineering and from the Massachusetts Institute of Technology with a Master of Science in Technology and Policy.

I have over 25 years of professional experience in the energy industry. Before starting my consulting practice in 2020, I led the strategy function at Sempra Energy for fifteen years. My responsibilities included developing and implementing the enterprise-wide cost of capital estimation process. This critical corporate finance function entailed thorough and ongoing research of the academic and practitioner literature on the historical cost of capital and the various cost of capital estimation methodologies and models; creating a process to estimate, quarterly, the forward-looking, risk-adjusted cost of capital for Sempra's portfolio of companies spanning a variety of geographies and lines of business; and calibrating the results against historical data and reputable, objective third-party estimates. Previously, I held various positions in strategy, project development, and engineering with McKinsey, ExxonMobil, Southern California Edison, and Sanyo Electric.

I have provided expert testimony on finance- and economics-related issues in utility regulatory proceedings for various clients across the country. Most recently, I provided rate of return testimony on behalf of NC Justice Center et al. in Duke Energy Progress's current rate case and supported The Utility Reform Network (TURN) on wildfire liability insurance in three general rate cases before the California Public Utilities Commission. Last year, I provided rate of return expert testimony on behalf of The Protect Our Communities Foundation (PCF) before the California Public Utilities Commission in two separate proceedings that jointly covered five utilities, on behalf of Georgia Interfaith Power and Light before the Georgia Public Service Commission, and on behalf of Clean Wisconsin before the Public Service Commission of Wisconsin. Attachment MEE-1 contains more detail on my background.

A. <u>Summary of Conclusions</u>

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

A. I have been asked by NC Justice Center et al. to assess Duke Energy Carolinas's (DEC) test year 2023 cost of capital application to analyze and calculate the return on equity (ROE) and capital structure (or equity ratio) that "will (1) enable a well-managed utility to produce a fair return for its shareholders, (2) allow the utility to maintain its facilities and services at a reasonable level, and (3) enable the utility to compete in the market for capital funds on terms that are reasonable and fair to its customers as well as its existing investors." *State ex rel. Utilities Comm'n v. Pub. Staff-N. Carolina Utilities Comm'n*, 322 N.C. 689, 697, 370 S.E.2d 567, 572 (1988) (citing N.C. Gen. Stat. § 62–133(b)(4)). In establishing the criteria in G.S. § 62–133(b)(4), the "Legislature intended for the Commission to fix rates as low as may be reasonably consistent with the requirements of the Due Process Clause of the Fourteenth Amendment to the Constitution of the United States," which are identical to state constitutional due process requirements. *State ex rel. Utilities Comm'n v. Duke Power Co.*, 285 N.C. 377, 388, 206 S.E.2d 269, 276 (1974).[1]

Q. GENERALLY, WHAT CONCLUSIONS DO YOU REACH FROM YOUR ANALYSIS AND CALCULATIONS?

A. The Commission can substantially reduce the authorized ROE requested by DEC, and thereby customer costs (by approximately $520 million per year), while still enabling DEC to attract debt and equity investment capital, fairly compensate investors for risk, and maintain DEC's current credit rating.

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1 This due process standard requires an ROE and equity ratio that are (1) adequate to ensure that the public utility earns a return on its investments "commensurate with returns on investments in other enterprises having corresponding risk," and (2) "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944).

Q. DOES YOUR ANALYSIS INCLUDE A CONSIDERATION OF DEC'S MULTIYEAR RATE PLAN APPLICATION, OR IS IT CONFINED TO DEC'S GENERAL RATE CASE APPLICATION?

A. My analysis is based on DEC's general rate case application and does not consider any potential factors that would relate to its proposed multiyear rate plan application. I would note that DEC witness Morin's testimony also does not make any reference to the performance-based ratemaking (PBR) provisions found in N.C. Gen. Stat. § 62-133.16. As noted above, my analysis and recommendations are consistent with the governing principles for fixing the rate of return found in N.C. Gen. Stat. § 62-133, which are also the starting point for fixing rates under the PBR provisions in North Carolina.

Q. WHAT ARE YOUR RECOMMENDED AUTHORIZED ROE AND EQUITY RATIO?

A. I recommend an authorized return on equity (ROE) equal to DEC's cost of equity (COE) and paired with an equity ratio that, together with my recommended ROE, minimizes customer costs while maintaining DEC's credit rating and financial integrity and fairly compensating debt and equity investors for risk. **My recommended authorized ROE is 6.15% at an equity ratio of 58.8%**.

B. Summary of Findings

1. DEC's cost of capital testimony employs flawed models and assumptions that systematically produce upwardly biased ROE estimates.

Q. THERE IS A SIGNIFICANT DIFFERENCE BETWEEN YOUR RECOMMENDATIONS AND DEC'S RECOMMENDED ROE AND EQUITY RATIO. HOW DO YOU EXPLAIN THAT?

A. The divergence arises from differences in both the models and input assumptions used to determine our respective ROE and equity recommendations.

DEC's cost of equity expert witness, Roger Morin, conducts six different analyses, using five different models, to develop his recommended return on equity (ROE). Two of those models, which he refers to as the risk premium methodology (RPM), suffer from a severe, invalidating conceptual flaw: they are based on utilities' historical or allowed *return on equity*, not their actual *cost of equity* (COE), or "the [expected] return to the equity owner … commensurate with returns on investments in other enterprises having corresponding risks."[2] The RPM is not commonly used in finance outside of utility regulatory proceedings because it does not actually estimate the *cost* of equity. The RPM is akin to developing a diet recommendation based on what people *actually* eat, not on what they *should* eat to maintain a healthy weight.

Two of the models used by Witness Morin – the discounted cash flow model (DCF) and capital asset pricing model (CAPM) – are widely used

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2 *Id.*

throughout finance to estimate the cost of capital. But Witness Morin's implementations of each suffer from numerous flaws which bias his results upward.

In implementing the DCF, Witness Morin assumes demonstrably unrealistic, economically impossible long-term dividend growth rates that bias his results upward.

In implementing the CAPM, he uses an interest rate forecast long and widely known to be systematically upwardly biased. He cherry-picks a beta calculation methodology that does not reflect current investor risk perceptions and applies the "Blume" adjustment that is not valid for utilities, both of which upwardly bias his results. He fails to examine other, more robust beta estimation methodologies, investigate whether the pandemic-related changes in market conditions and investor perceptions of utility risk were temporary or have been sustained, and compare his results to the long-term history of utility betas. Witness Morin's chosen methodology does not reflect the wide range of ways beta could be estimated, each of which could produce dramatically different results. As Nobel laureate Fischer Black, one of the pioneers of empirical testing of beta and the CAPM, famously admonished, "Watch out for data mining!"[3] – reporting only the outcomes from methods that support one's conclusions.

Witness Morin's two estimates of the CAPM market risk premium (MRP) – the difference in returns on the market and long-term Treasury bonds – are

[3] Fischer Black, *Beta and Return*, 20(1) J. Portfolio Mgmt. 8 (1993), https://jpm.pm-research.com/content/20/1/8.

also calculated in ways that bias them upward. He incorrectly calculates his historical MRP using arithmetic average returns, not the geometric averages that are appropriate for estimating long-term returns, and using only one component of the bond return, not the total bond return that is required for comparability with the total market return. To estimate his forward-looking MRP, Witness Morin uses the same flawed implementation of the DCF used for his proxy group, again producing an economically impossible result.

Witness Morin's fifth model, the Empirical CAPM (ECAPM), was developed by Witness Morin himself and is used only in utility regulatory proceedings, particularly by experts testifying on behalf of utilities. No papers validating or endorsing the ECAPM have been published in any peer-reviewed journals, and it is not included in commonly used finance textbooks for students and corporate finance professionals. It is based on outdated academic research, the findings of which are no longer valid for either the market as a whole or for utilities specifically.

Finally, Witness Morin fails to adjust his ROE estimates for differences in equity ratio among the proxy group members, and between the proxy group average and DEC.

DEC's capital structure testimony is similarly deficient. DEC's capital structure expert is Karl Newlin, Duke Energy's Senior Vice President, Corporate Development and Treasurer. While Witness Newlin refers to key cash flow metrics used in assessing credit quality, neither he nor Witness Morin identifies and explains the critical interrelationships between ROE, cash flow, equity ratio, and credit quality, much less demonstrate how these interrelationships were analyzed to arrive at DEC's purported "optimal" capital structure.[4] Regulators in other states have authorized ROEs that are substantially lower than those requested by DEC, with comparable or lower equity ratios, without adversely impacting utilities' credit ratings, suggesting the Commission can substantially reduce the ROE requested by DEC, and thereby customer costs, while maintaining DEC's credit rating.

2. More rigorous, fact-based analysis of DEC's COE and credit metrics yields a recommended ROE 41% lower and an equity ratio slightly higher than DEC's proposal.

Q. PLEASE SUMMARIZE THE MAIN FINDINGS OF YOUR ROE ANALYSES FOR DEC.

A. Like Witness Morin, I use the DCF and CAPM, two models that are widely used throughout finance, to estimate the cost of capital. Unlike Witness Morin, I am careful to use realistic and rigorously supported assumptions about long-term dividend growth rates, current interest rates, and risk profiles and premia.

As I explain in Section XI.A below, the equity ratio required to maintain any given level of credit quality depends on the ROE. Consequently, the ROE and equity ratio must be determined jointly. Instead of Witness Morin's crude equity ratio peer group comparison, which does not consider the most important metrics of credit quality, I model the inter-relationships between key credit metrics, ROE, and equity ratio to arrive at the optimal equity ratio that

4 Direct Testimony of Karl W. Newlin for Duke Energy Carolinas, LLC, p. 13.

minimizes customer costs while meeting the return and credit quality requirements of both equity and debt investors.

Figure 1 summarizes the key findings of my review of Witness Morin's analysis, the modifications required to correct its deficiencies, the resulting COE estimates, and my ROE and equity ratio recommendations. More rigorous, fact-based, and accurate analyses result in a substantially lower recommendation for DEC's ROE: 6.15%, which is 41% less than Witness Morin's recommended 10.4%, and a slightly higher equity ratio, 58.8% vs. DEC's 53%.

Based on my analysis of DEC's general rate case filings, its proposed combined rate of return on both debt and equity, grossed up for taxes, accounts for more than 30% of its revenue requirement.[5] <u>My recommended ROE and equity ratio would reduce DEC customer costs by approximately 9%, or $520 million per year.</u>

[5] M. Ellis analysis of data provided in Duke Energy Carolinas response to Public Staff Data Request 203.34.

Figure 1. Comparison of DEC and Ellis ROE and capital structure methodologies and results[6]
Percent

Model	Morin	Ellis	Comment
DCF		**6.63**	
• Value Line	**9.34**		
• Zacks	**9.30**		
Dividend yield	3.57	3.76	DEC: Sourced from Value Line, which provides year-ahead estimates
Constant-growth rate • Value Line • Zacks	 5.89 5.35	NA	Extrapolates DPS using analysts' 3-to-5-year EPS growth forecasts • Economically impossible • Forecasts are upwardly biased • Low correlation between EPS and DPS forecasts • Inconsistency between EPS and DCF forecast starting periods • Results are inconsistent with analysts' own return forecasts
Initial growth rate	NA	5.58	Analysts' EPS growth forecasts for 3 years to mitigate upward bias
Terminal growth rate	NA	1.70	Based on long-term historical utility DPS growth rate equal to inflation
Flotation cost adjustment	0.20	NA	Conceptually invalid: assumes M/B ratio = 1.0
CAPM	**11.0**	**6.06**	
Risk-free rate (30-year Treasury)	4.3	3.87	DEC: Estimated from forecast 10-year Treasury + 0.5% • Forecast source widely known to be systematically upwardly biased for decades • 0.5% adjustment cherry-picked from recent historical average data; 4x greater than current spread between 30- and 10-year Treasurys Ellis: Current (one-month trailing average) rate
Beta	0.89	0.55	DEC: Value Line Blume-adjusted 5-year weekly • Inflated due to early-2020 market turmoil and not reflective of current market conditions • Blume adjustment not valid for utilities Ellis: average of 5-year monthly betas from Yahoo! Finance and Zacks; balances long-term historical trend and current market conditions
Market risk premium	7.3	3.96	Average of historical and forward-looking
• Historical	7.4	4.91	DEC: Incorrectly based on income-only bond return and arithmetic averages Ellis: Geometric average total bond and market returns
• Forward	7.4	3.01	DEC: Based on flawed CG DCF Ellis: MS DCF long-term growth rate equal to per- capita GDP
Flotation cost adjustment	0.20	NA	Conceptually invalid: assumes M/B ratio = 1.0
Empirical CAPM	**11.2**	**NA**	Conceptually invalid: based on outdated research that identified a phenomenon that no longer exists and is not valid for utilities
Beta[7]	0.92	NA	Adjusts beta ¼ of the way toward 1.0.
Historical RPM	**10.8**	**NA**	Conceptually invalid: equates COE to historical realized utility stock returns
Allowed RPM	**10.5**	**NA**	Conceptually invalid: equates COE to authorized ROE
Mean – Levered	**10.4**	**6.35**	
– Unlevered	NA	5.21	55% proxy group average *market* equity ratio
Equity ratio	**53**	**58.8**	DEC: No analysis demonstrating why proposal is "optimal" Ellis: Optimizes ROE and capital structure to minimize costs while maintaining DEC's credit quality and providing a fair return to equity investors
Relevered COE/ recommended ROE	**10.4**	**6.15**	

C. Organization of Testimony

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I review a few key conceptual issues related to the cost of capital. Next, I provide a detailed assessment of Witness Morin's cost of equity estimation methodology and implementation. For the DCF and CAPM, the two of Witness Morin's five cost of equity models that are conceptually valid, I explain various modifications to his methodology and assumptions to correct for the deficiencies in Witness Morin's analyses and then provide the resulting COE estimates.

I then provide an overview of the critical interrelationships between ROE, capital structure, and credit quality and apply these concepts to determine the optimal equity ratio that minimizes customer costs while maintaining DEC's credit quality and satisfying the demands of equity and debt investors. Finally, I estimate the potential savings to customers from adopting my recommended ROE and equity ratio instead of Witness Morin's proposal.

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[6] *See* Direct Testimony and Exhibits of Roger A. Morin for Duke Energy Carolinas, LLC.

[7] ECAPM risk-free rate and market risk premium assumptions are the same as for Witness Morin's CAPM.

II. CONFUSION BETWEEN THE *RATE OF RETURN ON* CAPITAL AND *COST OF* CAPITAL HAS LED TO EXCESSIVE AUTHORIZED RETURNS.

A. ***Rate of return on*** **capital and** ***cost of*** **capital are not the same: rate of return on capital is a financial performance metric, whereas cost of capital is the measure of economic cost described in the** ***Hope*** **case.**

Q. WHAT IS THE OBJECTIVE IN SETTING A UTILITY'S AUTHORIZED RATE OF RETURN?

A. The authorized rate of return is the amount of money, expressed as a percentage of capital invested, that a utility is allowed to recover in customer rates to compensate debt and equity investors for assuming the risks of investing in the utility.

The Supreme Court provides the guiding ratemaking principles in its 1944 Hope Natural Gas case, in which it directs ratemakers to arrive at "just and reasonable rates" by a "balancing of the investor and the consumer interests."[8] Consumer interests are straightforward: they want to minimize costs and rates. Investors include holders of both the utility's debt and equity. A utility's debt investors expect to receive their contractual interest payments. Debtholders therefore have a "legitimate concern with the financial integrity of the company whose rates are being regulated,"[9] i.e., the utility's credit quality and anticipated ability to fulfill its obligations to debtholders. Equity investors expect a fair return, defined in Hope as "commensurate with returns on investments in other enterprises having corresponding risks."[10]

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8 *Hope Nat. Gas Co.,* 320 U.S. at 603.
9 *Id.*
10 *Id.*

Q. HOW DOES THE RATE OF RETURN ON CAPITAL DIFFER FROM THE COST OF CAPITAL?

A. The rate of return on capital, often shortened to "rate of return," is an accounting metric of financial performance, calculated by dividing the value returned to investors – e.g., interest, net income – by the amount of capital invested. The cost of capital is the return investors expect on their investment. It is referred to as a "cost" because it reflects what investors expect in return for assuming the risk of the investment and, therefore, what companies must pay for that investment. The rate of return on each form of capital, whether calculated retrospectively or estimated prospectively, may or may not equal its respective cost of capital.

Q. HOW DOES THE AUTHORIZED RATE OF RETURN ON CAPITAL DIFFER FROM THE RATE OF RETURN AND THE COST OF CAPITAL?

A. The authorized rate of return refers to a specific use of this accounting metric to determine a utility's revenue requirement and customer rates. According to long-established ratemaking principles, which will be explained in more detail below, the authorized rate of return should be set equal to the cost of capital. Figure 2 summarizes the differences between these three sets of metrics for debt, equity, and the combined return.

Figure 2. Comparison of terminology: cost of capital, (rate of) return on capital, and authorized rate of return

	Cost	(Rate of) return	Authorized rate of return
Capital	*Cost of capital*	*(Rate of) return on capital*	*Authorized rate of return*
	Economic concept: payment investors require to assume risk of investment.	Accounting concept: measured performance, historical or prospective	Regulatory concept: profitability benchmark determined by regulators to set utility revenue requirement and customer rates, balancing customer and investor interests
Equity	*Cost of equity (COE)*	*(Rate of) return on equity*	*Authorized return on equity (ROE)*
	Forward-looking return, based on *market* value of equity, investors expect in compensation for risk assumed; not directly observable	Profitability metric equal to net income divided by *book* value of equity	Per *Hope*, should equal cost of equity to ensure investors are adequately compensated at minimal customer cost
Debt	*Cost of debt*	*(Rate of) return on debt*	*Authorized cost of debt*
	Forward-looking market-based interest rate on debt with commensurate credit risk, adjusted for *expected* default and liquidity risk	Contractual interest (coupon) rate, adjusted for *actual* default or transaction losses	Contractual interest rate; weighted average of current (for existing debt) and expected (for anticipated new debt)

Q. WHAT PRINCIPLES DO YOU USE TO DETERMINE YOUR RECOMMENDED AUTHORIZED RATE OF RETURN?

A. As the National Association of Regulatory Utility Commissioners (NARUC) has explained, "Fundamental financial concepts demonstrate that the fair rate of return to use in ratemaking for a utility is its cost of capital in order to achieve the proper balance between customers and investors."[11] Witness Morin has also acknowledged, in his own textbook, that the "[t]he regulator should set the allowed rate of return equal to the cost of capital so that the utility can achieve the optimal rate of investment at the minimum price to the ratepayers."[12] The objective in setting a utility's authorized rate of return

[11] John D. Quackenbush, *Cost of Capital and Capital Markets: A Primer for Utility Regulators*, Nat'l Ass'n of Regul. Util. Comm'n at 10 (2019) (emphasis added), https://pubs.naruc.org/pub.cfm?id=CAD801A0-155D-0A36-316A-B9E8C935EE4D&_gl.

[12] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports at 23 (2006) [hereinafter "New Regulatory Finance"].

should, therefore, be to set the rate of return on each source of capital – debt and equity – as close as possible to the actual cost of each source of capital.

Q. DOES THE APPROACH TO CALCULATING COST OF EQUITY DIFFER FROM THE APPROACH TO CALCULATING COST OF DEBT?

A. Yes. The cost of outstanding debt can be directly determined from its contractual interest rates. Similarly, the cost of debt expected to be issued can be accurately determined from known interest rate indexes for debt of comparable credit quality, such as Moody's utility bond indexes, which, in turn, are based on interest rates directly observed in the market. In contrast, the cost of equity, both existing and to-be-issued, cannot be directly observed and must be estimated using various models.

Q. WHY IS THE DISTINCTION BETWEEN THE COST OF CAPITAL AND RATE OF RETURN IMPORTANT?

A. The cost of capital and rate of return (on capital) are entirely different concepts. The rate of return is a financial performance metric. The cost of capital is an economic concept. Nonetheless, they are frequently referred to interchangeably in utility regulatory proceedings, perhaps in part because finance professionals commonly refer to the cost of capital as the expected return (on capital).[13]

[13] *See, e.g.*, Tim Koller et al., *Valuation*, McKinsey & Co. at 35 (5th ed. 2010) ("The cost of capital is the price charged by investors for bearing the risk that the company's future cash flows may differ from what they anticipate when they make the investment. The cost of capital to a company equals the minimum return that investors expect to earn from investing in the company. That is why the terms *expected return to investors* and *cost of capital* are essentially the same. The cost of capital is also called the discount rate, because you discount future cash flows at this rate when calculating the present value of an investment, to reflect what you will have to pay investors" (emphasis in original).

The muddling of the difference between the cost of capital and the rate of return is not just of semantic concern, particularly for the cost of equity, which must be estimated using various models rather than directly observed (like the cost of debt).

This confusion between the cost of capital and the return on capital has infiltrated some of the models commonly used in utility cost of capital proceedings to estimate the cost of equity. These models' apparent influence on regulatory decisions, though, does not make them correct or mean they provide a suitable basis for estimating the cost of equity.

Models that rely exclusively on historical or forecast utility rates of return on equity, without reference to utilities' actual cost of equity, should be rejected outright. Witness Morin uses two such models, one relying exclusively on historical utility shareholder returns, the other on allowed ROEs. These models incorporate no information about the actual cost of equity and are therefore inherently flawed and produce invalid results. <u>Consistent with the fairness principle described by NARUC, North Carolina law, and Witness Morin's own statements, only models that estimate the cost of equity should be used to determine the authorized ROE.</u>

B. <u>Multiple, diverse sources of evidence demonstrate that utilities' authorized ROEs far exceed their cost of equity.</u>

Q. DO AUTHORIZED ROES REFLECT THE ACTUAL COST OF EQUITY?

A. No. Substantial, robust evidence suggests that authorized ROEs for nearly all U.S. utilities exceed their cost of equity. DEC's ROE follows this national pattern. Below, I provide three different analyses that demonstrate, individually and collectively, the substantial gap between authorized ROEs and utilities' actual cost of equity: expected equity return forecasts produced by investment professionals, utility market-to-book ratios, and the increasing spread between authorized ROEs and interest rates.

1. Investment firms' expected return forecasts for the U.S. equity market as a whole – which is riskier, on average, than utilities – are consistently lower than utilities' authorized ROEs.

Q. ARE THERE OTHER PUBLIC SOURCES FOR COST OF EQUITY ESTIMATES OUTSIDE UTILITY REGULATORY PROCEEDINGS?

A. Utility cost of capital proceedings are not the only purpose for which expected returns on equity are estimated. Investment firms, such as JP Morgan, BlackRock, and T. Rowe Price, regularly publish capital market assumption (CMA) reports – expected return forecasts for various asset classes. Figure 3 summarizes a survey of U.S. equity market return forecasts published by over thirty firms in 2022 and 2023.

The CMA forecasts shown in Figure 3 are grouped by assumed investment horizon: less than ten years, ten years (the most common), and more than ten years. The average across the longer-term 10-year and more-than-10-year horizons, 6.6%, is over 30% lower than the average ROE authorized for regulated utilities throughout the United States in 2022, 9.5%.[14]

[14] M. Ellis analysis of S&P Global Market Intelligence data [hereinafter "S&P GMI"], https://www.spglobal.com/marketintelligence/en/ (last visited Jul. 3, 2023).

Not a single one of the 47 expected return forecasts that I reviewed[15] is as high as the ROE produced by any of Witness Morin's six different analyses.

CMA equity market return forecasts are a relevant and useful benchmark for utility ROEs. Investors perceive U.S. utilities, including DEC, as lower-risk than the market – both historically and prospectively – due to their cost-plus regulatory model and relatively stable long-term growth. For example, the popular personal finance website, The Motley Fool, explains:[16]

> Utility stocks typically make stable investments. Demand for utility services such as electricity, natural gas, and water distribution tends to remain steady, even during a recession. Meanwhile, the rates they charge for delivering these services are either regulated (approved by a government entity) or contractually guaranteed (non-regulated), so utilities generate reliable earnings. That also allows them to pay dividends with above-average yields.
>
> The combination of predictable profitability and income generation makes utility stocks lower-risk options for investors because they're less volatile.

Investors therefore have lower return expectations for utilities than for the market. The fact that authorized utility ROEs are so much higher than the expected returns on the overall market, which has higher risk, is a compelling indicator that authorized ROEs far exceed utility investors' expected returns, i.e., utilities' actual cost of equity.

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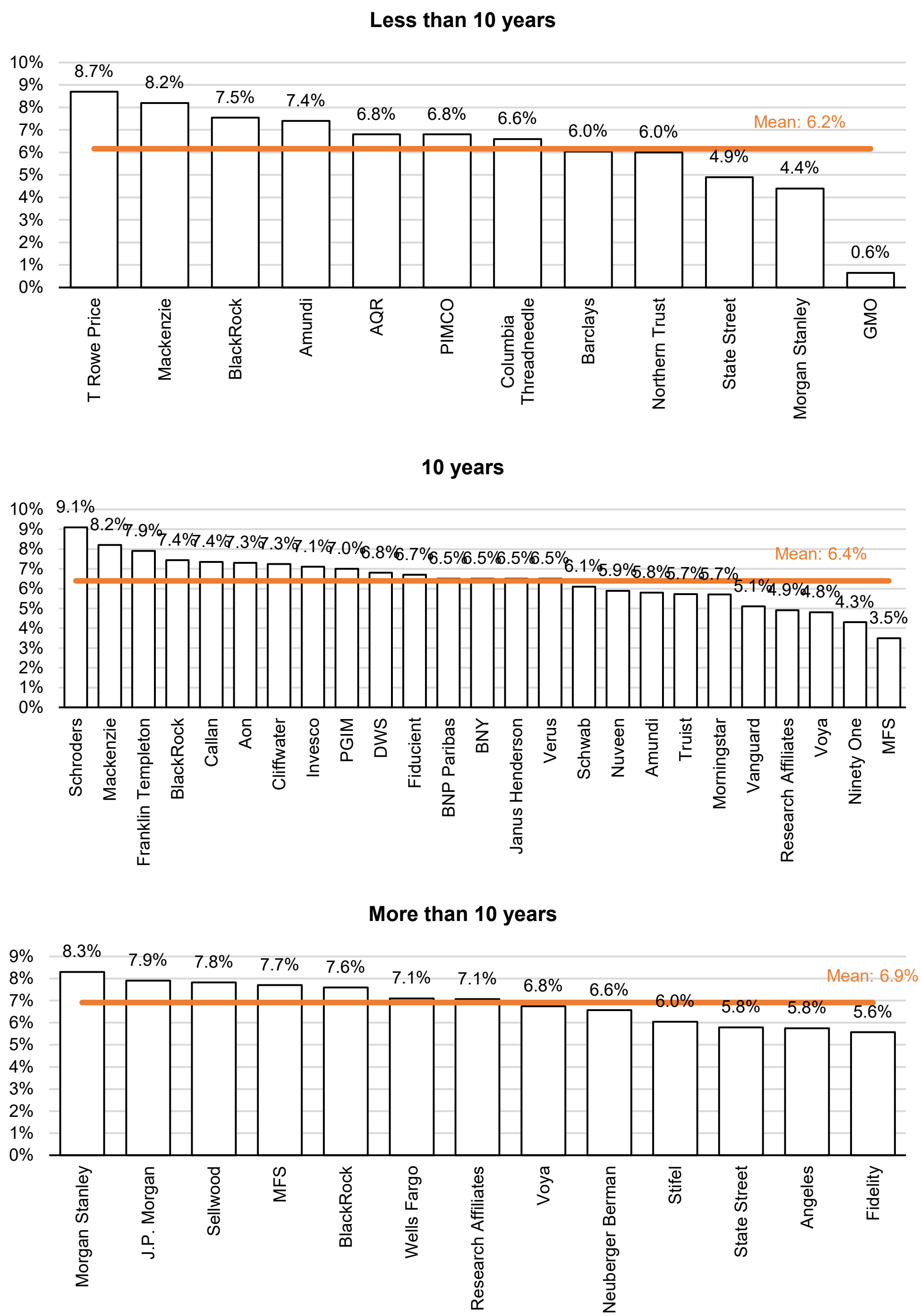
15 Some CMAs included forecasts for multiple time horizons, so the number of forecasts exceeds the number of reports.

16 Matthew DiLallo, *Investing in Top Utility Stocks*, The Motley Fool, Jan. 13, 2023, https://www.fool.com/investing/stock-market/market-sectors/utilities/.

Figure 3. U.S. equity market expected returns[17]
Nominal, geometric



[17] M. Ellis analysis of investment firm capital market assessment (CMA) reports, included with workpapers.

2. Market-to-book ratios reveal that utilities' cost of equity is substantially lower than authorized ROEs.

Q. WHAT IS A MARKET-TO-BOOK RATIO?

A. "Market" value refers to the price one must pay to purchase a share of a company's stock at any given time. "Book" value refers to the net equity invested in a company. In general, market value reflects the discounted value of a company's future cash flows, while book value reflects the historical investment in the company. The market-to-book ratio (M/B) is a commonly used financial metric that indicates the amount of shareholder value added in excess of shareholders' return expectations when the company invests.

Q. HOW DOES THE MARKET-TO-BOOK RATIO RELATE TO RETURNS?

A. It is a well understood financial principle that a market-to-book ratio greater than 1.0 indicates the company is expected to earn a return on its investment in excess of the actual cost of capital. A positive net present value (NPV), i.e., the value of a company minus its investments, is the signature indicator of a rate of return that exceeds the cost of capital. NPV is equal to investment multiplied by (M/B – 1.0), so M/B exceeding 1.0 indicates that NPV is positive.

Q. WHAT DO UTILITY STOCK MARKET-TO-BOOK RATIOS REVEAL ABOUT ROES RELATIVE TO UTILITIES' COST OF EQUITY?

A. It has long been recognized that utilities' market-to-book (M/B) ratios provide insight into the relationship between authorized return and the true cost of capital. Legendary regulatory economist Alfred Kahn[18] called attention to this

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[18] *See, e.g.*, Susan Lang, *Economist Alfred Kahn, 'father of airline deregulation' and former presidential adviser, dies at 93*, Cornell Chronicle, Dec. 27, 2010, https://news.cornell.edu/stories/2010/12/alfred-kahn-father-airline-deregulation-dies-93.

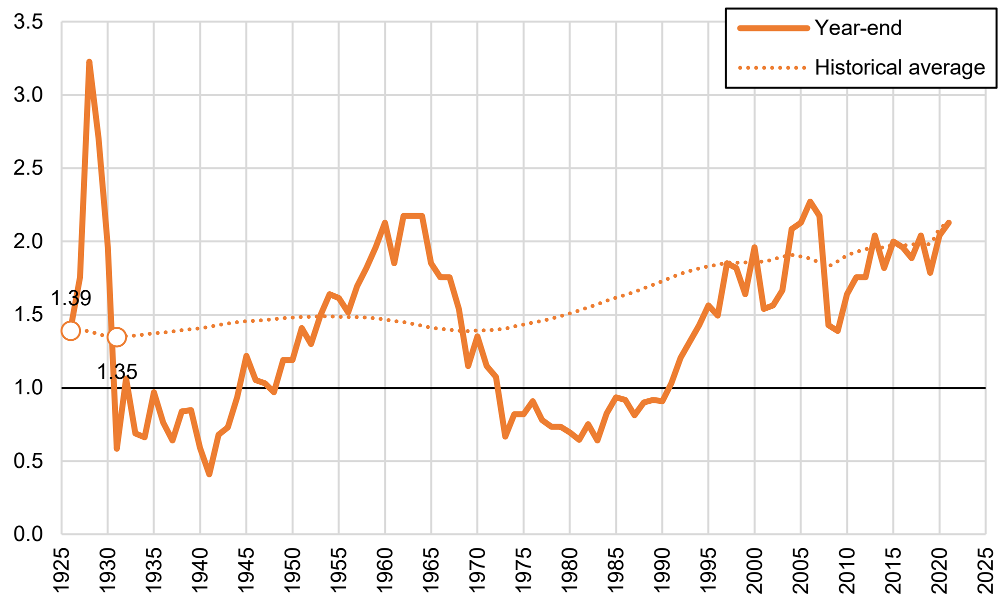
phenomenon over fifty years ago in his 1970 classic, *The Economics of Regulation: Principles and Institutions*:[19]

> [T]he sharp appreciation in the prices of public utility stocks, to one and half and then two times their book value during this period, reflected … a growing recognition that the companies in question were in fact being permitted to earn considerably more than their cost of capital. … The source of the discrepancy between market and book value has been that commissions have been allowing *r*'s [returns on equity] in excess of *k* [market cost of equity]; if instead they had set *r* equal to *k*, or proceeded at some point to do so … the discrepancy between market and book value … would have disappeared, or would never have arisen.

Kahn was referring to the period of the late 1940s to 1965, but the observation that utilities trade above book value is equally valid today. As seen in Figure 4, the utility sector average M/B has exceeded 1.0 for nearly thirty years and, except for a short period after the global financial crisis, has exceeded 1.5 since 1995.

[19] Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, Mass. Inst. Tech. at 48 (fn. 69), 50 (1970).

Figure 4. Utility sector average market-to-book ratio[20]
Year-end



The average of Witness Morin's proxy group members' M/B ratios, listed in Figure 4, is even higher, at 1.9.[21] For comparison, DEC parent Duke Energy's M/B ratio, 1.48 is also shown. As Kahn observed, the utility sector trading at 1.5 to 2.0 times book value for decades clearly demonstrates that utilities have once again been "permitted to earn considerably more than their cost of capital."

[20] M. Ellis analysis of French Data Library data [hereinafter "FDL"], https://mba.tuck.dartmouth.edu/pages/faculty/ken.french/data_library.html (last visited Jul. 13, 2023).

[21] M. Ellis analysis of S&P GMI data (last visited Jun. 30, 2023). M/B ratio is the monthly average for June 2023.

Figure 5. DEC proxy group market-to-book ratio and Value Line return on book equity[22]
June 2023

			Value Line return on book equity (%)		
Utility	**Ticker**	**M/B**	2022	2023	’25-‘27
Alliant	LNT	2.09	11.0	11.5	11.5
Ameren	AEE	2.04	10.0	10.0	10.0
AEP	AEP	1.82	11.0	10.5	11.0
Avista	AVA	1.28	6.5	7.5	8.0
Black Hills	BKH	1.33	8.0	8.0	9.0
CenterPoint	CNP	1.91	9.5	10.0	10.0
CMS	CMS	2.54	12.5	13.0	13.0
Dominion	D	1.64	12.5	12.5	13.0
DTE	DTE	2.15	9.0	11.5	12.5
Edison	EIX	1.91	13.0	13.0	13.0
Entergy	ETR	1.61	11.0	10.5	11.5
Evergy	EVRG	1.42	8.5	9.0	10.0
Eversource	ES	1.56	9.0	9.5	10.0
FirstEnergy	FE	2.16	15.5	15.0	14.5
IDACORP	IDA	1.87	9.0	9.0	9.0
NorthWestern	NWE	1.28	7.5	7.5	8.0
OGE	OGE	1.65	12.0	12.0	13.0
Otter Tail	OTTR	2.50	19.5	13.5	11.5
Portland General	POR	1.50	9.0	9.0	9.5
Sempra	SRE	1.72	10.5	10.5	11.0
Southern	SO	2.52	13.0	13.0	14.5
WEC	WEC	2.41	12.5	12.5	13.0
Xcel	XEL	2.06	10.5	10.5	11.0
Mean		**1.87**	**10.9**	**10.8**	**11.2**
Duke	*DUK*	*1.48*	*8.5*	*9.0*	*9.0*

Kahn drew his conclusions from the basic financial concept of net present value discussed above. Because utilities trade at a premium to book value (i.e., invested capital), they have positive NPVs – prima facie evidence that they are earning more than their cost of capital.

Figure 5 also contains past and forecast ROE estimates from Value Line, an investment research provider. Forecast ROEs for the proxy group are, on average, approximately 11%. A rough rule of thumb equates the M/B

[22] M. Ellis analysis of S&P GMI data (last visited Jun. 30, 2023); Value Line reports associated with Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC; *see* Duke Energy Carolinas response to NCJC et al. Data Request 1.5.

ratio to the ratio of ROE to COE, implying a proxy group average COE of approximately 5.5%.[23]

Q. IN PRACTICAL, DOLLARS-AND-CENTS TERMS, WHAT DOES IT MEAN FOR A UTILITY TO HAVE A MARKET VALUE THAT IS HIGHER THAN ITS BOOK VALUE?

A. In practical terms, this means that, for every dollar of equity a utility invests, shareholders receive back not just their investment plus a reasonable return, which would be the case when M/B = 1.0, but additional value equivalent to their equity investment multiplied by (M/B – 1.0). At current M/B ratios near 2.0, authorized ROEs effectively double the value of utilities' equity investments, *on top of* returning their cost of equity. Such high returns are not necessary to attract capital and needlessly increase customer costs.

Q. ARE YOU ABLE TO CALCULATE DEC'S MARKET-TO-BOOK RATIO?

A. DEC is not publicly traded, so its market value is not directly observable. Nonetheless, Duke Energy's market-to-book ratio, averaging 1.48 over the month of June 2023,[24] provides a reasonable estimate.

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[23] This rule of thumb can be derived from the formula for the present value (PV) of a perpetuity stream of constant annual cash flow: $PV = \frac{r}{k}$, where r is the annual return and k is the discount rate. The formula is not exact, because utilities typically (1) retain a portion of each year's return to reinvest to grow and (2) issue new shares over time. These factors tend to increase the present value modestly, so the rule of thumb will slightly underestimate the true COE. These factors do *not* change the fundamental relationship between M/B, COE, and ROE, i.e., an M/B of 1.0 implies ROE equals COE.

[24] M. Ellis analysis of S&P GMI data (last visited Jun. 30, 2023).

Q. IS WITNESS MORIN AWARE OF THE RELATIONSHIP BETWEEN THE MARKET-TO-BOOK RATIO AND ROE?

A. Yes. Witness Morin describes the relationship between market-to-book ratio and ROE in his textbook, *New Regulatory Finance*:[25]

> [I]f regulators set the allowed rate of return equal to the cost of capital, the utility's earnings will be just sufficient to cover the claims of the bondholders and shareholders. No wealth transfer between ratepayers and shareholders will occur.
>
> The direct financial consequence of setting the allowed return on equity, r, equal to the cost of equity capital, K, is that share price is driven toward book value per share, at least in theory under ideal conditions. Intuitively, if r > K, and is expected to remain so, then market price will exceed book value per share since shareholders are obtaining a return [on book equity] in excess of their opportunity cost.

Nonetheless, Witness Morin advises regulators *not* to look at the M/B ratio for guidance in determining whether ROE exceeds the cost of equity, in violation of the *Hope* and NARUC standards:[26]

> It is sometimes argued that because current M/B ratios are in excess of 1.0, this indicates that companies are expected by investors to be able to earn more than their cost of capital, and that the regulating authority should lower the authorized return on equity, so that the stock price will decline to book value. It is therefore plausible, under this argument, that stock prices drop from the current M/B value to the desired M/B range of 1.0 times book.
>
> There are several reasons why this view of the role of M/B ratios in regulation should be avoided.

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[25] New Regulatory Finance at 359.
[26] *Id.* at 376.

Witness Morin proceeds to provide four reasons to ignore M/B ratios in assessing ROEs. All four are flawed; some lack any reasonable foundation.

Q. WHAT IS WITNESS MORIN'S FIRST REASON REGULATORS SHOULD AVOID USING M/B RATIOS AS A GUIDE IN SETTING AUTHORIZED ROES?

A. Witness Morin's first reason for not using M/B ratios to assess the reasonableness of authorized ROEs is that it would somehow *require* that investors behave irrationally:[27]

> The view that regulation should set an allowed rate of return so as to produce an M/B of 1.0 *presumes that investors are irrational*. They commit capital to a utility with an M/B in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. For example, assume a utility company with an M/B ratio of 1.5. If investors expect the regulator to authorize a return on book value equal to the DCF cost of equity, the utility stock price would decline to book value, inflicting a capital loss of some 30%. The notion that investors are willing to pay a price of 1.5 times book value only to see the market value their investment drop by 30% is irrational.

This argument begs the question – or assumes what must be proven. Witness Morin's unstated assumption is that investors are willing to pay 1.5 times book value for the utility's shares *in the full knowledge that regulators will reduce the authorized ROE to the COE*. The only reason investors would be willing to pay 1.5 times book value, though, is precisely because they *do not* "expect the regulator to authorize a return on book value equal to the DCF cost of equity." If they did expect regulators to reduce the ROE to the COE, the M/B

[27] *Id*. (emphasis added).

ratio would not be 1.5 but much closer to 1.0, as Witness Morin indicates ("the utility stock price would decline to book value, inflicting a capital loss of some 30%"). Witness Morin's hypothetical – "assume a utility company with an M/B ratio of 1.5" – is accepted as "rational" only because regulators in nearly every state have a decades-long track record of authorizing ROEs far in excess of actual COEs and, so far, have given no indication that they will not continue to do so.

Q. WHAT IS WITNESS MORIN'S SECOND REASON REGULATORS SHOULD AVOID USING M/B RATIOS AS A GUIDE IN SETTING AUTHORIZED ROES?

A. Witness Morin's second purported reason is not an argument at all, but merely a restatement of the basic relationship between M/B ratio, ROE, and COE:[28]

> The condition that the M/B ratio will gravitate toward 1.0 if regulators set the allowed return equal to capital costs will be met only if the actual return expected to be earned by investors is at least equal to the cost of capital on a consistent long-term basis and absent inflation. The cost of capital of a company refers to the expected long-run earnings level of other firms with similar risk. If investors expect a utility to earn an ROE equal to its cost of equity in each period, then its M/B ratio would be approximately 1.0 or higher with the proper allowance for flotation cost.

Witness Morin provides no reason in this passage for regulators not to set the COE such that the M/B ratio equals 1.0.

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[28] *Id.*

It should be noted that Witness Morin's qualifications regarding inflation and flotation cost are not warranted. Expected inflation is reflected in the cost of both debt and equity capital. For example, interest rates have risen in the last two years as actual and expected inflation have increased. To the extent the ROE is based on the actual cost of equity, it will necessarily incorporate expected inflation. There is no need for the economy to be "absent inflation" for the basic relationship between M/B ratio, ROE, and COE to hold.

I will discuss flotation costs later in my testimony in Section IX below.

Q. WHAT IS WITNESS MORIN'S THIRD REASON REGULATORS SHOULD AVOID USING M/B RATIOS AS A GUIDE IN SETTING AUTHORIZED ROES?

A. Witness Morin's third reason entails several different arguments. The first argument:[29]

> The achievement of a 1.0 M/B ratio is appropriate, but only in a long-run sense. For utilities to exhibit a long-run M/B ratio of 1.0, it is clear that during economic upturns and more favorable capital market conditions, the M/B ratio must exceed its long-run average of 1.0 to compensate for the periods during which the M/B ratio is less than its long-run average under less favorable economic and capital market conditions.
>
> Historically, the M/B ratio for utilities has fluctuated above and below 1.0. It has been consistently above 1.0 from the 1980s to the mid-2000s [and since then, as well]. This indicates that earnings below capital costs and M/B ratios below 1.0 during less favorable economic and capital market conditions *must necessarily* be accompanied with earnings in excess of capital

[29] *Id*. at 377 (emphasis added).

> costs and M/B ratios above 1.00 during more favorable economic and capital market conditions.

Going back to 1926, the average M/B ratio for utilities has been 1.39; regardless of the calculation starting point, the historical average has never been lower than 1.35 (from 1931 through 2021).[30] Mathematically, ROEs could be set at a level to keep M/B ratios at 1.0 into perpetuity without the average dropping below 1.0. The facts flatly contradict Witness Morin's claim that "[f]or utilities to exhibit a long-run M/B ratio of 1.0, it is clear that during economic upturns and more favorable capital market conditions, the M/B ratio must exceed its long-run average of 1.0 to compensate for the periods during which the M/B ratio is less than its long-run average under less favorable economic and capital market conditions."

More importantly, contrary to Witness Morin's above assertion that "earnings below capital costs and M/B ratios below 1.0 during less favorable economic and capital market conditions *must necessarily* be accompanied with earnings in excess of capital costs and M/B ratios above 1.00 during more favorable economic and capital market conditions," there is no regulatory principle requiring rates to be set so as to compensate current and future shareholders for past earnings shortfalls, especially shortfalls that were last experienced by shareholders in the 1980s. Witness Morin has fabricated this argument out of whole cloth.

Witness Morin's third reason includes a second argument:[31]

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30 M. Ellis analysis of FDL data (last visited Mar. 6, 2023).
31 New Regulatory Finance at 377 (emphasis added).

> M/B ratios are determined in the marketplace, and utilities cannot be expected to compete for and attract capital in an environment where industrials [and other industries] are commanding M/B ratios well in excess of 1.0 while regulation reduces their M/B ratios toward 1.0. Moreover, if regulators were to currently set rates so as to produce an M/B of 1.0, not only would the long-run target M/B ratio of 1.0 be violated, but more importantly, the inevitable consequence would be to inflict severe capital losses on shareholders. Investors have not committed capital to utilities with the expectation of incurring capital losses from a misguided regulatory process.

The implication of Witness Morin's claim that "utilities cannot be expected to compete for and attract capital in an environment where industrials [and other companies] are commanding M/B ratios well in excess of 1.0 while regulation reduces [utilities'] M/B ratios toward 1.0" is that investors will invest only in the companies with the highest M/B ratios. A moment's reflection reveals this simply cannot be true. Investors buy the shares of companies spanning a range of M/B ratios, including those with M/B ratios less than 1.0, like General Motors, with an M/B ratio of 0.81 as of July 14, 2023.[32] And, as just explained above, rates could be set "so as to produce an M/B of 1.0" into perpetuity without "violating" Witness Morin's fictitious regulatory "long-run target M/B ratio of 1.0."

Witness Morin acknowledges that even *utilities* with M/B ratios less than 1.0 can "compete for and attract capital in an environment where industrials [and other industries] are commanding M/B ratios well in excess of 1.0":[33]

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[32] Yahoo! Finance, https://finance.yahoo.com/quote/GM/key-statistics?p=GM (last visited Jul. 14, 2023).

[33] New Regulatory Finance at 364.

> The above example [illustrating the adverse consequences for existing shareholders of selling stock below book value] does not imply that utilities cannot, in fact, raise capital when share prices are below book value, but that they can only do so at the expense of existing shareholders.

It is important to recognize that *Hope* established that regulators are not obligated to maintain utility stock market valuations, and that such an obligation would make a nonsense of regulators' consumer protection mandate:[34]

> Ratemaking is indeed but one species of price-fixing. The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. *But the fact that the value is reduced does not mean that the regulation is invalid.* It does, however, indicate that "fair value" is the end product of the process of ratemaking, not the starting point, as the Circuit Court of Appeals held. The heart of the matter is that rates cannot be made to depend upon "fair value" when the value of the going enterprise depends on earnings under whatever rates may be anticipated.

The impact on existing shareholders of reducing ROEs to a level that brings M/B ratios to the *Hope* and NARUC standard of 1.0 should not factor at all into regulators' determination of the appropriate rate of return.

Q. WHAT IS WITNESS MORIN'S FOURTH REASON REGULATORS SHOULD AVOID USING M/B RATIOS AS A GUIDE IN SETTING AUTHORIZED ROES?

A. Witness Morin's fourth reason is that:[35]

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[34] *Hope Nat. Gas Co.*, 320 U.S. at 601 (emphasis added).

[35] New Regulatory Finance at 377 (emphasis added).

> Rate of return regulation is fundamentally a surrogate for competition. The fundamental goal of regulation should be to set the expected economic profit for a public utility equal to the level of profits expected to be earned by firms of comparable risk, in short, to emulate the competitive result. For unregulated firms, the natural forces of competition will ensure that in the long run, the ratio of the market value of these firms' securities equals the replacement cost of their assets. Competitive industrials of comparable risk to utilities have consistently been able to maintain the real value of their assets in excess of book value, consistent with the notion that, under competition, the Q-ratio will tend to 1.00 and not the M/B ratio. This suggests that a fair and reasonable price for a public utility's common stock is one that produces equality between the market price of its common equity and the replacement cost of its physical assets. The latter circumstance will not necessarily occur when the M/B ratio is 1.0.

Witness Morin is correct that "[r]ate of return regulation is fundamentally a surrogate for competition." But the "competitive result" is different for utilities than for competitive industrials. As Kahn observed, "returns in industry generally contain some monopoly component" and the risk profiles of nonregulated industries are not comparable to utilities.[36] In addition,[37]

> if utility stocks are compared with those of non-utility corporations …, utilities which are protected from many forms of competition will be compared with the winners in other areas with no such … protection. Somehow, in strict logic, the shadow losses of long defunct automobile companies would have to be subtracted from the profits of General Motors, after these in turn had been adjusted downward for the hypothetical competition.

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[36] Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, Mass. Inst. Tech. at 52-53 (1970).

[37] Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, Mass. Inst. Tech. at 53 (fn. 81) (1970), citing William G. Shepherd & Thomas G. Gies, *Utility Regulation New Directions in Theory and Policy*, New York: Random House at 35-45 (1966).

This is why neither Witness Morin nor any other cost of capital expert uses or even evaluates Q-ratios in their cost of capital analyses. Witness Morin's invocation of the Q-ratio is a rhetorical red herring; it has no relevance whatsoever to a utility's cost of capital. Rather, as Kahn observed more than 50 years ago, for utilities the competitive result is revealed by an M/B ratio of 1.0.

A simple thought experiment reveals why. It is a basic financial truism that paying more for a given stream of cash flows entails a lower return. For example, if I pay $100 for an asset that returns $5 per year for 20 years plus my initial $100 investment at the end of year 20, my rate of return will be 5%. If I pay $150 for the same stream of cash flows (including the return of only $100 in year 20), my rate of return is reduced to 2%.

Similarly, when investors buy a utility stock earning a 10% ROE at more than book value, their expected return, i.e., their cost of equity, *must* be less than 10%. The "competitive result" is the lower return that investors are willing to accept. By itself, the M/B ratio cannot reveal that required rate of return. But it can tell us if the authorized ROE is higher or lower than the required return, the cost of equity; an M/B ratio of 1.0 tells us that the authorized ROE is equal to the COE, i.e., the "competitive result" in the market for capital investment.

Q. WHY DO YOU THINK WITNESS MORIN IS SO DETERMINED TO CONVINCE REGULATORS TO IGNORE M/B RATIOS?

A. As referenced above, Witness Morin recognizes the basic financial principle relating the M/B ratio, the cost of equity, and the allowed return:[38]

> The direct financial consequence of setting the allowed return on equity, r, equal to the cost of equity capital, K, is that share price is driven toward book value per share …

Witness Morin nonetheless provides a great deal of unsupported rhetoric in his effort to convince regulators to ignore M/B ratios. Witness Morin is not alone in his efforts. The Brattle Group consulting firm, which employs a stable of cost of capital experts who provide testimony on behalf of utilities similar to Witness Morin's, likewise encourage regulators to ignore M/B ratios, employing equally unfounded arguments.[39]

It should be noted as well that utilities' advice to regulators to ignore M/B ratios is a complete reversal of their views when M/B ratios were last persistently below 1.0. In 1984, after over a decade of sub-1.0 utility M/B ratios, Lawrence Kolbe, co-author of the 2017 Brattle text arguing against the use of M/B ratios, co-authored a commonly referenced textbook on utility regulation, *The Cost of Capital: Estimating the Rate of Return for Public Utilities*, that recommends using a M/B ratio of 1.0 as a "guide for regulators" in setting the cost of capital:[40]

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38 New Regulatory Finance at 359.

39 Bente Villadsen, Michael Vilbert, Dan Harris, and Lawrence Kolbe, *Risk and Return for Regulated Industries*, Acad. Press at 293-295 (2017).

40 A. Lawrence Kolbe, James A. Read, Jr., and George R. Hall, *The Cost of Capital: Estimating the Rate of Return for Public Utilities*, Charles River Associates, Inc. at 25 (1984).

> …that regulators' actions should make the ratio of a regulated stock's market value to its book value (slightly more than) one. … It turns out to be simply another way of saying that the allowed rate of return should equal the cost of capital. It is worth approaching the topic from this direction because understanding this proposition's premises yields additional insights into the nature of the cost of capital and the "fairness" of alternative policies. It also shows that failure to follow the prescription may prove very costly in the long run.
>
> Why Choose a Market-to-Book Ratio of One?
>
> The market-to-book ratio expresses the market value of the firm's outstanding common stock to the book value of its equity. If the two are equal the expected return on the book will equal the expected return on the market value of the company, which in turn will equal the cost of capital for a company of that degree of risk.

Similarly, Peter Navarro, most recently President Trump's Director of Trade and Manufacturing Policy, in a 1980 report for the Department of Energy on national energy policy and utility regulation, defined the "normative standard" for utility regulation as an M/B ratio of 1.0:[41]

> The normative standard for a regulated industry is to ensure that this market to book ratio (M/B) is equal to 1, that is the market price should be equal to the book value. … That return is a close proxy for the firm's cost of equity capital.

Utility M/B ratios are timely, transparent, and easily accessible in real-time for free from popular financial websites like Yahoo! Finance. They provide unambiguous feedback to regulators and the public on whether

[41] Peter Navarro, *Public Utility Regulation and National Energy Policy*, U.S. Dep't of Energy, Off. of Pol'y & Evaluation at 12 (1980), https://www.osti.gov/servlets/purl/6705612.

allowed ROEs are set appropriately. They are the elephant in the living room of utility regulation that utilities want us to ignore.

3. Authorized ROEs and interest rates have diverged without a corresponding increase in utilities' risk profile.

Q. WHAT ARE SOME POSSIBLE EXPLANATIONS FOR WHY REGULATORS APPROVE AUTHORIZED ROES IN EXCESS OF UTILITIES' ACTUAL COST OF EQUITY?

A. A mathematical model called the Pólya urn can provide insight into why regulators have continued to approve authorized ROEs in excess of utilities' actual cost of capital.[42] Historical return on equity decisions can be thought of as balls in an urn. To decide on a new case, the regulator draws a ball from the urn. The ball is then replaced, along with a new ball – representing the current ROE decision – with the same value. This process of sampling-with-replacement-plus-duplication has a self-reinforcing property sometimes called the rich-get-richer or Matthew effect.

Of course, this model is over-simplified because regulators look at other information besides past authorized ROEs. The basic model can be modified to include additional balls in the urn representing new information, such as the estimated current cost of equity. Nonetheless, as long as regulators look at, much less rely on, past ROEs, changes in authorized ROEs will lag changes in the current true cost of equity.

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[42] *See, e.g.,* Learning Machines, *The Polya Urn Model: A simple simulation of "The Rich get Richer,"* Sep. 7, 2021, https://blog.ephorie.de/the-polya-urn-model-a-simple-simulation-of-the-rich-get-richer.

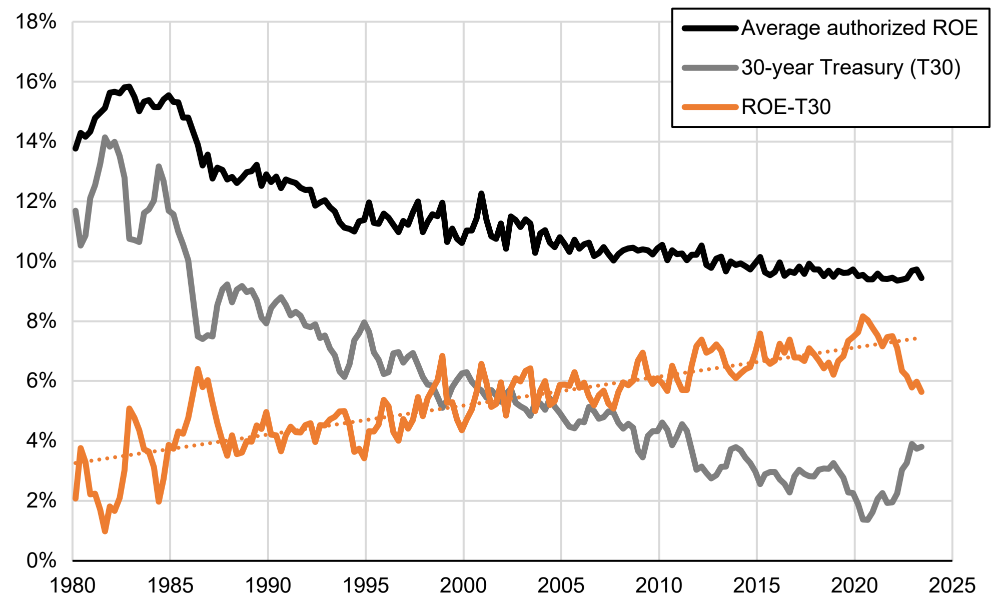
The basic utility regulatory model and risk profile have not changed significantly for decades, as revealed in utility credit ratings, which "have changed little over 35 years."[43] The utility equity risk premium – the spread of the cost of capital over risk-free government interest rates – has therefore remained stable. The Pólya urn model predicts that, in a market in which interest rates and, therefore, utilities' cost of equity, have been trending downward for decades, authorized ROEs will consistently exceed the actual cost of equity, and the spread will widen over time.

The data confirm the Pólya urn model's prediction of such a widening spread between authorized ROEs and the actual cost of equity. Figure 6 shows the quarterly average authorized ROE for all U.S. utilities, the 30-year Treasury rate (T30), and their difference. While interest rates declined steadily from the mid-1980s through 2021, authorized ROEs did not keep pace. As a result, the ROE-Treasury spread (the orange line in Figure 6) nearly quadrupled, from 2.2% in the early 1980s to over 8% in mid-2020. Even after the T30 increased by 2.4%, from 1.4% in mid-2020 to 3.8% in Q2 2023, the spread remained at nearly 6%. It can be estimated from the Pólya urn model described above that, even under conservative assumptions, regulators, on average, assign no more than a 20% weight to the current cost of equity and at least 80% to recent ROEs. No evidence suggests that utilities' risk profile – particularly vertically integrated utilities like DEC that are not

[43] *See, e.g.*, Karl Dunkle Werner and Stephen Jarvis, *Rate of Return Regulation Revisited*, Energy Institute at Haas Working Paper 329 at 12-13 (2022), https://haas.berkeley.edu/wp-content/uploads/WP329.pdf, which is available as Exhibit MEE-2.

subject to any wholesale or retail competition – has systematically increased over this period, so setting ROEs higher and higher relative to utilities' actual cost of equity unnecessarily raises rates and costs to customers.

Figure 6. Quarterly average authorized ROE and 30-year Treasury rate[44]



Others have made similar observations about the growing divergence between authorized ROEs and utilities' actual COEs. In a study published in 2019 exploring potential explanations, Carnegie Mellon researchers David Rode and Paul Fischbeck concluded:[45]

> It would appear that regulators are authorizing excessive returns on equity to utility investors and that these excess returns translate into tangible profits for utility firms.

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[44] M. Ellis analysis of S&P GMI data; Federal Reserve Bank of St. Louis Economic Data [hereinafter "FRED"], https://fred.stlouisfed.org/categories/115 (last visited Jul. 3, 2023).

[45] David C. Rode & Paul S. Fishchbeck, *Regulated equity returns: A puzzle*, 133 Energy Pol'y 1, 16 (2019) (emphasis in original), https://doi.org/10.1016/j.enpol.2019.110891, which is attached as Exhibit MEE-3.

> …
>
> In the end, we may observe simply that what regulators should do, what regulators say they're doing, and what regulators actually do may be three very different things.

University of California, Berkeley researchers Karl Dunkle Werner and Stephen Jarvis similarly observed in 2022:[46]

> The gap between the approved return on equity and other measures of the cost of capital have [*sic*] increased substantially over time.
>
> …
>
> Our analysis shows that the RoE that utilities are allowed to earn has changed dramatically relative to various financial benchmarks in the economy. We estimate that the current approved average return on equity is substantially higher than various benchmarks and historical relationships would suggest.

The practice of using old rates to set new ones has recently come under increased scrutiny. In an August 2022 decision, the United States Court of Appeals for the District of Columbia rejected FERC's use of models based on past authorized ROEs, as doing so presents "'particularly direct and acute' circularity problems."[47] As previously noted, looking at *actual* authorized ROEs to estimate the *required* ROE is akin to developing a diet

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[46] *See, e.g.*, Karl Dunkle Werner and Stephen Jarvis, *Rate of Return Regulation Revisited*, Energy Institute at Haas Working Paper 329 at 14, 34-35 (2022), https://haas.berkeley.edu/wp-content/uploads/WP329.pdf, which is available as Exhibit MEE-2.

[47] *MISO Transmission Owners v. FERC*, 45 F.4th 248, 264 (D.C. Cir. 2022).

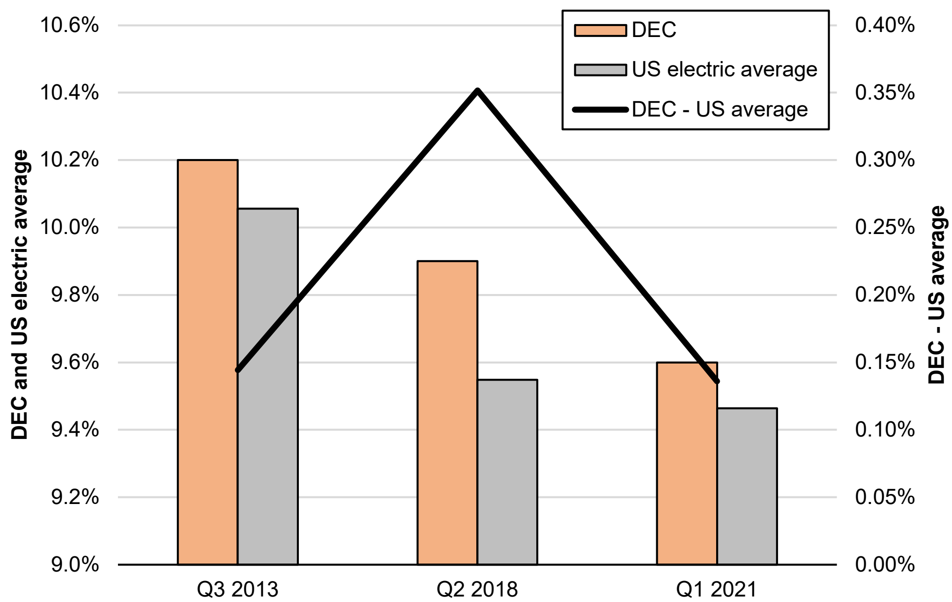
recommendation based on what people *actually* eat, not what they *should* eat to be healthy.

4. These nationwide trends have been even more pronounced for DEC.

Q. DO THESE NATIONAL TRENDS APPLY TO DEC?

A. Yes. Authorized ROEs for DEC have been set substantially higher than the national average authorized ROE for the last decade, as seen in Figure 7, which shows the difference between DEC's authorized ROEs and the corresponding quarterly national average electric utility authorized ROE in DEC's last five cost of capital authorizations. On average, DEC's authorized ROEs have been 0.21% higher than the national electric utility average, despite its lower-risk vertically integrated business model not being subject to wholesale or retail competition.

Figure 7. DEC and average U.S. electric utility authorized ROE since 2013[48]



III. WITNESS MORIN EMPLOYS FLAWED MODELS AND ASSUMPTIONS THAT SYSTEMATICALLY PRODUCE UPWARDLY BIASED ROE ESTIMATES FOR DEC.

Q. HOW DOES WITNESS MORIN ESTIMATE DEC'S ROE?

A. Witness Morin uses a total of six different analyses, employing five different models, to estimate DEC's ROE: (1-2) the constant-growth discounted cash flow model (CG DCF) using growth rate forecasts from two different sources; (3) the capital asset pricing model (CAPM); (4) the Morin "empirical CAPM" (ECAPM); and the risk premium methodology (RPM) using (5) historical realized utility stock returns and (6) historical authorized ROEs. Witness Morin's CG DCF, CAPM, and ECAPM analyses estimate ROEs for a number of proxy group companies, and he bases his recommended ROEs on the proxy group average.

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48 M. Ellis analysis of S&P GMI data (last visited Jul. 3, 2023).

Q. DO YOU HAVE ANY CONCERNS WITH WITNESS MORIN'S PROXY GROUP?

A. Witness Morin uses reasonable criteria to select companies similar to DEC with respect to their financial strength, business model, size, and risk profile. The resulting sample size, 23 peers, is sufficiently large to calculate statistically robust results. I use the same proxy group members in my various analyses.

Q. WHAT IS YOUR OVERALL ASSESSMENT OF WITNESS MORIN'S APPROACH?

A. Although two of Witness Morin's five models, the CG DCF and CAPM, are widely used by financial professionals and utility cost of capital experts to estimate the cost of equity, his implementations of each of these models are deeply flawed. They rely on unrealistic, systematically upwardly biased assumptions that invalidate their results. I describe these deficiencies in more detail in Sections IV and V below.

Witness Morin's other three models, the ECAPM and Historical and Allowed RPMs, while frequently used by cost of capital experts testifying on behalf of investor-owned utilities, are not commonly used elsewhere in finance outside of utility regulatory proceedings, and both suffer from severe, invalidating conceptual flaws. I describe these conceptual flaws in Sections VII and VIII below.

IV. WITNESS MORIN'S DCF MODEL USES UPWARDLY BIASED DIVIDEND YIELD CALCULATIONS AND UNREALISTICALLY EXTRAPOLATES ANALYSTS' NEAR-TERM EARNINGS GROWTH FORECASTS INTO PERPETUITY, PRODUCING ECONOMICALLY IMPOSSIBLE RESULTS.

Q. WHAT IS YOUR ASSESSMENT OF WITNESS MORIN'S DCF MODEL?

A. Witness Morin uses the constant-growth version of the DCF model (CG DCF) in his analysis, with a growth rate equal to equity analysts' 3-to-5-year earnings-per-share (EPS) growth rate estimates from Value Line and Zacks.[49] The key shortcoming in his implementation of the CG DCF is the assumption that dividends can grow at analysts' short-term, 3-to-5-year estimated EPS growth rates into perpetuity. This assumption is economically impossible and adds substantial upward bias to his results.

Q. PLEASE DESCRIBE THE CONSTANT-GROWTH DCF MODEL.

A. The constant-growth DCF is based on the well-known and widely used mathematical formula for the value of a stream of cash flows that grows in perpetuity. It assumes a single, constant rate of cash flow growth. Consistent with common practice among financial professionals both within and outside the utility sector, Witness Morin's DCF cash flows are expected dividends, and the perpetuity value formula can be expressed as:

$$M_0 = \frac{D_1}{(k-g)},$$

[49] Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, p. 26. Value Line's and Zacks's EPS growth rates have different forecast periods. Value Line provides estimated growth rates over the period 2019-21 through 2025-27, or approximately 3 years from 2023. *See, e.g.*, Duke Energy Carolinas response to NCJC et al. Data Request 1.5. Zacks provides 3- to 5-year estimates. *See, e.g.*, Zacks, https://www.zacks.com/stock/quote/DUK.

where M_0 refers to the current market value (stock price), D_1, the dividend expected in the first forecast year, g, the forecast perpetuity growth rate, and k, the cost of equity. Rearranging terms, the cost of equity can be expressed as a function of the dividend yield, d ($\frac{D_1}{M_0}$), and growth rate:

$$k = d + g.$$

Typically, the cost of equity is estimated for each member of the proxy group, with the mean or median reflecting the cost of equity for the target company. Witness Morin uses the mean.

The *general* DCF model, which, distinct from Witness Morin's *constant-growth* version, allows for varying growth rates over time, is a particularly apt representation of stock returns because its assumptions realistically reflect several key features of share prices and expected returns. First, the DCF model's perpetual cash flow stream assumption mirrors equity's claim on a firm's cash flows into perpetuity. Second, the assumption of steady growth in dividends over time reasonably reflects their much greater stability relative to other potential measures of profitability, like earnings or cash flow. Third, the resulting single discount rate into perpetuity is consistent with the no-arbitrage principle of finance. If investors expected higher (lower) returns in the future, they would impute that into the price today and bid up (down) the price accordingly, such that near-term and long-term returns roughly equilibrate.[50]

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50 Some equity return projections vary with forecast horizon, generally due to a valuation-reversion assumption in the model, e.g., price-to-earnings ratios returning to their long-term historical average over an initial horizon and remaining at that level afterward. *See, e.g.*, BlackRock Investment Institute, *Capital market assumptions* (2023) https://www.blackrock.com/institutions/en-us/insights/charts/capital-market-assumptions.

Nonetheless, the limitations of the *constant-growth* DCF used by Witness Morin make it inappropriate for estimating a utility's cost of equity.

It should be noted that the DCF model yields a *geometric* average return, or the fixed annual rate of return on M_0 that, if compounded every year, would have the same value over time as the sum of the DCF model's past and future streams of dividends, compounded (past) and discounted (future) at the same rate.

Q. WHY IS THAT CLARIFICATION IMPORTANT?

A. When analyzing investment returns, another commonly reported average is the *arithmetic* average: the simple, unweighted average of returns across multiple historical holding periods (e.g., the average of monthly or annual returns over multiple years). A simple example illustrates the difference. Suppose a stock price increases by 50% in one year, then declines by 50% the following year, such that the ending value is 75% of the starting value. The arithmetic average is 0%, (+50% – 50%)/2, while the geometric average is -13.3%, $[(1 + 50\%) \times (1 - 50\%)]^{1/2} - 1$.

Returns can be reported on either basis, depending on the context, but investors are not indifferent between them. Investors care most about changes in asset values over time, and only the geometric return provides an unambiguous indicator of this change. Given a starting investment value, for

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Whether variation in expected equity returns across different forecast horizons can be estimated with any accuracy is a subject of ongoing debate among academic and investment professionals. Some forecasters assume no mean reversion in their return forecasts. *See, e.g.*, AQR Capital Management, *2014 Capital Market Assumptions for Major Asset Classes* (2014) https://www.aqr.com/Insights/Research/Alternative-Thinking/2014-Capital-Market-Assumptions-for-Major-Asset-Classes.

any geometric return there is a single future value, but for any arithmetic return there are an infinite number of potential future values. If the geometric average return is 5%, for example, in two years the value will be 1.05 x 1.05 – 1 = 1.1025. In contrast, if the arithmetic return is 5%, in two years the value could be anywhere from 0, (1 + 110%) x (1 – 100%), to 1.1025 if the return is the same 5% in each year. The arithmetic return, on its own, does not indicate the future value and, unless it does not vary from year to year, systematically overstates it.

For this reason, geometric returns are generally considered a better measure of investor expectations. I will return to this topic later in my testimony in the critique of Witness Morin's CAPM historical market risk premium, which is based on arithmetic average returns.

Q. IS WITNESS MORIN'S IMPLEMENTATION OF THE DCF MODEL APPROPRIATE FOR ESTIMATING A UTILITY'S COST OF EQUITY?

A. The *constant-growth* version of the DCF used by Witness Morin is not well-suited for estimating the cost of equity for a utility or any other stock, for two reasons. First, it is not realistic to assume that a utility will maintain its currently forecast near-term growth rate into perpetuity. At any given time, the 3-to-5-year growth rate will deviate from its long-term trend due to any number of factors, such as weather; economic conditions; new capital projects; regulatory, tax, and other policy changes; and unforeseen events like the Covid-19 pandemic. Second, the results of the CG DCF are particularly sensitive to the perpetuity growth rate assumption. The inaccuracy that is introduced by assuming a relatively short-term, 3-to-5-year growth rate will be sustained forever invalidates the results of Witness Morin's CG DCF. Witness Morin's use of analyst estimates, a source widely known to be upwardly biased, for his growth rate assumption further invalidates his results.

A. Witness Morin's perpetuity growth rate is based on analysts' 3-to-5-year growth rate forecasts, producing economically impossible results.

Q. HOW DOES WITNESS MORIN ESTIMATE EACH PEER UTILITY'S PERPETUITY GROWTH RATE?

A. While estimating the current dividend yield is fairly straightforward, estimating the perpetuity dividend-per-share (DPS) growth rate is more subjective. Cost of capital and valuation practitioners commonly use equity analysts' growth rate forecasts as an input to their models. As Witness Morin notes, due to data availability limitations – DPS forecasts are much less common than earnings-per-share (EPS) forecasts – cost of capital practitioners often use forecast EPS growth rates as a proxy for DPS growth.[51] Witness Morin uses EPS growth rate forecasts from two different sources, each with different forecast periods. Value Line provides estimated EPS growth rates over the period 2019-21 through 2025-27, or approximately 3 years from 2023. Zacks provides 3-to-5-year estimates.[52]

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51 Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, p. 28.

52 *See, e.g.*, Duke Energy Carolinas response to NCJC et al. Data Request 1.5; Zacks, *Duke Energy (DUK)*, https://www.zacks.com/stock/quote/DUK.

Q. IS IT REASONABLE TO ASSUME ANALYSTS' 3-TO-5-YEAR GROWTH RATES INTO PERPETUITY IN A DCF MODEL?

A. No. There are several problems with using analysts' estimates for the perpetuity growth rate. A wealth of academic research over decades has found that analyst forecasts tend to be optimistic.[53] Several other observations and analyses demonstrate the unreasonableness of using analysts' 3-to-5-year EPS growth rate estimates for the perpetuity dividend growth rate in the constant-growth DCF model.

1. It is economically impossible for analysts' 3-to-5-year growth forecasts to be sustained into perpetuity.

Q. WHAT IS YOUR FIRST OBSERVATION OR ANALYSIS THAT DEMONSTRATES THE UNREASONABLENESS OF USING ANALYSTS' 3-TO-5-YEAR EPS GROWTH RATE ESTIMATES FOR THE PERPETUITY DIVIDEND GROWTH RATE IN THE CG DCF?

A. It is economically impossible for analysts' 3-to-5-year earnings growth forecasts to be sustained even for one decade, much less into perpetuity. Figure 8 compares the forecast aggregate earnings of the S&P 1500[54] to forecast U.S. GDP.[55] Currently, these companies' combined earnings are

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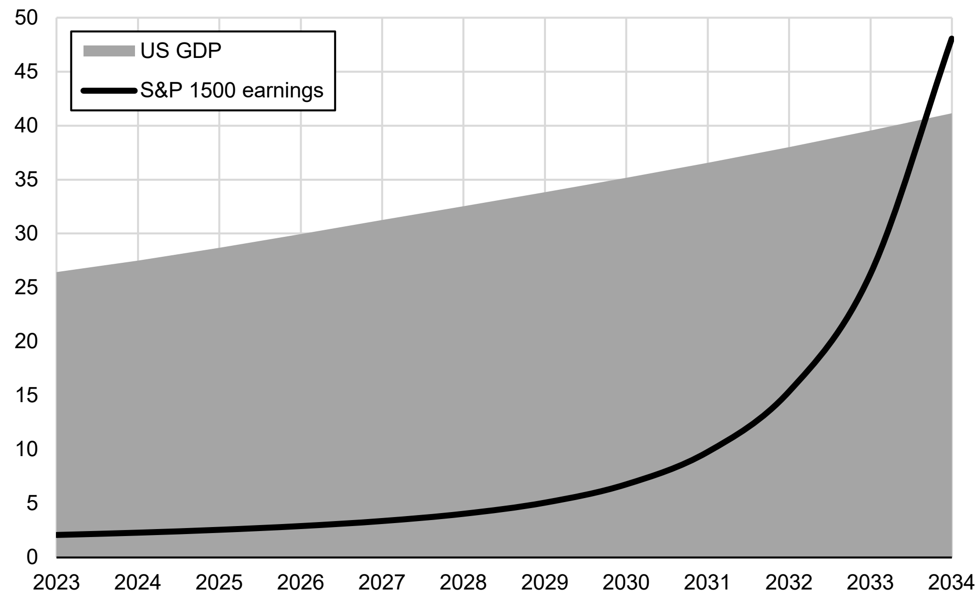
[53] *See, e.g.,* Marc Goedhart, Rishi Raj, Abjishek Saxena, *Equity analysts: Still too bullish*, McKinsey Quarterly (Apr. 2010), https://www.mckinsey.com/business-functions/strategy-and-corporate-finance/our-insights/equity-analysts-still-too-bullish. For a more recent example, *see also* Stefano Cassella, Benjamin Golez, Huseyin Gulen, Peter Kelly, *Horizon Bias and the Term Structure of Equity Returns* (Nov. 2021), https://ssrn.com/abstract=3328970.

[54] M. Ellis analysis of S&P GMI data (last visited Jul. 3, 2023). Excludes companies for which analyst growth forecasts are unavailable or with growth rates less than -100%.

[55] GDP forecast is average of Congressional Budget Office, *The 2023 Long-Term Budget Outlook* (Jun. 2023), https://www.cbo.gov/system/files/2023-06/57054-2023-06-LTBO-econ.xlsx; U.S. Energy Information Administration, *Annual Energy Outlook 2023 Macroeconomic Indicators* Table 20 (Mar. 2023), https://www.eia.gov/outlooks/aeo/excel/aeotab20.xlsx; U.S. Social Security Administration, *The 2023 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds* Supplemental Single-Year Tables (Mar. 2023), https://www.ssa.gov/OACT/TR/2023/SingleYearTRTables_TR2023.xlsx.

equal to roughly 8% of U.S. GDP. Yet if analysts' growth projections were correct, they would exceed total U.S. GDP by the middle of the next decade.

Figure 8. U.S. stock market forecast earnings vs. forecast GDP
$ trillion



The Research Foundation of CFA Institute has made a similar critique of projecting analysts' estimates beyond their forecast horizon:[56]

> [C]onsensus long-term earnings growth estimates routinely exceed sustainable GDP growth. The current consensus growth rate for earnings on the S&P 500, according to the Zacks Investment Research survey, is 10 percent, which, if we assume a consensus inflation expectation of 2-3 percent, corresponds to 7-8 percent real growth. Real earnings growth of 8 percent is six times the real earnings growth of the past century, however, and three times the consensus long-term GDP growth rate. This growth is not possible.

[56] Robert D. Arnott, *Equity Risk Premium Myths,* Rethinking the Equity Risk Premium, Research Foundation of CFA Institute at 97 (P. Brett Hammond, Jr., et al. eds. 2011), https://www.cfainstitute.org/-/media/documents/book/rf-publication/2011/rf-v2011-n4-full-pdf.pdf.

Witness Morin himself has acknowledged the potential unreasonableness of assuming analyst growth rates into perpetuity in his CG DCF model, explaining in his book *New Regulatory Finance*:[57]

> Although the constant-growth DCF model does have a long history, analysts, practitioners, and academics have come to recognize that it is not applicable in many situations. A multiple-stage DCF model that better mirrors the pattern of future dividend growth is preferable. … *The problem is that . . . from the standpoint of the DCF model that extends into perpetuity, analysts' horizons are too short, typically five years. It is often unrealistic for such growth to continue into perpetuity.* … It is useful to remember that eventually all company growth rates, especially utility services growth rates, converge to a level consistent with the growth rate of the aggregate economy.

As I will explain in Section IV.B below, I use the multi-stage DCF model that Witness Morin himself acknowledges is preferable.

2. Earnings-per-share growth is a poor proxy for dividend growth over analysts' 3-to-5-year forecast period.

Q. WHAT IS YOUR SECOND OBSERVATION OR ANALYSIS THAT DEMONSTRATES THE UNREASONABLENESS OF USING ANALYSTS' 3-TO-5-YEAR EPS GROWTH RATE ESTIMATES FOR THE PERPETUITY DIVIDEND GROWTH RATE IN THE CG DCF?

A. EPS and DPS do tend to have similar growth rates over extended, multi-decade periods of time because, as Witness Morin states, "it is growth in earnings that will support future dividends."[58] Nonetheless, both forecast and historical data reveal that EPS growth is a poor proxy for DPS growth over the 3-to-5-year horizon of analysts' EPS forecasts.

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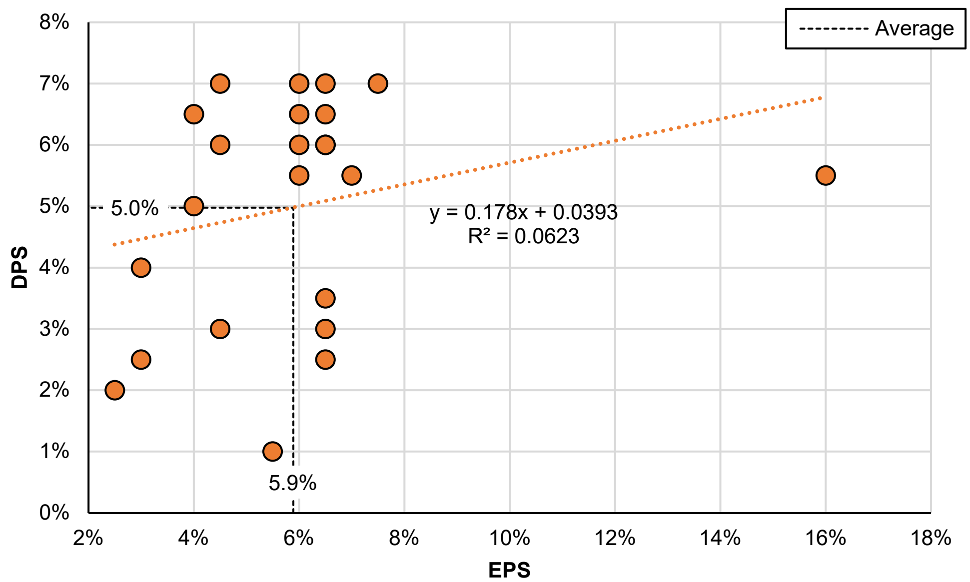
[57] New Regulatory Finance at 308 (emphasis added).
[58] Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, p. 28.

Few analysts provide both DPS and EPS projections, but Value Line, one source of Witness Morin's growth estimates, does provide both EPS and DPS growth forecasts, and they vary considerably. Figure 9 compares Value Line's forecast EPS and DPS growth rates for the members of Witness Morin's proxy group, with each orange dot showing the DPS and EPS for each of the companies in the proxy group. On average, the DPS growth rate is lower, 5.0% vs 5.9% for EPS; EPS overestimates expected dividend growth, introducing upward bias into Witness Morin's DCF results. More importantly, as shown in Figure 9, a cross-plot of Value Line's EPS and DPS growth rate estimates, the correlation between the two sets of numbers is low (R^2 coefficient of 0.06); EPS explains only 6% of the variation in DPS growth rates.

As Witness Morin acknowledges, "[t]he standard [i.e., constant-growth] DCF model would be incorrectly specified when the investors' intermediate term [i.e., 3-to-5-year] EPS growth rate differs from the long-term sustainable EPS growth rate." Value Line's DPS growth estimates are as readily available to Witness Morin as their DPS rates, yet he appears to make no attempt to assess whether EPS growth is, in fact, a viable proxy for DPS growth.

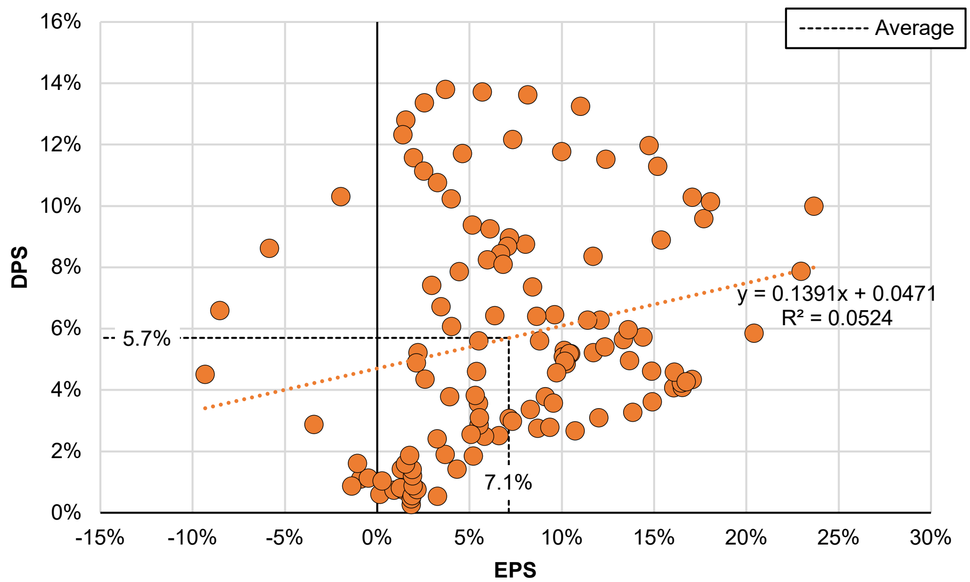
Figure 9. Value Line forecast EPS and DPS forecast growth rates[59]



Historically, the variation between EPS and DPS 3-to-5-year growth rates is even greater. Figure 10 compares historical 5-year EPS and DPS growth rates for the S&P 500 from the first quarter (Q1) of 1988 through Q1 of 2023. Historically, average EPS growth has also been greater than DPS, 7.1% vs. 5.7%, and the correlation between EPS and DPS is even lower than for the forecast utility growth rates – R^2 coefficient of just 0.05.

59 M. Ellis analysis of data provided in Duke Energy Carolinas response to NCJC et al. Data Request 1.5.

Figure 10. Historical S&P 500 EPS and DPS 5-year growth rates[60]
Q1 1988-Q1 2023



In both the historical and projected data, the average 3-to-5-year growth rate for EPS is higher than for DPS, seemingly contradicting Witness Morin's assumption that EPS growth rate estimates are a reasonable proxy for forecast DPS growth. But EPS and DPS do, in fact, grow at roughly the same *compound* rate over the *long term*.[61] Nonetheless, analysts' 3-to-5-year forecast horizons are not long-term, and simply because earnings are more volatile than dividends, the figure reported for EPS growth over analysts' 3-to-5-year forecast period will tend to be higher than DPS, as both the

60 M. Ellis analysis of data from S&P Dow Jones Indices, *S&P 500 Earning and Estimate Report*, (last visited Jun. 30, 2023).

61 "Compound" refers to the single, constant growth rate at which an initial value would need to grow to reach a final value. Importantly, the initial value could follow any number of different growth paths to achieve the same compound growth rate. EPS and DPS can have the same compound growth rate over an extended, multi-decade period, but have very different growth rates over the intervening 5-year periods.

historical growth rates in Figure 10 and the forecast growth rates in Figure 9 demonstrate.

This is due to the mathematical relationship between compound, or *geometric*, and *arithmetic* average growth rates.[62] An illustrative example demonstrates the principle. Suppose both EPS and DPS grow at a compound average growth rate (CAGR) of 5% over 25 years, but they take different paths to get there. DPS grows at the same 5% every year, or 27.6% over each 5-year period. Annual EPS growth varies between -5% and +15% over each 5-year period, say 15% in the first 5 years, followed by -5%, 0%, 6%, and 10% over the next four 5-year periods. The average of the DPS growth rates over each of the 5-year periods is 5.0%, but the average of the EPS growth rates is 5.2%. The effect is relatively small, but it is another source of upward bias introduced by using EPS growth rates as a proxy for DPS growth.

For the two reasons observed in both forecast and historical data – overestimation on average and low correlation – EPS is a poor proxy for DPS, and it is inappropriate to assume that analysts' relatively short-term EPS growth estimates reasonably reflect investors' DPS growth expectations into perpetuity.

62 *See, e.g.,* Madhuri Thakur, *Difference Between Geometric vs. Arithmetic Mean*, Educba (Jun. 29, 2023), https://www.educba.com/geometric-mean-vs-arithmetic-mean/.

3. Analysts' EPS forecast horizons are likely not compatible with the CG DCF's forecast horizon.

Q. WHAT IS YOUR THIRD OBSERVATION OR ANALYSIS THAT DEMONSTRATES THE UNREASONABLENESS OF USING ANALYSTS' 3-TO-5-YEAR EPS GROWTH RATE ESTIMATES FOR THE PERPETUITY DIVIDEND GROWTH RATE IN THE CG DCF?

A. EPS growth rate horizons are likely not compatible with the CG DCF's forecast horizon. The starting time periods of analysts' estimates are not specified with precision. S&P explains of its estimates:[63]

> Long Term Growth Rate (LTG) is a compound annual growth rate based on current and projected EPS values provided directly by the analysts. … Most analysts define LTG as an estimated average rate of earnings growth for the next 3-5 years. The exact time frame differs from broker to broker. Since the analysts providing LTG may differ from the analysts providing fiscal year estimates and the variation in time periods of 3-5 years, it is not possible to reconcile LTG with fiscal year estimates.

The starting points for Yahoo! Finance's estimates are similarly unknown:[64]

> [A]s most analysts do not provide the basis of the calculation of their growth rates, the estimates collected are assumed to include a combination of past and future years with at least one future period included and are calculated on a compounded annual growth rate (CAGR) basis.

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63 *See* YCharts Financial Glossary, *Long Term Growth Rate*, https://ycharts.com/glossary/terms/eps_est_long_term_growth (last visited Jul. 14, 2023) (reporting estimates provided by S&P).

64 *See* Stockopedia Financial Ratio Glossary, *Long Term Growth Forecast*, https://www.stockopedia.com/ratios/long-term-growth-forecast-5107/ (last visited Jul. 14, 2023) (referring to Reuters, now Refinitiv, the source of Yahoo! Finance's estimates); Yahoo!, *Exchanges and data providers on Yahoo Finance*, https://help.yahoo.com/kb/finance-for-web/SLN2310.html (last visited Jul. 14, 2023).

Zacks does not provide any information on its EPS growth rate forecast horizon.

Value Line *does* specify the starting point and forecast horizon of its estimates. Nonetheless, Value Line's growth rate forecast horizons are virtually certain not to be consistent with the dividend yield used in the CG DCF, i.e., the end of the last trading day of the share price averaging period. The starting period for the Value Line growth estimates used by Witness Morin, for example, is '19-'21, the midpoint of which, June 2020, is almost three years before the first dividend payment in his DCF model.[65]

EPS can vary significantly from one year to the next, typically much more than the annual variation in DPS. Without knowing the forecast period, it is not possible to determine whether the estimate reflects the growth rate over the three to five years, much less the rate into perpetuity, from the starting point of the CG DCF. Following a year of poor performance, for example, expected growth would be elevated, potentially significantly above what could be sustained long-term.

4. Expected returns produced by a CG DCF model assuming DPS grows into perpetuity at analysts' 3-to-5-year EPS growth rates are inconsistent with analysts' own expected return forecasts.

Q. WHAT IS YOUR FOURTH OBSERVATION OR ANALYSIS THAT DEMONSTRATES THE UNREASONABLENESS OF USING ANALYSTS'

[65] Witness Morin uses Value Line's dividend yield, which are as of September, October, or November 2022. The CG DCF assumes annual dividend payments start one year later, or the corresponding months in 2023.

3-TO-5-YEAR EPS GROWTH RATE ESTIMATES FOR THE PERPETUITY DIVIDEND GROWTH RATE IN THE CG DCF?

A. The expected returns produced by a CG DCF model assuming DPS grows into perpetuity at analysts' 3-to-5-year EPS growth rates are inconsistent with analysts' own expected return forecasts.

In addition to their EPS and DPS growth rates, Value Line publishes a variety of other forecasts, including for share prices.[66] These forecasts can be used to estimate Value Line's own expected return for each company, which can be compared to the CG DCF results using Value Line's dividend yield and EPS growth rate forecasts in Witness Morin's model.[67] Figure 11 compares the results of the two models. The horizontal axis is the COE estimated using Witness Morin CG DCF and Value Line's yield and EPS growth rate assumptions; the vertical axis is COE implied by Value Line's own dividend and price forecasts.

On average, the CG DCF cost of equity (COE) estimates (9.5%) are significantly higher than the COE implied by Value Line's price and dividend forecast (8.0%). More importantly, the correlation between the two sets of model results is low (R^2 = 0.26). A CG DCF COE based on Value Line's dividend yield and EPS growth bears little resemblance to the COE implied

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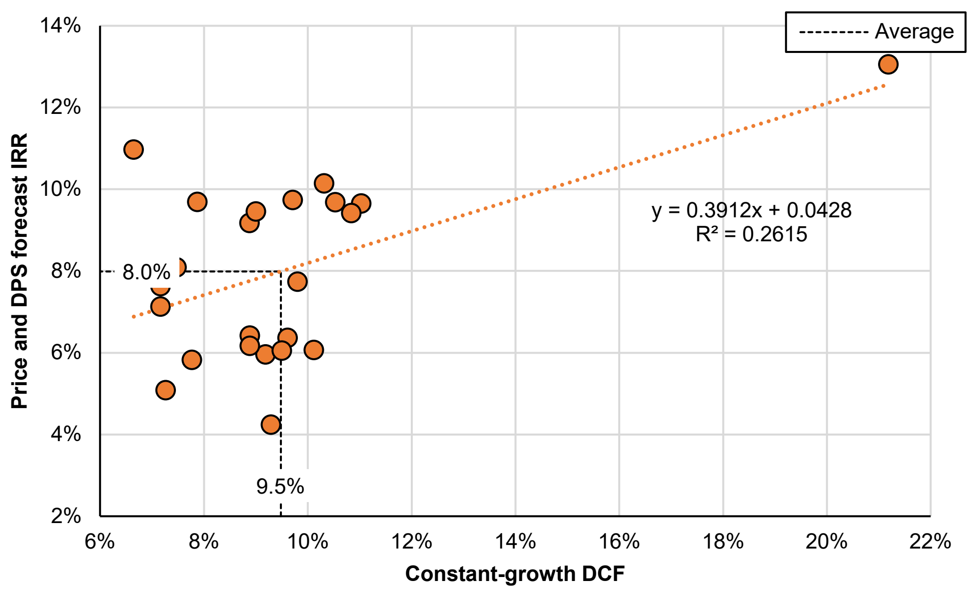
66 Value Line reports do not include actual share price forecasts, but EPS and price-earnings multiple (P/E) forecasts. Price can be calculated by multiplying these two figures: P = EPS x P/E. *See* Duke Energy Carolinas response to NCJC et al. Data Request 1.5 (Value Line reports for each member of Witness Morin's proxy group).

67 A simple DCF model can be constructed from Value Line's most recent annual average price (investment), dividend forecast (with missing years interpolated assuming a constant growth rate), and '25-'27 price forecast (exit value). The COE is the internal rate of return (IRR) of this cash flow stream.

in its own dividend and price forecast. The analysts that provide 3-to-5-year EPS growth forecasts clearly do not assume those rates apply to dividends or will be sustained into perpetuity, as Witness Morin does. For Witness Morin's proxy group, Value Line assumes DPS will grow more slowly, on average, than EPS beyond its forecast horizon.

Figure 11. COE based on Value Line CG DCF and price and DPS forecast IRR[68]



5. Analyst earnings (and, by assumption, dividend) growth forecasts tend to be significantly higher than utilities' long-term historical growth rates.

Q. WHAT IS YOUR FIFTH OBSERVATION OR ANALYSIS THAT DEMONSTRATES THE UNREASONABLENESS OF USING ANALYSTS'

68 M. Ellis analysis of data provided in Duke Energy Carolinas response to NCJC et al. Data Request 1.5 (Value Line reports for each member of Witness Morin's proxy group).

3-TO-5-YEAR EPS GROWTH RATE ESTIMATES FOR THE PERPETUITY DIVIDEND GROWTH RATE IN THE CG DCF?

A. Analyst earnings (and, by assumption, dividend) growth forecasts tend to be significantly higher than utilities' long-term historical growth rates, additional evidence that analysts' 3-to-5-year growth forecasts are not sustainable into perpetuity and are therefore unreasonable assumptions in a CG DCF model.

Figure 12 compares Witness Morin's proxy group average growth forecasts to their historical 30-year (10/1992-10/2022) DPS compound annual growth rates (CAGR). On average, forecast rates are approximately 3.5% higher, in both nominal (as reported) and real (inflation-adjusted) terms, than the historical average. The ~3.5% difference between historical and forecast growth highlights the unreasonableness of assuming analysts' estimates into perpetuity.[69]

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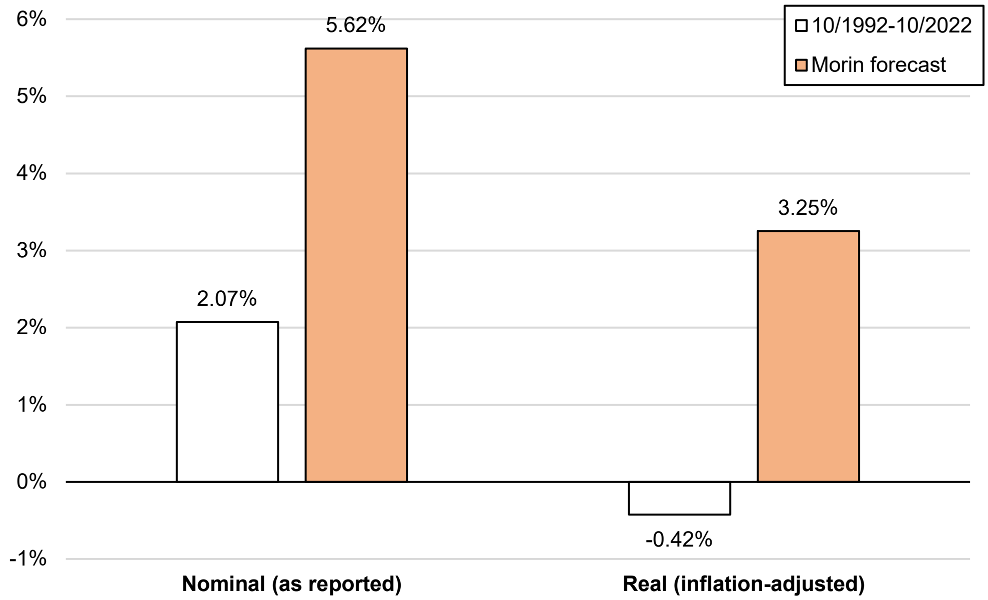
[69] Forecast growth rates are adjusted by the monthly average Treasury-TIPS spread for October 2022, 2.33%, to correspond with the inflation forecast for the most recent full month prior to the date of Witness Morin's EPS growth forecasts.

Figure 12. Historical and Morin forecast proxy group average dividend per share annualized growth rates[70]
October 1992-October 2022



6. Witness Morin's flawed DCF results should be disregarded.

Q. WHAT IS YOUR CONCLUSION REGARDING WITNESS MORIN'S RESULTS?

A. Witness Morin's DCF model results should be disregarded completely. While, in principle, a constant-growth DCF model could be used to estimate the cost of equity, Witness Morin's implementation is deeply flawed. Witness Morin's DCF unrealistically assumes analysts' earnings per share (EPS) growth estimates are valid for forecasting dividends into perpetuity. Several analyses demonstrate the invalidity of this assumption: the economic impossibility of sustaining EPS growth forecasts even for one decade, much less into

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70 M. Ellis analysis of S&P GMI (last visited Feb. 23, 2023); U.S. Bureau of Labor Statistics data [hereinafter "BLS"] (last visited Feb. 23, 2023); Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, Exhibits 3 and 4.

perpetuity; the low correlation between analysts' EPS and DPS growth forecasts; the unknown starting period for analyst growth forecasts and therefore likely inconsistency with the DCF model's starting period; the inconsistency between the CG DCF results and analysts' own implied expected return estimates; and the wide disparity between analyst forecasts and utilities' long-term historical DPS growth rates.

B. <u>The multi-stage DCF should be used instead of the CG DCF because it allows for more realistic cash flow projections, yielding more accurate results.</u>

1. The multi-stage DCF model enhances the CG DCF by allowing different dividend growth rates over time.

Q. WHAT IS THE MULTI-STAGE DCF MODEL?

A. The multi-stage DCF model (MS DCF) enhances the CG DCF by allowing different dividend growth rates over time. As we saw previously, analysts' estimated 3-to-5-year growth rates are too high to be sustained in perpetuity, and may be biased. But analyst estimates should not be ignored completely. Analysts' estimated 3-to-5 year growth rates provide useful information about the relative expected growth across companies. Over the long term though, it is reasonable to assume investors expect growth rates, in real terms, to revert to their long-term historical trends. The MS DCF explicitly models different growth rates over time.

The MS DCF can incorporate any number of stages. For equity valuation, a three-stage model is commonly used, in which the initial stage uses analysts' estimates over their 3-to-5-year forecast horizon, and the terminal stage uses the long-term real historical growth rate plus current long-term inflation expectations. In between lies a transition phase, typically 5 to 15 years, in which the growth rate is the simple average of the initial and terminal rates. The MS DCF model can be expressed as:

$$1 = d\,\frac{1+g_1}{k-g_1}\left(1-\left(\frac{1+g_1}{1+k}\right)^{t_1}\right) + d\left(\frac{1+g_1}{1+k}\right)^{t_1}\frac{1+g_2}{k-g_2}\left(1-\left(\frac{1+g_2}{1+k}\right)^{t_2}\right)$$

$$+d\left(\frac{1+g_1}{1+k}\right)^{t_1}\left(\frac{1+g_2}{1+k}\right)^{t_2}\frac{1+g_3}{k-g_3},$$

where d is the current dividend yield; g_1, g_2, and g_3 are the initial, transition, and terminal growth rates, respectively (where $g_2 = \sqrt{(1+g_1)(1+g_3)} - 1$);[71] t_1 and t_2 are the initial and transition stage durations; and k is the cost of equity such that the equation is true. Substantial precedent exists for the MS DCF model, in both its two- and three-stage forms, in both corporate finance and regulatory contexts.[72]

In my implementation of the MS DCF, I assume an initial growth stage of three years – the low end of analysts' EPS growth rate forecast horizon, to mitigate the effect of their upward bias – and a 10-year transition. To account for the quarterly distribution of dividends, I convert the reported rates to quarterly and multiply the number of periods in the initial and transition

[71] The geometric mean of g_1 and g_3 is used to ensure consistency between annual and quarterly versions of the model.

[72] *See, e.g.*, Richard Brealey, Stewart Myers, and Franklin Allen, *Principles of Corporate Finance*, McGraw Hill/Irwin at 83-88 (10th ed. 2010); Surface Transportation Board, *Use of a multi-stage discounted cash flow model in determining the railroad industry's cost of capital*, 73 Fed. Reg. 47642, 47642-47644 (2008), https://www.federalregister.gov/documents/2008/08/14/E8-18865/use-of-a-multi-stage-discounted-cash-flow-model-in-determining-the-railroad-industrys-cost-of.

phases by 4.[73] The dividend yield is the most recent quarterly dividend divided by the average price over January 2023.

Q. HOW DO YOU ESTIMATE THE DIVIDEND YIELD FOR THE MS DCF?

A. In estimating the dividend yield, it is advisable to use a multi-day average of the share price to reduce the effect of any day-to-day price fluctuations that may not be reflective of investors' long-term expectations. Averaging the most recent month of data, approximately 21 trading days, better balances the competing objectives of mitigating the potential short-term volatility cited by Witness Morin and reflecting current investor expectations.

2. The MS DCF's initial growth rate can be estimated from analysts' EPS growth forecasts.

Q. GIVEN THE NUMEROUS SHORTCOMINGS OF ANALYSTS' FORECASTS, SHOULD THEY BE USED AT ALL IN DCF MODELS?

A. Discounted cash flow models can be a robust approach to estimating expected returns and are widely used throughout finance. The key shortcoming of the constant-growth version of the DCF model – assuming a relatively short-term growth rate into perpetuity – can be easily remedied by assuming that analysts' estimated growth rates apply only for a limited period, after which they converge toward a market- or sector-average terminal growth rate, as in the MS DCF. Despite the various deficiencies in analysts' estimates even in the short-term, they are viewed as the best available estimates of near-term investor expectations. That said, relatively little weight

73 All rates are converted from annual (r_a) to quarterly (r_q) using the formula: $r_q = (1 + r_a)^{\frac{1}{4}} - 1$.

should be placed on them in estimating the cost of equity, and the MS DCF model can weight them more appropriately.

Q. HOW DO YOU ESTIMATE THE INITIAL GROWTH RATE FOR THE MS DCF?

A. I use an average of analysts' EPS growth forecasts from CNN.com, S&P Global Market Intelligence (S&P GMI), Yahoo! Finance, and Zacks.

3. The MS DCF's terminal growth rate can be estimated from expected inflation, based on utilities' long-term historical dividend growth.

Q. HOW DO YOU ESTIMATE THE TERMINAL GROWTH RATE FOR THE MS DCF?

A. The terminal growth rate is intended to reflect a sector-wide dividend growth rate toward which all stocks in the peer group are expected to converge over the long term. Figure 13 shows real (inflation-adjusted) utility-sector average per-share price and dividend from 1927 through 2022, and book value from 1927 through 2021. While there have been periods of growth and decline, the long-term trend for all three has been in line with inflation for over 90 years. For comparison, for the market as a whole, real per-share book value has increased by 8x, dividend by 6x, and price by 15x over the same periods.[74] Based on this long-term history, the terminal growth rate in the MS DCF for the DEC proxy group is assumed to be equal to long-term inflation.

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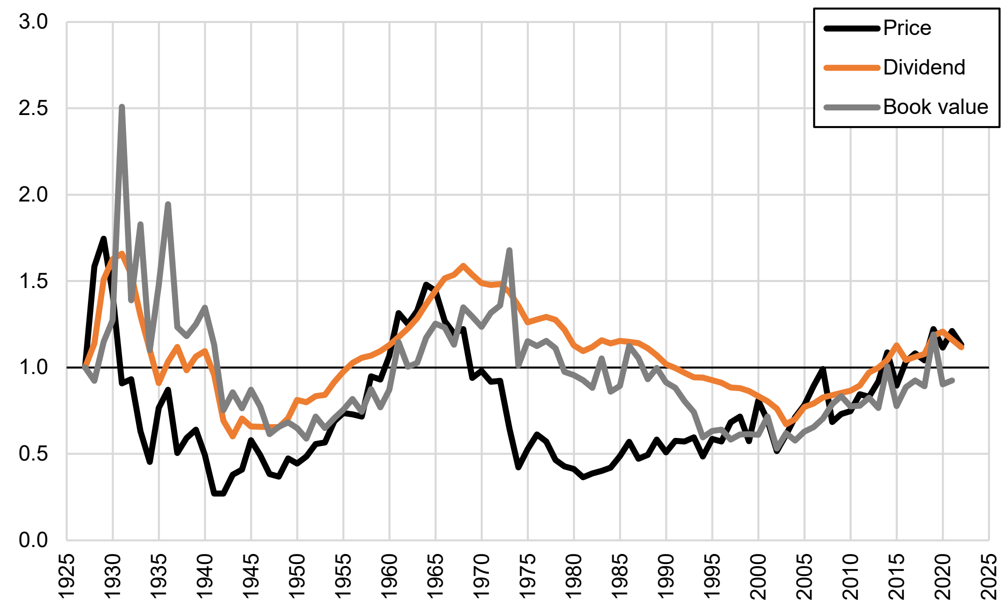
[74] M. Ellis analysis of FDL and BLS data (last visited Mar. 6, 2023).

Figure 13. Utility sector real average per-share price, dividend, and book value[75]
1927=1.0



For the market as a whole, long-term real DPS growth has tracked GDP per capita, about 1.9% per year.[76] At any given time, some sectors grow faster, some slower. The technology and healthcare industries, for example, have sustained DPS growth rates higher than the market average for decades. Utilities are a mature industry, though, and end-use demand for electricity, gas, and water has grown more slowly than GDP for decades, so it is not unreasonable for utility companies' per-share dividend growth to lag the market as whole. The long-term track record of essentially zero real dividend growth further highlights the unreasonableness of Witness Morin's assumption that analyst growth forecasts can be sustained into perpetuity.

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[75] *Id.*

[76] *See, e.g.*, Roger Ibbotson & James Harrington, *Stocks, Bonds, Bills, and Inflation 2021 Summary Edition*, CFA Institute Research Foundation Books at 157-60 (2021) (analysis is for total payout to account for the effect of net stock repurchases).

Q. HOW DO YOU ESTIMATE EXPECTED LONG-TERM INFLATION?

A. For expected long-term inflation, I use Treasury-TIPS spreads. TIPS are Treasury Inflation-Protected Securities, which provide investors a return equivalent to inflation plus the quoted TIPS yield. The difference in yield between Treasurys and TIPS of equal maturity is a current measure of the market's forward-looking inflation expectation over the life of the bonds.

The MS DCF uses inflation for the terminal, not initial or transition, growth rate, so inflation into perpetuity is estimated at the end of the transition phase, not from today. I use the expected inflation, i_{lt}, rate over the period from 20 to 30 years from now, as implied by the difference in the 30-year and 20-year Treasury-TIPS spreads:

$$i_{lt} = \left(\frac{(1+i_{30})^{30}}{(1+i_{20})^{20}}\right)^{\frac{1}{10}} - 1.$$

Using average Treasury yields for the month of June 2023, the long-term inflation estimate is 1.70%.[77]

4. The MS DCF produces COE estimates substantially lower than Witness Morin's CG DCF.

Q. WHAT ARE YOUR MS DCF COE RESULTS?

A. Figure 14 summarizes the MS DCF results for the DEC proxy group. The average COE for the DEC proxy group is 6.63% – substantially lower than Witness Morin's corresponding CG DCF average 9.3%[78] and, as expected,

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[77] M. Ellis analysis of FRED data (last visited Jul. 4, 2023).

[78] Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, p. 5.

slightly higher than the B/M x ROE rule of thumb, 6%, described in Section II.B.2 above.

Figure 14. DEC proxy group multi-stage discounted cash flow COE[79]
As of June 2023

				Initial growth rate (%)					
Utility	**Price**	**DPS**	**Yield (%)**	CNN	S&P GMI	Yahoo!	Zacks	Average	**COE (%)**
Alliant	52.72	1.81	3.43	6.48	6.18	6.20	6.47	6.33	6.44
Ameren	82.38	2.52	3.06	5.85	6.97	5.90	6.43	6.29	5.93
AEP	83.86	3.32	3.96	5.22	5.88	5.20	5.61	5.48	6.87
Avista	40.31	1.84	4.56	5.00	5.26	6.30	6.35	5.73	7.72
Black Hills	61.63	2.50	4.06	5.10	3.65	5.40	2.20	4.09	6.57
CenterPoint	28.95	0.76	2.63	7.83	6.71	-1.07	7.41	5.22	5.11
CMS	59.62	1.95	3.27	7.75	7.76	7.50	7.50	7.63	6.58
Dominion	52.19	2.67	5.12	-1.77	0.09	9.00	20.00	6.83	8.83
DTE	111.11	3.81	3.43	6.75	6.30	7.40	6.00	6.61	6.51
Edison	68.31	2.95	4.32	5.41	5.24	4.57	3.83	4.76	7.09
Entergy	99.54	4.28	4.30	6.35	6.78	6.60	5.69	6.36	7.58
Evergy	58.65	2.45	4.18	4.74	5.32	2.67	5.22	4.49	6.83
Eversource	70.53	2.70	3.83	6.00	6.30	6.70	6.34	6.34	6.96
FirstEnergy	38.63	1.56	4.04	5.88	2.54	6.76	6.45	5.41	6.94
IDACORP	104.19	3.16	3.03	4.84	4.64	3.70	3.68	4.22	5.38
NorthWestern	57.84	2.56	4.43	5.00	5.17	4.50	6.76	5.36	7.42
OGE	36.07	1.66	4.59	0.31	1.03	-12.34	17.89	1.72	6.46
Otter Tail	75.89	1.75	2.31	6.75	6.75	9.00	NA	7.50	5.17
Portland General	48.29	1.90	3.93	6.40	6.22	5.90	5.90	6.11	7.03
Sempra	146.47	4.76	3.25	3.00	5.43	4.14	4.80	4.34	5.67
Southern	70.49	2.80	3.97	4.50	5.80	7.30	4.00	5.40	6.86
WEC	89.07	3.12	3.50	6.25	6.27	5.50	5.76	5.95	6.42
Xcel	63.06	2.08	3.30	6.60	5.97	6.10	6.30	6.24	6.23
Mean	**69.56**	**2.56**	**3.76**	**5.23**	**5.32**	**4.91**	**6.85**	**5.58**	**6.63**
Duke	*90.57*	*4.02*	*4.44*	*6.24*	*5.78*	*5.74*	*6.12*	*5.97*	*7.64*

Q. DO YOU USE THE MS DCF ELSEWHERE IN YOUR ANALYSIS?

A. Yes. I use it as one of two methods to estimate the market risk premium for the CAPM.

[79] Cnn.com, https://www.cnn.com/business (last visited Jun. 30, 2023); S&P GMI (last visited Jun. 30, 2023); Yahoo! Finance, https://finance.yahoo.com/ (last visited Jun. 30, 2023); Zacks, https://www.zacks.com/ (last visited Jun. 30, 2023).

V. WITNESS MORIN'S CAPITAL ASSET PRICING MODEL USES UNREALISTIC, UPWARDLY BIASED ASSUMPTIONS FOR ALL THREE INPUTS.

Q. WHAT IS THE CAPITAL ASSET PRICING MODEL?

A. Witness Morin's analysis incorporates another well-known cost of equity model, the capital asset pricing model (CAPM). It estimates the cost of equity, k, from the formula:

$$k = r_f + \beta(r_m - r_f),$$

where r_f is the risk-free rate (typically a long-term U.S. Treasury), r_m is the expected return on the market, and β is a measure of risk of the company in question relative to the market. The market risk premium (MRP), the difference between the market return and the risk-free rate, $r_m - r_f$, reflects the additional return investors require as compensation for taking on equity market risk. The CAPM is a simple model of the fundamental financial risk-reward trade-off: investors demand higher returns as risk increases.

A. <u>Witness Morin's risk-free rate forecast has two sources of upward bias.</u>

Q. WHAT RISK-FREE RATE DOES WITNESS MORIN USE IN HIS CAPM?

A. Witness Morin uses the 30-year Treasury (T30). Because the models estimate the expected return on equity, which is a claim on cash flows into perpetuity, the longest-term rate available should be used. The 30-year Treasury is the longest-term risk-free rate, so the T30 is an appropriate term. Witness Morin calculates his CAPM COE estimates using forecast Treasury rates.

Q. DO YOU HAVE ANY CONCERNS WITH WITNESS MORIN'S RISK-FREE RATE ESTIMATE?

A. Yes. Witness Morin uses a forecast rate, not the current rate. Using a forecast rate raises several problems.

First, using a forecast rate creates inconsistencies with the time horizon of the DCF, which is estimated as of today (or, more precisely, as of the end of the trailing price averaging period). The mathematical formula for the present value of a periodic time series upon which the DCF is based discounts the stream of future cash flows to a "time zero" one period before the first payment. The resulting discount rate is as of that time zero. The first payment in the DCF model is typically assumed to occur one time step from today; therefore, the rate determined by the DCF model is as of today. Using an interest rate expected at some future date in the CAPM produces a COE as of that future date, not today, and that COE is not directly comparable to the DCF's COE.

Ignoring the consistency concern, even if we did want to use a forecast rate, in general, commonly available interest rate forecasts are no better predictors of future interest rates than the current market rate, as Witness Morin has acknowledged in *New Regulatory Finance*:[80]

> The [academic] literature suggests that on balance, the bond market is very efficient in that it is difficult to consistently forecast interest rates with greater accuracy than a no-change [from the current interest rate] model."

[80] New Regulatory Finance at 172.

Most critically, though, I am particularly concerned about Witness Morin's chosen methodology for estimating the forecast 30-year Treasury rate, in which he adds 50 basis points to the November 2022 Blue Chip Economic Indicators (BCEI) forecast for the 10-year Treasury in 2023.[81] BCEI's 10-year Treasury forecast has an exceptionally poor track record, and Witness Morin's 50-basis point adjustment is not warranted by current market conditions.

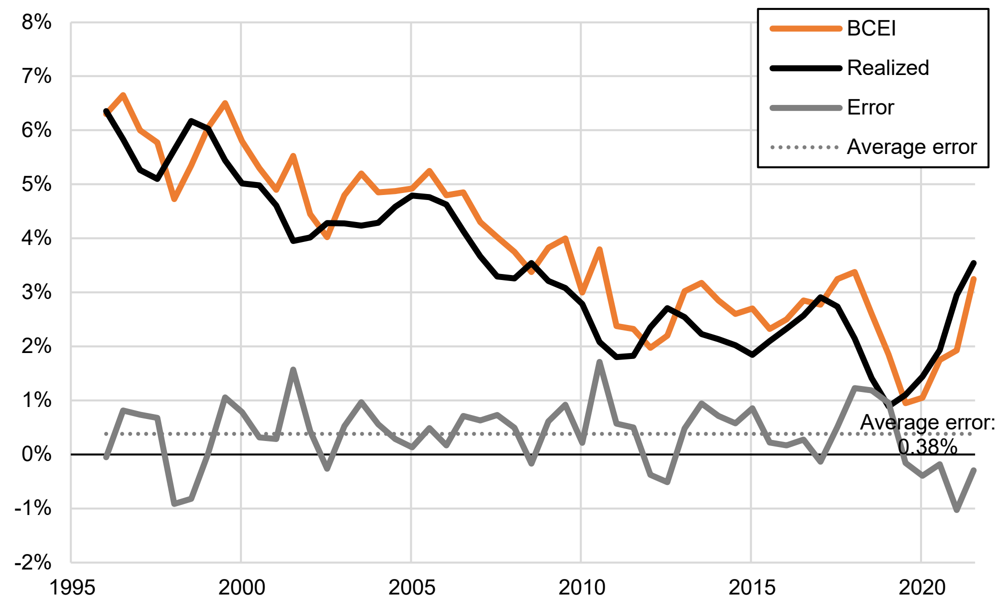
1. Witness Morin's selected forecast source, Blue Chip Economic Indicators, has a decades-long track record of upwardly biased interest rate forecasts.

Q. HOW ACCURATE HAS THE BLUE CHIP ECONOMIC INDICATORS 10-YEAR TREASURY FORECAST BEEN HISTORICALLY?

A. BCEI has a multi-decade track record of producing systematically upwardly-biased forecasts, and the errors have only increased over time. Figure 15 compares the BCEI next-year forecast used by Witness Morin to the corresponding next-four-quarter average realized rate, going back to December 1996. BCEI's 10-year Treasury forecast has consistently overestimated the future rate, by approximately 0.38%.

[81] Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, p. 35-36.

Figure 15. BCEI next-year 10-year Treasury forecast vs. realized rate[82]



2. Witness Morin's arguments for using a forecast risk-free rate do not withstand scrutiny.

Q. HOW DOES WITNESS MORIN JUSTIFY HIS USE OF FORECASTS WITH SUCH A POOR TRACK RECORD?

A. Witness Morin gives four reasons for using forecast Treasury rates. None of them supports his use of the BCEI forecast.

Witness Morin's first and second reasons are that "investors price securities on the basis of long-term expectations, including interest rates," and "investors' required returns can and do shift over time with changes in capital market conditions, hence the importance of considering interest rate forecasts."[83] It is certainly true that investors price securities based on their expectations, and those expectations, and therefore investors' required

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[82] M. Ellis analysis of FRED (last visited Jul. 4, 2023); M. Ellis analysis of Blue Chip Economic Indicators data [hereinafter "BCEI"].

[83] Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, p. 39.

returns, change over time. But the truth of these statements by no means requires or even implies that investors rely on third-party forecasts in general, or the BCEI forecast specifically, in doing so. As Witness Morin has acknowledged, "on balance, the bond market is very efficient in that it is difficult to consistently forecast interest rates with greater accuracy than a no-change [from the current interest rate] model."[84]

Witness Morin proceeds to assert that BCEI's forecast "reflects the expectations of actual investors in the market."[85] BCEI may be relied upon by *some* investors, but there is no basis for assuming that BCEI forecasts represent a reasonable proxy for investor expectations. BCEI has no more than a hundred thousand subscribers,[86] less than 0.1% of the hundreds of millions of investors who are exposed to Treasury rates through direct investments or as a benchmark for other investments.[87] Although utility cost of capital experts routinely argue that these forecasts represent the "market's view," 0.1% in no way represents the market. The hundreds of millions of market participants respond to all kinds of information, and the small slice of

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84 New Regulatory Finance at 172.

85 Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, p. 39.

86 In the 2020 annual report of Wolters Kluwer, BCEI's owner, $905 million of revenue was attributed to the Legal & Regulatory segment, of which BCEI is just 1 of 99 offerings. *See* Wolters Kluwer, *Legal Solutions*, https://www.wolterskluwer.com/en/legal/our-solutions. BCEI costs approximately $2,500/year. Even assuming BCEI accounts for 10% of segment revenue – roughly ten times the segment average – BCEI has no more than 40,000 subscribers.

87 More than half of U.S. adults and households are invested in the stock market. *See, e.g.*, Kim Parker & Richard Fry, *More than half of U.S. households have some investment in the stock market*, Pew Research Center, Mar. 25, 2020, https://www.pewresearch.org/fact-tank/2020/03/25/more-than-half-of-u-s-households-have-some-investment-in-the-stock-market/; Lydia Saad and Jeffrey Jones, *What Percentage of Americans Owns Stock*, Gallup, May 12, 2022, https://news.gallup.com/poll/266807/percentage-americans-owns-stock.aspx.

the market used by Witness Morin, via BCEI, does not represent an adequate or reasonably proxy.

Q. WHAT IS WITNESS MORIN'S THIRD REASON FOR USING THE BCEI FORECAST INTEREST RATE?

A. Witness Morin's third reason is "the fact that investors are willing to purchase such expensive services confirm [*sic*] the importance of economic/financial forecasts in the minds of investors."[88]

Witness Morin's "willing to purchase" argument implicitly assumes that investors rely *only* on BCEI forecasts, to the exclusion of all other ways that investors might develop their expectations; that they rely on BCEI's forecasts as-is, with no adjustment for their historical inaccuracy; and that investors' only use of the forecasts is for investment decisions. None of Witness Morin's assumptions is true. The consistent errors in BCEI forecasts are well-known; the Congressional Budget Office has issued public reports on BCEI's interest rate forecasting errors for nearly twenty years.[89] Investors undoubtedly take BCEI's forecasts "with a grain of salt" and inform their decisions with other forecasts and information. Finally, BCEI reports include dozens of other forecasts, as well as commentary and analysis. Investors might "rely" on the reports for that other content, not BCEI's interest rate forecasts, per se.

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88 Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, p. 39.

89 *See, e.g.,* Congressional Budget Office, *CBO's Economic Forecasting Record* at 13, 18 (Nov. 2002), https://www.cbo.gov/sites/default/files/107th-congress-2001-2002/reports/11-07-economicforecast.pdf.

Q. WHAT IS WITNESS MORIN'S FOURTH REASON FOR USING THE BCEI FORECAST INTEREST RATE?

A. Witness Morin's fourth reason is that "the empirical evidence demonstrates that stock prices do indeed reflect prospective financial input data."[90]

During discovery, Witness Morin was asked for any and all "empirical evidence" – whether papers, textbook passages, or other documentation –in support of his assertion that "the empirical evidence demonstrates that stock prices do indeed reflect prospective financial input data" with respect, specifically, to Blue Chip interest rate forecasts. None of the materials provided discussed the use of *any* interest rate forecasts, much less the Blue Chip forecasts specifically.[91]

While it may be true that "the empirical evidence demonstrates that *stock prices* do indeed reflect prospective financial input data," the CAPM requires an *interest rate*, not a stock price, assumption. This non sequitur argument appears to be another red herring; an argument that may be relevant to stock prices tells us nothing about its validity for interest rates.

Q. WHAT IS WITNESS MORIN'S FIFTH REASON FOR USING THE BCEI FORECAST INTEREST RATE?

A. Witness Morin's fifth reason for using the BCEI forecast is, "given that this proceeding is to provide ROE estimates for setting electric rates going forward, forecast interest rates are far more relevant. The use of interest rate

[90] Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, p. 39.
[91] Duke Energy Carolinas response to NCJC et al. Data Request 5.7.

forecasts is no different than the use of projections of other financial variables in DCF analyses."[92]

As explained above, the use of a forecast interest rate in the CAPM is actually *inconsistent* with the assumptions and results of the DCF model, which estimates the discount rate as of *today*, not some time in the future.

But even if we ignore consistency with the DCF, it turns out that current interest rates generally provide an unbiased forecast of future rates. Figure 16 is a cross-plot of the 20-year Treasury rate one year ahead against the current rate. Current interest rates account for approximately 91% of the variation in future interest rates. The current rate is also unbiased – exhibiting no tendency to be systematically too high or too low.[93] Similar predictive validity is obtained for 30-year Treasury and corporate bonds.[94]

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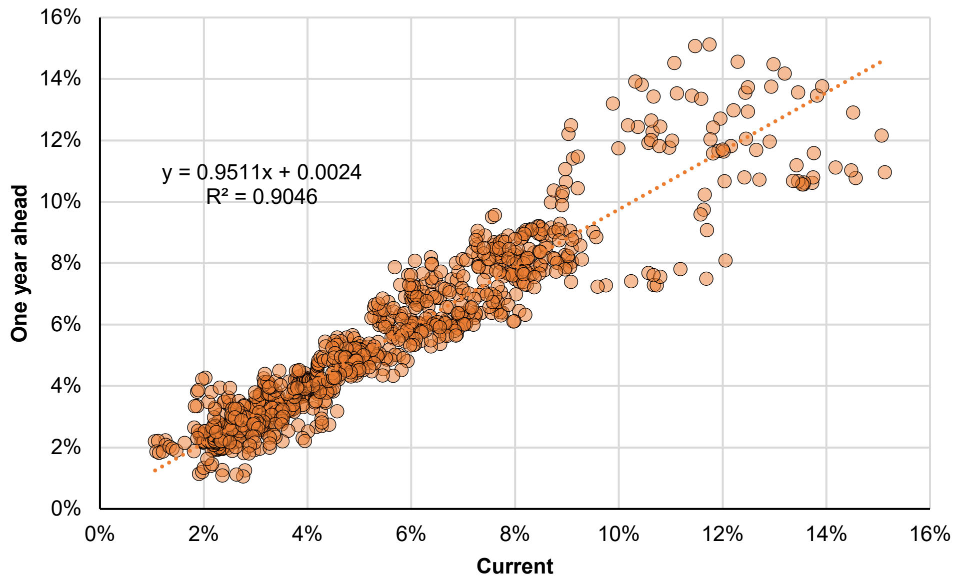
92 Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, p. 40.

93 The bias in a forecast can be assessed from the decomposition of the mean square error into bias, inefficiency, and random variation components. For the 20-year Treasury, bias accounts for less than 0.001% of forecast error. *See, e.g.*, Jacob Mincer and Victor Zarnowitz, *The Evaluation of Economic Forecasts*, Economic Forecasts and Expectations: Analysis of Forecasting Behavior and Performance, Nat'l Bureau of Econ. Rsch. at 3-46 (1969), http://www.nber.org/chapters/c1214.

94 The 20-year Treasury is used here because much more historical data are available.

Figure 16. Twenty-year Treasury rate, one year in the future vs. current[95]
January 1925-**June** 2023



Current rates' high validity in predicting future rates can be explained more intuitively by the market's forward-looking nature. If investors expect interest rates to rise, their expectations will be incorporated into current yields. Consider the alternative. Suppose an investor expects the yield on the 30-year Treasury to rise from its current ~4% to 5% over the next six months. There is an inverse relationship between a bond's value and its yield; when the yield rises, the value falls, and vice versa. An investor who expects bond yields to rise would not buy a bond today, because to do so would be to invest expecting a loss; better not to buy the bond at all. But market participants *do* buy at the current ~4%, implying that the market overall does *not* expect rates to rise in the future. Current yields are the best predictor of future yields, especially for longer-term bonds.

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[95] M. Ellis analysis of FRED data (last visited Jul. 4, 2023).

BCEI's consistently poor track record, the high predictive validity of current interest rates, and economic intuition are consistent with an extensive body of research on the superiority of simple prediction models to both more complex models and expert judgment.[96]

Current interest rates are the most accurate and unbiased publicly available estimates for future interest rates that I am aware of. Conveniently, using the current rate also entirely skirts the potential concern about horizon inconsistency with the DCF.

3. Witness Morin's 50-basis point (0.5%) adjustment to BCEI's 10-year Treasury rate to forecast the 30-year Treasury rate is arbitrary and far exceeds current market conditions.

Q. WHAT IS THE SOURCE OF WITNESS MORINS' 50-BASIS POINT (0.5%) ADJUSTMENT TO THE BCEI 10-YEAR TREASURY FORECAST TO ARRIVE AT HIS 30-YEAR TREASURY FORECAST?

A. The November 2022 BCEI report does not contain a 30-year Treasury forecast. Instead, Witness Morin estimates it by adding 50 basis points (0.5%) to BCEI's 10-year Treasury (T10) rate forecast for 2023. The 0.5% adjustment is based on the average difference between the actual, not forecast, yields of the 30- and 10-year Treasurys from January 2020 through November 2022, 0.49%, rounded to the nearest 0.1%.[97]

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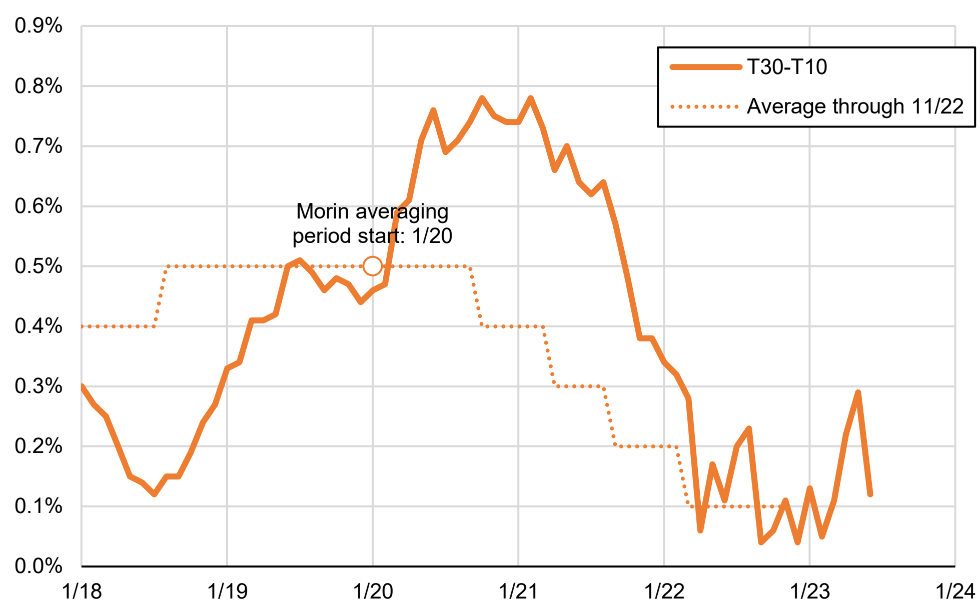
[96] *See, e.g.*, Daniel Kahneman, Olivier Sibony, and Cass Sunstein, *Noise: A Flaw in Human Judgment*, Hachette Book Group at 111-147 (2021).

[97] Duke Energy Carolinas response to NCJC et al. Data Request 3.1.

Q. IS WITNESS MORIN'S 50-BASIS POINT ADJUSTMENT A REASONABLE WAY TO FORECAST THE FUTURE 30-YEAR TREASURY RATE?

A. No, it is not. Witness Morin's 0.5% adjustment is arbitrary and not reflective of current market conditions. The average spread between the 30- and 10-year Treasury rates was 0.11% in November 2022, and 0.12% in June 2023, less than one-quarter of Witness Morin's adjustment.[98] Figure 17 shows the T30-T10 spread and, for each month before November 2022, the average calculated through November 2022 and rounded to the nearest 0.1%, going back to January 2018. Witness Morin has selected a trailing period that maximizes his calculated historical average. Once again, "Watch out for data mining!"

Figure 17. T30-T20 spread[99]
January 2018-June 2023



98 FRED data (last visited Jul. 4, 2023).
99 M. Ellis analysis of FRED data (last visited Jul. 4, 2023).

B. <u>Witness Morin cherry-picks his beta calculation methodology, ignoring the wide variety of valid potential approaches and best practice for choosing among them.</u>

Q. HOW DOES WITNESS MORIN ESTIMATE THE BETA IN HIS CAPM MODEL?

A. Witness Morin uses beta estimates from Value Line.

Q. HOW DOES VALUE LINE ESTIMATE BETA?

A. Value Line estimates beta from the slope of a linear regression model of a stock's returns against the returns of the market overall. "Raw" betas are calculated from a regression of trailing weekly, price-only returns of the stock in question against the corresponding market returns. Value Line reports "Blume-adjusted" betas – a weighted-average of approximately 2/3 of the raw beta and 1/3 of the market average of 1.0 – to correct for an empirically observed tendency for betas, on average, to regress toward the market mean over time that I discuss in more detail below.[100]

1. Value Line's beta estimates are higher than other commonly used data providers' estimates.

Q. IS VALUE LINE'S METHODOLOGY THE ONLY WAY TO ESTIMATE BETA?

A. No. Academic studies commonly use five years of *monthly* returns, without the Blume adjustment. Other financial data providers, including some used by Witness Morin elsewhere in his analysis, calculate beta using different trailing histories, return frequencies, and without the Blume adjustment.

[100] E-mail from Cheryl Dhanraj, Technical Support, Value Line, to Mark Ellis (Oct. 6, 2021), which is attached as Exhibit MEE-4.

Yahoo! Finance and Zacks – sources of data used in Witness Morin's other cost of capital analyses[101] – use five years of monthly returns and are unadjusted, like many academic studies. S&P Global Market Intelligence (S&P GMI), another data source frequently cited by Witness Morin,[102] reports 1- and 3-year betas using daily returns, also without the Blume adjustment.[103]

Figure 18 lists recent betas from S&P GMI, Yahoo! Finance, and Zacks for Witness Morin's DEC proxy group. The average betas are 0.63 and 0.49 for S&P GMI using 1 and 3 years of daily returns, and 0.55 for both Yahoo! Finance and Zacks using 5 years of monthly returns. All four sources' beta estimates are lower than Witness Morin's 0.89 estimate.[104]

[101] Witness Morin uses Value Line and Zacks EPS growth rates in his DCF model. *See* Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, p. 26.
[102] *See, e.g.*, Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, Exhibit 9.
[103] S&P GMI.
[104] Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, Exhibit 5.

Figure 18. S&P GMI, Yahoo! Finance, and Zacks betas[105]
As of June 30, 2023

Utility	Ticker	S&P GMI 1-year daily	S&P GMI 3-year daily	Yahoo! Finance 5-year monthly	Zacks 5-year monthly
Alliant	LNT	0.64	0.46	0.54	0.56
Ameren	AEE	0.63	0.46	0.45	0.44
AEP	AEP	0.64	0.45	0.46	0.46
Avista	AVA	0.58	0.43	0.51	0.51
Black Hills	BKH	0.65	0.54	0.58	0.59
CenterPoint	CNP	0.60	0.60	0.89	0.88
CMS	CMS	0.59	0.42	0.36	0.36
Dominion	D	0.56	0.42	0.46	0.44
DTE	DTE	0.61	0.47	0.60	0.60
Edison	EIX	0.78	0.60	0.83	0.81
Entergy	ETR	0.65	0.52	0.65	0.65
Evergy	EVRG	0.60	0.46	0.50	0.50
Eversource	ES	0.67	0.49	0.49	0.47
FirstEnergy	FE	0.63	0.46	0.44	0.44
IDACORP	IDA	0.60	0.47	0.62	0.62
NorthWestern	NWE	0.49	0.45	0.46	0.44
OGE	OGE	0.65	0.56	0.70	0.73
Otter Tail	OTTR	0.70	0.62	0.51	0.51
Portland General	POR	0.75	0.48	0.60	0.58
Sempra	SRE	0.67	0.58	0.74	0.73
Southern	SO	0.59	0.44	0.51	0.51
WEC	WEC	0.58	0.40	0.41	0.41
Xcel	XEL	0.64	0.48	0.44	0.43
Mean		**0.63**	**0.49**	**0.55**	**0.55**
Duke	*DUK*	*0.56*	*0.39*	*0.43*	*0.43*

Q. WHY DO VALUE LINE AND OTHER FINANCIAL DATA PROVIDERS USE DIFFERENT BETA CALCULATION METHODOLOGIES?

A. Beta is intended to be a *forward-looking* measure of relative risk, so it is inherently uncertain. It cannot be measured directly (like an interest rate) and is usually estimated from *historical* data, as the slope of the regression of the returns of a stock against the returns of the market over a recently-ended historical period. Generally, estimates based on historical data reasonably reflect future expectations, because most companies' risk profiles change slowly over time. The assumption of slowly changing risk profiles is particularly valid for the relatively stable and predictable utility sector.

105 S&P GMI, Yahoo! Finance, and Zacks data (last visited Jun. 30, 2023).

But if a dramatic change in the market or an individual stock occurs, as in the pandemic-related market turmoil of early 2020, that change will influence the beta estimate for as long as the period of change is included in the trailing data used in the beta calculation, even if investors' risk perceptions have returned to their level prior to the dramatic change. Because Value Line calculates beta using 5 years of trailing data, the pandemic-related market turmoil of early 2020 continues to influence its beta estimates. In deciding which beta calculation methodology to use, analysts should always examine whether any past shift in market conditions was temporary or is sustained. Witness Morin fails to examine whether the pandemic-related change in market conditions was temporary or has been sustained, and therefore whether Value Line's beta estimates accurately reflect *current* investor risk perceptions.

2. Value Line's beta estimates do not reflect current investor risk perceptions.

Q. HOW CAN WE DETERMINE WHETHER THE CHANGE IN INVESTORS' RISK PERCEPTIONS WAS TEMPORARY OR HAS BEEN SUSTAINED?

A. Determining whether the change in investors' risk perception was temporary or has been sustained is typically done by examining how betas calculated using different amounts of trailing data and returns calculated at different frequencies – for example, daily, weekly, or monthly – have changed over time.

Q. IS THE NEED TO ESTIMATE BETA USING DIFFERENT METHODOLOGIES WELL KNOWN?

A. Yes. Utility cost of capital expert witnesses Michael Vilbert and Bente Villadsen have written about the trade-offs of different methodologies, highlighting the need to consider shorter calculation intervals in the wake of abrupt disruptions such as was experienced first during and then immediately after the pandemic-driven bout of market turmoil in early 2020:[106]

> The choices for the interval for the return data and the length of the beta estimation window involve trade-offs between obtaining more observations through the choice of a longer window and/or more frequent return data, ensuring that no structural change has occurred during the estimation window, and avoiding problems due to insufficient trading activity. … Balancing these considerations, economists typically recommend estimating beta using daily, weekly, or monthly returns over the most recent 2- to 5-year period, with weekly being the more common, *except if there are reasons to think that the industry might be subject to recent changes in systematic risk so that the use of a more recent data window is desirable*.

Witness Morin also acknowledges the issues that arise when calculating beta using trailing data that includes one or more structural shifts:[107]

> Such structural shifts in risk are not fully reflected in the measured beta and standard deviation, since such estimates are calculated using five years of past data using pre and post structural shift observations.

[106] Bente Villadsen, Michael J. Vilbert, Dan Harris, and Lawrence Kolbe, *Risk and Return for Regulated Industries*, Acad. Press at 73-76 (2017) (emphasis added).

[107] Roger A. Morin, *Modern Regulatory Finance*, Pub. Util. Reports at 86 (2021) [hereinafter "Modern Regulatory Finance"].

The need to examine beta using different calculation methodologies is reflected in data providers' offerings. For example, Bloomberg allows users to easily override its default beta calculation parameters. S&P GMI, in addition to reporting betas calculated using 1 and 3 years of trailing data, provides its users with spreadsheet models that allow them to modify all its beta calculation parameters.

In his book *Modern Regulatory Finance*, Witness Morin identifies six other commercially available sources, including Bloomberg, Yahoo! Finance, and S&P Global Market Intelligence,[108] and acknowledges, "estimates of beta may vary over a wide range of when different computation methods are used. The return data, the time period used, its duration, the choice of market index, and whether annual, monthly, or weekly return figures are used will influence the final result."[109] The Value Line methodology selected by Witness Morin hardly reflects the wide range of ways beta could be calculated, each of which could produce dramatically different results, raising concerns about the "data mining" Nobel laureate Fischer Black warned against.[110]

Q. WHICH METHODOLOGICAL DIFFERENCES ACCOUNT FOR THE MOST VARIATION IN BETA ESTIMATES?

A. The largest potential sources of variation in beta estimates arise from their trailing return history duration, return calculation frequency, and Blume adjustment parameters.

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108 *Id.* at 79.
109 *Id.* at 80.
110 Fischer Black, *Beta and Return*, 20(1) J. Portfolio Mgmt. 8 (1993), https://jpm.pm-research.com/content/20/1/8.

Q. HOW DOES THE DURATION OF TRAILING RETURN HISTORY AFFECT BETA ESTIMATES?

A. Following bouts of high market volatility, such as was experienced in the early days of the pandemic in February and March 2020, betas will be affected as long as the trailing history includes the volatile period, even if market conditions have stabilized. For example, the Value Line adjusted betas used by Witness Morin are calculated using 5 years of weekly returns[111] through September, October, or November of 2022 and therefore include the 2020 volatility. Their unadjusted average, 0.84,[112] is significantly higher than the average (unadjusted) S&P GMI 1- and 3-year betas, 0.63 and 0.49 as of June 30, 2023, respectively, which do not include the volatile period.[113]

Figure 19 plots the raw beta for the entire utility sector using 1, 2, and 5 years of weekly returns from July 1926 through May 2023. At any given time, beta can be very sensitive to the trailing history used. As of the end of January 2023, the betas using the 1-, 2-, and 5-year trailing histories were 0.70, 0.60, and 0.75, respectively.

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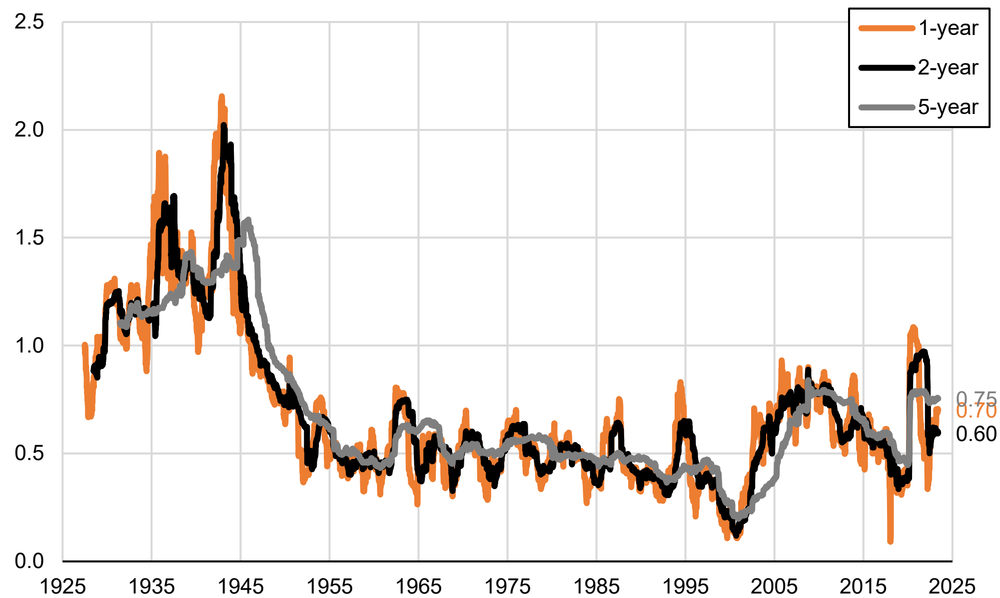
[111] E-mail from Paul Cordle, Client Support Associate, S&P Global Market Intelligence, to Mark Ellis (Nov. 17, 2021), which is attached as Exhibit MEE-5.

[112] Average Value Line unadjusted beta = [adjusted average of 0.89 – 1/3] x 3/2 = 0.84.

[113] M. Ellis analysis of S&P GMI data (last visited Jun. 30, 2023).

Figure 19. Utility sector raw beta – trailing return history sensitivity[114]
July 1926-May 2023



In general, betas calculated using longer return histories tend to be more stable over time, as the effect of any short-term period of volatility is reduced by longer surrounding periods of stability. Because utility cost of capital proceedings seek a relatively long-term estimate, it might be tempting to conclude that a longer trailing history is preferred in estimating a utility's beta for purposes of authorizing an ROE. As Vilbert and Villadsen astutely recommend, though, "if there are reasons to think that the industry might be subject to recent changes in systematic risk … the use of a more recent data window is desirable."[115] The current 5-year weekly beta of 0.75, driven by the market turmoil of early 2020, is higher than its historical range since 1955 of 0.5-0.6.

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[114] M. Ellis analysis of FDL data (last visited Jul. 13, 2023).

[115] Bente Villadsen, Michael J. Vilbert, Dan Harris, and Lawrence Kolbe, *Risk and Return for Regulated Industries*, Acad. Press at 73-76 (2017).

Regardless of the duration of the trailing return used, utility sector betas were in a decade-plus-long decline before the pandemic. After the brief period of unusual market volatility in early 2020 not seen since the World War II era, investor perceptions of utility risk quickly settled to their pre-pandemic levels. Once the early-pandemic period of market turmoil fell out of the trailing historical data, as with the 1- and 2-year betas, betas returned to their pre-pandemic levels. Because of their shorter trailing histories, the 1- and 2-year betas are more reflective of *current* investor sentiment.

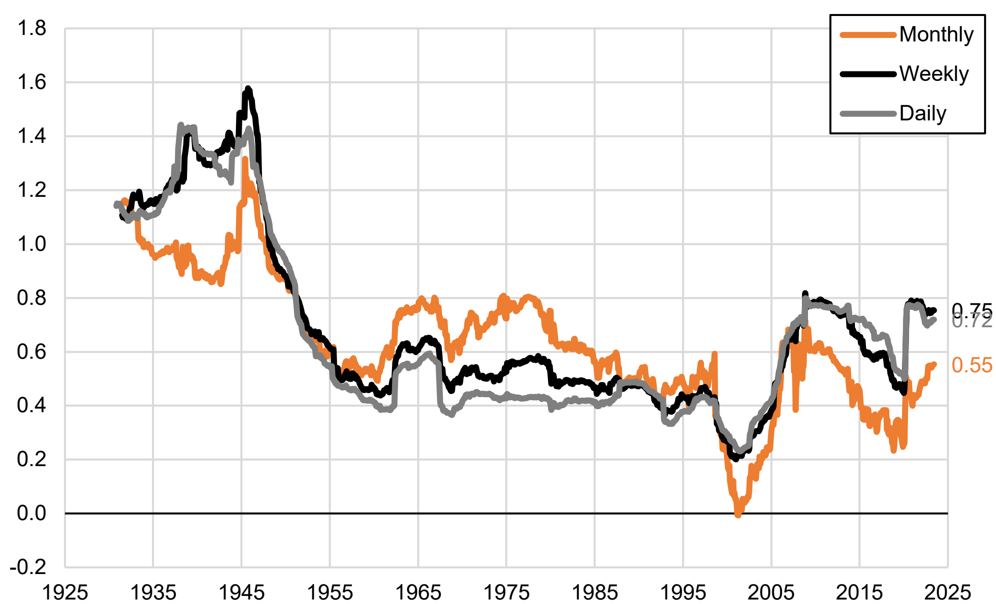
The sharp declines in the 1- and 2-year betas in Figure 19, after the early-2020 period of unusual market volatility drops out of the trailing data, make it clear that Witness Morin's elevated 5-year weekly betas are not valid indicators of current investor expectations but purely artifacts of the inclusion of a transitory and short-term market anomaly.

Q. HOW DOES THE FREQUENCY OF RETURN CALCULATION AFFECT BETA ESTIMATES?

A. Figure 20 plots the raw beta for the entire utility sector using 5 years of monthly, weekly, and daily returns from July 1926 through May 2023. As with the trailing history, at any given time, beta can be very sensitive to the return calculation frequency used. As of the end of January 2023, the betas using monthly, weekly, and daily trailing histories were 0.55, 0.75, and 0.72, respectively. In general, betas tend to be more stable at higher return calculation frequencies. For any given trailing history duration (e.g., 1, 2, or 5 years), shorter return frequencies generate more data for use in the beta calculation: weekly returns generate approximately four times more data than monthly; daily approximately five times more than weekly. As the return frequency increases, any extreme data points are averaged with a larger number of "typical" data points, which tends to mitigate abrupt changes in beta over time.

This finding would tend to recommend using shorter return frequencies, due to their greater stability over time. But the choice of return frequency should reflect the time horizon of the analysis in which the CAPM-derived cost of equity will be used. Utility cost of capital proceedings seek to estimate a cost of equity that applies over a multi-year period. This consideration recommends a longer calculation frequency.

Figure 20. Utility sector 5-year raw beta – return calculation frequency sensitivity[116]
July 1926-May 2023



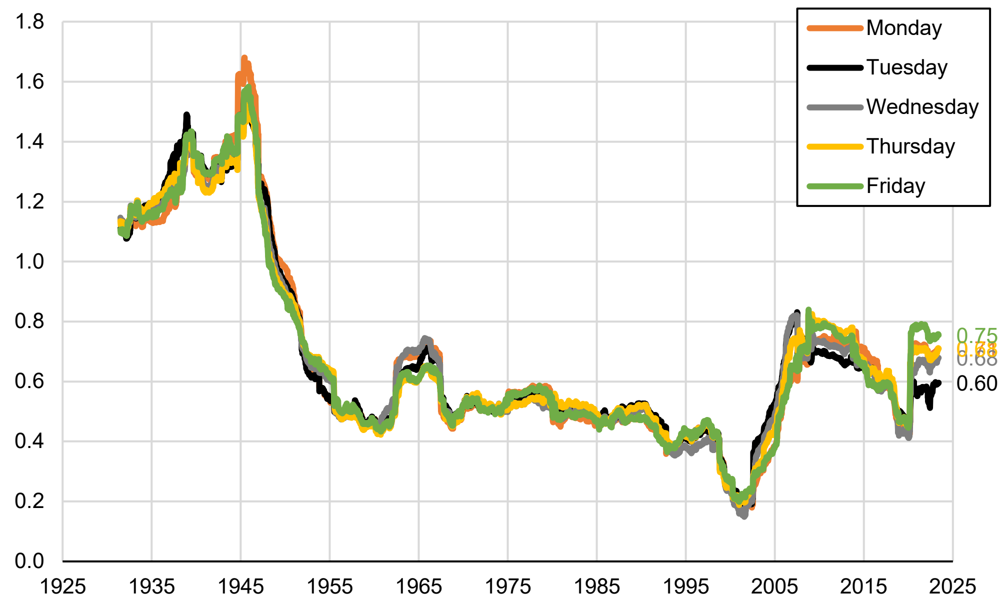
[116] M. Ellis analysis of FDL data (last visited Jul. 13, 2023).

Q. HOW DO OTHER BETA CALCULATION PARAMETERS AFFECT THE VARIATION IN BETA ESTIMATES?

A. Even a beta calculation parameter as seemingly arbitrary as the day of the week on which weekly returns are calculated can materially affect the beta estimate. Figure 21 shows the 5-year trailing beta, i.e., raw Value Line-equivalent, with returns calculated on each weekday. Currently, Friday yields the highest beta, 0.75, but simply changing the calculation day to Tuesday reduces the beta to 0.60, 20% lower. This day-of-the-week return calculation effect is only partially mitigated by averaging multiple utilities. The stock prices of individual companies within the sector tend to move together on any given day, so weekly returns calculated on the same day will tend to be similar.

This finding highlights the deficiency in Witness Morin's analysis in failing to examine alternative beta calculation methodologies and the potential arbitrariness of his choice of methodology. It also further highlights the need for caution in using the mechanically calculated betas provided by Value Line, Zacks, or other financial data providers, particularly betas calculated using weekly returns, without examining how they've changed over time or comparing them to long-term historical averages.

Figure 21. Utility sector 5-year weekly raw beta – return calculation day sensitivity[117]
July 1926-May 2023



Q. YOU LISTED THE BLUME ADJUSTMENT AS A THIRD SOURCE OF VARIATION IN BETA ESTIMATES. WHAT IS THE ORIGIN OF THE BLUME ADJUSTMENT?

A. The Blume adjustment is based on an analysis conducted by Wharton professor Marshall Blume in the early 1970s. Analyzing beta-sorted portfolios, he found a tendency for betas, on average, to regress toward the market average beta, 1.0, from one time period to the next.[118] Based on this finding, some providers of beta estimates report adjusted betas that are a weighted average of the raw estimate and the market mean. The most common weighting is 2/3 on the raw beta, 1/3 on the market beta (1.0):[119]

117 *Id.*

118 Marshall E. Blume, *On the Assessment of Risk*, 26:1 The J. of Fin. at 1-10 (1971) https://onlinelibrary.wiley.com/doi/10.1111/j.1540-6261.1971.tb00584.x.

119 The 2/3 and 1/3 weights are based on the regression coefficients Blume presented in his original paper, which regressed betas in one period against betas in the previous period.

$$\beta_{adjusted} = \frac{2}{3}\beta_{raw} + \frac{1}{3}.$$

For stocks with raw betas below 1.0, like most utilities historically,[120] the effect of the adjustment is to increase the beta one-third of the way toward 1.0. For example, a stock with a raw beta of 0.4 would have an adjusted beta of 2/3 x 0.4 + 1/3 = 0.6. For its adjusted beta, Bloomberg uses the common 2/3 and 1/3 weights. Value Line's weights are similar: 0.67 and 0.35, respectively. Value Line also rounds to the nearest 0.05.[121]

As Vilbert and Villadsen note, "analysts have different views on whether to use raw or adjusted betas,"[122] hence the reporting of unadjusted betas by Bloomberg, S&P GMI, Yahoo! Finance, and Zacks.

Q. IS THE BLUME ADJUSTMENT VALID FOR UTILITIES?

A. No, it is not. The Blume adjustment is based on an observation of the tendency of betas, *on average*, to regress toward 1.0. But not every stock exhibits this tendency. Blume did not investigate whether and how this tendency might vary across stocks with different characteristics.

Rutgers professor Richard Michelfelder investigated the validity of the beta adjustment specifically for utility stocks and found no evidence of the average tendency observed by Blume.[123] This can be clearly seen in Figure

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120 As shown in Figure 19, Figure 20, and Figure 21, the utility sector average beta has been consistently below 1.0 almost since the 1950s, under most calculation methodologies.

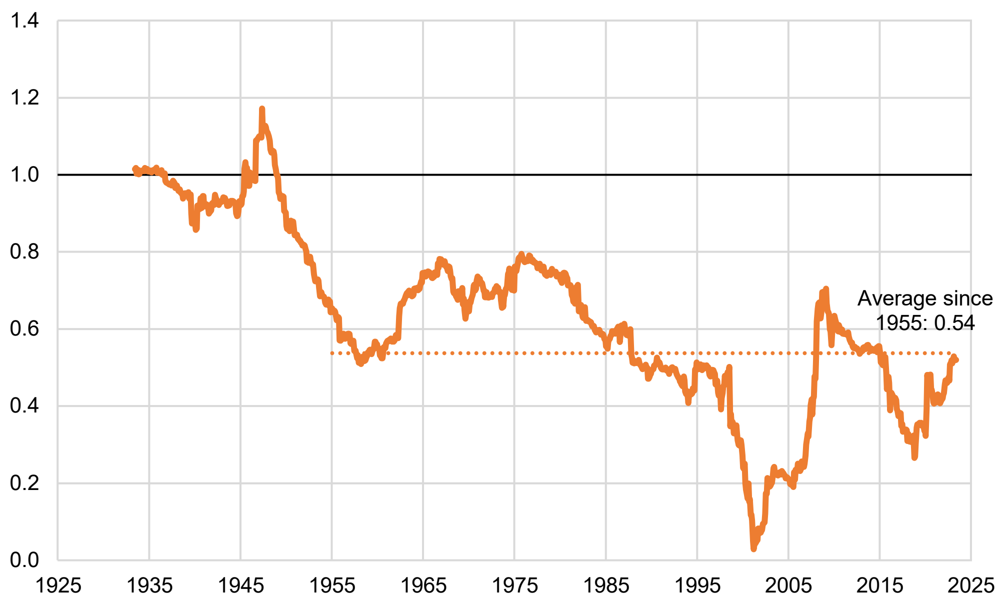
121 E-mail from Cheryl Dhanraj, Technical Support, Value Line, to Mark Ellis (Oct. 6, 2021), which is attached as Exhibit MEE-3.

122 Bente Villadsen, Michael J. Vilbert, Dan Harris, and Lawrence Kolbe, *Risk and Return for Regulated Industries*, Acad. Press at 80 (2017).

123 Richard A. Michelfelder & Panayiotis Theodossiou, *Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings*, 26:9 The Electricity J. at 60-68 (2013), which is attached as Exhibit MEE-6.

22, which shows the same 7-year monthly beta used by Blume in his original analysis for the entire utility sector going back to 1926. Since the 1950s, the beta for the utility sector as a whole has tended to regress toward 0.50-0.60, not 1.0.[124]

Figure 22. Utility sector 7-year monthly raw beta[125]
July 1926-May 2023



Blume speculated as to why betas, on average, tend to regress toward 1.0 over time.[126] High-beta firms tend to be newer and smaller; as they mature and grow, they become more risk-averse. In contrast, low-beta firms tend to run out of low-risk investment opportunities and must accept more risk to stay

124 One might ask whether the utility sector average reflects the tendency of individual utility stocks. Betas are additive, so a tendency for individual utility stocks to regress toward 1.0, on average, would be reflected in the industry beta. Blume used the same logic to extrapolate from the portfolios he analyzed to individual stocks. *See* Eugene F. Fama & Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, 18:3 J. of Econ. Perspectives 25, 31 (2004), https://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430.

125 Market capitalization-weighted average of all NYSE-, AMEX-, or NASDAQ-listed utilities. M. Ellis analysis of FDL data (last visited Jul. 13, 2023).

126 Marshall E. Blume, *Betas and Their Regression Tendencies*, 30:3 The J. of Fin. 785-795 (1975), https://onlinelibrary.wiley.com/doi/abs/10.1111/j.1540-6261.1975.tb01850.x.

in business. Neither of these causal explanations applies to utility operating companies, like DEC and the publicly traded members of the DEC proxy group. They are large and mature, and their investments tend to have consistently low risk profiles over time. These attributes combine to keep utilities' betas sustainably and significantly below 1.0.

Empirical analysis specifically investigating utility betas, grounded in sound economic reasoning, demonstrates that utility betas do *not* have a tendency to regress toward the market average and therefore should not be Blume-adjusted.[127]

3. Contrary to Witness Morin's assertions, Value Line betas are not widely used relative to other providers' betas.

Q. ARE VALUE LINE BETAS WIDELY USED BY INVESTORS?

A. When Witness Morin was asked to justify his reliance on Value Line as his sole source for beta estimates, responded only with platitudes: "Value Line is the granddaddy of investment research companies which has been in existence since 1931 and is a very respected research firm with an extremely strong performance record" whose "periodicals and related publications and services are marketed to individual and professional investors, as well as to institutions including municipal and university libraries and investment firms. Many large university libraries receive the print version of the Value Line Investment Survey and provide it to patrons for free. This provides free access to Value Line for millions of investors with an opportunity to learn

[127] Blume used mean squared error (MSQ) to assess the accuracy of his adjustment. It can be shown that the standard 2/3 and 1/3 weights increase the MSQ for utility betas by approximately 40%.

about, use, and thoroughly evaluate investment opportunities."[128] Elsewhere, he has asserted that "Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors."[129]

Website visitor data, easily obtained from a simple internet search, belie Witness Morin's claims about Value Line's reach and influence. As seen in the screenshots in Figure 23, the websites of Yahoo! Finance and Zacks, two sources of free beta estimates (and, as explained below, the sources of my beta estimates), have more than 1,200 and 18 times as many visitors, respectively, as Value Line.[130]

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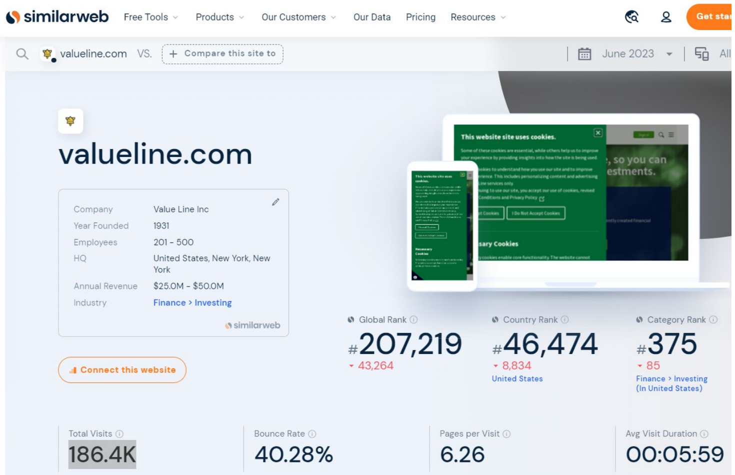
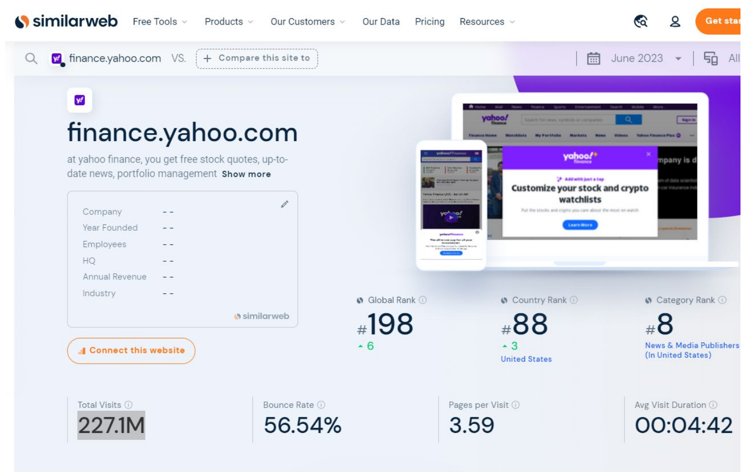
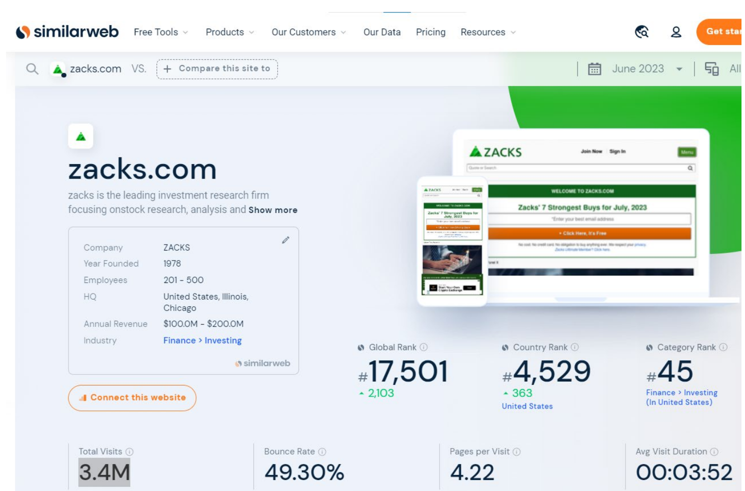
[128] Duke Energy Carolinas response to NCJC et al. Data Request 5.4.
[129] Modern Regulatory Finance at 71.
[130] Similarweb.com (last visited Jul. 11, 2023).

Figure 23. Value Line, Yahoo! Finance, and Zacks website visitor data







Q. WHAT ARE YOUR CONCLUSIONS ABOUT WITNESS MORIN'S CHOICE OF BETA ESTIMATION METHODOLOGY?

A. The variation in the three most recent beta estimates in Figure 19 suggests we should not unthinkingly use the most recent trailing betas from Value Line or any other data provider. It's important to keep in mind that all methodologies are intended to produce *estimates of investors' future expectations*. The elevated current 5-year betas used by Witness Morin are artifacts of arbitrary choices of calculation period. The seven-week bout of market volatility in early 2020 was an anomaly, and investor perceptions of utility risk quickly returned to their pre-pandemic levels. The 5-year weekly return history used in Witness Morin's beta estimates does not accurately reflect current investor sentiment. Witness Morin's beta estimates are further inflated by the Blume adjustment, which is not valid for utilities.

Q. HOW DOES WITNESS MORIN ESTIMATE THE THIRD ASSUMPTION IN THE CAPM, THE MARKET RISK PREMIUM?

A. Witness Morin's market risk premium (MRP) is the average of a long-term historical MRP and forward-looking estimate based on the same constant-growth discounted cash flow model he uses for the proxy group in his DCF analysis. Using the average of a long-term historical MRP and a forward-looking estimate is a reasonable approach, as it reflects two of the most common methods for developing financial model inputs – long-term trends and market-derived, forward-looking estimates. Nonetheless, Witness Morin's implementations of these two methods to estimate the MRP are deeply flawed.

C. Witness Morin's historical MRP incorrectly uses only the income component of the risk-free return and is calculated in arithmetic, not geometric, terms.

Q. WHAT IS WRONG WITH WITNESS MORIN'S HISTORICAL MRP?

A. There are two main flaws with Witness Morin's historical MRP. First, he uses only the income (interest) component of the long-term Treasury return, which tends to understate the return on the risk-free asset. Second, he calculates the returns on both the market and long-term Treasury in arithmetic, not geometric, terms, which overstates the returns on both the market and the long-term Treasury, but especially the market. Both of these errors systematically inflate the resulting MRP estimate.

1. Witness Morin excludes a key component of bond returns in his historical MRP calculation, introducing upward bias to his MRP estimate.

Q. WHY DOES WITNESS MORIN USE ONLY THE INCOME COMPONENT OF THE LONG-TERM TREASURY RETURN?

A. Witness Morin maintains that only the income portion of a Treasury bond's return is risk-free:[131]

> The historical MRP should be computed using the income component of bond returns because the intent, even using historical data, is to identify an expected MRP. When Treasury bonds are issued, the income return on the bond is risk free, but the total return, which includes both income and capital gains or losses, is not. Thus, the income return should be used in the CAPM because it is only the income return that is risk free. Moreover, the income component of total bond return (*i.e.*, the coupon rate) is a far better estimate of expected return than the total return (*i.e.*, the coupon rate + capital gain), because both realized capital gains and realized losses are largely

[131] Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, p. 42.

unanticipated by bond investors. The long-horizon (1926-2021) MRP is 7.4%.

Witness Morin appears to have fallen victim to a semantic fallacy. While it is true that the historical MRP is being used to estimate an *expected* MRP, the historical MRP must be calculated from historical *actual*, not *expected*, return data because only *actual* data are available for both bond and market historical returns. The income component of the total bond return may reflect investors' historical return expectations for bonds, but no corresponding data are available for investors' historical return expectations for the market.

In fact, a robust academic research literature has concluded that actual returns on equities substantially exceeded investor expectations during most of the twentieth century, a widely recognized phenomenon known as the equity premium puzzle.[132] According to Witness Morin's calculations, capital gains account for an additional 0.7% on top of the 5.0% income component of the total return on long-term Treasurys from 1931 through 2021.[133] Including the capital gains component in the historical return for equities in the MRP, but not for bonds, systematically overstates the historical MRP.

[132] *See, e.g.*, "Equity Premium Puzzle," Wikipedia, Jul. 8, 2023, https://en.wikipedia.org/wiki/Equity_premium_puzzle.

[133] Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, Exhibit 8.

2. Witness Morin incorrectly estimates his historical MRP from the difference in arithmetic, not geometric, returns, further biasing his MRP estimate upward.

Q. WHY SHOULD THE HISTORIC MRP BE CALCULATED USING GEOMETRIC RETURNS, NOT ARITHMETIC, AS WITNESS MORIN DOES?

A. Previously, I described the difference between arithmetic and geometric returns, how arithmetic returns are always greater than or equal to geometric returns, and that for any given future geometric return, there is only one future investment value. In contrast, for any given arithmetic return, there is an infinite number of potential future outcomes, so the arithmetic return is a poor indicator of investor expectations. I concluded that the geometric return is a better indicator of future investor expectations. I would like to explain this distinction in more detail.

Q. WHY ARE GEOMETRIC RETURNS A BETTER INDICATOR OF FUTURE INVESTOR EXPECTATIONS?

A. The choice between arithmetic and geometric returns for estimating investor expectations has been hotly debated among academics and practitioners for decades. Some of the disagreement arises from differences in potential application. For example, in portfolio management, where Monte Carlo simulation is common, arithmetic averages, in combination with return distributions, are appropriate. In corporate finance and valuation, which is more analogous to our objective, the choice depends on the life of the investment under consideration. The widely used finance text *Valuation* summarizes the current status:[134]

> The choice of averaging methodology will affect the results. For instance, between 1900 and 2014, U.S. stocks outperformed long-term government bonds by 6.4 percent per year when averaged arithmetically. Using a geometric average, the number drops to 4.2 percent. This difference is not random; arithmetic averages always exceed geometric averages when returns are volatile.
>
> So which averaging method on historical data best estimates the expected rate of return? Well-accepted statistical principles dictate that the best unbiased estimator of the mean (expectation) for any random variable is the arithmetic average. Therefore, to determine a security's expected return for one period, the best unbiased predictor is the arithmetic average of many one-period returns. A one-period risk premium, however, can't value a company with many years of cash flow. *Instead, long-dated cash flows must be discounted using a compounded rate of return. But when compounded, the arithmetic average will generate a discount factor that is biased upward (too high).*
>
> There are two reasons why compounding the historical arithmetic average leads to a biased discount factor. First, the arithmetic average may be measured with error. Although this estimation error will not affect a one-period forecast (the error has an expectation of zero), squaring the estimate (as you do in compounding) in effect squares the measurement error, causing the error to be positive. This positive error leads to a multiyear expected return that is too high. Second, a number of researchers have argued that stock market returns are negatively autocorrelated over time. If positive returns are typically followed by negative returns (and vice versa), then squaring the average will lead to a discount factor that overestimates the actual two-period return, again causing an upward bias.

[134] Tim Koller et al., *Valuation*, McKinsey & Co. at 852-853 (6th ed. 2015) (emphasis added).

Valuation goes on to recommend a widely used weighted average of the geometric and arithmetic averages, weighted more heavily toward arithmetic for short-lived investments, converging toward the geometric average if the investment life equals or exceeds the duration of the historical time series from which the averages are calculated.

NYU finance professor Aswath Damodaran, known for his simple, practical advice to practitioners, reaches a similar conclusion:[135]

> As we move to longer time horizons, and as returns become more serially correlated (and empirical evidence suggests that they are), it is far better to use the geometric risk premium. In particular, when we use the risk premium to estimate the cost of equity to discount a cash flow in ten years, the single period in the CAPM is really ten years, and the appropriate returns are defined in geometric terms. In summary, … the geometric mean is more appropriate if you are using the Treasury bond rate as your risk-free rate, have a long-time horizon, and want to estimate the expected return over that long time horizon.

In his discussion of his use of the long-term Treasury for the risk-free rate in the CAPM, Witness Morin acknowledges that we are seeking to estimate a long-term cost of equity: "Common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely. … The expected common stock return is based on very long-term cash flows, regardless of an individual's holding period."[136] A share of common stock is a claim on cash flows into perpetuity, i.e., the investment

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[135] Aswath Damodaran, *Discussion Issues and Derivations*, http://people.stern.nyu.edu/adamodar/New_Home_Page/AppldCF/derivn/ch4deriv.html (last visited Jul. 18, 2023).

[136] Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, p. 36.

life is infinite, which dictates using a long-term risk-free rate, as both Witness Morin and I do, and geometric averages, which Witness Morin has failed to do. The geometric average is also consistent with the results of the DCF model, which produces a continuously compounded, i.e., geometric, average estimated return.

Witness Morin has asserted in recent testimony that stock returns are uncorrelated over time, based on his own analysis of stock returns.[137] Witness Morin did not provide the details of his analysis, but it appears he examined only the autocorrelation of returns from one year to the next.[138] In this proceeding, though, the Commission is interested in long-term term returns, so his finding is not relevant to our objective. When *multi-year* stock returns are analyzed, we find they are strongly negatively autocorrelated from one period to the next. Figure 24 shows the autocorrelation of annual stock market returns from 1927 through 2022, as a function of the return calculation period, replicating and updating an academic study of long-term autocorrelation in stock market returns.[139] For return calculation periods of 14 to 20 years, the negative autocorrelation of returns is statistically significant

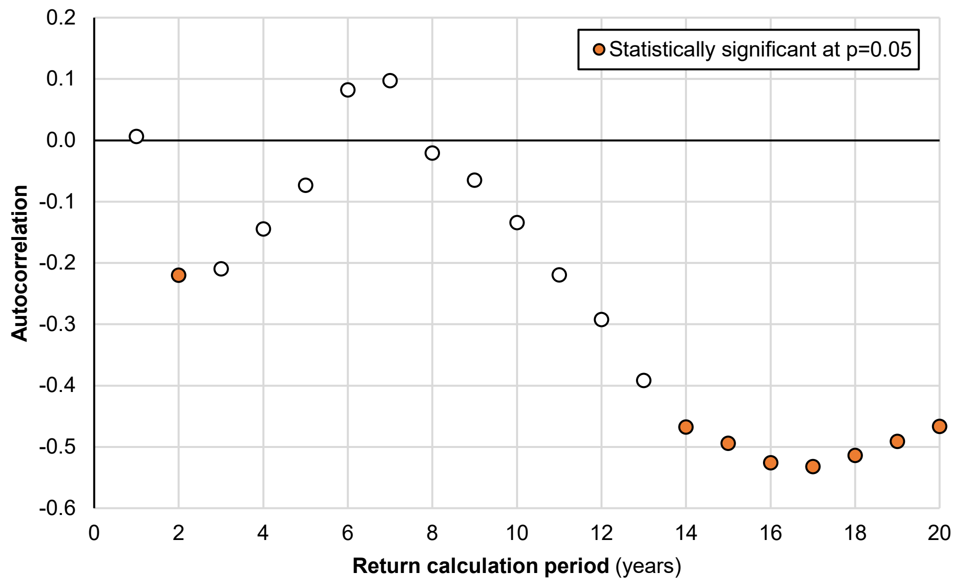
137 Application of Duke Energy Progress, LLC for Adjustment of Rates, Docket No. E-2, Sub 1300, hearing transcript vol. 8, 301 (May 4, 2023).

138 *Id*. ("So what I've done in my research is I've looked at the average returns year by year, and it's a random walk").

139 M. Ellis analysis of FDL data (last visited Jun. 1, 2023). Autocorrelation is adjusted for small-sample bias, as described in Valeriy Zakamulin, *Secular Mean Reversion and Long-Run Predictability of the Stock Market*, 69:4 Bull. of Econ. Rsch. (2017), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2209048, which is attached as Exhibit MEE-7.

at the p=0.05 level.[140] Over the long term, periods of high returns do, in fact, follow periods of low returns, and vice versa, so the arithmetic average is upwardly biased, as Koller et al. explain, and the historical geometric is the correct average to use as Koller et al. and Damodaran recommend.

Figure 24. Autocorrelation of annual stock market returns as a function of return calculation period[141]
1927-2022



[140] P-value is the probability of obtaining results at least as extreme as those observed assuming the null hypothesis – here, that returns *are not* autocorrelated – is correct. The lower the p-value, the stronger the evidence in favor of the alternative hypothesis – here, that returns *are* autocorrelated. A p-value less than 0.05 means there is less than a 5% chance that the null hypothesis is true and the observed results occurred by chance. A p-value less than 0.05 is generally considered statistically significant. *See, e.g., P-Value: What It Is, How to Calculate It, and Why It Matters*, https://www.investopedia.com/terms/p/p-value.asp (last visited Jul. 16, 2023).

[141] Market capitalization-weighted average return of all NYSE-, AMEX-, or NASDAQ-listed utilities, adjusted for inflation. M. Ellis analysis of FDL and BLS data (last visited May 25, 2023).

D. Witness Morin's forward-looking market risk premium (MRP) is based on the same flawed implementation of the constant-growth discounted cash flow model (CG DCF) used in his proxy group DCF analysis, which assumes economically impossible perpetuity growth rates.

Q. HOW DOES WITNESS MORIN ESTIMATE HIS FORWARD-LOOKING MRP?

A. Witness Morin estimates his forward-looking MRP using the same constant-growth DCF model used in his proxy group DCF analysis. Witness Morin's implementation of the CG DCF is fatally flawed as it erroneously assumes analysts' 3-to-5-year EPS growth estimates can be sustained into perpetuity, a deficiency of which he is aware, as explained in Section IV.A above. This assumption is invalid for several reasons, perhaps the most compelling of which is that it is simply economically impossible for the market to sustain analysts' forecast growth rates for even a decade, much less forever. Since 1926, U.S. stock market dividend growth has averaged 5.0% (1.9% in real terms)[142] – 45% lower than Witness Morin's 9.1% projection.[143] The market has never sustained 9.1% dividend growth for even eight years, much less into perpetuity, validating Witness Morin's observation that "[t]he problem is that the from the standpoint of the DCF model that extends into perpetuity, analysts' horizons are too short, typically five years. It is often unrealistic for such growth to continue into perpetuity."[144] Witness Morin nonetheless ignores his own advice and uses the constant-growth DCF to estimate his forward-looking MRP.

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[142] M. Ellis analysis of FDL data (last visited Jul. 13, 2023).
[143] Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, Exhibit 6.
[144] New Regulatory Finance at 308.

E. <u>Witness Morin's flawed CAPM results should be disregarded.</u>

Q. WHAT IS YOUR OVERALL ASSESSMENT OF THE CAPM AND WITNESS MORIN'S IMPLEMENTATION OF IT?

A. The CAPM is conceptually sound and one of the most widely used COE models in corporate finance. But Witness Morin's implementation choices – a forecast, not current, risk-free interest rate; a cherry-picked adjusted beta that is not reflective of current market conditions or utilities' long term risk profile; and a flawed MRP model – yields systematically upwardly-biased results. His flawed CAPM results should be disregarded.

VI. IMPLEMENTING THE CAPM WITH MORE RIGOROUSLY ESTIMATED ASSUMPTIONS PRODUCES SUBSTANTIALLY LOWER COE ESTIMATES.

Q. PLEASE EXPLAIN YOUR IMPLEMENTATION OF THE CAPM.

A. There are three components to the CAPM: the risk-free rate, beta, and the market risk premium. My assumptions for each fall out of the analyses described in the foregoing critique of Witness Morin's implementation.

A. <u>The risk-free rate, one of the three CAPM inputs, should be estimated from the current, not forecast, interest rate.</u>

Q. HOW DO YOU ESTIMATE THE RISK-FREE RATE?

A. Like Witness Morin, I use the 30-year Treasury for the risk-free rate. Unlike Witness Morin, though, I use the current, not forecast, rate. I use the most recent full-month average 30-year Treasury rate, for June 2023, of 3.87%. As explained in Section V.A.2 above, current market interest rates provide an unbiased estimate of future rates and are generally superior to publicly available "expert" forecasts.

B. Betas calculated using five years of monthly returns are consistent with the objective of a cost of capital proceeding and strike an appropriate balance between recent market conditions and utilities' long-term historical risk profile.

Q. HOW DO YOU ESTIMATE BETA?

A. As explained in Section V.B above, no single, widely used approach to estimating beta exists. Beta estimates can vary substantially depending, in particular, on the historical trailing period used, return calculation frequency, and adjustment for long-term trend reversion. I use 5-year monthly betas such as those provided by Yahoo! Finance and Zacks and commonly used in academic studies. Five-year betas using monthly returns are consistent with cost of capital proceedings' objective of estimating a multi-year expected cost of equity, and their current values strike a reasonable balance between current market sentiment and the long-term historical average for utilities. The current average of 0.55 for the DEC proxy group, shown in Figure 18, is consistent with both the long-term historical range of 0.5-0.6 and recent investor risk perceptions, as reflected in 1-year betas using daily returns of 0.63.

C. The market risk premium estimate should be estimated in light of both current market conditions and the long-term historical trend.

Q. WHY CAN'T WE JUST LOOK UP THE MRP LIKE, WE CAN LOOK UP A STOCK PRICE OR INTEREST RATE?

A. The market risk premium is the difference between investors' expectations of future stock returns and the risk-free (interest) rate. While interest rates are directly observable, expected future market returns are not. The MRP must therefore be estimated. A historical average is a useful check for reasonableness, but the cliché, "past performance is no guarantee of future results," applies. Instead, analysts use a variety of models and input assumptions to estimate the MRP.

Q. HOW DO YOU ESTIMATE THE MARKET RISK PREMIUM?

A. Like Witness Morin, I estimate the market risk-premium from the average of the long-term historical actual MRP and a forward-looking estimate calculated using a DCF. Unlike him, though, I use the historical *geometric* MRP and estimate a forward-looking MRP using a multi-stage, not constant-growth, DCF model.

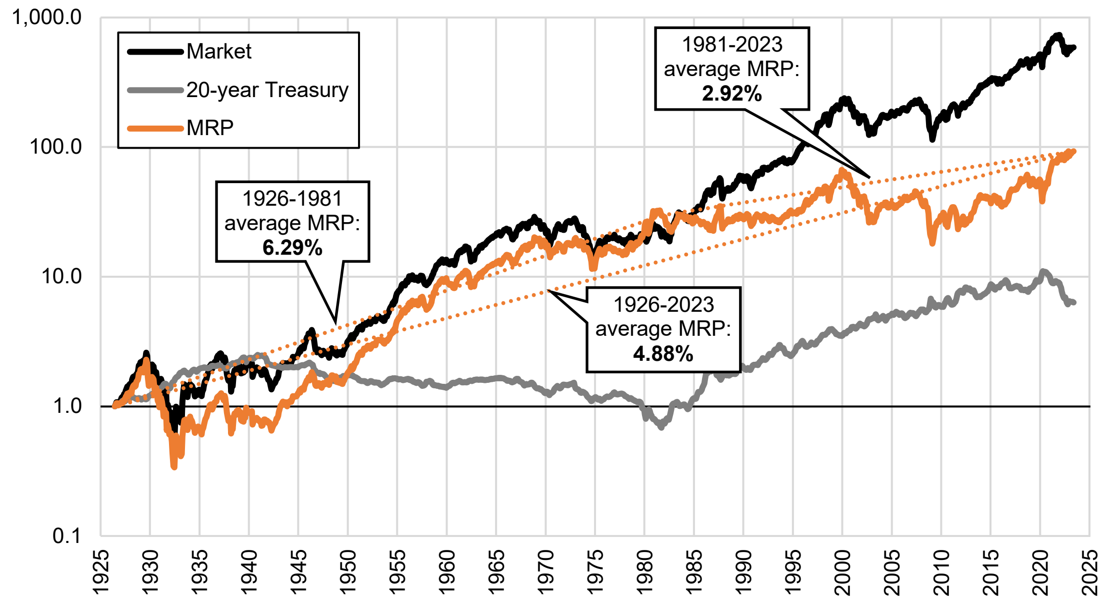
Q. HOW DO YOU ESTIMATE THE HISTORICAL MARKET RISK PREMIUM?

A. I use the long-term historical difference in the average real total returns on the market and long-term Treasury bond.[145]

Figure 25 shows the long-term historical real returns on the market and 20-year Treasury bonds, as well as the implied MRP, from June 1926 through May 2023. Over the last 96+ years, stocks have outperformed 20-year Treasurys by 4.88% per year.

[145] Total bond return is the monthly interest (the yield divided by 12) plus any capital gain or loss, estimated as the change in value from discounting the remaining interest payments (i.e., the previous time period's interest rate) and outstanding principal at the current time period's interest rate. This method is widely used, for example, by NYU finance professor Aswath Damodaran and UCLA finance professor Ivo Welch. *See, e.g.*, Aswath Damodaran, http://people.stern.nyu.edu/adamodar/pc/datasets/histretSP.xls; Ivo Welch, *A Different Way to Estimate the Equity Premium* (for CAPM and One-Factor Model Use Only) (2008), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=1077876.

Figure 25. Market, 20-year Treasury, and MRP real total return index[146]
June 1926=1.0 (log scale)



The historical MRP is calculated using 20-year Treasury data because that is the most extensive Treasury bond data set available.[147] Because I use the 30-year Treasury in my CAPM analysis, though, the premium is reduced by the current difference in the inflation-adjusted 20- and 30-year Treasurys (TIPS), 0.08%, for a 30-year real MRP of 4.80%. Adjusted for the 30-year inflation rate estimated from the Treasury-TIPS spread, 2.19%, the nominal MRP is 4.91%.

Q. EARLIER IN YOUR TESTIMONY, YOU REFERRED TO THE EQUITY PREMIUM PUZZLE,[148] THE RESEARCH FINDING THAT HISTORICAL EQUITY RETURNS EXCEEDED INVESTOR EXPECTATIONS. HOW

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[146] M. Ellis analysis of FDL data (last visited Jul. 13, 2023).

[147] The early historical monthly data available for long-term Treasurys is not specifically for the 20-year. A simple regression model is used to adjust the long-term Treasury data to estimate the 20-year yield.

[148] *See* Section V.C.1 above.

DOES THE EQUITY PREMIUM PUZZLE AFFECT YOUR HISTORICAL MRP?

A. As can be seen in Figure 25, the realized MRP from 1926 through 1981 was 6.297%; since then, it's been over 3% lower, only 2.92%. Some analysts recommend using the lower, more recent historical MRP.[149] I conservatively use the higher long-term average.

Q. HOW DO YOU ESTIMATE THE FORWARD-LOOKING MARKET RISK PREMIUM?

A. I apply the same multi-stage DCF model I use for the DEC proxy group to the market as a whole, represented by the S&P 500 Index, and subtract the current 30-year Treasury.

Q. HOW DO YOU ESTIMATE THE CURRENT DIVIDEND YIELD FOR THE S&P 500 INDEX?

A. I use the same methodology I use for the proxy group members: the most recent dividend paid, through June 30, 2023, divided by the average price of the index over the month of January 2023. The current annualized yield is 1.96%.[150]

Q. HOW DO YOU ESTIMATE THE INITIAL GROWTH RATE FOR THE S&P 500 INDEX?

A. I use the weekly estimate provided in S&P's weekly S&P 500 earnings and estimate report. I use this source because it is publicly available, well-known, frequently updated, and produced by the party with the most intimate

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149 *See, e.g.*, Ivo Welch, *Chapter 9: Benchmarked Costs of Capital*, Corporate Finance (5th ed. 2022), https://book.ivo-welch.info/read/source5.mba/09-benchmarking.pdf.

150 M. Ellis analysis of S&P GMI data (last visited Jun. 30, 2023).

knowledge of the index. As of June 30, 2023, S&P's estimate for the S&P 500 Index's 3-to-5-year growth rate is 12.42%.[151]

Q. HOW DO YOU ESTIMATE THE TERMINAL GROWTH RATE FOR THE S&P 500 INDEX?

A. Many analysts incorrectly assume long-term dividend growth equal to nominal GDP growth. Historically, per-share payout growth, whether measured as dividends or dividends plus net share buybacks, has tracked GDP per capita.[152] I assume a terminal growth rate based on forecast real long-term per-capita GDP plus the current market forecast for long-term inflation, estimated as described in Section IV.B.3 above.

For long-term per-capita GDP growth, I use the average of the most recent long-term CPI-adjusted forecasts from three government agencies: the Congressional Budget Office (CBO),[153] the Energy Information Administration (EIA),[154] and the Social Security Administration (SSA).[155] I use the compound annual growth rate from 2043 to remove any near-term transitory effects, such as post-Covid economic recovery, and to align with

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[151] S&P Dow Jones Indices, *S&P 500 Earning and Estimate Report*, https://www.spglobal.com/spdji/en/documents/additional-material/sp-500-eps-est.xlsx (last visited Jun. 30, 2023).

[152] *See, e.g.*, Roger Ibbotson & James Harrington, *Stocks, Bonds, Bills, and Inflation 2021 Summary Edition*, CFA Institute Research Foundation Books at 157-60 (2021) (analysis is for total payout to account for the effect of net stock repurchases).

[153] Congressional Budget Office, *The 2023 Long-Term Budget Outlook* (Jun. 2023), https://www.cbo.gov/system/files/2023-06/57054-2023-06-LTBO-econ.xlsx.

[154] U.S. Energy Information Administration, *Annual Energy Outlook 2023 Macroeconomic Indicators* Table 20 (Mar. 2023), https://www.eia.gov/outlooks/aeo/excel/aeotab20.xlsx.

[155] U.S. Social Security Administration, *The 2023 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds* Supplemental Single-Year Tables (Mar. 2023), https://www.ssa.gov/OACT/TR/2023/SingleYearTRTables_TR2023.xlsx.

the time period used to estimate long-term inflation (years 21 through 30 from today).

TIPS payouts are tied to CPI, so the Treasury-TIPS spread provides a forecast of *consumer* price inflation. In contrast, real GDP forecasts are deflated by the GDP deflator, which reflects the prices of all domestic expenditures, including by businesses and government. For consistency with the CPI forecast derived from the Treasury-TIPS spread, which reflects only the prices paid by consumers, I use each agency's nominal GDP forecast deflated by its CPI forecast, rather than its GDP deflator forecast. Figure 26 summarizes the three agencies' real long-term per-capita GDP forecasts.

Figure 26. Real long-term per-capita GDP forecasts
Percent

		GDP						
Forecast	**Horizon**	Real	Deflator	Nominal	Population	**Nominal GDP pc**	**CPI**	**CPI-deflated GDP pc**
CBO	2053	1.50%	2.02%	3.54%	0.23%	3.31%	1.92%	1.37%
EIA	2050	2.08%	2.37%	4.50%	0.30%	4.19%	2.34%	1.81%
SSA[156]	2100	NA	NA	4.08%	0.42%	3.65%	2.40%	1.22%
Mean		1.79%	2.19%	4.04%	0.31%	3.71%	2.22%	1.46%
+ Treasury-TIPS long-term inflation						**3.19%**	1.70%	

The average of the CBO, EIA, and SSA (the agencies) CPI-deflated long-term per-capita GDP growth rates is 1.46%. Adding the same long-term inflation expectation, 1.70%, used to estimate the terminal growth rate in the proxy group MS DCF in Section IV.B.3 above gives a nominal rate of 3.19%.[157]

[156] The U.S. Social Security Administration does not forecast real GDP or the GDP deflator, only nominal GDP and CPI.

[157] Because these are compound growth rates, the geometric sum is used, $(1+g)(1+i)-1$.

The corresponding average of the CBO, EIA, and SSA long-term per-capita nominal GDP growth rates is 3.71%. I use the market-implied long-term inflation rate rather than the agencies' for two reasons. First, although all three forecasts are the agencies' most recent, they are stale in comparison to the June 2023 average Treasury rates used to estimate inflation. Second, as demonstrated by the analysis of BCEI forecasts, market-derived data are generally considered less biased and more accurate indicators of investor expectations than expert forecasts.

Q. WHAT IS YOUR FORWARD-LOOKING MRP?

A. The S&P 500 MS DCF yields a forecast return of 6.88%. This result is consistent with the buy-side equity return forecasts summarized in Figure 3, which average 6.6% over horizons of 10 or more years. Subtracting the current T30, 3.87%, gives an MRP of 3.01%. This result is consistent with the historical trend since 1981 of 2.92%, as shown in Figure 25 above.

Q. AND YOUR COMBINED MRP?

A. The average of my historical (4.91%) and forward-looking (3.01%) MRPs is 3.96%.

D. Implementing the CAPM with more rigorously estimated parameters yields COE estimates approximately one-third of Witness Morin's values.

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A. The Yahoo! Finance and Zacks 5-year monthly betas for the DEC proxy group, listed in Figure 18, average to 0.55. The corresponding COE is 6.06%, 45% lower than Witness Morin's 11.0% CAPM estimate[158] and, as expected, slightly higher than the B/M x ROE rule of thumb, 5.5%, described in Section II.B.2 above.

Q. RECENT UTILITY BOND YIELDS ARE CLOSE TO YOUR MS DCF AND CAPM RESULTS, 6.63% AND 6.06%, RESPECTIVELY. SHOULDN'T THE PREMIUM OVER BOND YIELDS BE GREATER?

A. To compare my COE results to utility bond yields, we must use the monthly average yield that corresponds to the proxy group's average credit-rating, Baa1, as of June 2023,[159] the averaging period of the inputs to my MS DCF and CAPM. Moody's provides several widely referenced utility bond yield indexes, but not specifically for Baa1-rated utility bonds. Nonetheless, the Baa1 yield can be estimated by interpolating between Moody's Baa and A monthly average utility bond yields for June 2023, 0.68 x 5.73% + 0.32 x 5.38% = 5.62% – lower than both my MS DCF and CAPM results.[160]

It's important to note, as well, that a utility COE estimate – an expected return on equity – cannot be directly compared to the corresponding utility bond yield. Reported bond yields are yields to maturity, assuming no default. Default risk for bonds with a Baa1 rating reduces their expected returns by approximately 0.47%. Similarly, bonds are not as liquid as stocks, and a Baa1

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158 Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, p. 5.

159 M. Ellis analysis of S&P GMI data (last visited Jun. 30, 2023). S&P credit ratings are used; it is assumed that, on average, the ratings are comparable to Moody's. The proxy group average is just slightly below Baa1 (0.04 of a grade).

160 The ratings of Moody's A- and Baa-rated utility bond indexes are comparable to Moody's A2 and Baa2 ratings, respectively. The intermediate ratings are A3 and Baa1, so the proxy group's Baa1 rating falls slightly more than two-thirds of the way between A and Baa.

rating attracts a liquidity premium of approximately 0.30%.[161] Deducting the default and liquidity premia from the Baa1 utility bond yield to maturity reduces it to approximately 4.85%, 1.78% and 1.20% lower than my MS DCF and CAPM COE estimates, respectively.

VII. THE ECAPM, A MODEL CREATED BY WITNESS MORIN, IS NOT USED ELSEWHERE IN FINANCE AND IS NOT SUPPORTED BY UPDATED RESEARCH.

Q. WHAT IS THE MORIN EMPIRICAL CAPM (ECAPM)?

A. The ECAPM is a modification of the traditional CAPM developed by Witness Morin. It is based on an empirical observation in various historical academic studies that low-beta stocks tended to perform better than predicted by the CAPM, and high-beta stocks worse, resulting in a "flattened" security market line (SML), the relationship between beta and return. The ECAPM model modifies the traditional CAPM as follows:[162]

$$k = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f).$$

Mathematically, the effect of the ECAPM is similar to the Blume beta adjustment, further adjusting beta toward 1.0 by a factor of 0.75.

[161] Wolfgang Bühler & Monika Trapp, *Time-Varying Credit Risk and Liquidity Premia in Bond and CDS Markets*, CFR Working Papers 09-13, Univ. of Cologne, Ctr. for Fin. Rsch. at 37 (2008), https://www.fdic.gov/analysis/cfr/2008/april/trapp-buhler.pdf.

[162] Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, p. 52.

A. **<u>The ECAPM is not used outside of utility regulatory proceedings, has not been validated by academic research, and cannot be found in standard finance textbooks.</u>**

Q. IS THE ECAPM WIDELY USED?

A. The ECAPM is used only in utility cost of capital proceedings, particularly by experts testifying on behalf of utilities. It is a model developed by Witness Morin not used anywhere else in finance; indeed, the latest version of Witness Morin's cost of capital textbook, Modern Regulatory Finance, refers to it as the "Empirical (Morin) CAPM."[163] No papers validating or endorsing the ECAPM have been published in any peer-reviewed journals, and it is not included in commonly used finance textbooks for students and corporate finance professionals. The papers commonly cited in support of the ECAPM discuss only the empirical observation of the security market line's (SML) flatness; they do not propose or validate the ECAPM itself. It is mentioned only in utility-focused practitioner guides, most notably Witness Morin's own books.

B. **<u>The research on which the ECAPM is based is not applicable to estimating the cost of equity in utility regulatory proceedings.</u>**

Q. IS THE ECAPM VALID FOR ESTIMATING THE COST OF EQUITY FOR A UTILITY?

A. The ECAPM is not valid for estimating the cost of equity for a utility, because the assumptions and data used in the academic studies on which it is based

[163] Modern Regulatory Finance at 220.

are not analogous to how the CAPM is implemented in utility cost of capital proceedings. There are two important differences.

First, the academic studies Witness Morin cites in support of his ECAPM all use a short-term risk-free rate; utility rate case CAPMs typically use a long-term risk-free rate, as both Witness Morin and I do. Using a long-term rate implicitly flattens the SML – the risk-free rate is higher, while the market return is unchanged. Because the ECAPM is based on the observation of a flattened slope relative to a short-term rate, it over-compensates.[164] Second, the academic studies cited in support of the ECAPM do not examine utilities specifically. As observed with beta, utilities' regulatory model can affect the behavior of their equity returns relative to the market. In addition, the academic studies Witness Morin cites in support of his ECAPM are all at least 25 years out of date.[165] The most recent study was published in 1995, based on data through 1990.[166]

When analyses in the papers cited in support of the ECAPM are re-run using a long-term risk-free rate and more recent data, the "flatness" in the SML largely disappears for the market as a whole, and completely disappears

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164 In substituting a long-term Treasury for a short-term risk-free rate, as is typically done in utility cost of capital analyses, analysts are implicitly adopting the zero-beta CAPM developed by Fisher Black, co-creator of the Nobel Prize winning Black-Scholes option pricing equation. This more general version of the CAPM does not require the existence of a risk-free rate (over the long term, the short-term rate is not risk-free, as investors are exposed to inflation and reinvestment risk; the long-term rate is subject to inflation if held to maturity and capital gains or losses due to interest rate changes if not), just an investable asset or portfolio with a beta equal to zero. Long-term government bonds meet this criterion.

165 Modern Regulatory Finance at 222.

166 Glenn Pettengill, Sridhar Sundaram, and Ike Mathur, *The Conditional Relation Between Beta and Returns*, 30 J. of Fin. & Quantitative Analysis at 101-116 (1995), https://doi.org/10.2307/2331255.

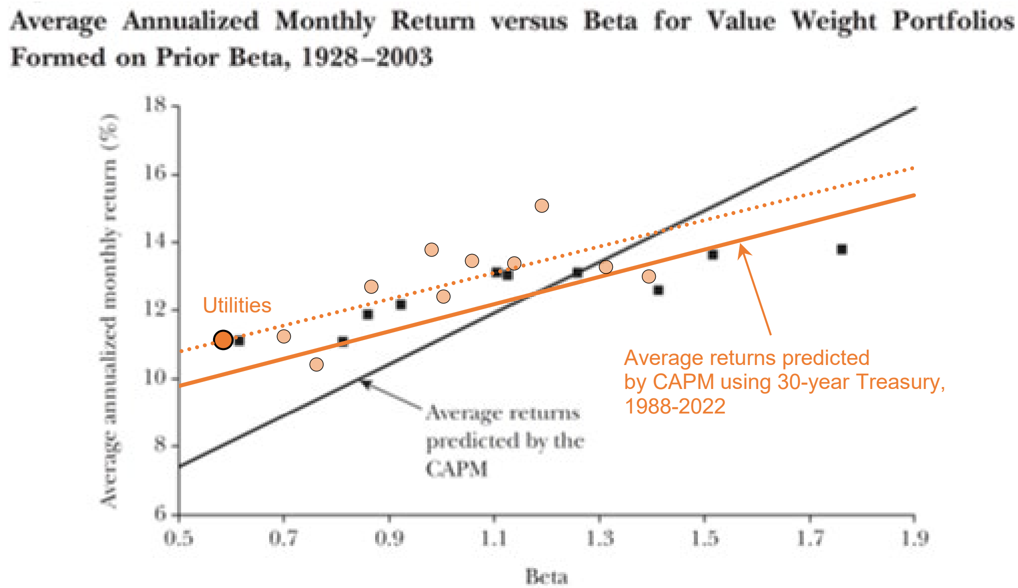
for utilities. Figure 27 shows a 2004 update of the well-known Fama-French (FF) analysis that is frequently cited in support of the ECAPM.[167] The FF analysis regresses the monthly annualized absolute returns of beta-sorted portfolios against realized beta.[168] Overlaying it is a replication using the 30-year Treasury instead of the original study's 1-month T-bill and adding the utility index. The data span the 35 years from January 1988 through December 2022. While the beta-sorted portfolios lie slightly above the SML, their regression slope and intercept coefficients are not statistically significantly different than the SML's (t-statistics of -0.09 and 0.66, respectively).[169] Utilities are also not statistically significantly different than the SML's prediction (t-statistic of 0.38).

[167] Eugene F. Fama & Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, 18:3 J. of Econ. Perspectives at 25-46 (2004), https://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430.

[168] In the replication, realized betas are calculated using excess returns, per the specification of the CAPM model, $k = r_f + \beta(r_m - r_f) + \varepsilon$.

[169] The t-statistic is the ratio of the departure of the estimated value of a parameter from its hypothesized value to its standard error. In regression models, t-statistics above 2.0 suggest the null hypothesis – here, that the regression slope and intercept are equal to the SML's – is not valid. The t-statistics of the replicated Fama-French analysis are both well below 2.0, indicating that the regression line of the portfolios against their betas is not statistically different than the SML.

Figure 27. Original Fama-French absolute return analysis and replication using 30-year Treasury[170]



Another classic test of the CAPM that is frequently cited in support of the ECAPM comes from Black, Jensen, and Scholes (BJS).[171] They regress monthly *excess* returns – the return on the asset in question minus the return on the zero-beta asset – against beta, as seen in Figure 28. The original BJS regression returned an intercept and slope statistically significantly different from the SML's, as seen in the solid (regression) and dotted (SML) black lines in Figure 28. When the BJS analysis is updated and excess returns calculated relative to the 30-year Treasury, the regression of the returns of the beta-sorted portfolios against beta (the solid orange line in Figure 28) are not

[170] Eugene F. Fama & Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, 18:3 J. of Econ. Perspectives at 33 (2004), https://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430; M. Ellis analysis of FDL data (last visited Mar. 6, 2023).

[171] Michael C. Jensen, Fischer Black, and Myron S. Scholes, *The Capital Asset Pricing Model: Some Empirical Tests*, Studies in the Theory of Capital Markets, Praeger Publishers Inc. (1972), https://ssrn.com/abstract=908569.

significantly different from the SML (the dotted orange line in Figure 28).[172] As with the Fama-French analysis, utilities are also not statistically significantly different than the SML's prediction (t-statistic of 0.29).

[172] Intercept t-statistic (H_0: 0): 0.26, slope t-statistic (H_0: SML slope): 0.36; comparable values for BJS are 6.52 and 6.53, respectively.

Figure 28. Original BJS excess return analysis and replication using 30-year Treasury[173]

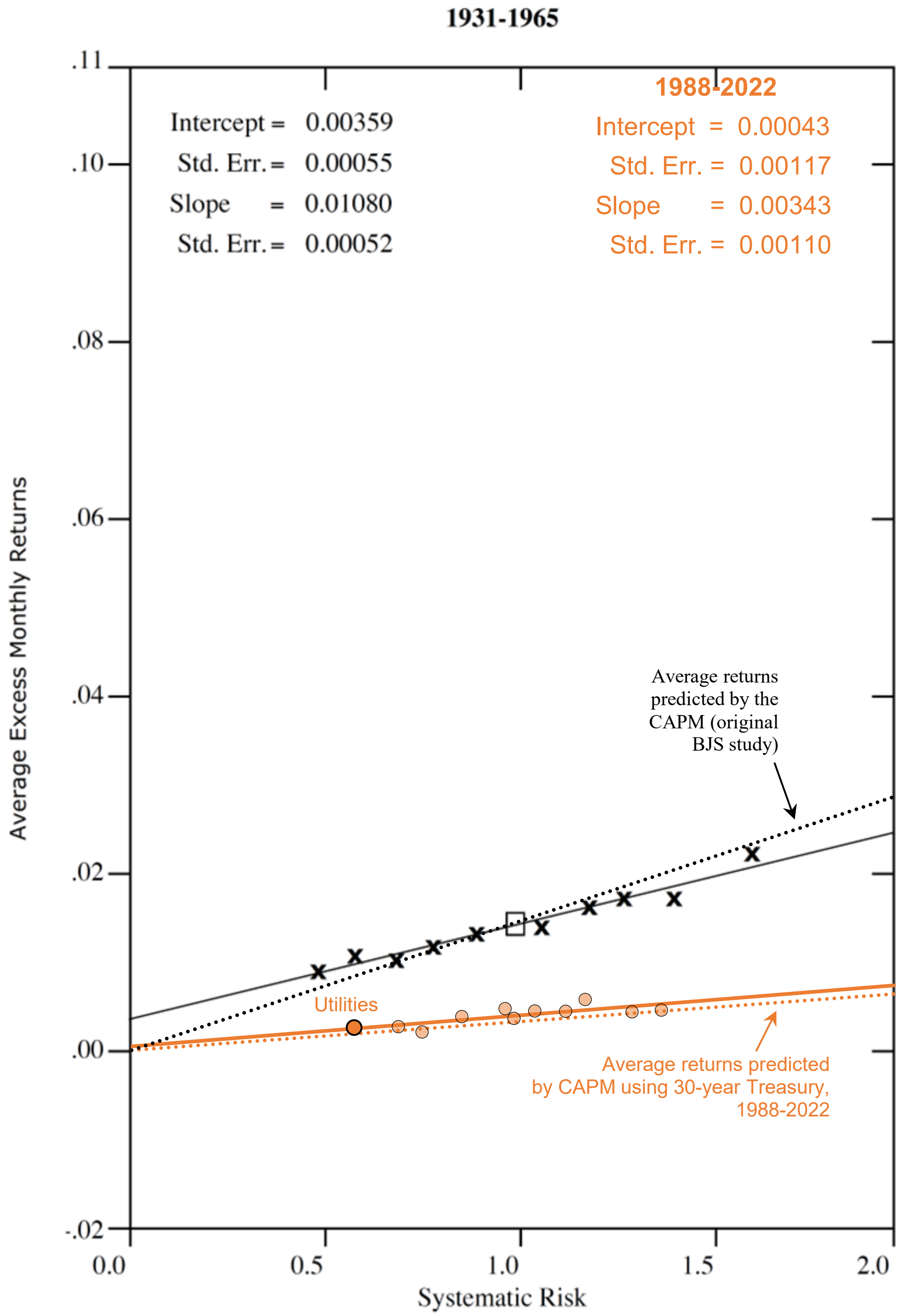


Figure 1 Average excess monthly returns versus systematic risk for the 35-year period 1931-65 for each of ten portfolios (denoted by ×) and the market portfolio (denoted by ☐).

C. <u>Witness Morin's ECAPM results should be disregarded.</u>

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ECAPM?

A.The ECAPM was developed by Witness Morin specifically for use in utility cost of capital proceedings; it is not used elsewhere and cannot be found in widely used finance texts. It is based on a misapplication of the academic research, which uses a short-term risk-free rate and does not examine utilities specifically. The findings of the original academic research cannot simply be "cut-and-pasted" into the utility cost of capital context.

When the analyses cited in support of the ECAPM are revised to reflect the context of utility cost of capital proceedings in which it is commonly applied – utility equity returns in excess of the return on the *long-term* Treasury – the purported "flatness" in the security market line disappears for both the market as a whole and specifically for utilities. Despite its name, the empirical data do not support the ECAPM's modifications to the traditional CAPM for use in estimating the cost of equity in utility regulatory proceedings. Witness Morin's ECAPM model results should be disregarded.

VIII. WITNESS MORIN'S RISK PREMIUM METHODOLOGY IS CONCEPTUALLY FLAWED.

Q. PLEASE EXPLAIN WITNESS MORIN'S RISK PREMIUM METHODOLOGY.

A. Witness Morin's Risk Premium methodology (RPM) refers to two models based on historical utility returns. The Historical RPM simply adds the average difference between historical utility sector stock market returns and long-term Treasury bond returns. The Allowed RPM is a regression model of historical authorized utility ROEs against long-term Treasury bond returns.

A. <u>Both the Historical and Allowed RPMs confuse the *cost of equity* with the *return on equity*.</u>

Q. WHAT IS THE INVALIDATING CONCEPTUAL FLAW IN THE RPM?

A. Both versions of Witness Morin's RPM confuse the cost of equity and the return on equity.

Q. PLEASE EXPLAIN HOW THE CONFUSION BETWEEN COE AND ROE IS MANIFEST IN THE HISTORICAL RPM.

A. The Historical RPM is based on historical actual stock market returns. As explained above, researchers have concluded that historical stock market returns exceeded reasonable investor expectations, a phenomenon known as the equity premium puzzle.[174] Because historical realized returns exceeded historical expected returns, historical realized returns should not be relied upon to predict expected future returns.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE HISTORICAL RPM?

A. Yes. As with the estimation of his CAPM MRP,[175] Witness Morin incorrectly calculates the utility risk premium using arithmetic returns and only the income component of long-term Treasury bond returns. He then adds this premium to his overstated forecast 30-year Treasury rate.

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[174] *See* Section V.C. above.
[175] *See* Section VI.C. above.

Q. PLEASE EXPLAIN HOW THE CONFUSION BETWEEN COE AND ROE IS MANIFEST IN THE ALLOWED RPM.

A. The Allowed RPM is essentially a model of past ROE decisions, not the actual cost of equity. By design, therefore, it repeats the historic overearnings arising from the excess ROEs authorized in the past. As explained in Section II.A above, the cost of equity and the return on equity are two entirely different concepts; there is no basis to assume that they are necessarily equal. In fact, as explained in Section 0 above, authorized ROEs have diverged dramatically from utilities' actual cost of equity, as reflected in the disparity between authorized ROEs and substantially lower forecast returns for the U.S. equity market as a whole, despite the latter's higher risk; utility market-to-book ratios exceeding 1.0 for decades; and the growing divergence between average authorized ROEs and interest rates. Basing a utility's authorized ROE on historically authorized ROEs without any reference to the actual cost of equity, as both the Allowed RPM does, merely perpetuates these errors.

A simple calculation illustrates the Allowed RPM's conceptual flaw in equating ROE and COE. ROE is the ratio of earnings to the book value of equity. But investors cannot buy shares at book value; they must pay market value. The market value of the stocks Witness Morin chose to include in his peer group tend to trade at a significant premium over book value, currently an average of 2.0x. Mathematically, if investors pay more than book value for the same stream of earnings, their expected return, i.e., the cost of equity, *must* be less than the ROE calculated using the book value.[176] For companies earning just their cost of equity, the expected return, i.e., the cost of equity, can be estimated by dividing earnings per share (EPS) by equity book value per share.[177] EPS can be expressed as the product of ROE and book value per share, so COE can similarly be expressed as ROE divided by the market-to-book ratio.[178] The COEs so calculated are dramatically lower than Witness Morin's Allowed RPM estimate of 10.5%. According to Value Line, the proxy group average 2022 ROE was just under 10.9%. At a M/B ratio of 2.0, investors' expected return would be only 10.9%/2.0 = 5.4%.[179] As Kahn explained, and Witness Morin has acknowledged (see Section II.B.2 above), M/B ratios greater than 1.0 imply COE is less than ROE. It is simply mathematically impossible for COE to equal ROE when M/B is not equal to 1.0 yet Witness Morin's Allowed RPM is nonetheless premised on this mathematical impossibility.

Q. ARE THERE ANY OTHER PROBLEMS WITH THE ALLOWED RPM?

A. In addition to its fundamental conceptual invalidity, Witness Morin's implementation is flawed in using a forecast Treasury bond yield as input. His

[176] A simple example illustrates why this must be true. Suppose one pays $1 for an investment that guarantees a payment of $0.10 – a return of $0.010/$1.00 = 10% – every year into perpetuity. If instead the initial cost was $2 instead of $1 for the same perpetual stream of $0.10 per year, the return would be $0.10/$2.00 = 5%. If the initial investment for the *identical* cash flow stream is higher, the return is lower.

[177] Aswath Damodaran, *Implied Equity Risk Premium: Principles & Mechanics* at 5 https://pages.stern.nyu.edu/~adamodar/pdfiles/eqnotes/webcasts/ERP/ImpliedERP.pdf (last visited Jul. 18, 2023).

[178] COE = EPS / stock price = ROE x book value per share / stock price = ROE / M/B.

[179] The EEA suffers other flaws, such as the growth adjustment to book value which does not account for new share issuance, but their effect is minor relative to the central conceptual flaw of confusing ROE and COE.

regression is based on actual, not forecast, Treasury yields. For consistency he would need to either base his model on historical forecast Treasury yields or use the current actual Treasury yield as his model input. This inconsistency is yet another instance of upward bias in Witness Morin's analysis.

B. <u>FERC has rejected the Allowed RPM.</u>

Q. HAS THE ALLOWED RPM BEEN REJECTED ELSEWHERE?

A. Yes. FERC has also recognized the flaws in the Allowed RPM. In Opinion No. 569 (November 2019), FERC rejected the use of the Allowed RPM to estimate the cost of equity:[180]

> [T]he Risk Premium model is likely to provide a less accurate current cost of equity estimate than the DCF model or CAPM because it relies on previous ROE determinations, whose resulting ROE may not necessarily be directly determined by a market-based method, whereas the DCF and CAPM methods apply a market-based method to primary data. For example, previous ROE determinations may not involve an explicit determination as to whether an ROE is just and reasonable, but instead focused on whether to allow an ROE incentive adder or were approving a preexisting RTO-wide ROE for a new RTO member. Similarly, many previous ROE determinations used in the Risk Premium model were the product of rate case settlements. Such settlements often involve compromises on a variety of issues present in a rate case, of which the appropriate ROE is only one. Consequently, such settlements could include ROEs that are not representative of the market cost of equity because the ROEs were negotiated above or below that market cost of equity in order to form an overall settlement package, together with negotiated outcomes on other issues, that were acceptable to the parties.

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[180] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Docket No. EL14-12-003, Opinion No. 569, 169 FERC at 166 ¶ 61,129 (2019).

Although FERC subsequently reinstated the RPM in Opinion No. 569-A (May 2020), the D.C. Circuit Court of Appeals found that FERC's reinstatement of the RPM was arbitrary and capricious and has vacated Opinion 569-A.[181]

C. Both of Witness Morin's Risk Premium methodology results should be disregarded.

Q. WHAT IS YOUR RECOMMENDATION REGARDING WITNESS MORIN'S RISK PREMIUM METHODOLOGIES?

A. Because they are based on data that reflect the actual (historical or authorized) *return* on equity, not the *cost* of equity, both the Historical and Allowed RPMs are conceptually flawed, and the results of both models should be disregarded.

IX. WITNESS MORIN'S FLOTATION COST ADJUSTMENT IS NOT ANALYTICALLY SOUND AND IS THEREFORE UNWARRANTED.

A. Witness Morin's flotation cost adjustment derivation reflects model blindness.

Q. WITNESS MORIN ADDS A FLOTATION COST ADJUSTMENT TO HIS ROE MODEL RESULTS. IS A FLOTATION COST ADJUSTMENT WARRANTED?

A. No. Witness Morin's flotation cost adjustment derivation is an example of model blindness, or mistaking his model, and the conclusions derived from it, for reality. Witness Morin derives his flotation cost adjustment as follows:[182]

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[181] Xena Burwell, *D.C. Circuit Court of Appeals Decision Puts FERC's Revised Method for ROE Determinations in Question*, Van Ness Feldman, LLP, Aug. 10, 2022, https://www.vnf.com/dc-circuit-court-of-appeals-decision-puts-fercs-revised-method-for-roe-determinations-in-question.

[182] Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, Appendix B: Flotation Cost Allowance, p. 4-5 (emphasis added).

From the standard DCF model, the investor's required return on equity capital is expressed as:

$$k = \frac{D_1}{P_0} + g.$$

If P_0 is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, *that is,* P_0 *equals* B_0, the book value per share, then the company's required return is:

$$r = \frac{D_1}{B_0} + g.$$

Denoting the percentage flotation costs f, proceeds per share B_0 are related to market price P_0 as follows:

$$P - fP = B_0$$
$$P(1 - f) = B_0$$

Substituting the latter equation into the above expression for return on equity, we obtain:

$$r = \frac{D_1}{P(1-f)} + g$$

that is, the utility's required return adjusted for underpricing. For flotation costs of 5%, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6% for example, the magnitude of the adjustment is 32 basis points: .06/.95 = .0632.

Witness Morin's model is clearly flawed. Consider the implication of the first term, $\frac{D_1}{P(1-f)}$. Flotation costs only affect the fraction of total shares that are newly issued each year, on the order of 2% for utilities, so Witness Morin's model overcompensates the owners of the other 98% percent of shares outstanding. Clearly, his model is not describing investors' expected returns in a competitive capital market.

A second clear flaw is his assumption that P_0 equals B_0, i.e., the M/B ratio is 1.0. As we know, utility stocks have not traded at an M/B ratio of 1.0 in decades. The standard version of the DCF model cannot be used to estimate the impact of new equity issuance on shareholder returns and the cost of equity.

B. <u>The Gordon DCF model explicitly accounts for the effect of new issuance on shareholder returns and the cost of equity.</u>

Q. HOW SHOULD WE THINK ABOUT THE IMPACT OF NEW EQUITY ISSUANCE ON THE COST OF EQUITY?

A. Another version of the DCF model *can* be used to estimate the impact of new equity issuance on shareholder returns and the cost of equity. Myron Gordon, in his classic 1974 text *The Cost of Capital to a Public Utility,* provides an alternative version of the DCF model that expands the growth term, g, into its two components: reinvestment of retained earnings and new share issuance:[183]

$$k = \frac{D_1}{P} + br + sv,$$

where b is the earnings retention ratio, r is ROE, s is the annual rate of new equity issuance (expressed as a share of existing book equity), and v is the accretion factor, equal to $1 - \frac{B}{P}$. Gordon's model explicitly incorporates both new equity issuance and the M/B ratio into the cost of equity. When the

[183] Myron J. Gordon, *The Cost of Capital to a Public Utility* at 31-32 (1974).

accretion factor is greater than 1.0, new equity issuance is *accretive* to existing shareholders, as Gordon explains:[184]

> [I]f $P > B$, part of the funds raised accrues to the existing shareholders. Specifically, it can be shown that $v = 1 - \frac{B}{P}$ is the fraction of the funds raised by the sale of stock that *increases* the book value of the existing shareholders' common equity. Also, v is the fraction of earnings and dividends generation by the new funds that accrues to the existing shareholders.

Incorporating flotation costs and writing out the accretion factor in the Gordon model yields:

$$k = \frac{D_1}{P} + br + s(1 - \frac{B}{P(1-f)}).$$

Mathematically, as long as $(1 - f)$ exceeds $\frac{B}{P}$, i.e., the reciprocal of the market-to-book ratio, existing shareholders *gain* from new share issuance. In Witness Morin's 5% flotation cost example, $1 - f$ = 0.95, much greater than the reciprocal of the DEC proxy group average M/B ratio, 1/2.0 = 0.5.

C. <u>In the face of a net reduction in total shares outstanding for the market overall, utilities have been the most active issuers of new shares over the past decade, providing direct evidence of new equity issuance's accretive effect for utilities.</u>

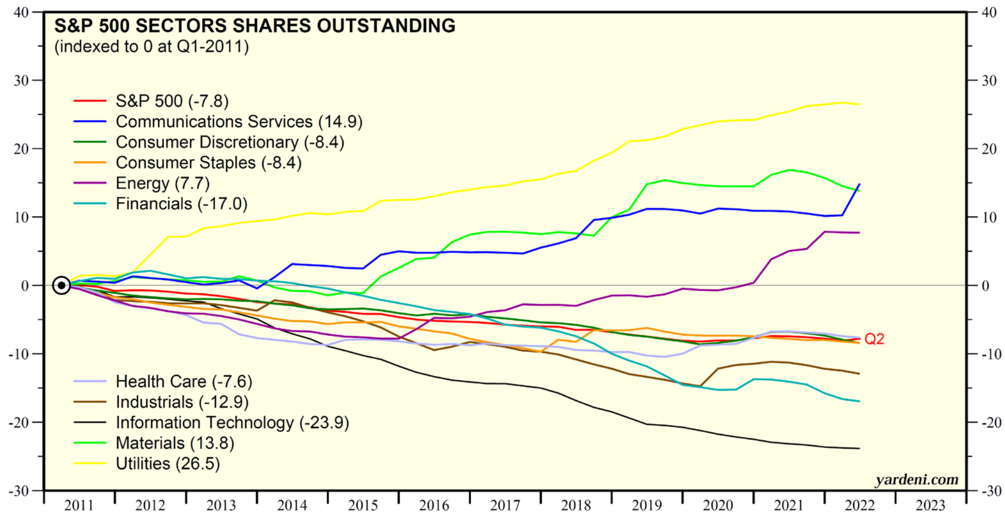
Q. IS THERE ANY MARKET EVIDENCE OF THE ACCRETIVE EFFECT OF UTILITY STOCK ISSUANCE?

A. The accretion effect of new equity issuance when the M/B ratio is greater than 1.0 in part explains why the utility sector has bucked the nationwide trend of net share repurchases over the last decade. As shown in Figure 29, while

[184] *Id*. at 32 (emphasis added).

total shares outstanding for the S&P 500 (red line) has declined by approximately 8% since 2011, the utility sector's share count (yellow line) has increased by over 25%.

Figure 29. S&P 500 sectors shares outstanding[185]



* Total basic shares outstanding for current S&P 500 companies with data for all periods and adjusted for stock splits and stock dividends.
Source: Yardeni Research and I/B/E/S data by Refinitiv.

Q. UNDER THE HOPE STANDARD AND NARUC FAIRNESS PRINCIPLE, ROE SHOULD EQUAL THE ACTUAL COST OF EQUITY. THIS WOULD IMPLY THAT THE MARKET-TO-BOOK RATIO EQUALS 1.0, IN WHICH CASE NEW EQUITY ISSUANCE WOULD NOT BE ACCRETIVE. IF THE COMMISSION ADHERES TO THE NARUC FAIRNESS PRINCIPLE, SHOULD ROE BE ADJUSTED FOR FLOTATION COSTS?

A. In principle, it could be argued that the ROE should be adjusted for anticipated equity issuance costs, *but only if* two conditions are met. First, the ROE, pre-flotation cost adjustment, must be set at the actual cost of equity, such that the M/B ratio is equal to 1.0. Second, the company must have concrete plans

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185 Edward Yardeni, et al., *Corporate Finance Briefing: S&P 500 Earnings & Share Count*, Yardeni Research, Inc., Nov. 14, 2022, https://www.yardeni.com/pub/sp500earnshare.pdf.

to issue new stock. According to Value Line's forecast, Duke Energy's share count will remain unchanged through 2027.[186]

In practice, though, adjusting for flotation costs is unwarranted, as doing so reflects false precision.[187] Using the Gordon model, we can estimate the magnitude of the flotation cost adjustment when the M/B ratio is 1.0. For large companies, secondary offering costs are roughly half Witness Morin's assumed 5%.[188] With a lower M/B ratio, a utility's incentive to issue new stock is reduced, so we can anticipate the rate of new issuance to be lower than the current 2.1% sector average, say 1%. At the DEC proxy group's estimated 6% COE, the flotation cost adjustment would be 0.03% – an amount that is overwhelmed by the imprecision in the models used to estimate the cost of equity. Adding a flotation cost adjustment is akin to the elementary school student, who, upon being asked what they learned during a field trip to the science museum, proudly says, "Earth is 4.5 billion years and [glancing at a clock] six hours and forty-three minutes old."

Witness Morin's flotation cost adjustment is conceptually flawed and not material. It should be disregarded.

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[186] Value Line, "Duke Energy" (Feb. 10, 2023).

[187] *See, e.g.*, "False Precision," Wikipedia, https://en.wikipedia.org/wiki/False_precision.

[188] *See, e.g.*, State of Georgia Public Service Commission Docket No. 44280, "Direct Testimony of James M. Coyne on Behalf of Georgia Power Company" at 41, Jun. 24, 2022, https://psc.ga.gov/search/facts-document/?documentId=190559.

X. WITNESS MORIN FAILS TO ACCOUNT FOR DIFFERENCES IN CAPITAL STRUCTURE AMONG THE PROXY GROUP MEMBERS.

Q. HOW DOES THE CAPITAL STRUCTURE AFFECT THE COST OF EQUITY?

A. All else equal, a lower equity ratio tends to raise the cost of equity. This can be understood intuitively. The cash generated by a business is pledged to holders of its debt and equity, with debtholders having first priority. As the equity ratio declines, a smaller share of the cash goes to equity owners. To the extent there is uncertainty in the cash generated, it is amplified by a lower equity ratio, increasing the riskiness of those cash flows. This increased risk is reflected in a higher cost of equity.

The companies in Witness Morin's proxy group have different (market) equity ratios,[189] and their average, 55%,[190] is also different from the 53% book equity ratio proposed by DEC. The proxy group average COE therefore cannot be used to estimate DEC's COE under its proposed equity ratio without taking these differences into account. Witness Morin's analysis neglects to do so.

I will revisit adjusting the COE model results for differences in equity ratios among the proxy group members, and between the proxy group average and DEC, in Section 0 below.

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[189] When determining the cost of capital, the market value of equity should be used. *See, e.g.*, Tim Koller et al., *Valuation*, McKinsey & Co. at 204 (3rd ed. 2000) ("Where possible, you should estimate *market* values of the elements of the current capital structure") (emphasis added).

[190] M. Ellis analysis of S&P GMI data (last visited Jun. 30, 2023).

XI. ROE AND CAPITAL STRUCTURE ARE INTERRELATED AND CANNOT BE DETERMINED SEPARATELY.

A. <u>ROE and capital structure are interrelated through ROE's impact on cash flow.</u>

Q. DOES THE CAPITAL STRUCTURE IMPACT CUSTOMER COSTS?

A. Yes. Capital structure refers to the share of a utility's investment that is funded by debt and equity. Because equity generally has a higher cost than debt, assuming no change in authorized ROE, a higher equity ratio tends to increase customer costs.

Q. DOES THE CAPITAL STRUCTURE IMPACT A UTILITY'S CREDIT QUALITY?

A. Yes. A primary determinant of a company's credit quality – its anticipated ability to repay its debts – is the amount of debt outstanding relative to the total amount of capital, both debt and equity, invested in the company. In general, a higher equity ratio tends to improve a utility's credit quality. Equity ratio is not the only determinant of credit quality, though. As will be explained in more detail below, credit quality is also determined by the amount of cash available to service the debt.

Q. PLEASE EXPLAIN THE RELATIONSHIP BETWEEN ROE AND CAPITAL STRUCTURE.

A. A data request response provided by Spencer Heuer, DEC's Treasury Manager, reveals that ROE and capital structure are inextricably linked:

> The key financial metric both agencies monitor for credit rating purposes is Funds from Operations (FFO) to Debt. Moody's also refers to this as Cash Flow from Operations pre working capital (CFO pre-W/C) to Debt. Moody's benchmark FFO/Debt range for

> DE Carolinas' current rating is 20% to 25%. S&P uses a family rating methodology, in which the subsidiaries credit ratings are notched up or down from the credit rating of Duke Energy Corp. As shown in DE Carolinas' most recent S&P credit report the FFO/Debt range for Duke Energy Corp.'s current rating is 12% to 16%.[191]

Mr. Heuer describes the importance of the ratio of funds from operations (FFO) to debt in rating agencies' assessments of utility credit quality. FFO (or, for Moody's the similar CFO pre-W/C) measures the cash available to pay debt interest and principal. What Mr. Heuer does not explain is that net income is a key component of FFO.[192] Net income, in turn, is the product of rate base, equity ratio, and ROE. Consequently, ROE and equity ratio are key determinants of FFO.

In the context of the regulatory objective of setting a capital structure that appropriately balances customer and investor interests, as ROE increases, the amount of debt in the capital structure can also increase while still maintaining the utility's credit quality; similarly, as the ROE declines, the equity ratio would need to increase to maintain the same creditworthiness.

Curiously, the testimony of DEC's capital structure expert, Treasurer Karl Newlin, makes no reference whatsoever to FFO or any other credit

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191 *See* Duke Energy Carolinas response to Public Staff Data Request 14.12. Though DEC's response to this request is marked confidential, counsel for DEC have confirmed that the information provided in this quote does not contain any confidential material.

192 The basic definition of FFO is net income + depreciation and amortization. *See, e.g.*, Corporate Finance Institute, *FFO – Funds from Operations: A measure of cash flow used in real estate*, Dec. 16, 2020, https://corporatefinanceinstitute.com/resources/knowledge/accounting/funds-from-operations-ffo/.

metrics, yet refers to his 53% equity ratio recommendation as "optimal."[193] Witness Newlin does not provide quantitative analysis of any sort in support of his capital structure recommendation.[194]

Q. HOW SHOULD A UTILITY'S CAPITAL STRUCTURE BE DETERMINED?

A. The appropriate capital structure can be determined more rigorously by using the analytical methods and metrics employed by credit rating agencies and referenced by Mr. Heuer. The level of debt that can be accommodated in the capital structure will vary with ROE, because funds from operation (FFO), a key determinant of a utility's creditworthiness, is based on net income, and net income is based on ROE, for any given credit rating and its corresponding FFO/debt ratio.

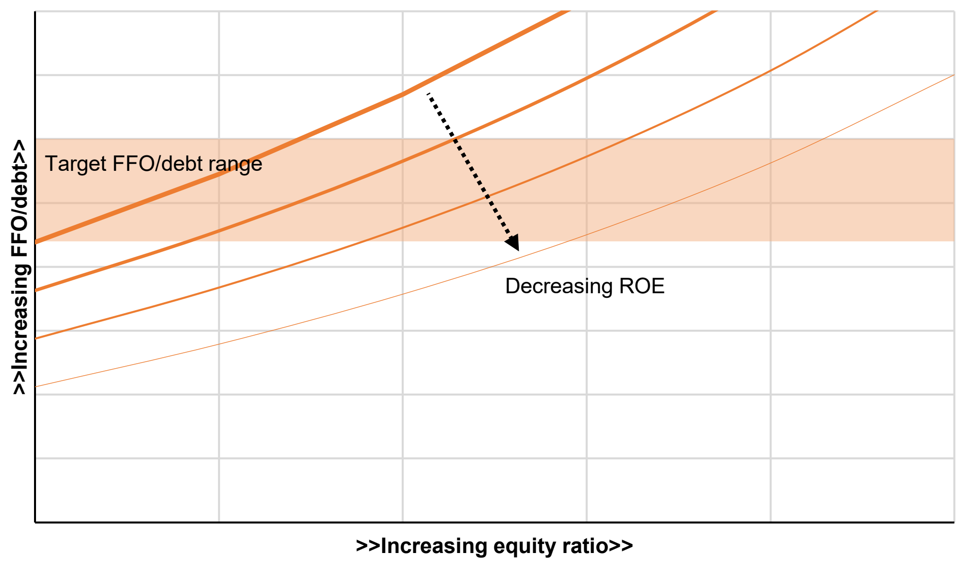
Figure 30 illustrates the relationships between equity ratio, ROE, and FFO/debt. The horizontal axis is the equity ratio; the vertical axis is FFO/debt. The light orange horizontal band represents the range of FFO/debt that corresponds to the utility's desired credit rating. The dark orange arcing lines correspond to different levels of authorized ROE, with increasing line thickness representing increasing ROE. Holding the equity ratio constant, FFO/debt declines as the ROE is reduced (moving down from a thicker ROE line to a thinner line). But the decline in FFO/debt when ROE is reduced can be reversed by increasing the equity ratio (moving along the thinner ROE line

[193] Direct Testimony of Karl W. Newlin for Duke Energy Carolinas, LLC, p. 13. Witness Newlin's testimony refers in passing to the FFO/debt ratio in the context of coal ash basin closure costs (p. 18-19) but does not explain its meaning or significance nor provide any quantitative analysis of the metric.

[194] Direct Testimony of Karl W. Newlin for Duke Energy Carolinas, LLC.

up and to the right). Any number of combinations of ROE and equity ratio can meet the level of FFO/debt needed to maintain the utility's credit rating. A higher ROE requires less equity to maintain the same FFO/debt and credit rating; a lower ROE can maintain the same FFO/debt and credit rating if it is paired with a higher equity ratio.

Figure 30. Illustrative relationships between equity ratio, ROE, and FFO/debt



Many observers see utilities' healthy credit ratings and low cost of debt and conclude that the best way to reduce customer costs is to increase the amount of debt in the capital structure. As explained above, current authorized ROEs far exceed utilities' actual cost of equity, so ample scope exists for the Commission to reduce DEC's ROE without adversely affecting its ability to raise equity. At typical utility credit ratings, savings from a lower ROE, after grossing up for taxes, generally more than make up for the incremental cost of any additional equity required in the capital structure. For example, based on analysis of data provided in Moody's May 2023 DEC credit opinion,[195] every 1.0% reduction in ROE reduces total customer costs by more than 2%, *even after* accounting for the approximately 1.6% increase in equity ratio needed to maintain DEC's current cash flow-to-debt ratio.[196]

Total customer costs can be reduced by decreasing the ROE while increasing the equity ratio to maintain the utility's creditworthiness (i.e., its cash flow-to-debt) because the trade-off is not one-for-one. Net income accounts for about 46% of DEC's FFO; other items, such as depreciation and amortization, account for the rest. Consequently, a relatively large reduction in net income due to a sharp cut in ROE would reduce FFO by less than half as much in percentage terms. In addition, ROE is grossed-up for taxes, which are not included in FFO, so the savings to customers from a lower ROE is amplified. Rather than "lever up," i.e., reduce the equity ratio and increase debt, at current ROEs to reduce rates, it is more cost-effective to use any spare credit capacity to reduce the utility's ROE, or even to increase the equity ratio if necessary to maintain a target credit rating, than to increase debt.

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[195] M. Ellis analysis of data provided in Duke Energy Carolinas response to NCJC et al. Data Request 5.1 (Moody's Investors Service, *Duke Energy Carolinas, LLC: Update to credit analysis*, May 11, 2023).

[196] Moody's preferred cash flow metric is cash flow from operations (CFO), not FFO, and the analysis is based on Moody's CFO/debt data. The basic definition of CFO is net income + depreciation and amortization + changes in working capital, i.e., FFO + changes in working capital. *See* Corporate Finance Institute, *How to Calculate FCFE from CFO?*, Jan. 6, 2023, https://corporatefinanceinstitute.com/resources/knowledge/accounting/how-to-calculate-fcfe-from-cfo/.

Reducing ROE and increasing the equity ratio has the additional benefit of reducing debt-to-capitalization, another key metric used by rating agencies to assess credit quality.[197]

B. <u>DEC's capital structure proposal does not address the interaction between ROE and capital structure.</u>

Q. DOES DEC'S CAPITAL STRUCTURE PROPOSAL TAKE INTO ACCOUNT THE INTERACTION BETWEEN ROE AND CAPITAL STRUCTURE?

A. Neither Witness Morin nor Witness Newlin provides any analysis or calculations demonstrating how FFO/debt interacts with ROE and how that interaction influences DEC's proposed equity ratio. As a result, how much DEC's proposed ROE and/or the equity ratio could be reduced to lower customer costs while still maintaining its desired investment-grade credit rating cannot be assessed from the testimony and data DEC has provided.

DEC's analysis should have included a detailed analysis of the relationships between ROE, equity ratio, and creditworthiness and the impact of different combinations of equity ratio and ROE on customers, lenders, and shareholders so that the Commission could examine the ability of DEC to obtain sufficient capital while minimizing customer costs. The Commission should require DEC to provide a detailed analysis of the relationships between ROE, equity ratio, and creditworthiness so that the Commission possesses the facts it needs to come to fact-based conclusions about DEC's

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197 *See, e.g.*, Duke Energy Carolinas response to NCJC et al. Data Request 5.1 (Moody's Investors Service, *Duke Energy Carolinas, LLC: Update to credit analysis*, May 11, 2023).

authorized capital structure. DEC's ROE and equity ratio should optimally balance customer and investor interests.

C. <u>COE model results must be adjusted for differences in equity ratio.</u>

Q. IN SECTION X ABOVE, YOU DISCUSSED ADJUSTING COE MODEL RESULTS FOR DIFFERENCES IN EQUITY RATIOS AMONG THE PROXY GROUP MEMBERS. HOW DO YOU DO THAT?

A. The MS DCF and CAPM yield levered costs of equity. To account for differences in capital structure among the proxy group members, the COE results are unlevered to estimate the cost of equity assuming 100% equity financing.[198] The unlevered cost of equity, k_u, is typically expressed as an adjustment to beta in the CAPM:

$$k_u = r_f + \beta_u(r_m - r_f),$$ [199]

where the unlevered beta, β_u, is expressed in terms of the levered equity beta, β_e:

$$\beta_u = \frac{E}{D+E}\beta_e.$$ [200]

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198 The unlevered cost of equity differs from the weighted average cost of capital ("WACC"). The unlevered cost of capital assumes 100% equity financing; the WACC assumes the company's current capital structure. While under the Modigliani and Miller theorem of capital structure independence, the cost of capital should be the same regardless of capital structure, the WACC typically overstates the unlevered cost of equity because the *expected* return on corporate debt is lower than the yield due to default and liquidity risk.

199 *See, e.g.*, Aswath Damodaran, *Damodaran on Valuation: Security Analysis for Investment and Corporate Finance*, Wiley at 129 (2d ed. 2006).

200 Unlevered beta is sometimes adjusted for taxes (the "Hamada" adjustment). As explained in *Valuation*, when the capital structure is constant over time, as it is with utilities, then the value of tax shields tracks the value of operating assets. Thus, the risk of tax shields will mirror the risk of operating assets and have the same discount rate, i.e., the unlevered cost of equity. *Id*. at 790-93.

For consistency and comparability, I apply the same methodology – unlevering relative to the risk-free rate, not the company's cost of debt – to the MS DCF model results:

$$k_u = r_f + \frac{E}{D+E}\beta_l(r_m - r_f)$$

$$k_e - r_f = \beta_l(r_m - r_f)$$

$$k_u = r_f + \frac{E}{D+E}(k_e - r_f)$$

$$k_u = \frac{D}{D+E}r_f + \frac{E}{D+E}k_e,$$

where D and E refer to debt and equity, respectively. Best practice is to use market, not book, values for both debt and equity as market reflects investors' actual exposure; they buy and sell securities at market value, not book.[201] Market values for the debt carried by the proxy group members are not readily available, though, so book value is assumed.

[201] *See, e.g.*, Tim Koller et al., *Valuation*, McKinsey & Co. at 204 (3d ed. 2000) ("Where possible, you should estimate *market* values of the elements of the current capital structure") (emphasis added).

Figure 31. Proxy group levered COEs, equity ratios, and unlevered COEs
Percent, as of June 2023

	Levered COE			Equity	Unlevered COE		
Utility	MS DCF	CAPM	Average	**ratio**[202]	MS DCF	CAPM	Average
Alliant	6.44	6.05	6.24	59.8	5.41	5.17	5.29
Ameren	5.93	5.63	5.78	58.0	5.06	4.89	4.98
AEP	6.87	5.69	6.28	49.9	5.36	4.78	5.07
Avista	7.72	5.89	6.80	51.1	5.83	4.90	5.37
Black Hills	6.57	6.19	6.38	47.6	5.15	4.97	5.06
CenterPoint	5.11	7.37	6.24	51.5	4.51	5.67	5.09
CMS	6.58	5.30	5.94	54.2	5.34	4.64	4.99
Dominion	8.83	5.65	7.24	47.6	6.23	4.72	5.47
DTE	6.51	6.25	6.38	54.0	5.30	5.15	5.23
Edison	7.09	7.12	7.10	41.0	5.19	5.20	5.19
Entergy	7.58	6.44	7.01	44.8	5.53	5.02	5.28
Evergy	6.83	5.85	6.34	52.2	5.42	4.90	5.16
Eversource	6.96	5.77	6.37	50.7	5.44	4.83	5.13
FirstEnergy	6.94	5.61	6.28	49.0	5.38	4.72	5.05
IDACORP	5.38	6.32	5.85	70.0	4.93	5.59	5.26
NorthWestern	7.42	5.65	6.53	57.2	5.90	4.89	5.39
OGE	6.46	6.70	6.58	60.7	5.44	5.59	5.51
Otter Tail	5.17	5.89	5.53	80.2	4.91	5.49	5.20
Portland General	7.03	6.21	6.62	54.8	5.60	5.15	5.37
Sempra	5.67	6.78	6.23	58.5	4.93	5.57	5.25
Southern	6.86	5.89	6.37	54.7	5.51	4.98	5.24
WEC	6.42	5.49	5.96	60.7	5.42	4.85	5.14
Xcel	6.23	5.59	5.91	57.2	5.22	4.85	5.04
Mean	**6.63**	**6.06**	**6.35**	**55.0**	**5.35**	**5.07**	**5.21**
Standard deviation	0.86	0.59	0.43	4.9	0.38	0.27	0.15
High	8.83	7.37	7.24	59.8	6.23	5.67	5.47
Low	5.11	5.30	5.78	41.0	4.51	4.64	4.98
High-low	3.72	2.08	1.46	18.9	1.72	1.03	0.50
Duke	*7.64*	*5.57*	*6.60*	*46.2*	*5.61*	*4.66*	*5.13*

The variation in the unlevered COE estimates is much lower than in the levered COEs, with approximately one-third the standard deviation (0.15 vs 0.43) and range (0.50 vs. 1.46). The underlying businesses of the proxy group members are very similar, so their risk profiles and corresponding overall costs of capital are expected to be similar as well. Their equity ratios vary considerably, though, from 41% to 60%, which introduces variation in their levered costs of equity. This variation due to differences in equity ratios makes levered COEs an inappropriate basis for determining the ROE of a

[202] M. Ellis analysis of S&P GMI data (last visited Jun. 30, 2023). Market equity ratio is based on June 2023 average.

target company, like DEC, which will likely have a different (market) equity ratio.

Q. HOW DO YOU USE THE PROXY GROUP AVERAGE UNLEVERED COE TO DETERMINE YOUR RECOMMENDATION FOR DEC'S ROE, WHICH IS LEVERED?

A. The unlevered COE is "relevered" using the same formula described above, the terms of which can be rearranged as:

$$k_e = \frac{D+E}{E} k_u - \frac{D}{E} r_f.$$

In Section XI above, I explained that the equity ratio depends on ROE. ROE, in turn, depends on the equity ratio. They can be determined jointly, in an iterative calculation process that is easily performed in common spreadsheet software like Microsoft Excel or Google Sheets.

D. <u>ROE and equity ratio should be optimized to minimize customer costs while meeting investor requirements.</u>

Q. IN SECTION XI.A ABOVE, YOU PROVIDED AN ILLUSTRATIVE ANALYSIS OF THE INTER-RELATIONSHIPS BETWEEN EQUITY RATIO, ROE, AND CREDIT QUALITY. CAN YOU CONDUCT THAT ANALYSIS SPECIFICALLY FOR DEC?

A. Yes. Such an analysis can be conducted for DEC using data provided in Moody's most recent credit update.[203]

Figure 32 applies the analysis illustrated in Figure 30 above to the financial data provided in Moody's May 2023 credit update for DEC. As

[203] Duke Energy Carolinas response to NCJC et al. Data Request 5.1 (Moody's Investors Service, *Duke Energy Carolinas, LLC: Update to credit analysis*, May 11, 2023). Data from Moody's is used, not the financial data in DEC's regulatory filing, because Moody's makes various adjustments to DEC's reported financials that are not explained in sufficient detail to replicate using DEC's data.

before, different levels of ROE are represented by the upward curving lines. As the equity ratio increases along the horizontal axis, so does the FFO-to-debt ratio, depicted on the vertical axis. Here, cash flow from operations (CFO) is used instead of FFO, for consistency with Moody's preferred metric.[204] Horizontal dashed black lines have been added at the CFO/debt level that corresponds to DEC's target A2 rating (23% CFO/debt), as well as the CFO/debt that would result from DEC's proposed 53% equity ratio and 10.40% ROE (indicated by the gray dot on the upper, gray arc).[205] The corresponding CFO/debt ratio, 24.1%, is well above the 23% required to maintain DEC's current A2 credit rating. Either or both of DEC's proposed ROE and equity ratio can be reduced to lower customer costs while still satisfying investor demands.

The lower, orange arc represents DEC's 5.21% unlevered (100% equity) COE. As discussed previously, the corresponding levered ROE will increase as the equity ratio declines. To maintain DEC's current A2 rating would require an equity ratio of 58.8%, modestly higher than DEC's proposal, and

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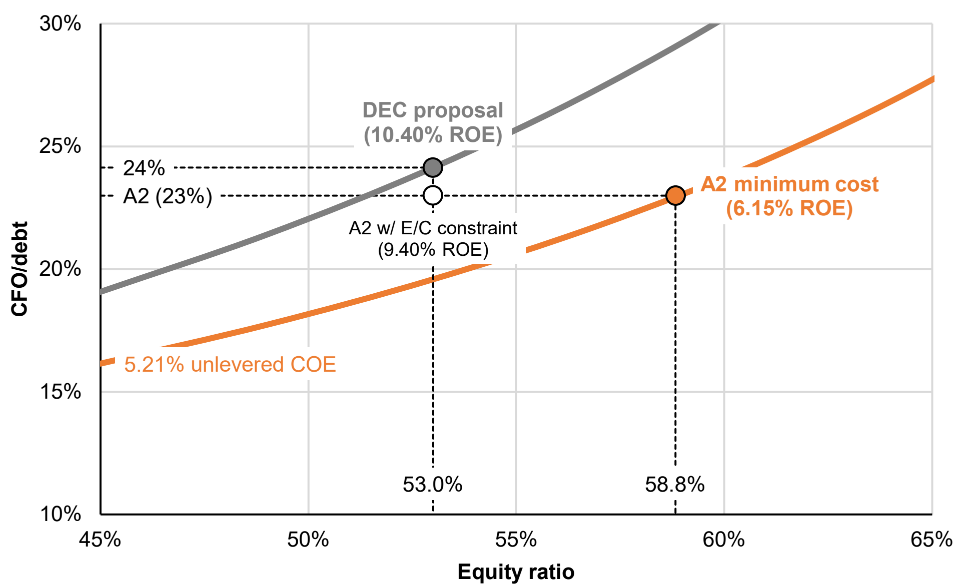
[204] *See* Duke Energy Carolinas response to NCJC et al. Data Request 5.1 (Moody's Investors Service, *Duke Energy Carolinas, LLC: Update to credit analysis*, May 11, 2023). Moody's preferred cash flow metric is cash flow from operations (CFO), not FFO, and the analysis is based on Moody's CFO/debt data. The basic definition of CFO is net income + depreciation and amortization + changes in working capital, i.e., FFO + changes in working capital. *See* Corporate Finance Institute, *How to Calculate FCFE from CFO?*, Jan. 6, 2023, https://corporatefinanceinstitute.com/resources/knowledge/accounting/how-to-calculate-fcfe-from-cfo/.

[205] In Duke Energy Carolinas response to NCJC et al. Data Request 5.1 (Moody's Investors Service, *Duke Energy Carolinas, LLC: Update to credit analysis*, May 11, 2023), Moody's provides CFO/debt thresholds for one-grade up- and downgrades of 21% and 25%, respectively. The threshold for DEC's current rating is estimated as the midpoint, 23%.

an ROE of 6.15%. The impact on customer costs associated with the lower ROE and higher equity ratio will be quantified below.

The white dot immediately below DEC's proposal represents a scenario in which an equity ratio constraint is imposed, here equal to DEC's proposed 53%. To maintain an A2 credit rating under this constraint, the ROE would need to be increased to 9.40%. The impact on customer costs associated with this equity ratio constraint will also be quantified below.

Figure 32. Relationship between equity ratio, ROE, and credit quality for DEC



E. <u>An optimized ROE and equity ratio can significantly reduce customer costs while meeting the demands of both equity and debt investors.</u>

Q. HOW WOULD AN OPTIMIZED ROE AND EQUITY RATIO IMPACT CUSTOMER COSTS?

A. Figure 33 compares the revenue requirement (pre-tax) weighted average rate of return for the three scenarios depicted in Figure 32. The ROE optimized for an A2 rating, 6.15%, is 41% lower than Witness Morin's proposed ROE of

10.40% (line 2). Even with the higher 58.8% equity ratio, after grossing up for taxes, the revenue requirement ROR, 6.49%, is 30% lower than DEC's 9.22% (lines 6-7).[206]

Figure 33 also shows the average annual total revenue requirement under each of the three scenarios (line 8). Based on analysis of DEC's general rate case filings, its proposed combined rate of return for both debt and equity, the latter grossed up for taxes, accounts for approximately 32% of its revenue requirement.[207] The 2021 test year total revenue requirement under DEC's proposal is $5.56 billion. An optimized ROE and equity ratio at an A2 target credit rating reduces total customer costs by over 9% (line 10) or $520 million per year (line 9).

An equity ratio constraint would impose fairly substantial costs on customers, increasing the revenue requirement ROR to 8.53%, more than 2% higher than the minimum cost scenario. While total customer costs are lower than under DEC's proposal, they are only 25% of the reduction without an equity ratio constraint. This result further demonstrates the flaw in the "lever up" (reduce the equity ratio) argument described in Section XI.A above. It is much more cost effective to use any spare credit capacity to reduce ROE than to increase debt.

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[206] M. Ellis analysis using Duke Energy Carolinas response to Public Staff Data Request 203.34.
[207] *Id.*

Figure 33. Revenue requirement (pre-tax) rate of return under different weighted under DEC proposal, minimum cost, and equity ratio constraint scenarios
Percent (except lines 8 and 9)

		DEC proposal	Minimum cost	Equity ratio constraint
1	Equity ratio	53.0%	58.8%	53.0%
2	ROE	10.40%	6.15%	9.40%
3	Cost of debt	4.31%	4.31%	4.31%
4	Rate of return	7.54%	5.39%	7.01%
5	Tax rate	23.4	23.4	23.4
6	**Rev. requirement rate**	9.22%	6.49%	8.53%
7	*ΔDEC proposal*		-30	-7
8	**Rev. requirement ($ B)**	5.56	5.04	5.43
9	Customer savings ($ B)		-0.52	-0.13
10	*ΔDEC proposal*		-9.3	-2.3

Q. WHAT ARE THE IMPLICATIONS OF AN OPTIMIZED ROE AND EQUITY RATIO ON RESIDENTIAL CUSTOMER BILLS?

A. DEC's projected average residential revenue is approximately $1,350 per year under its proposed ROE and equity ratio.[208] Assuming the 9.3% total cost reduction under my ROE and equity ratio recommendations is allocated uniformly across customer classes, DEC residential customers would save approximately $125 per year.

Q. WITNESS MORIN MAINTAINS THAT LOW ROES CAN INCREASE THE FUTURE COST OF CAPITAL AND CUSTOMER COSTS.[209] SHOULD THE COMMISSION BE CONCERNED THAT YOUR ROE AND CAPITAL STRUCTURE RECOMMENDATIONS WILL ADVERSELY IMPACT CUSTOMERS?

A. Like many of Witness Morin's other claims, this one is also unsubstantiated. During discovery, Witness Morin was asked to provide any empirical data,

[208] Residential sales and customer count from Duke Energy Carolinas response to Public Staff Data Request 89.1; average residential revenue per kWh from Beveridge Direct Exhibit No. 2_2.
[209] Direct Testimony of Roger A. Morin for Duke Energy Carolinas, LLC, p. 7-8.

academic studies, or other evidence to support his claim that low ROEs actually raise customer costs. He provided the single example of Arizona Public Service (APS), whose ROE was reduced in 2021, resulting in a credit downgrade.[210] Witness Morin provided no evidence that any associated increase in APS's cost of debt exceeded the customer savings from a lower ROE; indeed, he specifically cited evidence to the contrary: "The rate case decision result will in a base rate *decrease* of $119.8 million and a substantive decline in the authorized ROE to 8.7% from 10%."[211] As my detailed analysis for DEC demonstrates, a lower ROE can substantially reduce DEC customer costs.

Q. WHAT ARE YOUR ROE AND EQUITY RATIO RECOMMENDATIONS FOR DEC?

A. I recommend maintaining DEC's current A2 credit rating, which is two full grades above the Baa1 proxy group average rating. At its current A2 credit rating, a 6.15% ROE and 58.8% equity ratio would minimize customer costs while meeting investor return expectations, consistent with the Supreme Court's guidance provided in *Hope Natural Gas* to set "just and reasonable rates" through a "balancing of the investor and the consumer interests." In contrast, DEC's proposal and the equity ratio-constrained scenario, which caps the equity ratio at DEC's proposed 53% and sets the ROE sufficient to maintain an A2 credit rating, are overly generous to investors at the expense

[210] Duke Energy Carolinas response to NCJC et al. Data Request 5.2, which is attached as Exhibit MEE-8.
[211] *Id*. (emphasis added).

of customers and therefore fail the Hope standard. Figure 34 summarizes my COE analysis and ROE and equity ratio recommendations.

Figure 34. Summary of DEC COE analysis and recommended ROE and equity ratio
Percent

Model	COE	Key assumptions
MS DCF	**6.63**	
Dividend yield	3.76	Most recent quarterly dividend divided by one-month trailing price history (~21 trading days)
Initial growth rate	5.58	Analysts' earnings-per-share growth rates for three years to mitigate upward bias
Terminal growth rate	1.70	Based on long-term historical utility dividend-per-share growth rate equal to inflation
CAPM	**6.06**	
Risk-free rate	3.87	Current (one-month trailing average) 30-year Treasury
Beta	0.55	5-year monthly balances long-term historical trend and current market conditions
Market risk premium	3.96	Average of forward-looking using MS DCF and long-term historical average; MS DCF long-term growth rate equal to pre-capita GDP
• Historical	4.91	
• Forward	3.01	
Mean COE – Levered	**6.15**	Average of DCF and CAPM COE estimates
– Unlevered	5.21	55% proxy group average *market* equity ratio
Equity ratio	**58.8**	
Relevered COE/ recommended ROE	**6.15**	

Q. IF THE COMMISSION ADOPTS YOUR ROE AND EQUITY RATIO RECOMMENDATIONS, HOW WOULD DUKE ENERGY'S SHAREHOLDERS BE AFFECTED?

A. ROEs in excess of the cost of equity resembles a zero-sum game, with the interests of shareholders and customers in direct opposition. If the Commission adopted my recommended ROE and equity ratio, I would expect Duke Energy's share price to experience a one-time downward adjustment as investors reset their expectations for future returns. Duke Energy would still be able to access the equity markets, because DEC's ROE, based on its actual cost of equity, i.e., investors' *expected* return,[212] would be sufficient to satisfy investors' demands. Investors who purchase shares after the one-time adjustment would earn returns comparable to the return current Duke Energy shareholders expect.

I said that ROE above the cost of equity *resembles* a zero-sum game between shareholders and customers. It is not quite zero-sum between these two parties, though, because there is a third party: the tax authorities. ROE is grossed-up for taxes; to the extent ROE is reduced, taxes are also reduced. In aggregate, a lower ROE provides approximately 30% more benefit to customers than shareholders lose in foregone profit.[213] As shown in Figure 35, of the $520-million reduction in revenue requirement under my recommended ROE and capital structure (the minimum cost A2 scenario in Figure 33, line 9), the decline in DEC's net income accounts for $360 million; $110 million is foregone taxes, of which approximately $95 million (87%) is Federal.[214]

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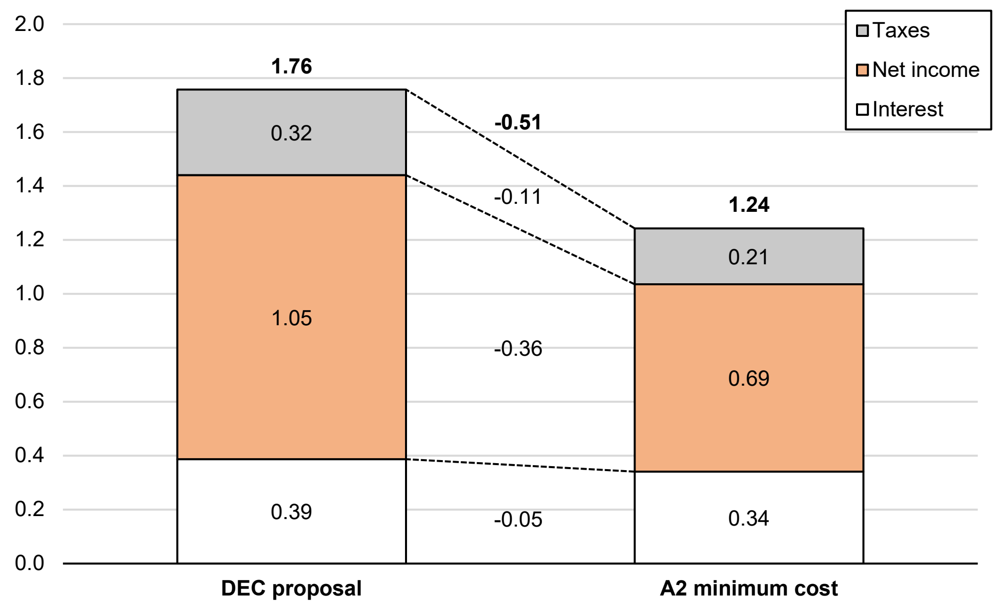
212 "Cost of equity" and "*expected* return on equity" are synonymous. *See supra* footnote 13.

213 DEC's marginal tax rate is approximately 23.4%. The tax gross-up is 1/(1 – 23.4%) = 1.3. *See* Duke Energy Carolinas response to Public Staff Data Request 203.34.

214 20.35725% Federal net of State / 23.3503% Composite = 87.3%. *See* Duke Energy Carolinas, LLC, Calculation of 2021 Tax Rates.

Figure 35. Interest, ROE, and income tax revenue requirement under DEC proposal and A2 minimum cost scenario
$ billion



It is important to recognize that *Hope* established that regulators are not obligated to maintain utility stock market valuations, and that such an obligation would make a nonsense of regulators' consumer protection mandate:

> Ratemaking is indeed but one species of price-fixing. The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact that the value is reduced does not mean that the regulation is invalid. It does, however, indicate that "fair value" is the end product of the process of ratemaking, not the starting point, as the Circuit Court of Appeals held. The heart of the matter is that rates cannot be made to depend upon "fair value" when the value of the going enterprise depends on earnings under whatever rates may be anticipated.[215]

[215] *Hope Nat. Gas Co.,* 320 U.S. at 601.

The impact on Duke Energy's stock price should not factor at all into the Commission's determination of the appropriate ROE and equity ratio.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of Mark E. Ellis on Behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Southern Alliance for Clean Energy, Natural Resources Defense Council, and Vote Solar either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 19th day of July, 2023.

/s/ Munashe Magarira

Munashe Magarira

MARK E. ELLIS

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Mark E. Ellis is a former utility executive now working as an independent consultant and testifying expert in finance and economics in utility regulatory proceedings.

Before establishing his own consultancy, Mark led the strategy function at Sempra Energy (parent of SDG&E and SoCalGas) for fifteen years. Previously, he worked as a consultant in McKinsey's energy practice, in international project development for ExxonMobil, and in industrial demand-side management for Southern California Edison. He has an MS from MIT's Technology and Policy Program, where he focused on utility policy and conducted research in the MIT Energy Lab, and a BS in mechanical engineering from Harvard.

EXPERT TESTIMONY

Client	State	Utility	Description	Docket	Date
North Carolina Justice Center et al.	NC	Duke Energy Carolinas	Cost of capital	E-7, Sub 1276	1/23-ongoing
North Carolina Justice Center et al.	NC	Duke Energy Progress	Cost of capital	E-2, Sub 1300	1/23-ongoing
The Utility Reform Network	CA	San Diego Gas & Electric, Southern California Gas	Wildfire liability insurance	A.22-05-015 & 016	1/23-ongoing
The Utility Reform Network	CA	Southern California Edison	Wildfire liability self-insurance	A.19-08-013	1/23-ongoing
Georgia Interfaith Power & Light	GA	Georgia Power	Cost of capital	44280	8/22-12/22
Clean Wisconsin	WI	Wisconsin Electric Power, Wisconsin Gas	Cost of capital	5-UR-110	8/22-12/22
The Protect Our Communities Foundation	CA	San Diego Gas & Electric, Southern California Gas	Cost of capital	A.22-04-008, et seq.	4/22-ongoing
The Utility Reform Network	CA	Pacific Gas & Electric	Wildfire liability self-insurance	A.21-06-021	11/21-ongoing
The Protect Our Communities Foundation	CA	Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison	Cost of capital	A.21-08-013, et seq.	11/21-ongoing
New Hampshire Department of Energy	NH	Aquarion Water Company of New Hampshire	Cost of capital	DW 20-184	6/21-2/22
The Utility Reform Network	CA	Pacific Gas & Electric	$7.5-billion wildfire cost securitization	A.20-04-023	6/20-2/21

EMPLOYMENT

Company	Title	Location	Date
Self-employed	Independent consultant and testifying expert	La Jolla, CA	2019-present
Sempra Energy	Chief of Corporate Strategy	San Diego, CA	2004-19
McKinsey & Company	Engagement Manager	Houston, TX	2000-03
ExxonMobil	Venture Development Advisor	Houston, TX	1996-2000
MIT Energy Laboratory	Research Assistant	Cambridge, MA	1994-96
Southern California Edison	Staff Engineer	Irwindale, CA	1994
Sanyo Electric Company	Research Engineer	Osaka, Japan	1992-93
Los Angeles Department of Water & Power	Seasonal Waterworks Laborer	Chatsworth, CA	1988

EDUCATION

Institution	Degree	Date
Massachusetts Institute of Technology	MS, Technology and Policy	1996
Harvard University	BS, *magna cum laude,* Mechanical and Materials Sciences and Engineering	1992

Title
Essays on Energy and Environmental Economics

Author
Dunkle Werner, Karl W

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2021

Peer reviewed|Thesis/dissertation

Essays on Energy and Environmental Economics

by

Karl W. Dunkle Werner

A dissertation submitted in partial satisfaction of the

requirements for the degree of

Doctor of Philosophy

in

Agricultural and Resource Economics

in the

Graduate Division

of the

University of California, Berkeley

Committee in charge:

Associate Professor James Sallee, Chair
Professor Severin Borenstein
Associate Professor Meredith Fowlie

Spring 2021

Essays on Energy and Environmental Economics

by
Karl Dunkle Werner

Abstract

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Doctor of Philosophy in Agricultural and Resource Economics

University of California, Berkeley

Associate Professor James Sallee, Chair

Over the past decades, two things have become increasingly apparent: first, climate change and associated environmental impacts are pressing issues, and second, despite this growing threat, existing policies still fall far short. The goal of my research, and what I hope for the field more broadly, is to achieve effective, efficient, and equitable policy. My dissertation research covers a wide range of topics, focusing on three different areas of energy and environmental economics: methane emissions from oil and gas production; flooding on agricultural land; and energy utility regulatory rates of return. The common thread is using applied economic tools and answering policy-relevant questions with data and analysis. Often, the data that are available are far from the ideal dataset, or the policies that are on the table are far from the first best. Here, my coauthors and I adopt the "economist as plumber" mindset, using the tools that are available to address the challenges at hand (Duflo 2017).

In my first chapter, my coauthor Wenfeng Qiu and I study emissions of methane, a powerful greenhouse gas, from oil and gas wells in the US. These emissions contribute significantly to climate change—they are approximately as large as the emissions of all fuel burned in the western US electricity grid. Methane emissions are rarely priced and lightly regulated—in part because they are hard to measure—leading to a large climate externality. However, measurement technology is improving, with remote sensing and other techniques opening the door for policy innovation. We present a theoretical model of emissions abatement at the well level and a range of feasible policy options, then use data constructed from cross-sectional scientific studies to estimate abatement costs. We simulate audit policies under realistic constraints, varying the information the regulator uses in choosing wells to audit. These policies become more effective when they can target on well covariates, detect leaks remotely, and charge higher fees for leaks. We estimate that a policy that audits 1% of wells with uniform probability achieves less than 1% of the gains of the infeasible first best. Using the same number of audits targeted on remotely sensed emissions data achieves gains of 30–60% of the first best. These results demonstrate that, because leaks are rare

events, targeting is essential for achieving welfare gains and emissions reductions. Auditing a small fraction of wells can have a large impact when properly targeted. Our approach highlights the value of information in designing policy, centering the regulatory innovation that is possible when additional information becomes available.

My second chapter is coauthored with Oliver Browne, Alyssa Neidhart, and Dave Sunding. We study high-frequency flood risk on agricultural land. Floods destroy crops and lower the value of agricultural land. Economic theory implies that the hedonic discount on the value of a parcel of flood-prone land should scale with the expected probability flooding. Most empirical studies of the impact of flood risk on property values in the United States focus on the relatively small risk posed by the 100-year or 500-year floodplains, as reported in maps produced by the Federal Emergency Management Agency (FEMA). These studies consequently find a relatively small corresponding discount in property values. However, a significant amount of agricultural bottom-land lies in floodplains that flood more frequently. We estimate the hedonic discounts on with agricultural land that floods at these higher frequencies along the Missouri River. As flood risk increases, the value of flood-prone land decreases, with a hedonic discount ranging from close to zero in the 500-year floodplain to approximately 17% in the 10-year floodplain. To illustrate the importance of characterizing these higher frequency flood risks, we consider a climate change scenario, where properties that already face some flood risk are expected to flood more frequently.

My third chapter, coauthored with Stephen Jarvis, examines the regulated rate of return on equity utility companies are allowed to collect from their customers. Utilities recover their capital costs through regulator-approved rates of return on debt and equity. The US costs of risky and risk-free capital have fallen dramatically in the past 40 years, but these utility rates of return have not. We estimate the gap between what utilities are paid now, and what they would have been paid if their rate of return had followed capital markets, using a comprehensive database of utility rate cases dating back to the 1980s. We estimate that the current average return on equity is 0.5–4 percentage points higher than historical relationships would suggest, and consumers pay an average of $2–8 billion per year more than they would otherwise. We then revisit the effect posited by Averch and Johnson (1962), estimating the consequences of this incentive to own more capital: a 1 percentage point increase in the return on equity increases new capital investment by about 5% in our preferred estimate.

REFERENCES

Averch, Harvey, and Leland L Johnson. 1962. "Behavior of the firm under regulatory constraint." *The American Economic Review* 52 (5): 1052–1069. (Cited on page 2).

Duflo, Esther. 2017. "The Economist as Plumber." *American Economic Review* 107, no. 5 (May): 1–26. https://doi.org/10.1257/aer.p20171153. (Cited on page 1).

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Transition

The next chapter focuses on state policies governing electricity and natural gas utility companies. These state-level decisions determine how utilities are paid for their investments, and how much utility customers have to pay for their service. Capital investments, from pipelines to solar farms, play an enormous role in shaping future US greenhouse gas emissions. While chapter 2 considered future changes in flood risk due to climate shifts, chapter 3 considers these very important capital investments. We focus on how much utilities are paid for their capital, the incentives utilities have to own more, and the effect of these incentives on capital ownership.

Chapter Three

Rate of Return Regulation Revisited

Coauthor: Stephen Jarvis

1 INTRODUCTION

In the two decades from 1997 to 2017, real annual capital spending on electricity distribution infrastructure by major utilities in the United States has doubled (EIA 2018a). Over the same time period annual capital spending on electricity transmission infrastructure increased by a factor of seven (EIA 2018b). The combined total is now more than $50 billion per year. This trend is expected to continue. Bloomberg New Energy Finance predicts that between 2020 and 2050, North and Central American investments in electricity transmission and distribution will likely amount to $1.6 trillion, with a further $1.7 trillion for electricity generation and storage (Henbest et al. 2020).[1]

These large capital investments could be due to the prudent actions of utility companies modernizing an aging grid. However, it is noteworthy that over this time period, utilities have earned sizeable regulated rates of return on their capital assets, particularly when set against the unprecedented low interest rate environment post-2008. As the economy-wide cost of capital has fallen, utilities' regulated rates of return have not fallen nearly as much. The exact drivers for this divergence are unclear, though we rule out large changes in riskiness in section 3. Whatever the underlying cause, the prospect of utilities earning excess regulated returns raises an age-old concern in the sector: the Averch–Johnson effect. When utilities are allowed to earn excess returns on capital, they will be incentivized to over-invest in capital assets. The resulting costs from "gold plating" are then passed on to consumers in the form of higher bills. Capital markets and the utility industry have undergone significant changes over the past 50 years since the early studies of utility capital ownership (Joskow 1972, 1974). In this paper we use new data to revisit these issues. We do so by exploring two main research questions. First, what can we say about the return on equity utilities are allowed by their regulators? Second, how has this return on equity affected utilities' capital investment decisions?

To answer our research questions, we use data on the utility rate cases of all major electricity and natural gas utilities in the United States spanning the past four decades (Regulatory Research Associates 2021). We combine this with a range of financial information on credit ratings, corporate borrowing and market returns. To examine possible sources of over-investment in more detail we also incorporate data from annual regulatory filings on

1. North and Central American generation/storage are reported directly. Grid investments are only reported globally, so we assume the ratio of North and Central America to global is the same for generation/storage as for grid investments.

individual utility capital spending.

We start our analysis by estimating the size of the gap between the allowed rate of return that utilities earn and the correct return on equity. A central challenge here, both for the regulator and for the econometrician, is estimating the correct cost of equity. We proceed by considering a range of approaches to simulating the correct cost of equity based on the observed rates of return and available measures of capital market returns. For the most part, our simulations ask "if approved RoE rates hadn't changed relative to some benchmark index since some baseline year, what would they be today?" We examine a number of benchmark indexes. None of these are perfect comparisons; the world changes over time, and different benchmarks may be more or less appropriate. Taken together, our various estimation approaches result in a consistent trend of excess rates of return. We find that the weighted median of the approved return on equity is 0.5–4 percentage points too high.[2] Applying these additional returns to the existing capital base we estimate excess costs to US customers of $2–8 billion per year. The majority of these excess costs are from the electricity sector, though natural gas contributes as well.[3]

However, excess regulated returns on equity will also distort the incentives to invest in capital. To consider the change in the capital base, we turn to a regression analysis. Here we aim to identify how a larger RoE gap translates into over investment in capital. Identification is challenging in this setting, so we again employ several different approaches, with different identifying assumptions. In addition to a fixed effects approach, we examine an instrumental variables strategy. We draw on the intuition that when a rate case is decided a utility's RoE is *fixed* at a particular nominal percentage for several years. The cost of capital in the rest of the economy, and therefore the true RoE, will shift over time. We use these shifts in the timing and duration of rate cases as an instrument for changes in the RoE gap. We argue that the instrument is valid, after controlling for an appropriate set of fixed effects. Across the range of specifications used, we find a broadly consistent picture. In our preferred specification we find that an additional percentage point increase in the RoE gap leads to the allowed increase in capital rate base to be about 5 percent higher.

2 BACKGROUND

Electricity and natural gas utility companies are regulated by government utility commissions, which allow the companies a geographic monopoly and, in exchange, regulate the rates the companies charge. These utility commissions are state-level regulators in the US. They set consumer rates and other policies to allow investor owned utilitys (IOUs) a designated rate of return on their capital investments, as well as recovery of non-capital costs. This rate of return on capital is almost always set as a nominal percentage of the installed capital base. For instance, with an installed capital base worth $10 billion and a rate of return of 8%, the utility is allowed to collect $800 million per year from customers for debt service and to provide a return on equity to shareholders. State utility commissions typically update these nominal rates every 3–6 years.

Utilities own physical capital (power plants, gas pipelines, repair trucks, office buildings, etc.). The capital depreciates over time, and the

2. Here we weight by the utilities' ratebase, so our results are not over-represented by very small utilities.

3. For comparison, total 2019 electricity sales by investor owned utilities were $204 billion, on 1.89 PWh of electricity (US Energy Information Administration 2020a). Natural gas sales to consumers are $146 billion on 28.3 trillion cubic feet of gas (These gas figures include sales to residential, commercial, industrial, and electric power, but not vehicle fuel. They include including all sales, not just those by investor owned utilities. US Energy Information Administration 2020b.)

set of all capital the utility owns is called the ratebase (the base of capital that rates are calculated on). Properly accounting for depreciation is far from straightforward, but we will not focus on that challenge in this paper. This capital ratebase has an opportunity cost of ownership: instead of buying capital, that money could have been invested elsewhere. IOUs fund their operations through issuing debt and equity, typically about 50%/50%. (For this paper, we focus on common stocks. Utilities issue preferred stocks as well, but those form a very small fraction of utility financing.) The weighted average cost of capital is the weighted average of the cost of debt and the cost of equity.

Utilities are allowed to set rates to recover all of their costs, including this cost of capital. For some expenses, like fuel purchases, it's easy to calculate the companies' costs. For others, like capital, the state public utilities commissions are left trying to approximate the capital allocation at a cost competitive capital markets would provide, if the utility was a competitive company, rather than a regulated monopoly. The types of capital utilities own, and their opportunities to add capital to their books, vary across states and time. Utilities in vertically integrated states might own a large majority of their own generation, the transmission lines, and the distribution infrastructure. Other utilities are "wires only," buying power from independent power producers and transporting it over their lines. Natural gas utilities are typically pipeline only – the utility doesn't own the gas well or processing plant.

In the 1960s and 70s, state public utilities commissions (PUCs) began adopting automatic fuel price adjustment clauses. Rather than opening a new rate case, utilities used an established formula to change their customer rates when fuel prices changed. The same automatic adjustment has not happened for capital costs, despite large swings in the nominal cost of capital over the past 50 years. We're aware of one state (Vermont) that has an automatic update rule; we'll discuss that rule in more detail in section 4.1, where we consider various approaches of estimating the RoE gap.[4]

The cost of debt financing is by no means simple, particularly for a forward-looking decision-maker who isn't allowed to index to benchmark values, but is easier to estimate than the cost of equity financing. The cost of debt is the cost of servicing historical debt, and expected costs of new debt that will be issued before the next rate case. The historical cost is known, and can serve a direct basis for future expectations. In our data, we see both the utilities' requested and approved return on debt. It's notable that the requested and approved amounts are very close for debt, and much farther apart for equity.

The cost of equity financing is more challenging. Theoretically, it's the return shareholders require on their investment in order to invest in the first place. The Pennsylvania Public Utility Commission's ratemaking guide notes this difficulty (Cawley and Kennard 2018):

> Regulators have always struggled with the best and most accurate method to use in applying the [*Federal Power Commission v. Hope Natural Gas Company* (1944)] criteria. There are two main conceptual approaches to determine a proper rate of return on common equity: "cost" and "the return necessary to attract capital." It must be stressed, however,

4. At least one other state, California, had an automatic adjustment mechanism that has since been abandoned. Regulators at the California PUC feel that the rule, called the cost of capital mechanism (CCM), performed poorly. "The backward looking characteristic of CCM might have contributed to failure of ROEs in California to adjust to changes in financial environment after the financial crisis. The stickiness of ROE in California during this period, in the face of declining trend in nationwide average, calls for reassessment of CCM." (Ghadessi and Zafar 2017)

> that no single one can be considered the only correct method and that a proper return on equity can only be determined by the exercise of regulatory judgment that takes all evidence into consideration.

Unlike debt, where a large fraction of the cost is observable and tied to past issuance, the cost of equity is the ongoing, forward-looking cost of holding shareholders' money. Put differently, the RoE is applied to the entire ratebase – unlike debt, there's typically no notion of paying a specific RoE for specific stock issues.

Regulators employ a mixture of models and subjective judgment. Typically, these formal models, as well as the more subjective evaluations, benchmark against other US utilities (and often utilities in the same geographic region). There are advantages to narrow benchmarking, but when market conditions change and everyone is looking at their neighbors, rates will update very slowly.

In figure 1 we plot the approved return on equity over 40 years, with various risky and risk-free rates for comparison. The two panels show nominal and real rates. Consistent with a story where regulators adjust slowly, approved RoE has fallen slightly (in both real and nominal terms), but much less than other costs of capital. This price stickiness by regulators also manifests in peculiarities of the rates regulators approve. Rode and Fischbeck (2019) notes the fact that regulators seem reluctant to set RoE below a nominal 10%.

That paper, Rode and Fischbeck (2019), is the closest to ours in the existing literature. The authors use the same rate case dataset we do, and note a similar widening of the spread between the approved return on equity and 10-year Treasury rates. That paper, unlike ours, dives into the financial modeling, using the standard capital asset pricing model (CAPM) to examine potential causes of the increase the RoE spread. In contrast, we consider a wider range of financial benchmarks (beyond 10-year Treasuries) and ask more pointed questions about "what should rates be today if past relationships held?" and "how much has this RoE gap incentivized utilities to own more capital?"

Using CAPM, Rode and Fischbeck (2019) rule out a number of financial reasons we might see increasing RoE spreads. Possible reasons include utilities' debt/equity ratio, the asset-specific risk (CAPM's β), or the market's overall risk premium. None of these are supported by the data. A pattern of steadily increasing debt/equity could explain an increasing gap, but debt/equity has fallen over time. Increasing asset-specific risk could explain an increasing gap, but asset risk has (largely) fallen over time. (They use the Dow Jones Utility Average as a measure of utility asset risk.) An increasing market risk premium has could explain an increased spread between RoE and riskless Treasuries, but the market risk premium has fallen over time. Appendix figure 8, reproduced from Rode and Fischbeck (2019), shows the evolution of asset risk and the market risk premium over time.

Prior research has highlighted the importance of macroeconomic changes, and that these often aren't fully accounted for in utility commission ratemaking (Salvino 1967; Strunk 2014). Because rates of return are typically set in fixed nominal percentages, rapid changes in inflation can dramatically shift a utility's real return. This pattern is visible in figure 1 in the early 1980s. Inflation has lower and much more stable in recent years,

Many authors have written a great deal about modifying the current system of investor-owned utilities. Those range from questions of who pays for fixed grid costs to the role of government ownership or securitization (Borenstein, Fowlie, and Sallee 2021; Farrell 2019). For this project, we assume the current structure of investor-owned utilities, leaving aside other questions of how to set rates across different groups of customers or who owns the capital.

Finally, we note that a utility's approved rate of return or return on equity might differ from the realized return. In this paper, we focus on approved values. Other recent work, e.g. Hausman (2019), highlights important differences between approved costs and realized prices that customers face.

3 DATA

To answer our research questions, we use a database of resolved utility rate cases from 1980 to 2021 for every electricity and natural gas utility that either requested a nominal-dollar ratebase change of $5 million or had a ratebase change of $3 million authorized (Regulatory Research Associates 2021). Summary statistics on these rate cases can be seen in table 1.

We transform this panel of rate case events into an unbalanced utility-by-month panel, filling in the rate base and rate of return variables in between each rate case. There are some mergers and splits in our sample, but our SNL Financial (SNL) data provider lists each company by its present-day (2021) company name, or the company's last operating name before ceased to exist. With this limitation in mind, we construct our panel by (1) not filling data for a company before its first rate case in a state, and (2) dropping companies five years after their last rate case. In contexts where a historical comparison is necessary, but the utility didn't exist in the benchmark year, we use average of utilities that did exist in that state, weighted by ratebase size.

We match with data on S&P credit ratings, drawn from SNL's *Companies (Classic) Screener* (2021) and Wharton Research Data Services (WRDS)' *Compustat S&P legacy credit ratings* (2019). Most investor-owned utilities are subsidiaries of publicly traded firms. We use the former data to match as specifically as possible, first same-firm, then parent-firm, then same-ticker. We match the latter data by ticker only. Then, for a relatively small number of firms, we fill forward.[5] Between these two sources, we have ratings data are available from December 1985 onward. Approximately 80% of our utility–month observations are matched to a rating. Match quality improves over time: approximately 89% of observations after 2000 are matched.

These credit ratings have changed little over 35 years. In figure 2 we plot the median (in black) and various percentile bands (in shades of blue) of the credit rating for utilities active in each month. We note that the median credit rating has not changed much over time. The distribution of ratings is somewhat more compressed in 2021 than in the 1990s. While credit ratings are imperfect, we would expect rating agencies to be aware of large changes in riskiness.[6] Instead, the median credit rating for electricity utilities is A−, as it was for all of the 1990s. The median credit rating for natural gas utilities is also A−, down from a historical value of A.

Beyond credit ratings, we also use various market rates pulled from Federal Reserve Economic Data (FRED). These include 1-, 10-, and 30-year treasury yields, the core CPI, bond yield indexes for corporate bonds rated by Moody's as Aaa or Baa, as well as those rated by S&P as AAA, AA, A, BBB, BB, B, and CCC or lower.[7]

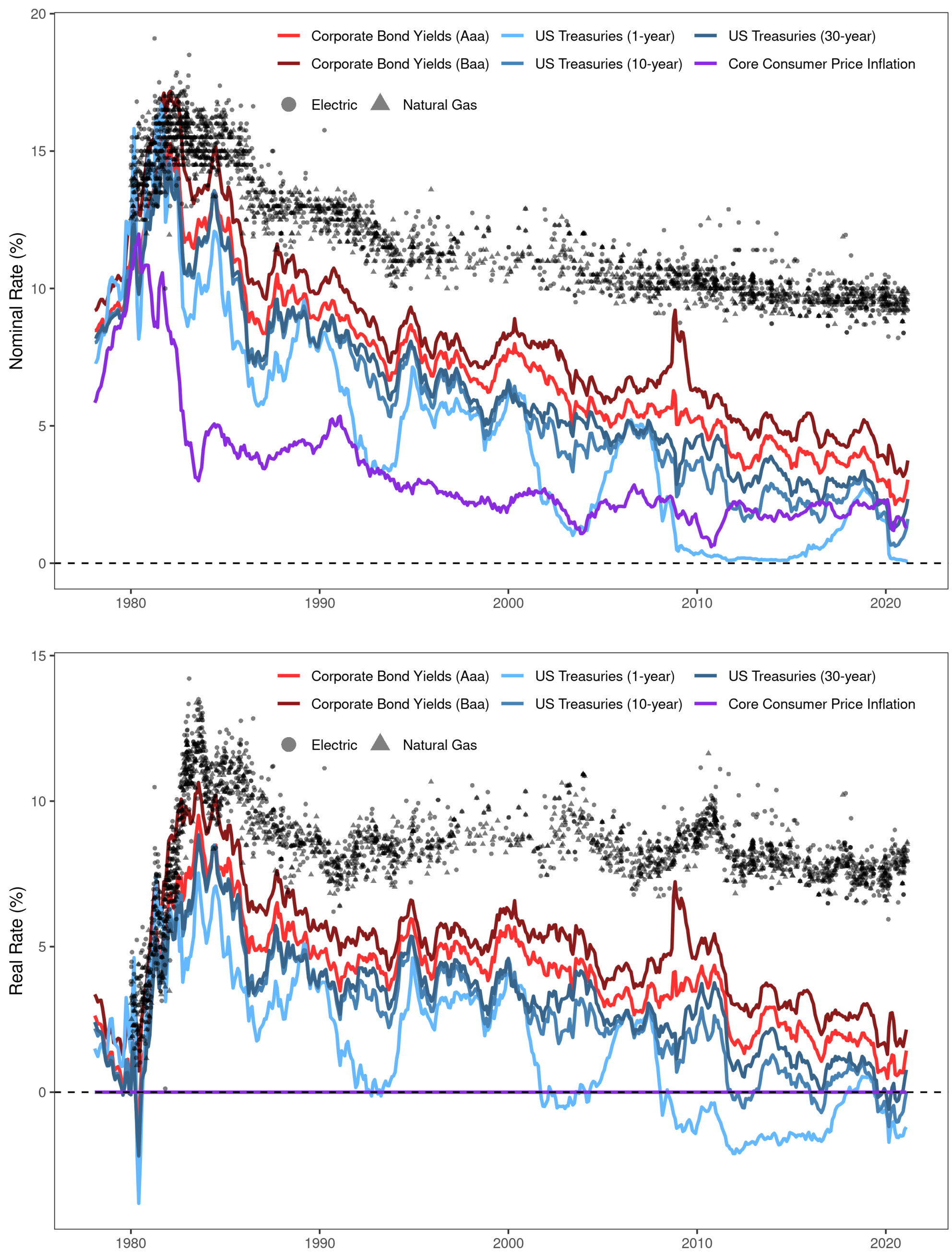
Matching these two datasets – rate cases and macroeconomic indicators – we construct the

5. When multiple different ratings are available, e.g. different ratings for subsidiaries trading under the same ticker, we take the median rating. We round down in the case of an even number of ratings, both here and in figure 2.

6. For utility risk to drive up the firms' cost of equity but not affect credit ratings, one would need to tell a very unusual story about information transmission or the credit rating process.

7. Board of Governors of the Federal Reserve System (2021a, 2021b, 2021c), US Bureau of Labor Statistics (2021), Moody's (2021a, 2021b), and Ice Data Indices, LLC (2021b, 2021a, 2021f, 2021d, 2021c, 2021g, 2021e).

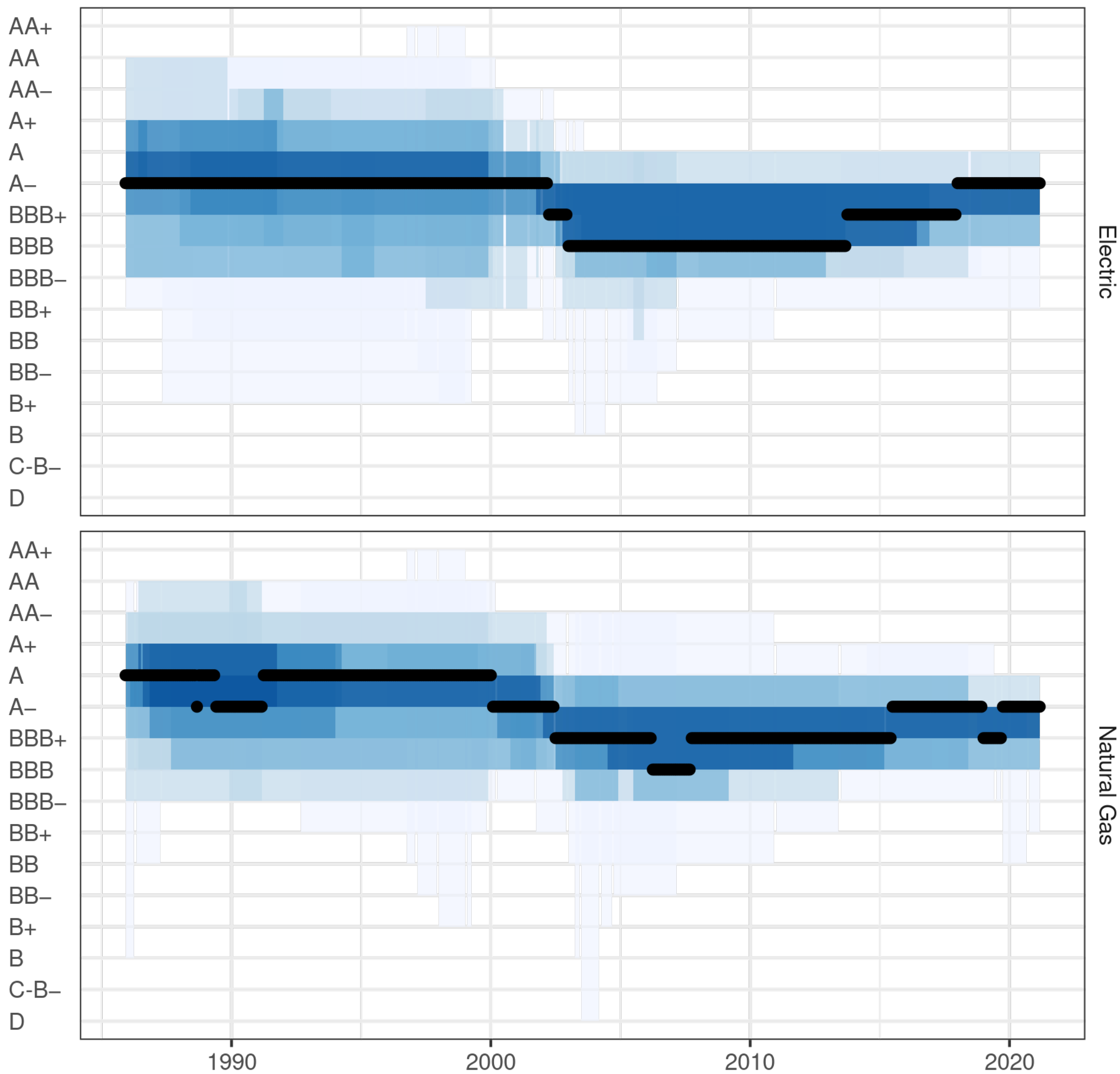
Figure 1: Return on Equity and Financial Indicators: Nominal and Real



Notes: These figures show the approved return on equity for investor-owned US electric and natural gas utilities. Each dot represents the resolution of one rate case. Real rates are calculated by subtracting consumer price index (CPI). Between March 2002 and March 2006 30-year Treasury rates are interpolated from 1- and 10-year rates.

Sources: Regulatory Research Associates (2021), Moody's (2021a, 2021b), Board of Governors of the Federal Reserve System (2021a, 2021b, 2021c), and US Bureau of Labor Statistics (2021).

Figure 2: Credit ratings have changed little in 35 years



NOTE: Black lines represent the median rating of the utilities active in a given month. We also show bands, in different shades of blue, that cover the 40–60 percentile, 30–70 percentile, 20–80 percentile, 10–90 percentile, and 2.5–97.5 percentile ranges. (Unlike later plots, these *are not* weighted by ratebase.) Ratings from C to B– are collapsed to save space.
SOURCE: *Companies (Classic) Screener* (2021) and *Compustat S&P legacy credit ratings* (2019).

Table 1: Summary Statistics

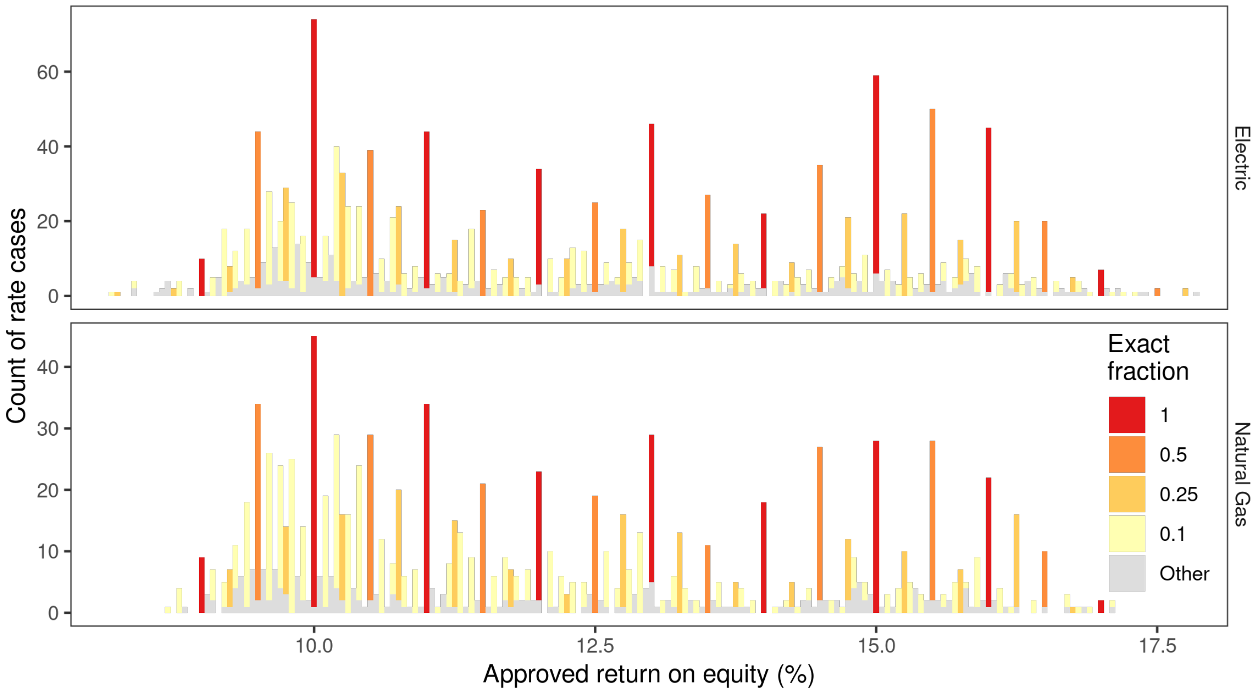
Characteristic	N	Electric	Natural Gas
Rate of Return Proposed (%)	3,324	9.95 (1.98)	10.07 (2.07)
Rate of Return Approved (%)	2,813	9.59 (1.91)	9.53 (1.95)
Return on Equity Proposed (%)	3,350	13.22 (2.69)	13.06 (2.50)
Return on Equity Approved (%)	2,852	12.38 (2.40)	12.05 (2.24)
Return on Equity Proposed Spread (%)	3,350	6.72 (2.18)	6.95 (1.99)
Return on Equity Approved Spread (%)	2,852	5.62 (2.27)	5.68 (2.10)
Return on Debt Proposed (%)	3,247	7.48 (2.11)	7.47 (2.16)
Return on Debt Approved (%)	2,633	7.54 (2.06)	7.44 (2.16)
Equity Funding Proposed (%)	3,338	45 (7)	48 (7)
Equity Funding Approved (%)	2,726	44 (7)	47 (7)
Rate Case Duration (mo)	3,713	9.1 (5.1)	8.1 (4.3)
Rate Base Increase Proposed ($ mn)	3,686	84 (132)	24 (41)
Rate Base Increase Approved ($ mn)	3,672	40 (84)	12 (25)
Rate Base Proposed ($ mn)	2,366	2,239 (3,152)	602 (888)
Rate Base Approved ($ mn)	1,992	2,122 (2,991)	583 (843)

NOTES: This table shows the rate case variables in our rate case dataset. Values in the Electric and Natural Gas columns are means, with standard deviations in parenthesis.
Approved values are approved in the final determination, and are the values we use in our analysis. Some variables are missing, particularly the approved rate base. The RoE spread in this table is calculated relative to the 10-year Treasury rate.
SOURCE: Regulatory Research Associates (2021) and author calculations.

timeseries shown in figure 1. A couple of features jump out, as we mentioned in the introduction. The gap between the approved return on equity and other measures of the cost of capital have increased substantially over time. At the same time, the return on equity has decreased over time, but much more slowly than other indicators. We quantify these observations in section 5.

We note that there are other distortions or ad-hoc evaluations in the PUC process. Rode and Fischbeck (2019) note a hesitancy for PUCs to set RoE below a nominal 10% level. We replicate this finding. In addition, we also note a bias toward round numbers, where regulators tend to approve RoE values at integers, halves, quarters, and tenths of percentage points. This finding is demonstrated in figure 3. We believe the true, unknown, cost of equity is smoothly distributed. If for instance, a PUC rounds in a way that changes the allowed RoE by 10 basis points (0.1%), the allowed revenue on the existing ratebase for the average electric utility in 2019 would change by $114 million. (The median is lower, at $52 million.) Small deviations have large implications for utility revenues and customer payments, though we don't know if rounding has a systematic bias toward higher or lower RoE. Of course, RoE values that aren't set at round numbers might not be any closer to the correct RoE. We leave this round number bias, as well as the above-10% stickiness, for future research.

Figure 3: Return on equity is often approved at round numbers



Colors highlight values of the nominal approved RoE that fall exactly on round numbers. More precisely, values in red are integers. Values in dark orange are integers plus 50 basis points (bp). Lighter orange are integers plus 25 or 75 bp. Yellow are integers plus one of {10, 20, 30, 40, 60, 70, 70, 80, 90} bp. All other values are gray.
Histogram bin widths are 5 bp. Non-round values remain gray if they fall in the same histogram bin as a round value. In that case, the bars are stacked.

SOURCE: Regulatory Research Associates (2021).

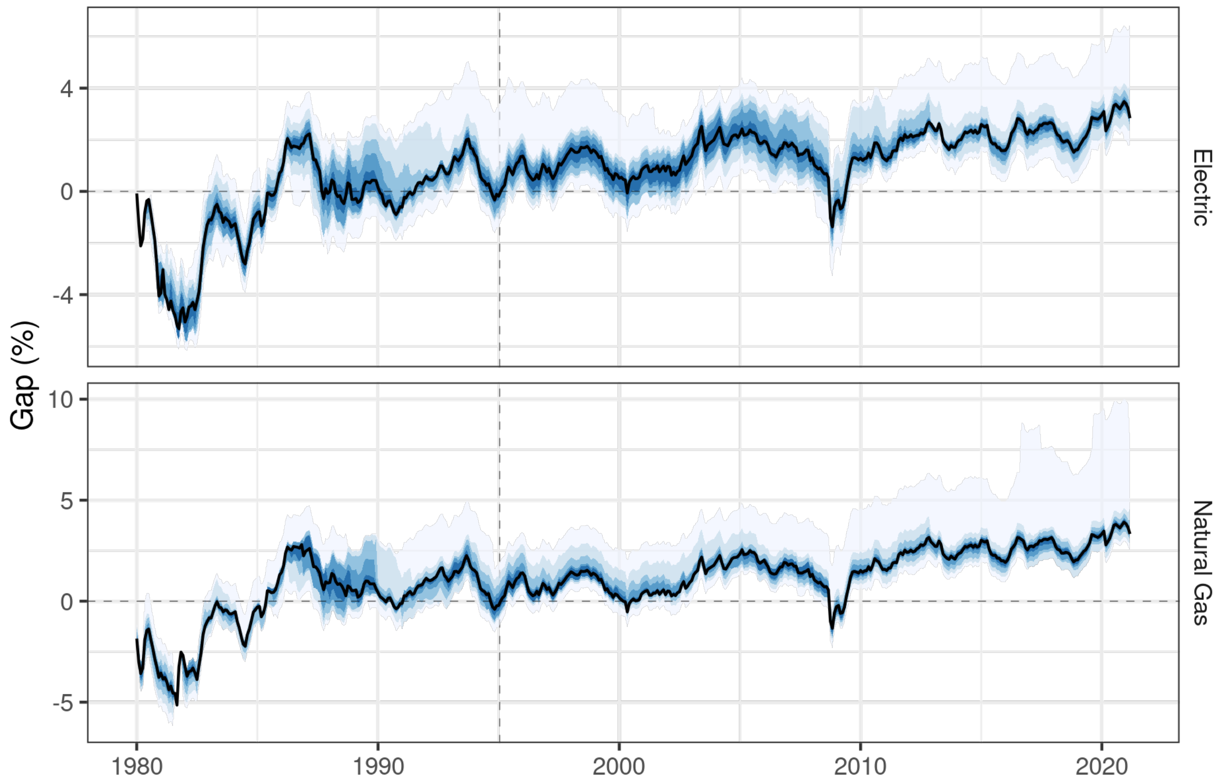
4 EMPIRICAL STRATEGY

4.1 RETURN ON EQUITY GAP

Knowing the return on equity (RoE) gap size is a challenge, and we take a couple of different approaches. None are perfect, but collectively, they shed light on the question. For each of the strategies we outline below (in sections 4.1.1, 4.1.2, 4.1.3, and 4.1.4) we plot the timeseries of the RoE gap. These are plotted in figures 4, 5, 6, and 7. Many of these strategies pick a specific time period as a benchmark. For all of these, we use January 1995. For the most part, our RoE gap results are flat over time (in the case of CPI) or steadily upward sloping (in the case of corporate bonds). The choice of baseline date determines where zero is, so changing the baseline date will shift the overall magnitude of the gap. As long as the baseline date isn't in the middle of a recession, our qualitative results don't depend strongly on the choice.

In each plot, we present the median of our RoE gap estimates, weighting by the utility's ratebase (in 2019 dollars). Our goal is to show the median of ratebase dollar value, rather than the median of utility companies, as the former is more relevant for understanding the impact of the RoE gap. We also show bands, in different shades of blue, that cover the 40–60 percentile, 30–70 percentile, 20–80 percentile, 10–90 percentile, and 2.5–97.5 percentile (all weighted by ratebase).

Figure 4: Return on equity gap, benchmarking to Baa-rates corporate bonds



Base year is 1995. Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total IOU ratebase. See calculation details in section 4.1.1.

4.1.1 *Indexed to Corporate Bonds*

We first consider a benchmark index of corporate bond yields, rated Baa by Moody's.[8] The idea here is to ask if the *average* spread against the Baa rating hadn't changed since the baseline, what would the RoE be today? The results are plotted in figure 4. Moody's Baa is approximately equivalent to S&P's BBB, which is at or slightly below our most of the utilities in our data. We use January 1995 as our baseline. Our findings are qualitatively the same for other dates, though the magnitude differs.

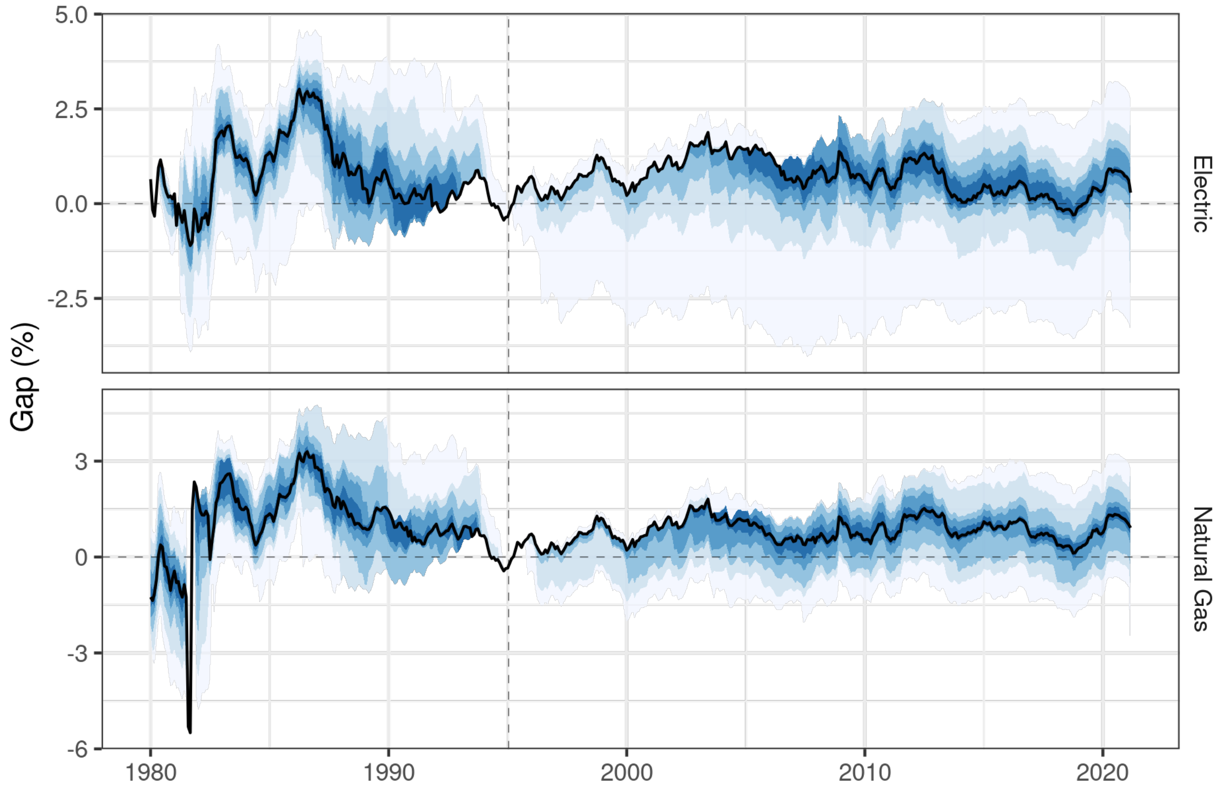
Making comparisons to debt instruments in this way, rather than benchmarking to some economy-wide cost of equity, means the measure of the RoE gap likely understates the gap. Rode and Fischbeck (2019) points out that (1) the market-wide equity risk premium has declined over the period and (2) the same is true for the utility sector.[9] Therefore, we would expect the mean spread against Baa bond yields to have declined, but instead, the spread has increased.

To calculate these results we first find the spread between the approved return on equity and the Moody Baa rate for each utility in each state in each month. We then take the average at our baseline and simulate what that spread would be if the overall average

8. This index is one of two rating-specific corporate bonds indexes that's available for our entire study period. The other is Moody's Aaa.

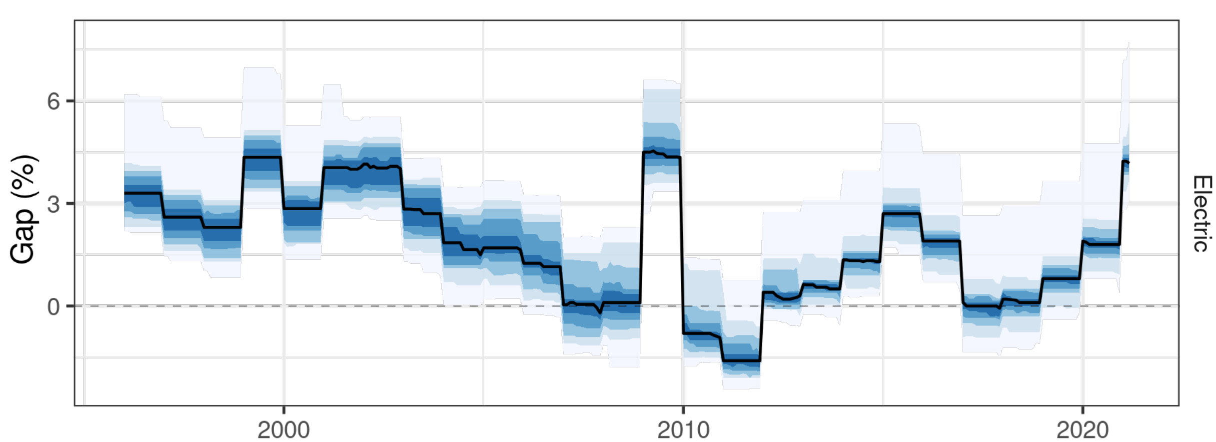
9. To the extent that observed utility stock returns are endogenous to the approved RoE, point #2 might be biased (Werth 1980).

Figure 5: Return on equity gap, using Vermont's update rule



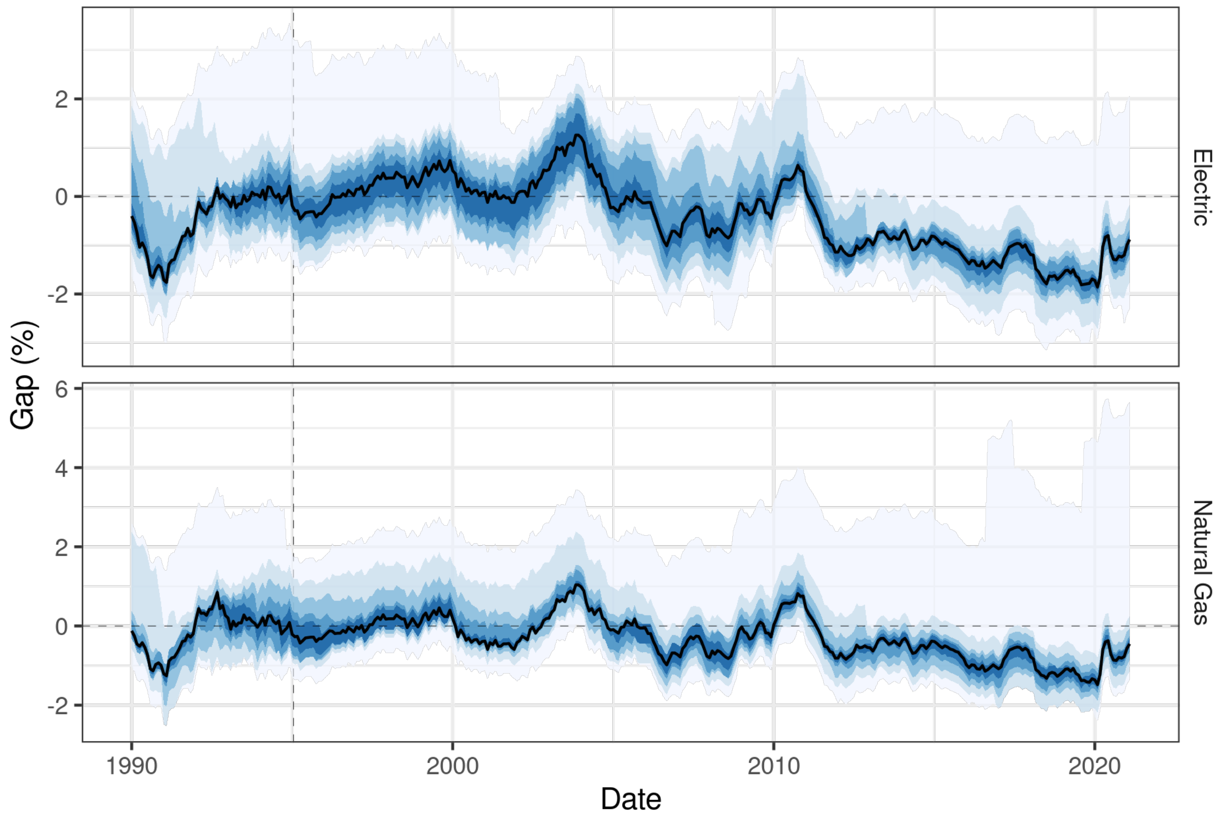
Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total IOU ratebase. See calculation details in section 4.1.2.

Figure 6: Return on equity gap, compared to UK utilities



Base year is 1995. Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total IOU ratebase. See calculation details in section 4.1.3.

Figure 7: Return on equity gap, benchmarking to CPI



Base year is 1995. Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total IOU ratebase. See calculation details in section 4.1.4. Dates before 1990 are omitted for better axis scaling.

spread hadn't changed. One advantage of this approach is that we can still allow utilities to move around in their relative rankings and RoE. For example if a particular utility gets riskier and has correspondingly high RoE, our measure allows for that change in individual riskiness.

4.1.2 *Indexed to Treasuries*

Our next measure uses the RoE update rule recently implemented by the Vermont PUC. This rule is the only one we're aware of, from any PUC, that currently does automatic updating. Define R' as the baseline RoE, B' as the baseline 10-year Treasury bond yield, and B_t as the 10-year Treasury bond yield in year t. The update rule says the RoE in year t is then:

$$R_t = R' + \frac{B_t - B'}{2}$$

In the graph, we set the baseline to January 1995. In reality the commission set the baseline period as December 2018, for their plan published in June 2019. (*Green Mountain Power: Multi-Year Regulation Plan 2020–2022* 2020). We simulate the gap between approved RoE and what RoE would have been if every state's utilities commission followed this rule from 1995 onward. (Pre-1995 values are not particularly meaningful, but we can calculate them with the same formula.) We plot results in figure 5.

4.1.3 International Benchmark

We also consider an international benchmark. Here we ask, "what if US utilities faced a return on equity that was the same as return on equity in the UK?" Unlike the previous cases, we're not considering some benchmark year. Instead, we're considering the contemporaneous gap between the US and UK. Of course many things are different between these countries, and it's not fair to say all US utilities should adopt UK rate making, but we've think this benchmark provides an interesting comparison. Our results are in figure 6.

4.1.4 Indexed to Inflation

We also consider a calculation where we benchmark against core CPI. The mechanics of this calculation are identical to the Baa comparison above, where we calculate the gap between approved RoE and what the RoE would be if the mean spread against core CPI were unchanged. In this analysis, we find a small negative gap: real approved values RoE have declined, but by less than other costs of capital.

4.2 RATE BASE IMPACTS

Next, we turn to the ratebase the utilities own. A utility with a positive RoE gap will have a too-strong incentive to have capital on their books. In this section, we investigate the change in ratebase utilities request and receive. For our purposes, change in ratebase is more relevant than the total ratebase, as the change is a flow variable that changes from rate case to rate case, while the total ratebase is the partially-depreciated stock of all previous ratebase changes. We consider both the requested change and the approved change, though the approved value is our preferred specification. We estimate $\hat{\beta}$ from the following:

$$\log(RBI_{i,t}) = \beta RoE_{i,t}^{gap} + \gamma X_{i,t}\theta_i + \lambda_t + \epsilon_{i,t} \quad (3.1)$$

where an observation is a utility rate case for utility i in year-of-sample t. The dependent variable, $RBI_{i,t}$, is the increase in the rate base, and we take logs. (Cases where the ratebase shrinks are rare, but do happen. We drop these cases.) The independent variable of interest, $RoE_{i,t}^{gap}$, is the gap between the allowed return on equity and the true return on equity over the length of the rate case, where each rate case has a duration of D years.

$$RoE_{i,t}^{gap} = RoE_{i,t}^{allowed} - \frac{1}{D}\sum_{t}^{t+D} RoE_{i,t}^{correct} \quad (3.2)$$

Unlike section 4.1, for this analysis we care about differences in the gap between utilities or over time, but do not care about the overall magnitude of the gap. For ease of implementation, we begin by considering the gap as the spread between the approved rate of return and the 10-year Treasury bond yield. We do not expect the correct return on equity to be equal to the 10-year Treasury yield, but our fixed effects account for any constant differences. Future research will consider a richer range of gap calculations.

4.2.1 Fixed Effects Specifications

Our goal is to make causal claims about $\hat{\beta}$, so we are concerned about omitted variables that are correlated with both the estimated RoE gap and the change in ratebase. We begin with a fixed-effects version of the analysis. Our preferred version includes time fixed effects, λ_t, at the year-of-sample level and the unit fixed effects, θ_i, are at the utility company and state level.[10] Here, the identifying assumption is that after controlling for state and year effects, there are no omitted variables that would be correlated with both our estimate of the RoE gap and the utility's change in ratebase. The identifying variation is the differences in the RoE gap within the range of rate case decisions

10. Many utilities operate within only on state, but some span multiple. These company and state fixed effects are only partially nested.

Table 2: RoE gap, by different benchmarks

A: Electric		Baa yield	VT rule	UK	CPI
Gap (%)	2000	0.796	0.21	3.17	0.531
	2020	3.26	0.485	2.03	−1.06
Excess payment ($bn)	2000	0.581	0.23	4.54	0.142
	2020	6.54	1.43	3.92	−2.61
B: Natural Gas					
Gap (%)	2000	0.969	0.142		0.704
	2020	3.9	1.15	1.89	−0.421
Excess payment ($bn)	2000	0.0896	0.0183		0.0212
	2020	2.14	0.658	0.975	−0.361

NOTE: Gap percentage figures are an unweighted average across utilities. Excess payments are totals for all IOUs in the US, in billions of 2019 dollars per year, *for the observed ratebase.*
For cases where it's relevant (Baa yield, VT rule, and CPI), the benchmark date is January 1995. See text for details of each benchmark calculation.

for a given utility, relative to the annual average across all utilities. These fixed effects handle some of the most critical threats to identification, such as macroeconomic trends, technology-driven shifts in electrical consumption, or static differences in state PUC behavior. In columns 1–3 of our results tables (3 and 4), we consider different specifications for our fixed effects.

In this case the identification hinges on looking at variation in the RoE gap within the range of rate case decisions for a given utility, relative to the annual average across all utilities. The identifying assumption is that after controlling for state, year, and company effects, there are no omitted variables that would be correlated with both our estimate of the RoE gap and the utility's change in ratebase. These fixed effects handle many of the stories one could tell, such as macroeconomic trends, technological shifts in electrical consumption, or static differences in state PUC behavior. However, there are certainly other avenues for omitted variables bias to creep in, so next we turn to an instrumental variables strategy.

4.2.2 Instrumenting with Rate Case Timing and Duration

To try and further deal with concerns regarding identification, we examine an instrumental variables approach based on the timing and duration of rate cases.

Our IV analysis takes the idea that rates move around in ways that aren't always easy for the regulator to anticipate. So for instance if the allowed return on equity is set in year 0 and financial conditions change in year 2 such that the real allowed return on equity increases, then we would expect the utility to increase their capital investments in ways that

Table 3: Relationship Between Proposed Rate of Return and Proposed Rate Base

	Fixed effects specs.			IV
Model:	(1)	(2)	(3)	(4)
Variables				
RoE gap (%)	0.0670***	0.0436*	0.0672***	0.0353
	(0.0134)	(0.0217)	(0.0151)	(0.0215)
Fixed-effects				
State	Yes	Yes	Yes	Yes
Year		Yes	Yes	Yes
Company			Yes	Yes
Fit statistics				
Observations	3,210	3,210	3,210	3,210
R^2	0.37	0.39	0.73	0.73
Within R^2	0.24	0.23	0.29	0.29
Wald (1st stage)				50.9
Dep. var. mean	63.69	63.69	63.69	63.69

Two-way (Year & Company) standard-errors in parentheses
*Signif. Codes: ***: 0.01, **: 0.05, *: 0.1*

NOTES: The dependent variable in the first panel is log of the utility's proposed rate base increase. Columns 1–3 show varying levels of fixed effects. Column 4 is the IV discussed in section 4.2. Our preferred specification is column 4 of table 4. First-stage F-statistic is Kleibergen–Paap robust Wald test. All regressions control for an indicator of electricity or natural gas.

are unrelated to other aspects of the capital investment decision. For this instrument to work, it needs to be the case that these movements in bond markets or the like are conditionally independent of decisions that the utility is making, except via this return on equity channel. We control for common year fixed effects, and then the variation that drives our estimate is that different utilities will come up for their rate case at different points in time.

5 RESULTS

Beginning with the RoE gap analysis from section 4.1, table 2 summarizes the graphs, using 2000 and 2020 as example points in time. The table highlights the RoE gap and the excess payment on the existing ratebase. Our results on the RoE gap can largely be guessed from a close inspection of figure 1. Approved RoE has not changed much in real terms (i.e. relative to core CPI), but the gap has increased between RoE and various financial benchmarks. Of our various imperfect estimates of the gap, we believe the Baa benchmark is the most credible.

Table 4: Relationship Between Approved Rate of Return and Approved Rate Base

	Fixed effects specs.			IV
Model:	(1)	(2)	(3)	(4)
Variables				
RoE gap (%)	0.0551***	0.0752***	0.0867***	0.0523**
	(0.0200)	(0.0240)	(0.0225)	(0.0252)
Fixed-effects				
State	Yes	Yes	Yes	Yes
Year		Yes	Yes	Yes
Company			Yes	Yes
Fit statistics				
Observations	2,491	2,491	2,491	2,491
R^2	0.33	0.36	0.69	0.69
Within R^2	0.21	0.20	0.22	0.22
Wald (1st stage)				69.1
Dep. var. mean	38.63	38.63	38.63	38.63

Two-way (Year & Company) standard-errors in parentheses
*Signif. Codes: ***: 0.01, **: 0.05, *: 0.1*

Notes: The dependent variable in the first panel is log of the utility's approved rate base increase. Columns 1–3 show varying levels of fixed effects. Column 4 is the IV discussed in section 4.2. Our preferred specification is column 4. First-stage F-statistic is Kleibergen–Paap robust Wald test. All regressions control for an indicator of electricity or natural gas.

Totalling up the 2020 excess payments gives us $8.7 billion in the Baa benchmark, or $2.1 billion in the Vermont benchmark. The UK benchmark falls between these, at $4.9 billion.

We also consider how the RoE gap affects capital ownership. Tables 3 and 4 show our regression results for proposed and approved values, respectively. Our preferred specification is column 4, the IV specification, in table 4. These results find that a 1 percentage point increase in the approved RoE gap leads to a 5.2% increase in the increase in approved rate base. These results have a strong first stage (Kleibergen–Paap F-stat of 69).

As a caveat, we note that an IOU can increase their capital holdings in two distinct ways. One option is to reshuffle capital ownership, either between subsidiaries or across firms, so that the IOU ends up with more capital on its books, but the total amount of capital is unchanged. The second option is to actually buy and own more capital, increasing the total amount of capital that exists in the state's utility sector. We do not differentiate between these two cases. Because we don't differentiate, we consider excess payments by utility customers, but we remain agnostic about the socially optimal level of capital investment.

6 CONCLUSION

Utilities invest a great deal in capital, and need to be compensated for the opportunity cost of their investments. Getting this rate of return, particularly the return on equity, correct is challenging, but is a first-order important task for state PUCs.

Our analysis shows that the RoE that utilities are allowed to earn has changed dramatically relative to various financial benchmarks in the economy. Across relevant benchmarks, we found that current rates are perhaps 0.5–4 percentage points too high, resulting in $2–8 billion in excess rate collected per year, given the existing ratebase.

We then turned to the Averch–Johnson effect, and estimated the additional capital this RoE gap generates. In our preferred specification, we estimate that an additional percentage point in the RoE gap leads to 5% higher rate base increases.

We hope that policymakers and regulators consider these changes and these benchmarks in future rate making and the role that a wider variety of metrics benchmarks and adjustments can play in utility rate cases. We close by echoing Rode and Fischbeck (2019) and the Vermont PUC. Just as PUCs adopted fuel adjustment clauses in the 1960s and 1970s, RoE adjustment clauses are a tool that would allow rates to automatically adjust to changing market conditions. It would, of course, be possible to change the formula from time to time, but by default, the PUC wouldn't need to, even as the cost of raising capital changes. If such a scheme was implemented, it would be necessary to think hard about the baseline rate. As we demonstrated, the approved RoE has grown over time, so the choice of baseline period is crucial.

Figure 8: Figures 8 and 9 from Rode and Fischbeck (2019), showing CAPM β and market risk premium

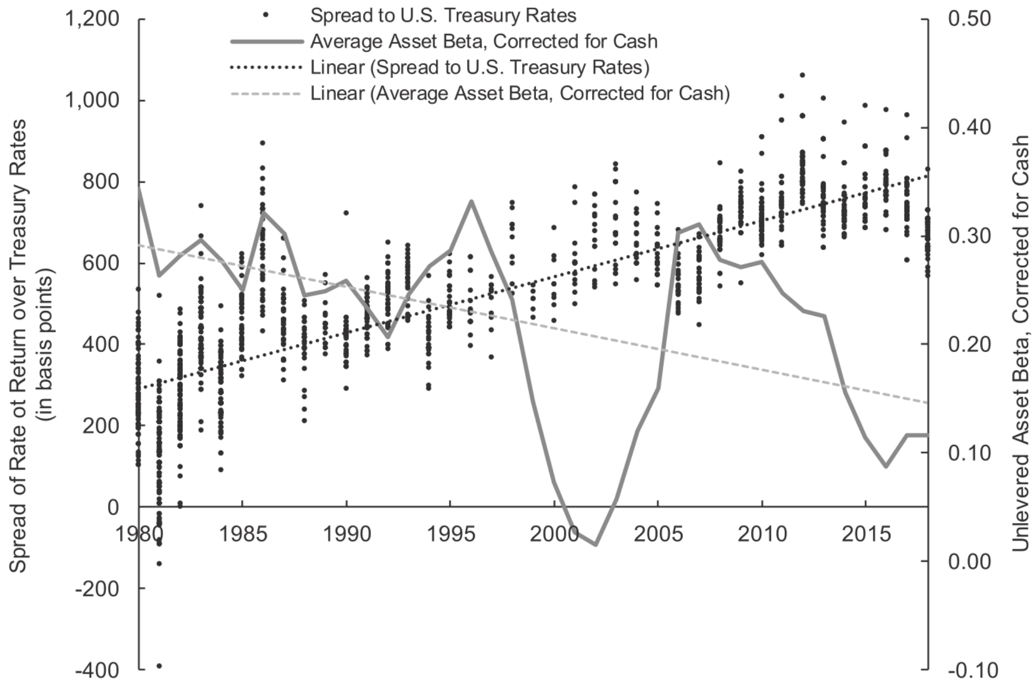


Fig. 8. Authorized return on equity premium vs. industry average asset beta.

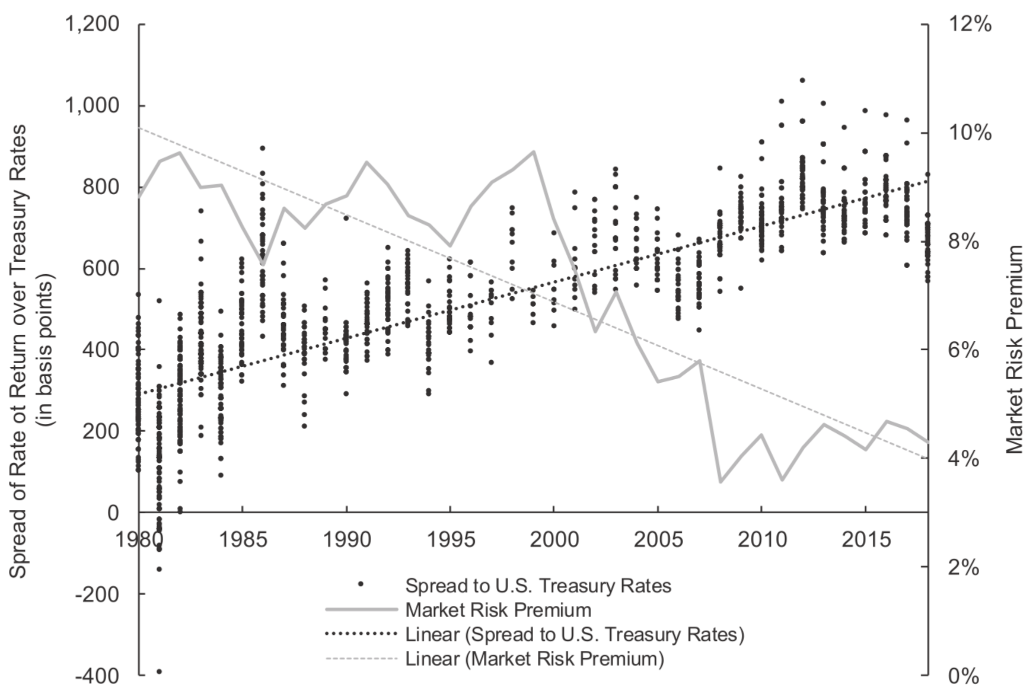


Fig. 9. Authorized rate-of-return premium vs. *ex ante* estimated market risk premium.

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Conclusion

These three papers cover a variety of topics in applied environmental economics. The first chapter addresses methane emissions from oil and gas wells, and considers the potential gains from policies that target these emissions. These gains could be large, but depend a great deal on the information the regulator has available and the details of the policy they enact. The second chapter considers the loss in value caused by flooding on agricultural land, examining losses over a wide range of flood frequencies. We contextualize these results in a world with changing climate, as properties that now flood occasionally are expected to flood more frequently in the future. The third chapter focuses on the rates of return utility companies are allowed to earn. These rates determine the profitability of investing in capital, the rates customers pay, and the amount of capital the utilities end up owning. All three of these chapters investigate policy-relevant economic topics, and all three use applied econometric tools to bring data to the question.

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Regulated equity returns: A puzzle

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ABSTRACT

Based on a database of U.S. electric utility rate cases spanning nearly four decades, the returns on equity authorized by regulators have exhibited a large and growing premium over the riskless rate of return. This growing premium does not appear to be explained by traditional asset-pricing models, often in direct contrast to regulators' stated intent. We suggest possible alternative explanations drawn from finance, public policy, public choice, and the behavioral economics literature. However, absent some normative justification for this premium, it would appear that regulators are authorizing excessive returns on equity to utility investors and that these excess returns translate into tangible profits for utility firms.

1. Introduction

In economics, the equity-premium puzzle refers to the empirical phenomenon that returns on a diversified equity portfolio have exceeded the riskless rate of return on average by more than can be explained by traditional models of compensation for bearing risk. Since Mehra and Prescott's (1985) initial paper on the subject, a large body of research has attempted to explain away the puzzle, but without much success (Mehra and Prescott, 2003). The most likely explanations for the premium appear to reside outside of classical equilibrium models. We call the reader's attention to the Mehra-Prescott puzzle as a means of introducing our instant problem, of which it may be considered an applied case. Simply put: why are the equity returns authorized by electric utility regulators so high, given that riskless rates are so low?

Our scope is as follows. We employ a much larger dataset than has previously been examined in the literature and seek to explain the rates of return *authorized* by state electric utility regulators. We investigate the extent to which the actual returns authorized can be explained by the Capital Asset Pricing Model (CAPM), which regulators (and others) purport to use. We also examine whether the CAPM is capable of explaining the clear trend of rising risk premiums present over the last four decades in electric utility rate cases.

While previous studies have investigated rates of return for regulated electric utilities, the majority of this work has either examined *actual* rates of return to utility stockholders, relied on very limited samples of rate cases, or tested a variety of hypotheses connecting utility earnings to various structural and institutional factors. Table 1 summarizes the previous literature most similar to our study. By contrast, our study employs a far larger sample of rate cases (1,596) than previously examined in the literature. In addition, our focus on authorized rates of return highlights the impact of regulatory rate-setting on consumers, as opposed to stockholders, to the extent that authorized rates are used to set utility revenue requirements, while earned returns accrue to stockholders. This setting also enables us to analyze rate-setting in the context of regulatory decision-making. Actual rates of return earned by utilities can differ from the rates of return authorized by regulators due to factors such as the impact of weather on demand, but primarily due to the operational performance of a utility, including its ability to operate efficiently and control costs to those approved by regulators.

This regulated equity return puzzle is important not just from a theoretical asset-pricing perspective, but also for very practical reasons. The database used in this study reflects more than $3.3 trillion (in 2018 dollars) in cumulative rate-base exposure.[1] An error or bias of merely one percentage point in the allowed return would imply tens of billions of dollars in additional cost for ratepayers in the form of higher retail power prices and could play a profound role in the allocation of investment capital. Coupled with utilities' tendencies toward excessive capital accumulation under rate regulation (Averch and Johnson, 1962; Spann, 1974; Courville, 1974; Hayashi and Trapani, 1976; Vitaliano

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[1] This figure reflects the simple cumulative sum of authorized rate bases across all cases. Because rate-base decisions may remain in place for several years, this sum most likely underestimates the actual figure, which should be the authorized rate base in each year examined, whether or not a new case was decided. We cite this figure merely as evidence of the substantial magnitude of the costs at stake.

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Table 1
Previous studies of the determinants of electric utility rates of return.

Study	Sample	Description
Joskow (1972)	20 cases in New York between 1960 and 1970	Only capital markets parameter included was cost of debt. Focused on the requested rate of return.
Joskow (1974)	174 cases between 1958 and 1972	No CAPM parameters tested. Regulators tended to ignoring overearning as long as prices were falling.
Hagerman and Ratchford (1978)	79 survey responses from utilities about their last rate case	Used authorized rates. Found positive coefficients related to beta and the debt/equity ratio.
Roberts et al. (1978)	59 cases from 4 Florida utilities between 1960 and 1976	No CAPM parameters tested. Only structural factors examined.
Roll and Ross (1983)	Utility stock returns between 1925 and 1980	No authorized returns used. CAPM underestimates returns relative to the APT.
Pettway and Jordan (1987)	58 electric service companies between 1969 and 1976	Used stockholder returns only.
Binder and Norton (1999)	92 firms	Used stockholder returns to estimate beta. Suggested that regulation causes cash flow "buffering" and that firms may be underearning.
PJM Interconnection (2016)	22 regulated firms between 2000 and 2015	Examined stockholder returns and found regulated firms had positive alpha.
Haug and Wieshammer (2019)	N/A	Regulators in continental Europe "uniformly adopt the [CAPM]" and courts have ruled that the authorized rates are too low. The opposite finding to our study.

and Stella, 2009), the magnitude of the problem makes it incumbent on the industry and regulators to get it right.

There are also policy implications for market design and regulation. A recent PJM Interconnection (2016) study compared and contrasted entry and exit decisions in competitive and regulated markets to evaluate the efficiency of competitive markets for power. One finding that emerged from the study was that regulated utilities appeared to be "overearning" and had generated positive alpha, while competitive firms had not generated positive alpha.[2] Although the study used a limited time window of rate case data and focused on utility stock returns, not returns authorized by regulators, its findings are consistent with those we explore in more detail here.

As an old joke goes, an economist is someone who sees something work in practice and asks whether it can work in theory. Undoubtedly, the utility sector has been successful in attracting capital over the past four decades. We cannot necessarily say, however, that had returns been consistent with the dominant theoretical model used (and thus lower), this would still have been the case. Accordingly, this article also raises the question of whether our theoretical models of required return and asset pricing must be refined. Or, at the very least, whether there are important considerations that must be accounted for in the application of those models to the regulated electric utility industry.

In this article, therefore, we examine the historical data on authorized rates of return on equity in U.S. electric utility rate cases. We compare these rates of return to several conventional benchmarks and the classical theoretical asset-pricing model. We demonstrate that the spread between authorized equity returns (and also earned equity returns) and the riskless rate has grown steadily over time. We investigate whether this growing spread can be explained by classical asset-pricing parameters and conclude that it cannot. We then evaluate possible explanations outside of classical finance to suggest fruitful paths for future research. Specifically, we investigate whether the addition of variables for commission selection and case adjudication contribute explanatory power, in line with existing theories in the pubic choice literature. We conclude with a discussion of the policy implications of the observed premiums and how regulatory rate-setting could be adjusted to mitigate higher premiums.

Section 2 reviews the legal, regulatory, and financial foundations of rate of return determination for utilities. Section 3 describes the data used in our analysis and defines the risk premium on which our analysis is based. Section 4 presents the results of our analysis and outlines the various factors explored, including both classical financial factors and factors outside of the classical paradigm. Section 5 highlights the policy implications of our research, suggests potential mitigating strategies, and concludes.

2. Regulated equity returns and the Capital Asset Pricing Model

At the outset, let us make clear that we are addressing only *regulated* rates of return on equity in this article. We draw no conclusions or inferences about the behavior of returns on non-regulated assets. Our focus is limited to regulated returns because in such cases it is regulators who are tasked with standing in for the discipline of a competitive market and ensuring that returns are just and reasonable. For more than a century, U.S. courts have ruled consistently in support of this objective, while recognizing that achieving it requires consideration of numerous factors that are subject to change over time. The task set to regulators, then, is to approximate what a competitive market would provide, *if one existed.*

Mindful of this mandate, two U.S. Supreme Court decisions are commonly thought to provide the conceptual foundation for utility rate-of-return regulation. In *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia* (262 U.S. 679 (1923)), the Court identified eight factors that were to be considered in determining a fair rate of return, ruling that "[t]he return should be reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economic management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties." This position was made more concrete in *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 591 (1944)), wherein the Court ruled that the "return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."

In both *Bluefield* and *Hope*, the Court sought to balance the need for utilities to attract capital sufficient to discharge their duties with the need for regulators to protect ratepayers from what would otherwise be rent-seeking monopolists. These efforts in determining "just and reasonable" returns received significant assistance in the 1960s when groundbreaking advances in asset-pricing theory were made in finance. Specifically, the development of the Capital Asset Pricing Model (CAPM) (Sharpe, 1964; Lintner, 1965; Mossin, 1966) provided a rigorous framework within which the question of the appropriate rate of return could be addressed in an objective fashion. The security market line representation of the CAPM [1] set out the equilibrium rate of return on equity, r_E, as the sum of the rate of return on a riskless asset,

[2] In asset pricing models, positive alpha is evidence of non-equilibrium returns, meaning that investors are receiving compensation in excess of what would be required for bearing the risks they have assumed.

r_f, and a premium related to the level of risk being assumed that was defined in relation (through the factor β) to the expected excess rate of return on the overall market for capital, r_m.

$$r_E = r_f + \beta(r_m - r_f) \quad (1)$$

It is outside of the scope of this paper to delve too deeply into the foundations of asset pricing. We note, also, that the CAPM methodology is not the sole candidate for rate-of-return determination in utility rate cases. Morin (2006, p. 13) identifies four main approaches used in the determination of the "fair return to the equity holder of a public utility's common stock," of which the CAPM is but one.[3] Nevertheless, the concept of the appropriate rate of return on equity being a combination of a riskless rate of return and a premium for risk-bearing has since become widely accepted as a means of determining the appropriate authorized return on equity in state-level utility rate cases (Phillips, 1993, pp. 394–400). In contrast, the Federal Energy Regulatory Commission relies exclusively on the DCF approach, which is also common with natural gas utilities. For electric utilities, however, the CAPM in particular is seen as the "preferred" (Myers, 1972; Roll and Ross, 1983, p.22) and "most widely used" (Villadsen et al., 2017, p. 51) method in regulatory proceedings. Multi-factor approaches such as Arbitrage Pricing Theory (APT) (Ross, 1976) and the Fama and French (1993) framework are used with significantly less frequency in practice (Villadsen et al., 2017, p. 206). In other words, our focus on the CAPM is not solely because of its perceived normative status, but also because it is the method most regulators *say they are using.*

In *Hope,* however, the Court also advocated the "end results doctrine," acknowledging that regulatory methods were (legally) immaterial so long as the end result was reasonable to the consumer and investor. In other words, there was no single formula for determining rates. A typical example of the latitude granted by the doctrine is found in Pennsylvania Public Utility Commission (2016, p. 17): "The Commission determines the [return on equity] based on the range of reasonableness from the DCF barometer group data, CAPM data, recent [returns on equity] adjudicated by the Commission, and **informed judgment** [emphasis added]." Rate determination in practice is often not simply a matter of arithmetic; rather, it is an act of judgment performed by regulators. As a result, our investigation examines not just the relation of authorized rates to those implied by the CAPM, but also the potential for that relationship to be influenced by regulator judgment.

Before we turn to the data, however, let us dispense with an alternate formulation of the underlying question. In questioning the size of the premium and why equity returns are so high, one might also ask instead why the riskless rate is so low. Indeed, Mehra and Prescott (1985) ask this very question, before dismissing it on theoretical grounds. We revisit this question in light of recent data and ask whether the premium during the period in question is more a function of riskless rates being forced down by the Federal Reserve's intervention, than of equity premiums increasing (since the manifest intent of quantitative easing was to lower riskless rates).[4] Our historical data, as Section 3 indicates, do not support that hypothesis. The premium growth has persisted since the beginning of our data series in 1980 and has persisted across a variety of monetary and fiscal policy regimes.

3. Regulated electric utility returns on equity, 1980–2018

3.1. Historical authorized return on equity data

The data used in this study were collected and maintained by Regulatory Research Associates (RRA), a unit of S&P Global. The RRA database is comprehensive. It contains every electric utility rate case in the United States since 1980 in which the utility has requested a rate change of at least $5 million or a regulator has authorized a rate change of at least $3 million. Our study comprises the period from 1980 through 2018. Table 2 illustrates the bridge from the RRA rate-case population to the rate-case sample used in our analyses. We examined the returns on equity authorized by the regulatory agencies, *not* the returns requested by the utilities.[5] The sample we use in this paper contains 79% of the RRA universe, but 97% of the rate cases in which a rate of return on equity was authorized by a state regulator.

Nearly all fifty states and Washington D.C. are represented in the data set.[6] Thirty-two electric utility rate cases satisfying the qualifications listed above were filed in the average state over the past thirty-eight years, with the most being filed in Wisconsin (120) and the fewest being filed in Tennessee (3), Alaska (2), and Alabama (1). The frequency of filing in a state does not appear to have any relationship to premium growth. The average risk premium has grown in both the ten states that completed the most rate cases and the ten states that completed the fewest rate cases and has grown at very similar rates (see Fig. 1). In fact, as Fig. 2 illustrates, the general trend across all states is similar.

In the early 1980s there were over 100 rate cases filed each year. By the late 1990s, in the midst of widespread deregulation of the electric power industry, the number of filings reached its lowest point (with six in 1999). Since then, filing frequency has increased to an average of forty-eight per year over the last three years (see Fig. 3). The decline in rate case activity in many instances was the direct result of rate moratoria related to the transition to competitive markets in the late 1990s, as well as to moratorium-like concessions made to regulators related to merger approvals over the last decade. Many of these moratoria will expire over the next two years, suggesting a new increase in rate case activity is likely. Finally, no individual utility had an outsized influence on the sample. One hundred forty-four different companies filed rate cases, but many have since merged or otherwise stopped filing.[7] The average firm filed eleven rate cases in our sample. Within our sample the most frequently-filing entity was PacifiCorp, which filed seventy-three rate cases, or less than 5% of the sample.

3.2. Calculating the regulated equity premium

Regulated equity returns are generally equal to the sum of the riskless rate of return and a premium for risk-bearing. In the CAPM, the premium for risk-bearing is given by $\beta(r_m - r_f)$, where β is the utility's

[3] The other three approaches identified by Morin (2006) are: Risk Premium (which is an attempt to estimate empirically what the CAPM derives theoretically), Discounted Cash Flows (or "DCF," which is a dividend capitalization model), and Comparable Earnings (which is an empirical approach to deriving cost of capital from market comparables based on *Hope*).

[4] This has also been an ongoing issue of contention in recent regulatory proceedings. In Opinion 531-B (Federal Energy Regulatory Commission, March 3, 2015, 150 FERC 61,165), the Federal Energy Regulatory Commission (FERC) found that "anomalous capital market conditions" caused the traditional discount rate determination methods not to satisfy the *Hope* and *Bluefield* requirements (150 FERC 61,165 at 7). But in a related decision only eighteen months later (Federal Energy Regulatory Commission, September 20, 2016, 156 FERC 61,198), FERC acknowledged that expert witnesses disagreed as to whether any market conditions were, in fact, "anomalous" (156 FERC 61,198 at 10).

[5] To be clear, we refer to the rates set by regulators as the "authorized" rates. These may be contrasted with utilities' "requested" rates and also with the "earned" rates of return actually realized by utilities. Regulatory *authorization* of a rate is not a guarantee that a utility will actually *earn* such a rate. We address this issue in further detail in Section 4.5.

[6] Only Nebraska did not have a reported rate case meeting the parameters of the data set. Nebraska is unique in that it is the only state served entirely by consumer-owned entities (e.g., cooperatives, municipal power districts) and therefore absent a profit motive it does not have the same adversarial regulatory system as all other states.

[7] The level of analysis is at the regulated utility level. We recognize that many holding companies have multiple ring-fenced regulated utility subsidiaries.

Table 2
Bridge illustrating how our sample is constructed from the RRA electric utility rate case population data.

Number of cases	Percent of cases	Description
2033	100.0%	All electric utility rate cases 1980–2018 in which utility has requested a rate change of at least $5 million or a regulator has authorized a rate change of at least $3 million.
−19	−0.9%	Rate cases with final adjudication (i.e., fully-litigated or settled) still pending as of December 31, 2018, are excluded
−369	−18.2%	Rate cases with no return on equity determination are excluded
−30	−1.5%	Rate cases with no capital structure determination are excluded
−19	−0.9%	Rate cases with authorized rates lower than the then-prevailing riskless rate are excluded
1596	79.0%	Rate cases used in our analysis

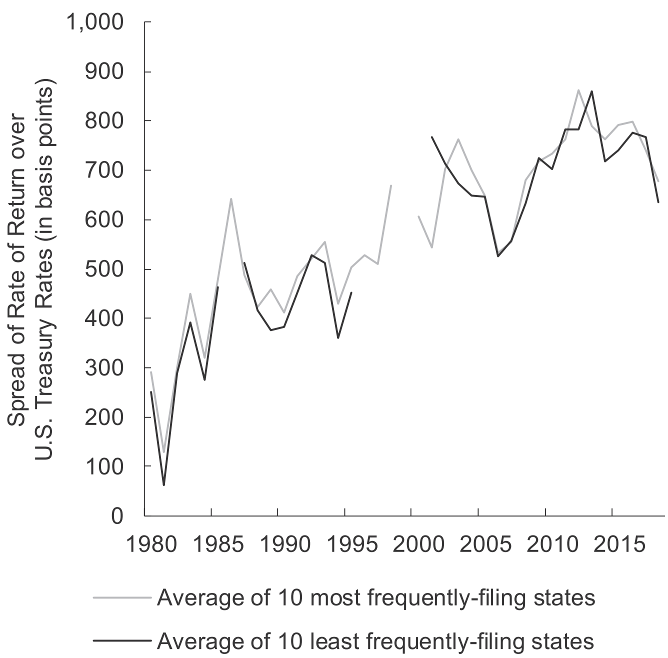

Fig. 1. Risk-premium growth by frequency of case filing. Gaps in the series reflect years in which no rate cases were filed for the subject group. The risk premium is calculated as $r_E - r_f$, or the excess of the authorized return on equity over the then-current riskless rate.

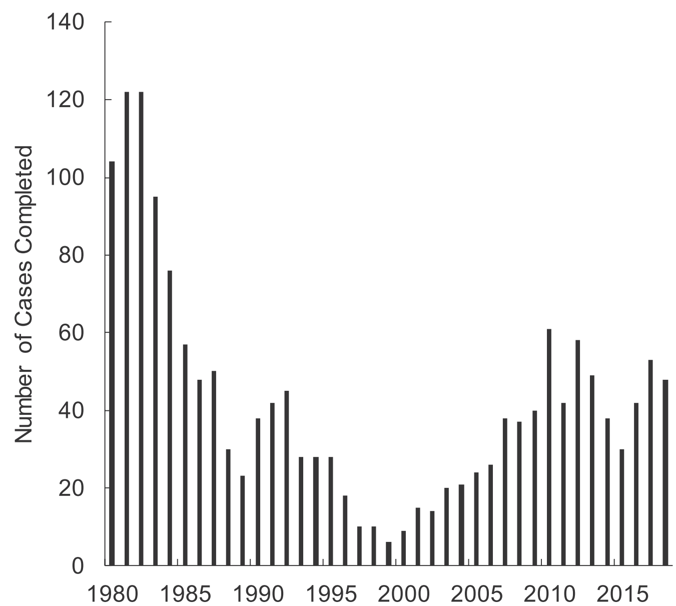

Fig. 3. Number of electric utility rate cases finalized by year.

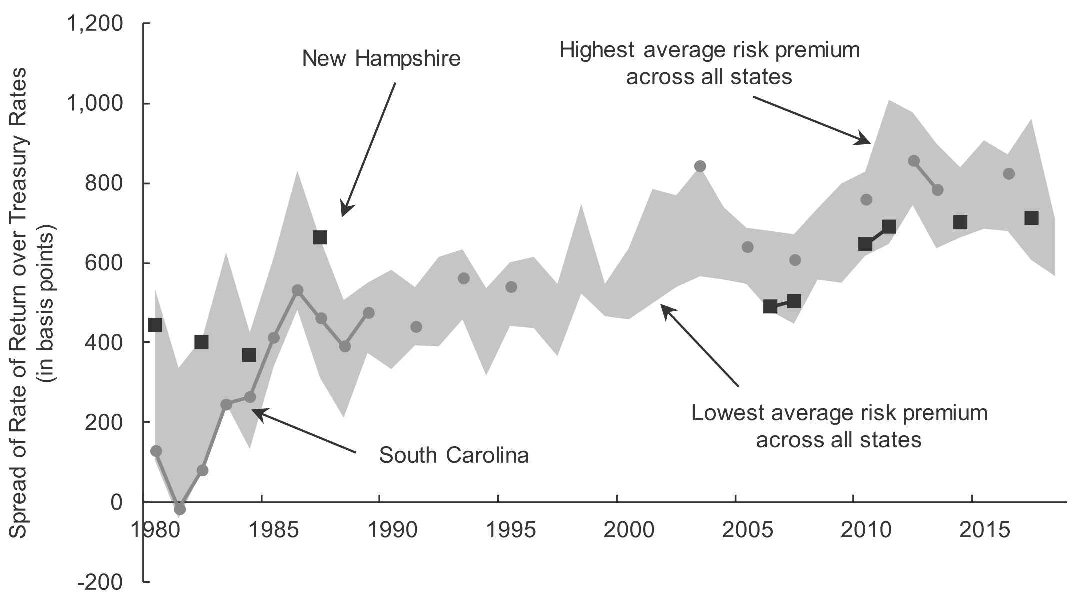

Fig. 2. Range of risk-premium growth across states. States with highest (New Hampshire) and lowest (South Carolina) rates of risk-premium growth over the period (among states with at least five rate cases) are highlighted.

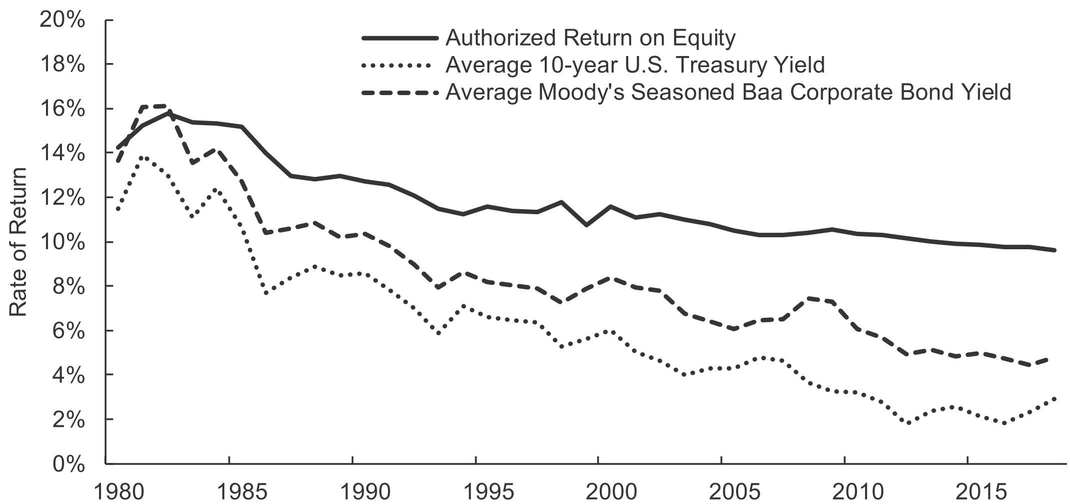

Fig. 4. Annual average authorized return on equity vs. U.S. Treasury and investment grade corporate bond rates.

equity beta. Rearranging the security market line equation [1], we define the regulated equity premium as $r_E - r_f = \beta(r_m - r_f)$. Presented thus, we first note that the existence of a (positive) regulated equity premium is not, by itself, evidence of irrational investor behavior or model failure. Neither is the existence of a growing regulated equity premium. We take no position here on what the "correct" premium should be in any instance. Rather, we shall be content in this article simply to determine whether or not the behavior of the risk premium in practice is consistent with financial theory.

On average, the authorized return on equity is 5.1% (standard deviation = 2.2%) higher than the riskless rate. Fig. 4 illustrates the average authorized return on equity over the period against the average annual riskless rate and investment-grade corporate bond rate.[8] For avoidance of doubt, we note that only the U.S. Treasury note rate should be considered the riskless rate. We include corporate bond rates solely to assess whether the trend in riskless rates is materially different from the trend in risky debt.

While the regulated equity premium has averaged 510 basis points across the entire time period, in 1980 the average premium was only 277 basis points, whereas in 2018 it averaged 668 basis points. Fig. 5 shows the difference between the authorized return on equity and the riskless rate for each case in the data over the past thirty-eight years. Although the premium is determined against the riskless rate of return (represented here as the yield on a 10-year U.S. Treasury note), we also present for comparison the spreads determined against the yield on the Moody's Seasoned Baa Corporate Bond Index to illustrate that the effect is not an artifact of recent monetary policy on Treasury rates. The trends of the two series are quite similar (and both have statistically-significant positive slopes); accordingly, we shall present only the Treasury rate-determined premiums throughout the remainder of this paper.

Given that a large and growing regulated equity premium exists, our question is whether or not it can be explained within an equilibrium asset-pricing framework such as the CAPM. If β were to have increased during the time period in question, for example, the growth of the regulated equity premium may well be explained by the increasing (relative) riskiness of utility equity. As Section 4 demonstrates, however, in fact it cannot.

[8] We used the 10-year constant maturity U.S. Treasury note yield as a proxy for the riskless rate and the yield on the Moody's Seasoned Baa Corporate Bond Index as a proxy for investment-grade corporate bond rates. Both series were obtained from the Federal Reserve's FRED database (Board of Governors of the Federal Reserve System, n.d.-a; n.d.-b).

4. Potential explanations for the premium

Having demonstrated the existence of a large and growing regulated equity premium, we investigate various potential explanations. As we indicated above, we proceed with our investigation of explanations for the premium via the Capital Asset Pricing Model. The CAPM allows three basic mechanisms of action for a change in the risk premium: (i) the manner in which the underlying assets are financed has changed, (ii) the risk of the underlying assets themselves has changed, and/or (iii) the rate at which the market in general prices risk has changed. We explore each in turn and formally test whether the trend in the data can be explained by the CAPM. Finding that it cannot, we then turn to theoretical explanations outside of the CAPM. The potential alternative explanations in Sections 4.5 through 4.7 all represent viable paths for further research.

4.1. *Capital structure effects*

As corporate leverage increases, the underlying equity becomes riskier and thus deserving of higher expected returns. In finance, the Hamada equation decomposes the CAPM equity beta (β) into an underlying asset beta (β_A) and the impact of capital structure (Hamada, 1969, 1972). Specifically, the Hamada equation states that $\beta = \beta_A\left[1 + (1-\tau)\frac{D}{E}\right]$, where τ is the tax rate and D and E are the debt and equity in the firm's capital structure, respectively. We use the marginal corporate federal income tax rate for the highest bracket, as provided in Internal Revenue Service (n.d.).

One explanation for a growing risk premium would be steadily increasing leverage among regulated utilities. However, regulators also generally approve of specific capital structures as part of the ratemaking process. As a result, our database also contains the authorized capital structures for each utility.[9] In fact, utilities are *less* leveraged today than they were in 1980. The average debt-to-equity ratio in the first five years of the data set (1980–1984) was 1.74; in 2014–2018 it was 1.05. More generally, we can observe the impact of leverage

[9] To be clear, the authorized capital structures evaluated here apply to the regulated utility subsidiaries, and not necessarily to any holding companies to which they belong. The holding companies themselves may utilize more or less leverage, but typically the regulated utility subsidiaries are "ring-fenced" so as to isolate them from holding company-level risks. Similarly, rate-of-return regulation would apply only to the regulated subsidiaries, not to the parent holding company. As a result, the capitalization of the regulated entity (studied here) is often different from the capitalization of the publicly-traded entity that owns it.

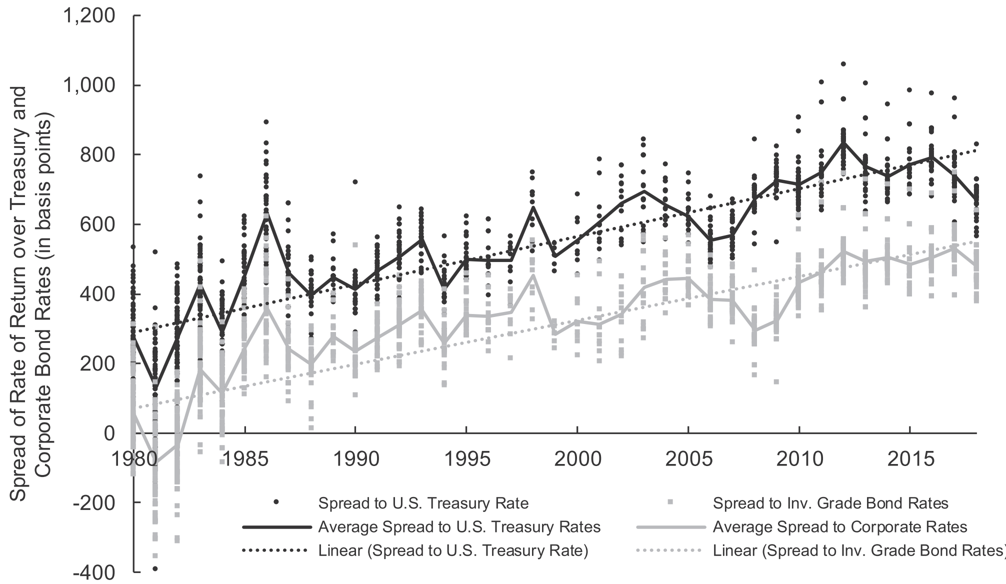

Fig. 5. Authorized return on equity premium, 1980–2018.

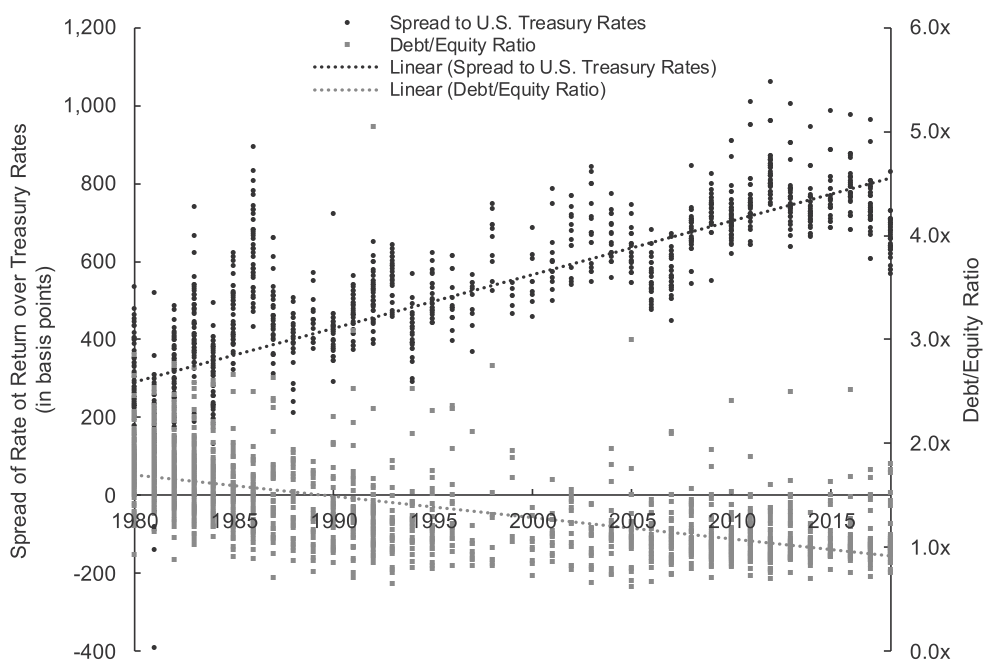

Fig. 6. Authorized return on equity premium vs. utility leverage.

moving in the opposite direction of what one may expect, whether we examine the debt-to-equity ratio exclusively or the Hamada capital structure parameter (i.e., the portion of the Hamada equation multiplied by β_A, or $\left[1 + (1-\tau)\frac{D}{E}\right]$) in its entirety. Figs. 6 and 7 illustrate these results. As a result, it does not appear as if capital structure itself can explain the behavior of the risk premium.

4.2. Asset-specific risk

As noted above, the Hamada equation decomposes returns into compensation for bearing asset-specific risks and for bearing capital structure-specific risks. Even if a firm's capital structure remains unchanged, the riskiness of its underlying assets may change. This risk is represented by the unlevered asset beta, β_A. An increase in the asset beta applicable to such investments would, all else held equal, justify an increase in the risk premium.

To examine such a hypothesis, we used the fifteen members of the Dow Jones Utility Average between 1980 and 2018 as a proxy for "utility asset risk." We estimated five-year equity betas for each firm by regression of their monthly total returns against the total return on the S&P 500 index.[10] The equity betas calculated were then converted to

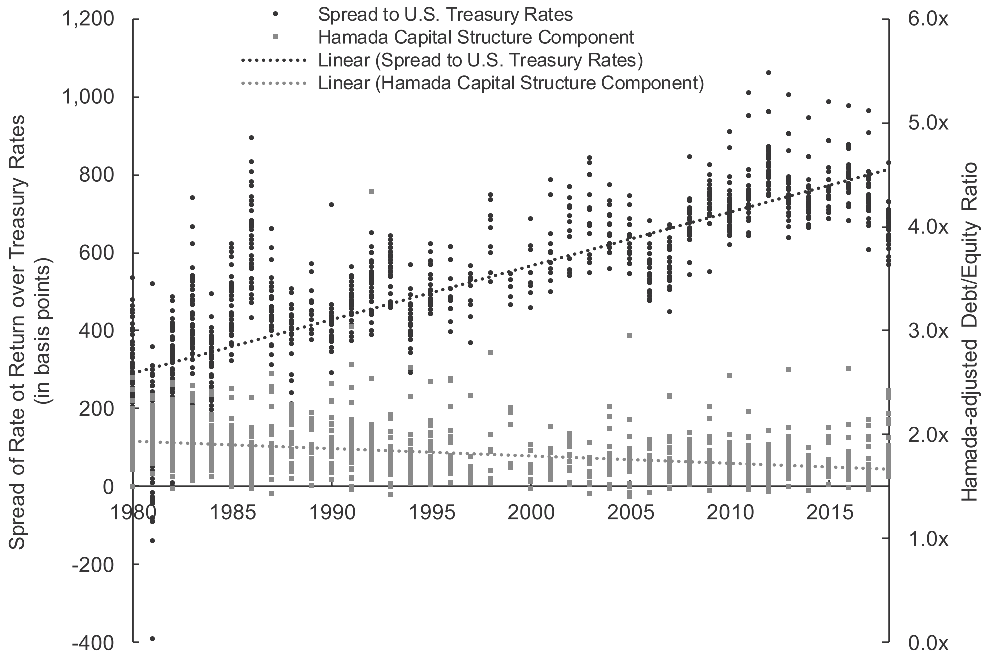

Fig. 7. Authorized return on equity premium vs. the Hamada capital structure parameter.

asset betas using Hamada's equation and corrected for firm cash holdings using firm-specific balance sheet information. We then averaged the fifteen asset betas calculated in each year as our proxy for utility asset risk.[11] The results remain substantively unchanged whether an equal-weighted or a capitalization-weighted average is used.

Although there is, of course, variation in the industry average asset beta across the thirty-eight years, the general trend is down. Fig. 8 presents the risk premium in comparison to the industry average asset beta. As a result, the asset beta is moving in the opposite direction from what one might expect, given a steadily-increasing risk premium, and therefore does not appear to explain the observed behavior of the risk premium.

4.3. The market risk premium

The last CAPM-derived explanation for a changing risk premium relates to the pricing of risk assets in general. If investors require greater compensation for bearing the systematic risk of the market in general, then the risk premium across all assets would increase as well (all else held equal) as a result of the average risk aversion coefficient of investors increasing. The market risk premium reflects this risk-bearing cost in the CAPM.

Although we can observe the *ex post* market risk premium, investors' assessment of the *ex ante* market risk premium is generally based on assuming that historical experience provides a meaningful guide to future experience.[12] It is customary to examine the actual market risk premium over some historical time period and base one's estimate of the *expected* future market risk premium on that historical experience (Sears and Trennepohl, 1993; Villadsen et al., 2017, p. 59). While the size of the historical window is subjective, it is sufficient for our purposes to note that the slope of the market risk premium over time has been negative irrespective of the historical window used.[13] Most sources advocate for using the longest time window available (Villadsen et al., 2017, p. 61); we use a fifty-year historical window for calculation purposes. As Fig. 9 illustrates, that declining trend in the market risk premium appears to be inconsistent with the increasing risk premium exhibited by the rates of return authorized by regulators.

4.4. Testing a theoretical model of the risk premium

Although we have illustrated that each component of the CAPM risk premium appears at odds with the risk premium derived from rates of return authorized by regulators, we now turn to a formal exploration of these relationships. By combining the security market line representation of the CAPM [1] and the Hamada equation, we can define the risk premium, $r_E - r_f$.

$$r_E - r_f = \beta_A \times \left[1 + (1-\tau)\frac{D}{E}\right] \times MRP \tag{2}$$

In [2], $r_E - r_f$ is the risk premium, or the difference between the authorized rate of return on equity for a given firm in a given rate case and the then-prevailing riskless rate. The asset beta, β_A, is calculated as described in Section 4.2. The middle component is taken from the Hamada equation and reflects the marginal corporate income tax rate (τ) in effect in the year in which the equity return was authorized and the authorized debt-to-equity ratio reflected in the regulators' decision for each case. Lastly, *MRP* is the *ex ante* estimate of the market risk

[10] We determined the composition of the Dow Jones Utility Average index at the end of each year and used a rolling five-year window to perform the regressions. For example, the 1980 regression betas were estimated based on monthly returns from 1975 to 1979, the 1981 regression betas were estimated based on monthly returns from 1976 to 1980, and so on.

[11] The balance sheet and total return data are taken from Standard & Poor's COMPUSTAT database. We calculate $\beta'_A = \beta/\left[1 + (1-\tau)\frac{D}{E}\right]$ and $\beta_A = \beta'_A/\left[1 - \frac{C}{D+E}\right]$, where C equals the amount of cash and cash equivalents held by each firm and D and E represent, respectively, the debt and equity of each firm. We measure D as the sum of Current Liabilities, Long-Term Debt, and Liabilities–Other in the COMPUSTAT data. Because final firm accounting information was not available for 2018 at the time of writing, we maintained the capital structures calculated using 2017 data.

[12] We do not dwell here on the issue of the "observability" of the market portfolio as it relates to testability of the CAPM. We shall assume that the S&P 500 index is a reasonable proxy for the market portfolio.

[13] The market risk premium data used here are taken from data on the S&P 500 and 10-year U.S. Treasury notes collected from the Federal Reserve (Damodaran, n.d.).

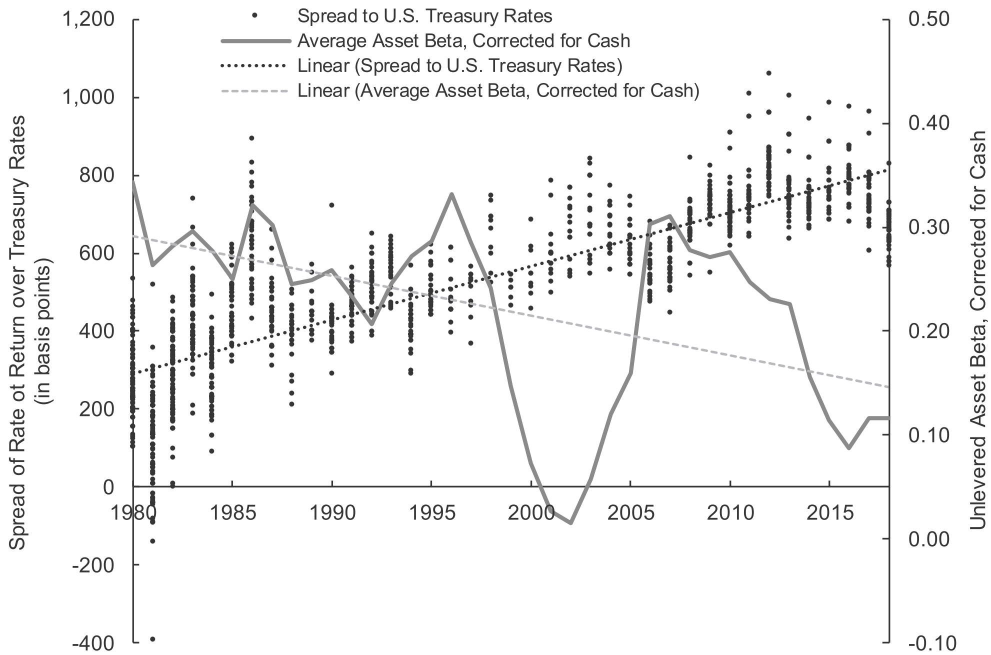

Fig. 8. Authorized return on equity premium vs. industry average asset beta.

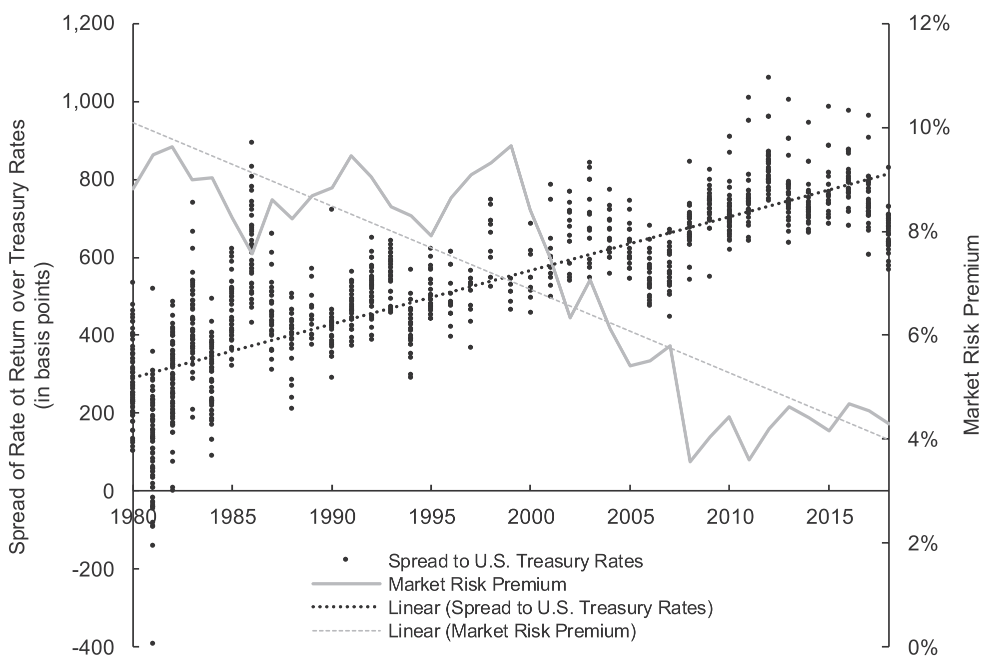

Fig. 9. Authorized rate-of-return premium vs. *ex ante* estimated market risk premium.

premium based on a fifty-year historical window as of the year in which each equity return was authorized.

Let $i = 1, \ldots, N$ index firms and $t = 1, \ldots, T$ index years. Not every firm files a rate case in every year. In addition, firms enter and exit over time due to merger or bankruptcy. Because regulators must have an evidentiary record to support their determinations, we assume that each rate case is evaluated independently in an adversarial hearing across time.

By using a logarithmic transform of [2], we arrive at equation [3].

$$ln(r_{E,it} - r_{f,t}) = \gamma_0 + \gamma_1 ln(\beta_{A,t}) + \gamma_2 ln\left[1 + (1 - \tau_t)\frac{D_{it}}{E_{it}}\right] + \gamma_3 ln(MRP_t) \quad (3)$$

In a traditional ordinary least squares (OLS) regression setting, the CAPM would hypothesize that γ_0 should be zero (or not significant) and γ_1, γ_2, and γ_3 should be positive and significant. What we find, however, is exactly the opposite of that (Table 3). The coefficients are negative and strongly significant. Further, a comparison of the observed risk premium to the risk premium estimated by our regression model reveals a good fit (Fig. 10). The negative coefficients are problematic for the CAPM, but also suggest rather counterintuitive effects at an applied

Table 3
Regression results for CAPM-based risk premium model. Coefficients for both the OLS regression model and a model controlling for utility-level fixed effects are shown.

	OLS	Controlling for utility-level fixed effects
	$ln(r_E - r_f)$	$ln(r_E - r_f)$
γ_0, Constant	3.641****	
	(0.130)	
γ_1, Asset beta, $ln(\beta_A)$	−0.158****	−0.156****
	(0.022)	(0.023)
γ_2, Capital structure, $ln\left[1+(1-\tau)\frac{D}{E}\right]$	−0.492****	−0.967****
	(0.103)	(0.142)
γ_3, Market risk premium, $ln(MRP)$	−0.947****	−0.898****
	(0.035)	(0.039)
R-squared	46.4%	46.6%
Adjusted R-squared	46.3%	41.2%
F statistic	458.8****	420.9****
No. of observations	1596	1596

Standard errors are reported in parentheses.
*, **, ***, and **** indicate significance at the 90%, 95%, 99%, and 99.9% levels, respectively.

level. Regulators use CAPM prescriptively in rate cases; they are determining what utilities *should* earn. A negative capital structure coefficient suggests, for example, that investors in firms with high leverage *should* be compensated with *lower* returns. Similarly, negative coefficients imply that investors in firms with riskier assets (higher asset betas) and during periods of higher risk aversion (higher market risk premiums) should also be compensated with *lower* returns. These results would be difficult for regulators to justify on normative grounds.

It may be the case, however, that common cross-sectional variation is biasing the results for this data by creating endogeneity issues for the OLS-estimated coefficients. For example, the repeated presence of the same utilities over time could introduce entity-level fixed effects into the analysis. Accordingly, we performed an F-test to evaluate the presence of individual-level effects in the data (Judge et al., 1985: p. 521). The test strongly supports the presence of individual (utility-level) effects ($F_{143,1449} = 1.5$, $p < 0.001$). In addition, the Hausman test (Hausman, 1978; Hausman and Taylor, 1981) supports the fixed-effect specification in lieu of random effects ($\chi^2(3) = 24.0$, $p < 0.001$). As a result, Table 3 also provides the regression coefficients controlling for utility-level fixed effects. These coefficients, while numerically different than the OLS results, are nevertheless still negative and strongly significant, in conflict with both financial theory and regulator intent.

Fig. 10 also reveals a distinct shift in the predicted trend of the risk premium beginning in 1999. This is notable because for many parts of the U.S., 1999 represented the year that implementation of electric market reform and restructuring began, with wholesale markets such as ISO-New England opening and several divestiture transactions of formerly-regulated generating assets occurring, establishing market valuations for formerly regulated assets (Borenstein and Bushnell, 2015). In addition, FERC issued its landmark Order 2000 encouraging the creation of Regional Transmission Organizations. To examine this point in time, we divided the data into two sets, 1980–1998 and 1999–2018, and estimated separate regression models for each subset using both OLS and controlling for utility-level fixed effects (Table 4). As before, the F (pre-1999 $F_{129,805} = 1.6$, $p < 0.001$; post-1998 $F_{129,525} = 3.2$, $p < 0.001$) and Hausman (pre-1999 $\chi^2(3) = 15.5$, $p < 0.01$; post-1998 $\chi^2(3) = 23.8$, $p < 0.001$) tests both strongly support the model controlling for utility-level fixed effects over OLS.

Although the results in both cases are consistent with our earlier finding that the standard finance model appears at odds with the empirical data, the two regression models are noticeably different from one another and appear to better represent the data (Fig. 11). We performed the Chow (1960) test and confirmed the presence of a structural break in the data in 1999 ($F_{4,1588} = 91.6$, $p < 0.001$).[14] We find this result suggestive that deregulatory activity may have an influence even on still-regulated utilities—a point to which we shall return in Section 5.2.

4.5. Potential finance explanations other than the CAPM

In Mehra and Prescott's (2003) review of the equity premium puzzle literature, the authors acknowledge that uncertainty about changes in the prevailing tax and regulatory regimes may explain the premium. Such forces may also be at work with regard to regulated rates of return. To the extent that investors require higher current rates of return because they are concerned about future shocks to the tax or regulatory structure of investments in regulated electric utilities (e.g., EPA's promulgation of the Clean Power Plan, the U.S. Supreme Court's stay of the Clean Power Plan, expiration of tax credits), such concern may be manifest in a higher degree of risk aversion that is unique to investors in the electric utility sector, and therefore a higher "market" risk premium on the assumption that capital markets are segmented for electric utilities.

A separate line of inquiry concerns a criticism of the Hamada equation in the presence of risky debt (Hamada (1972) excluded default from consideration). Conine (1980) extended the Hamada equation to accommodate risky debt by applying a debt beta. Subsequently, Cohen (2008) sought to extend the Hamada equation by adjusting the debt-to-equity parameter to incorporate risky debt in the calculation of the equity beta [4].

$$\beta = \beta_A\left[1 + (1-\tau)\frac{r_D}{r_f}\frac{D}{E}\right] \tag{4}$$

We view neither of these proposed solutions as entirely satisfying, and note that they tend to be material only for high leverage, which is not common to regulated utilities. Nevertheless, we acknowledge that adjustments to the capital structure may influence the risk premium. However, applying the Cohen (2008) modification and using the Moody's Seasoned Baa Corporate Bond Yield as a proxy for the cost of risky debt (r_D), we note that our regression results are substantively unchanged. As Table 5 illustrates, use of the Cohen betas still results in highly significant, but negative coefficients, which is contrary to theory. These results are maintained when controlling for utility-level fixed effects, and the F (Hamada $F_{143,1449} = 1.5$, $p < 0.001$; Cohen $F_{143,1449} = 1.3$, $p < 0.01$) and Hausman (Hamada $\chi^2(3) = 24.0$, $p < 0.001$; Cohen $\chi^2(3) = 6.3$, $p < 0.1$) tests are significant in support of the fixed effects model.

In lieu of modifying the CAPM parameters, some researchers have suggested that Ross's (1976) Arbitrage Pricing Theory (APT) is preferable to the CAPM because the CAPM produces a "shortfall" in estimated returns (Roll and Ross, 1983) and "underestimates" actual returns in utility settings (Pettway and Jordan, 1987). While the works of these authors are suggestively similar to the analysis contained in this paper, we note that those authors were examining the *actual* returns on utility common stocks, rather than the rates of return *authorized* by regulators for assets held in utility rate bases. The distinction is important. In the case of the former, it is a question of asset pricing models and efficient capital markets. In the case of the latter, it is an issue of regulator judgment. We note specifically that regulators are making decisions that set these rates, and in many cases are doing so explicitly stating that they are relying in whole or in part on the CAPM. Our question concerns not just whether the CAPM is a better asset pricing model (than the APT, for example), but whether regulators' own judgment can

[14] Additional testing using the Andrews (1993) approach supports the presence of structural breaks during the transitional regulatory period identified by Borenstein and Bushnell (2015), confirming the appropriateness of our selection of 1999 as a year with strong historical motivation for a structural break.

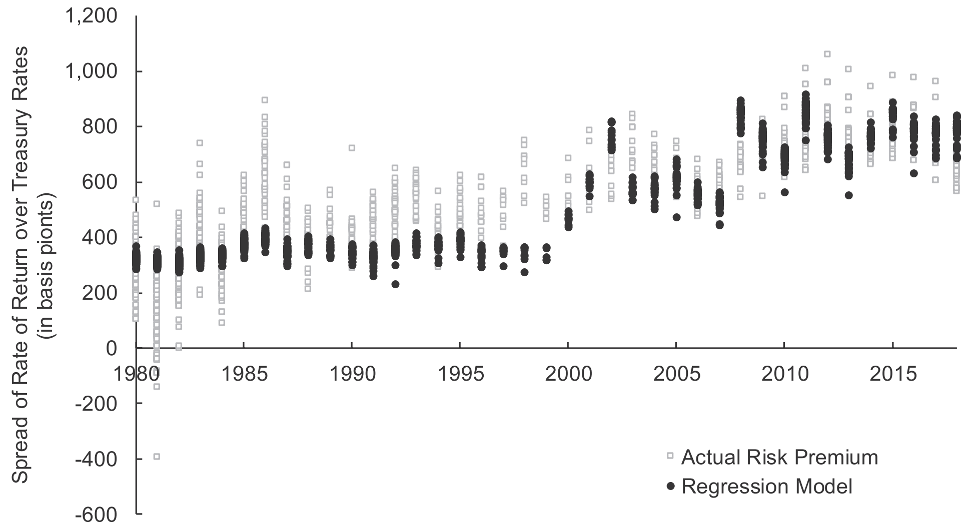

Fig. 10. Actual vs. OLS regression-model risk premium.

Table 4
Regression results for a two-period CAPM-based risk premium model. For purposes of the Chow test, the combined sum of squared residuals was 272.5. Coefficients for both the OLS regression model and a model controlling for utility-level fixed effects are shown.

	OLS		Controlling for utility-level fixed effects	
	1980–1998	1999–2018	1980–1998	1999–2018
	$ln(r_E - r_f)$	$ln(r_E - r_f)$	$ln(r_E - r_f)$	$ln(r_E - r_f)$
γ_0, Constant	−6.259****	5.159****		
	(0.718)	(0.093)		
γ_1, Asset beta, $ln(\beta_A)$	−0.940****	−0.071****	−0.972****	−0.065****
	(0.131)	(0.008)	(0.135)	(0.008)
γ_2, Capital structure, $ln\left[1 + (1 - \tau)\frac{D}{E}\right]$	−0.140	−0.325****	−0.865****	−0.636****
	(0.150)	(0.049)	(0.224)	(0.075)
γ_3, Market risk premium, $ln(MRP)$	−4.529****	−0.471****	−4.326****	−0.432****
	(0.261)	(0.026)	(0.267)	(0.025)
R-squared	26.7%	36.9%	30.2%	44.9%
Adjusted R-squared	26.4%	36.6%	18.8%	31.0%
F statistic	113.3****	127.3****	116.0****	142.5****
Sum of squared residuals	214.4	8.4	170.8	4.7
No. of observations	938	658	938	658

Standard errors are reported in parentheses.
*, **, ***, and **** indicate significance at the 90%, 95%, 99%, and 99.9% levels, respectively.

be explained by the model on which they claim to rely.

Lastly, to address a related point, we also examined the actual earned rates of return on equity for the 15 utilities in the Dow Jones Utility Average over our historical window. We used each firm's actual return on equity, calculated annually as Net Income divided by Total Equity, as reported in the COMPUSTAT database. This measure of firm profitability examines how successful the firms were at converting their *authorized* returns into *earned* returns. In general, the earned returns closely tracked the authorized returns, suggesting that the decisions of regulators are significantly influencing the actual earnings of regulated utilities. Fig. 12 compares the spread of *authorized* rates of return over riskless rates to the spread of *earned* rates of return over riskless rates and to the median net income of utilities in constant 2018 dollars.[15] The steadily increasing risk premium we have identified is present in both series. The series are correlated at 0.77 (authorized vs. earned), 0.59 (authorized vs. median net income), and 0.75 (earned vs. median net income), all of which are significantly greater than zero ($p < 0.001$). Further, the "capture rate" (the percentage of authorized rates actually earned by the utilities) averaged 96% over the entire time period. As a result, we conclude that the trend of increasing risk premiums is not an abstract anomaly occurring in a regulatory vacuum, but rather a direct contributor to the earnings of regulated utilities.

However, these measures of firm performance must be interpreted with caution. The authorized rates of return apply to jurisdictional utilities, while the earned rates of return are calculated based on holding company performance, which in many cases are not strictly equivalent. Further, increasing net income may be due to industry consolidation producing larger firms (with income increasing only proportionally to size), rather than an increase in profitability itself. In fact, the average income-to-sales ratio of the Dow Jones Utility Average members remained remarkably stable across the period of our study,

[15] We used the median earned rate of return over the 15 Dow Jones utilities. The results are substantively equivalent if the average earned rate of return is used but are more volatile due to the impact on earnings of the California energy crisis of 2000–2001 and the collapse of Enron in 2001.

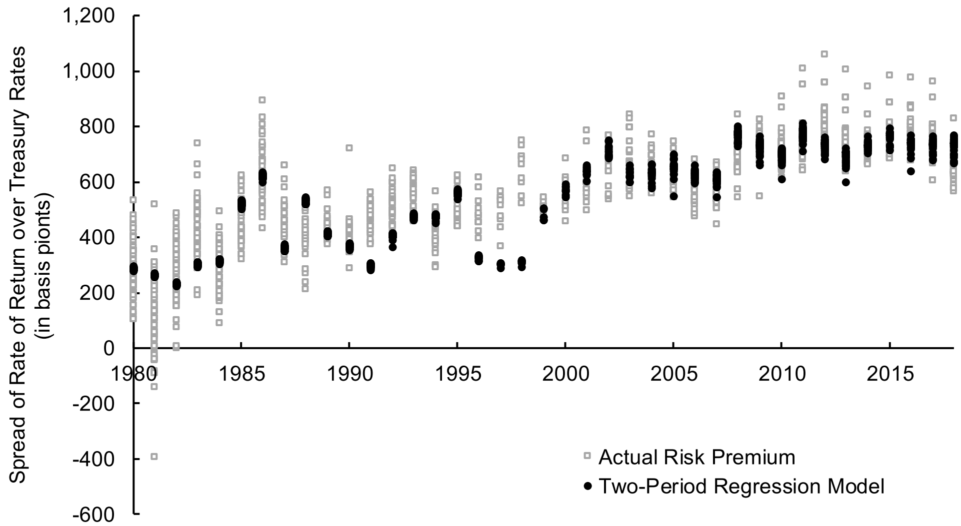

Fig. 11. Actual vs. two-period OLS model-predicted risk premium.

Table 5
Regression results for the standard Hamada capital structure model and Cohen (2008) capital structure model that incorporates risky debt. Coefficients for both the OLS regression model and a model controlling for utility-level fixed effects are shown.

	OLS		Controlling for utility-level fixed effects	
	Hamada $ln(r_E - r_f)$	Cohen $ln(r_E - r_f)$	Hamada $ln(r_E - r_f)$	Cohen $ln(r_E - r_f)$
γ_0, Constant	3.641****	3.191****		
	(0.130)	(0.085)		
γ_1, Asset beta, $ln(\beta_A)$	−0.158****	−0.169****	−0.156****	−0.175****
	(0.022)	(0.022)	(0.023)	(0.023)
γ_2, Capital structure, $ln\left[1 + (1-\tau)\frac{D}{E}\right]$	−0.492****		−0.967****	
	(0.103)		(0.142)	
γ_2', Capital structure, $ln\left[1 + (1-\tau)\frac{r_D}{r_f}\frac{D}{E}\right]$		−0.156*		−0.275***
		(0.081)		(0.040)
γ_3, Market risk premium, $ln(MRP)$	−0.947****	−1.046****	−0.898****	−1.087****
	(0.035)	(0.036)	(0.039)	(0.040)
R-squared	46.4%	45.7%	46.6%	45.1%
Adjusted R-squared	46.3%	45.6%	41.2%	39.6%
F statistic	458.8****	447.1****	420.9****	396.9****
No. of observations	1596	1596	1596	1596

Standard errors are reported in parentheses.
*, **, ***, and **** indicate significance at the 90%, 95%, 99%, and 99.9% levels, respectively.

and actually slightly declined, suggesting that gains in net income came from growing revenue, rather than increasing margins (although revenue growth may itself be a function of rising authorized rates of return). Nevertheless, the results are suggestive.

We have not repeated the analysis of Roll and Ross (1983) and Pettway and Jordan (1987) and examined the relationship between firm performance and stock performance. Their findings, however, suggest that regulated utilities have realized *higher* stock returns than can be explained by the CAPM—a finding congruent with our work and suggestive of other factors being priced by the market. This does not entirely explain the judgment issue, however: why regulators appearing to use a CAPM approach provide utilities with returns that also appear to be excessive.

4.6. Potential public choice explanations

Another category of potential explanations emerges from the public choice literature on the role of institutional factors. Regulators may be deliberately or inadvertently providing a "windfall" of sorts to electric utilities. Stigler (1971), among others in the literature on regulatory capture, noted that firms may seek out regulation as a means of protection and self-benefit. This is particularly true when the circumstances are present for a collective action problem (Olson, 1965) of concentrated benefits (excess profits to utilities may be significant) and diffuse costs (the impact of those excess profits on each individual ratepayer may be small). Close relationships between regulators and the industries that they regulate have been observed repeatedly, and one possible explanation for the size and growth of the risk premium is the electric utility industry's increasing "capture" of regulatory power.

We are somewhat skeptical of this explanation, however, both because of the degree of intervention in most utility rate cases by non-utility parties, and because the data do not suggest that regulators have become progressively laxer over time. Fig. 13 compares the rates of return on equity *requested* by utilities in our data set against the rates of return ultimately authorized. As the trend line illustrates, this ratio has remained remarkably stable (within a few percent) over the thirty-eight

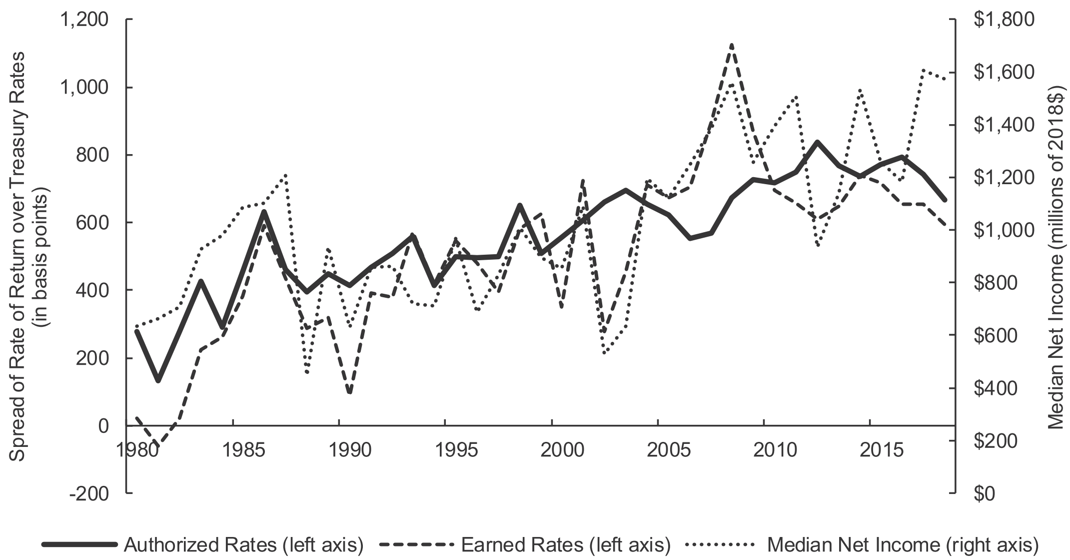

Fig. 12. Comparability of spreads measured with authorized and earned rates of return and utility net income.

years of data, even as the risk premium itself has steadily increased. As a result, the data do not suggest in general an obvious, growing permissiveness on the part of regulators. However, the last nine years are *suggestive* of an increasing level of accommodation among regulators. We propose a possible explanation for this particular pattern in Section 4.7.

To examine the public choice issues further, we investigated whether the risk premiums were related to the selection method of public utility commissioners and whether or not the rate cases in question were settled or fully litigated. The traditional hypothesis has been that elected (instead of appointed) commissioners were less susceptible to capture, more "responsive" to the public, and therefore more pro-consumer. Further, that cases that were settled were more likely to be accommodating to utilities (as money was "left on the table") and therefore would result in higher rates.

A sizable body of literature, however, has largely rejected the selection method hypothesis. Hagerman and Ratchford (1978) and Primeaux and Mann (1986) concluded that the selection method had no impact on returns or electricity prices respectively. Others have agreed that the selection method alone doesn't matter; it is how closely the regulators selected are monitored that matters (Boyes and McDowell, 1989). In addition, whatever evidence of an effect that may exist is likely due to selection method being a proxy for states with different intrinsic structural conditions (Harris and Navarro, 1983). Lastly, while states with elected utility commissioners (Kwoka, 2002) or commissioners whose appointment by the executive requires approval by the legislature (Boyes and McDowell, 1989) tend to have lower electricity prices, those low prices may create the perception of an "unfavorable" investment climate and may therefore lead to a higher cost of capital (Navarro, 1982). Alternatively, if lower prices are observed, it then remains unclear who actually pays (utility shareholders in foregone profits or consumers in higher costs of capital) for the lower observed prices (Besley and Coate, 2003).

To examine the impact of commission selection method and means of case resolution on risk premium, we categorized each state as having an elected or appointed utility commission based on data in Costello (1984), Besley and Coate (2003), and Advanced Energy Economy (2018). In addition, each rate case was reported as being either fully litigated or settled. The literature has hypothesized (but largely not found) that elected commissions are more "responsive" and therefore more pro-consumer. As a result, the expectation would be that the risk premiums implicit in authorized rates were higher for appointed commissions. Similarly, for means of case resolution, risk premiums would be higher for settled, rather than fully litigated rate cases.

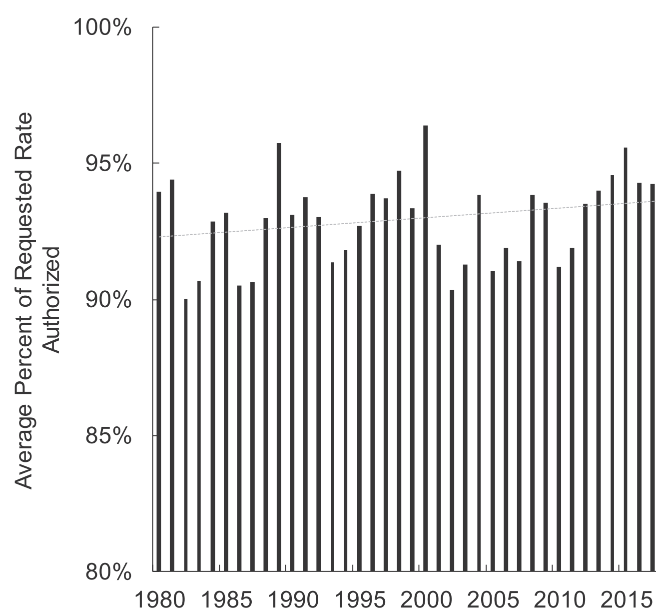

Fig. 13. Rate of return authorized as a percent of rate of return requested.

Table 6
Average risk premium in basis points by commission selection method and means of case resolution. The number of cases in each group is provided in parentheses.

	Appointed Commissions	Elected Commissions	Subtotals
Settled Cases	612 (367)	697 (89)	629 (456)
Fully Litigated Cases	460 (1008)	488 (181)	464 (1189)
Subtotals	500 (1375)	557 (270)	510 (1645)

Like other authors, we found no significant effect *overall* for selection method, but a very significant effect for whether cases were settled or fully litigated. In addition, there appears to be a significant *interaction* between selection method and means of case resolution, suggesting that the lack of evidence of an effect in the literature may be related to its interaction with the means of case resolution, which has not been examined in this depth before. Table 6 illustrates the average risk

Table 7
Regression results for the standard CAPM model and the CAPM model plus two public choice variables (commission selection method and means of case resolution). Coefficients for both the OLS regression model and a model controlling for utility-level fixed effects are shown.

	OLS		Controlling for utility-level fixed effects	
	CAPM $ln(r_E - r_f)$	CAPM + Public Choice $ln(r_E - r_f)$	CAPM $ln(r_E - r_f)$	CAPM + Public Choice $ln(r_E - r_f)$
γ_0, Constant	3.641****	3.519****		
	(0.130)	(0.137)		
γ_1, Asset beta, $ln(\beta_A)$	−0.158****	−0.159****	−0.156****	−0.154****
	(0.022)	(0.022)	(0.023)	(0.023)
γ_2, Capital structure, $ln\left[1+(1-\tau)\frac{D}{E}\right]$	−0.492****	−0.463****	−0.967****	−0.917****
	(0.103)	(0.102)	(0.142)	(0.141)
γ_3, Market risk premium, $ln(MRP)$	−0.947****	−0.927****	−0.898****	−0.858****
	(0.035)	(0.036)	(0.039)	(0.041)
γ_4, Settle = 1		0.223***		0.249****
		(0.057)		(0.060)
γ_5, Appointed = 1		0.159****		0.132**
		(0.034)		(0.058)
γ_6, Settle = 1 × Appointed = 1		−0.182***		−0.197***
		(-0.061)		(-0.065)
R-squared	46.4%	47.4%	46.6%	47.3%
Adjusted R-squared	46.3%	47.2%	41.2%	41.9%
F statistic	458.8****	238.5****	420.9****	216.5****
AIC	−2809	−2810		
No. of observations	1596	1596	1596	1596

Standard errors are reported in parentheses.
*, **, ***, and **** indicate significance at the 90%, 95%, 99%, and 99.9% levels, respectively.

premium observed in each group. The average risk premium for settled cases is significantly higher than for fully litigated cases ($p < 0.001$). Further, while the average risk premium for settled cases and appointed commissions is significantly greater than for fully litigated cases and elected commissions ($p < 0.001$), there is an interaction effect suggesting that the impact of selection method on risk premium depends on the means of case resolution ($p < 0.05$).

Notwithstanding these differences, the incremental explanatory value of these public choice variables is minimal (but significant). Table 7 compares the standard CAPM model with an OLS model that incorporates selection method and means of case resolution. The Akaike Information Criterion (AIC) indicates that incorporation of the public choice variables has only slight incremental value. We estimate that the marginal impact is only approximately 8 basis points—much less than the observed increase over time.[16] As before, the F (CAPM $F_{143,1449} = 1.5$, $p < 0.001$; CAPM + Public Choice $F_{143,1446} = 1.4$, $p < 0.001$) and Hausman (CAPM $\chi^2(3) = 24.0$, $p < 0.001$; CAPM + Public Choice $\chi^2(6) = 24.1$, $p < 0.001$) tests strongly support controlling for utility-level fixed effects in the model. Table 7 also includes coefficients incorporating such controls.

4.7. Potential behavioral economics explanations

To this point, we have examined a number of factors related to economic and institutional influences. At the outset, however, we noted the potential for rate determination to be influenced by regulator judgment. In many cases there is evidence that regulators are not behaving in accordance with the method they in fact purport to be using (i.e., CAPM). As we cannot escape the fact that ultimately the authorized return on equity is a product of regulator decision-making, we now consider possible explanations for the risk premium based on insights from behavioral economics.

First, we note that regulator attachment to rate decisions from the recent past may be coloring their forward-looking decisions. Earlier we referenced a report from Pennsylvania regulators about their stated reliance on (*inter alia*) "recent [returns on equity] adjudicated by the Commission" (Pennsylvania Public Utility Commission, 2016, p. 17). The legal weight attached to precedent may give rise here to a recency bias, where regulators anchor on recent rate decisions and insufficiently adjust them for new information. While stability in regulatory decision-making is seen as useful in assuring investors, to the extent that it results in a slowing of regulatory response when market conditions change, regulators should be encouraged to weigh the benefits of stability against the costs of distortionary responses to authorized returns that lag market conditions.

Our second insight from behavioral economics involves a curious observation in the empirical data: the average rate of return on regulated equity appears to have "converged" to 10% over time. Although the underlying riskless rate has continued to drop, authorized equity returns have generally remained fixed in the neighborhood of 10%, only dropping below (on average) over the last few years. Anecdotally, we have observed a reluctance among potential electric power investors to accept equity returns on power investments of less than 10%—even though those same investors readily acknowledge that *debt* costs have fallen. To that extent, then, a behavioral bias may be at work.

The finance literature has noted a similar effect related to crossing index threshold points (e.g., every thousand points for the Dow Jones Industrial Average). These focal points, which have no normative import, appear to influence investor behavior. Trading is reduced near major crossings (Donaldson and Kim, 1993; Koedijk and Stork, 1994; Aragon and Dieckmann, 2011), with some asserting that the behavior of investors in clienteles may produce this behavior (Balduzzi et al., 1997). We propose a related theory.

In economics, "money illusion" refers to the misperception of nominal price changes as real price changes (Fisher, 1928). Shafir et al. (1997) proposed that this type of choice anomaly arises from framing effects, in that individuals give improper influence to the nominal representation of a choice due to the convenience and salience of the nominal representation. The experimental results have been upheld in several subsequent studies in the behavioral economics literature (Fehr and Tyran, 2001; Svedsäter et al., 2007).

The effect here may be similar: investors and regulators may conflate "nominal" rates of return (the authorized rates) with the risk

[16] For example, the marginal impact of a settled vs. fully-litigated case would be $exp(3.513 + 0.223) - exp(3.513) = 8.4$ using the OLS coefficients.

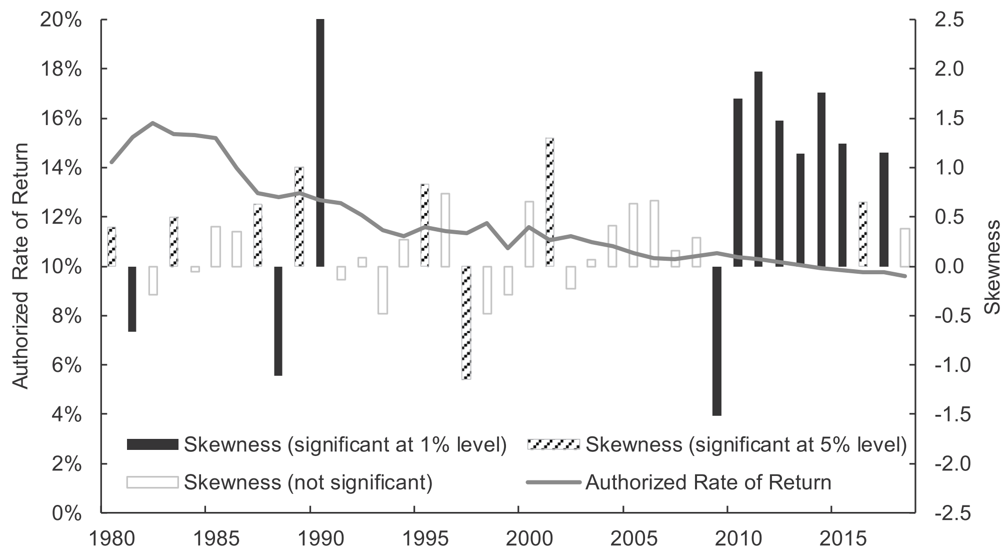

Fig. 14. Authorized rates of return on equity and skewness.

premium underlying the authorized rate. The apparent "stickiness" of rates of return on equity around 10% is similar to the "price stickiness" common in the money illusion (and, indeed, the rate of return is the price of capital). If there was in fact a tendency (intentional or otherwise) to respect a 10% "floor," one might expect that the distribution of authorized returns within each year may "bunch up" in the left tail at 10%, where absent such a floor one may expect them to be distributed symmetrically around a mean. As Fig. 14 illustrates, we see precisely such behavior. As average authorized returns decline to 10% (between 2010 and 2015), the skewness of the within-year distributions of returns becomes persistently and statistically significantly positive, suggesting a longer right-hand tail to the distributions, consistent with a lack of symmetry below the 10% threshold.[17] We note also that this period of statistically significant positive skewness coincides precisely with what appeared to be a period of increased regulator accommodation in Fig. 13. Further, once the threshold is definitively crossed, skewness appears to moderate and the distribution of returns appears to revert toward symmetry.

A related finding has been reported by Fernandez and colleagues (Fernandez et al., 2015, 2017, 2018), where respondents to a large survey of finance and economics professors, analysts, and corporate managers tended, on average, to overestimate the riskless rate of return. In addition, their estimates exhibited substantial positive skew, in that overestimates of the riskless rate far exceed underestimates.[18] The authors found similar results not just in the U.S., but also in Germany, Spain, and the U.K. In the U.S., the average response during the high skewness period exceeded the contemporaneous 10-year U.S. Treasury rate by 20–40 basis points, before declining as skewness moderated in 2018. It may be that overestimating the riskless rate is simply one way for participants in regulatory proceedings to "rationalize" maintaining the authorized return in excess of 10%. Alternatively, it may be an additional bias in the determination of authorized rates of return.

If such biases exist, there are clear implications for the regulatory function itself. For example, this apparent 10% "floor" was even recognized recently in a U.S. Federal Energy Regulatory Commission proceeding (Initial Decision, Martha Coakley, et al. v. Bangor Hydro-Electric Co., et al., 2013, 144 FERC 63,012 at 576): "if [return on equity] is set substantially below 10% for long periods […], it could negatively impact future investment in the (New England Transmission Owners)." Our findings here draw us back to Joskow's (1972) characterization of regulator decision-making as a sort of meta-analysis. That is, commissioners do not merely directly evaluate the CAPM equations. Rather, they look at the nature of the evidence *as presented to them*. Accordingly, their judgments are based not just on capital market conditions in a vacuum, but on the format, detail, and context of the information contained within the evidentiary record of a rate case. As a result, regulators are susceptible to biases in judgment, and calibration of regulatory decision-making during the rate-setting process should be a required step.

5. Conclusions and policy implications

In this paper, we have examined a database of electric utility rates of return authorized by U.S. state regulatory agencies over a thirty-eight-year period. These rates have demonstrated a growing spread over the riskless rate of return across the time horizon studied. The size and growth of this spread—the risk premium—does not appear to be consistent with classical finance theory, as expressed by the CAPM. In fact, regression analysis of the data suggests the *opposite* of what would be predicted if the CAPM holds. This is particularly perplexing given that regulators often *claim* to be using the CAPM. In addition to the traditional finance factors, our work examined the influence of institutional, structural, and behavioral factors on the determination of authorized rates of return. We find support for many of these factors, although most cannot be justified on traditional normative grounds.

The pattern of large and growing risk premiums illustrated in this paper has significant implications for both utility and infrastructure investment and regulation and market design in environments where both regulated and restructured firms compete for capital. In particular, if rate case activity increases over the next several years as rate moratoria expire, the implications for retail rate escalation and capital investment may be significant. We discuss each in turn before offering some thoughts on possible mitigating factors.

[17] Formally, we test the hypothesis that the observed skewness is equal to zero (a symmetric, normal distribution). The test statistic is equal to the skewness divided by its standard error $\sqrt{6n(n-1)/(n-2)(n+1)(n+3)}$, where n is the sample size. The test statistic has an approximately normal distribution (Cramer and Howitt, 2004).

[18] At the time of the 2015 survey, for example, the 10-year U.S. Treasury rate was 2.0%. The average riskless rate reported by the 1983 U.S. survey respondents was 2.4% (median 2.3%), but responses ranged from 0.0% to 8.0%.

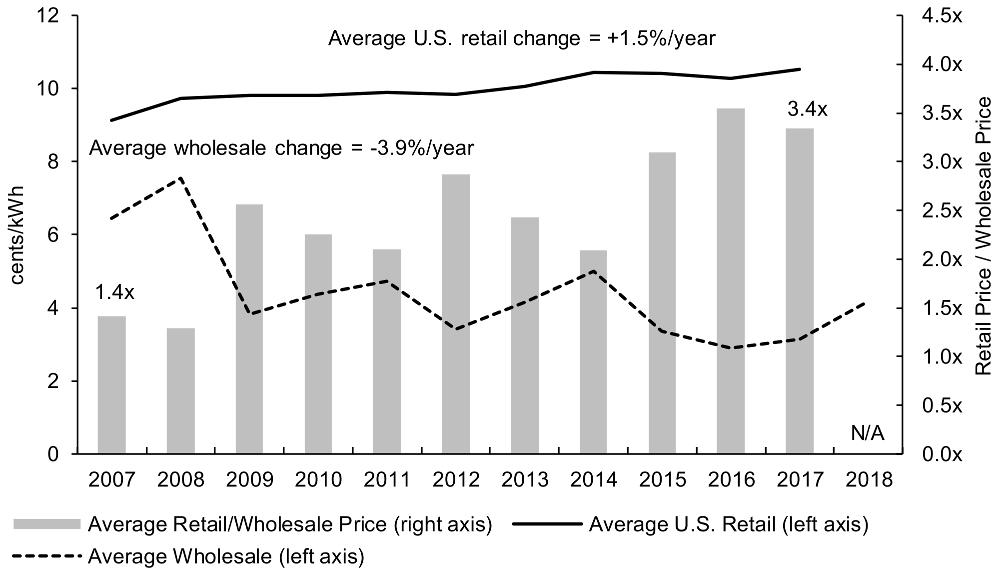

Fig. 15. Peak wholesale (2007–2018) vs. retail (2007–2017) power prices. Wholesale prices represent the average annual peak electricity price in MISO-IN, ISO-NE Mass Hub, Mid-C, Palo Verde, PJM-West, SP-15, and ERCOT-North. Retail prices collected from U.S. Energy Information Administration (https://www.eia.gov/electricity/data/state/avgprice_annual.xlsx). The retail price is the average for the entire country (using only the 7 states with wholesale markets included does not change the result).

5.1. Wholesale and retail electricity price divergence

A growing divergence has emerged over the last decade. Although fuel costs and wholesale power prices have declined since 2007, the *retail* price of power has increased over the same period (see Fig. 15). One explanation for this divergence in wholesale and retail rates may be the presence of a growing premium attached to regulated equity returns and therefore embedded into rates. To be sure, other forces may also be at work (for example, recovery of transmission and distribution system investments is consuming a greater portion of retail bills—a circumstance potentially exacerbated by excessive risk premiums). Further, even if the growing divergence between wholesale and retail rates is related to a growing risk premium, it does not necessarily follow that such growth is inappropriate or inconsistent with economic theory. Nevertheless, the potential for embedding of such quasi-fixed costs into the cost structure of electricity production may be significant for end users, as efficiency gains on the wholesale side are more than offset by excess costs of equity capital on the retail side.

5.2. Regulation itself as a source of risk

Public policy, or regulation itself, may be a causal factor in the observed behavior of the risk premium. The U.S. Supreme Court acknowledged, in *Duquesne Light Company* et al. *v. David M. Barasch* et al. (488 U.S. 299 (1989), p. 315) that "the risks a utility faces are in large part defined by the rate methodology, because utilities are virtually always public monopolies dealing in an essential service, and so relatively immune to the usual market risks." The recognition that the very act of regulating utilities subjects them to a unique class of risks may influence their cost of capital determination. And yet, if the *purpose* (or at least *a* purpose) of regulating electric utilities is to prevent these quasi-monopolists from charging excessive prices, but the *practice* of regulating them results in a higher cost of equity capital than might otherwise apply, it calls into question the role of such regulation in the first place.

Similarly, we may also question whether the hybrid regulated and non-regulated nature of the electric power sector in the U.S. plays a role as well. Has deregulation caused risk to "leak" into the regulated world because both regulated and non-regulated firms must compete for the same pool of capital? Has the presence of non-regulated market participants raised the marginal price of capital to all firms? In Section 4.4 we illustrated a shift in the trend of risk premium growth in 1999, as several U.S. markets were switching to deregulation, but further study of this question is needed.

The trajectory of public policy during the entire time period studied has been toward deregulation (beginning before 1980 with Public Utility Regulatory Policy Act, through the Natural Gas Policy Act in the 1980s, and electric industry deregulation in the 1990s) and "today's investments face market, political and regulatory risks, many of which have no historical antecedent that might serve as a starting point for modeling risk." (PJM Interconnection, 2016) The general unobservability of the *ex ante* expected returns on deregulated assets complicates determining if the progressive deregulation of the industry has caused a convergence in regulated and non-regulated returns over that time period. While the data do not suggest that utilities in states that have never undertaken deregulation have meaningfully different risk premiums, there are many ways to evaluate the "degree" of deregulatory activity that could be explored.

Another public policy-related factor could be a change in the nature of the rate base or of rate-making itself. Toward the beginning of our study period, most of the electric utilities were vertically integrated (i.e., in the business of both generation and transmission of power). Over time, generation became increasingly exposed to deregulation, while transmission and distribution of power have tended to remain regulated. To the extent that the portion of the rate base comprised of transmission and distribution assets has increased at the expense of generation assets, it may suggest a shift in the underlying risk profile of the assets being recognized by regulators. We note, for example, that public policy has tended to favor transmission investments with "incentive rates" in recent years in order to address a perceived relative lack of investment in transmission within the electric power sector. Our data, however, reveal the opposite. Based on data since 2000, there have been 172 transmission and distribution-only cases, out of 653 total cases. The average rate of return authorized in the transmission and distribution cases is approximately 60 basis points *lower* than those in vertically-integrated cases from the same period. These have been *state-*

level cases however. We note as deserving of further study that (interstate) electric transmission is regulated by FERC using a well-defined DCF approach instead of CAPM. The impact of having differing regulatory frameworks to set rates for assets that are functionally substantially identical remains an open question.

As for a change in the nature of rate-making itself, we note that the industry has tended to move from cost-of-service rate-making to performance-based ratemaking. If this shift, in an attempt to increase utility operating efficiency, has inadvertently raised the cost of equity capital through the use of incentive rates, it would be important to ascertain if the net cost-benefit balance has been positive. In general, there has been a lack of attention to the impact of regulatory changes on discount rates. The data on authorized returns on equity provides a unique dataset for such investigations.

5.3. Strategies for mitigating the growing premium

Our research does not necessarily imply that the rates of return authorized by regulators are too high, or otherwise necessarily inappropriate for utilities. An evaluation of whether these non-normative factors constitute a legitimate basis of rate of return determination deserves separate study. But if institutional or behavioral factors lead to departures from normative outcomes in setting rates of return on equity, then perhaps like Ulysses and the Sirens, regulators' hands should be "tied to the mast."

One notable jurisdictional difference in regulatory practice is between formulaic and judgment-based approaches to setting the cost of capital. In Canada, for example, formulaic approaches are more prevalent than in the United States (Villadsen and Brown, 2012). California also adjusts returns on equity for variations in bond yields beyond a "dead band," and the performance-based regulatory approaches in Mississippi and Alabama rely on formulaic cost of capital determination (Villadsen et al., 2017).

By pre-committing to a set formula (e.g., government bond rates plus *n* basis points) in lieu of holding adversarial hearings, regulators could minimize the potential for deviation from outcomes consistent with finance theory. Villadsen and Brown (2012) noted, for example, that then-recent rates set by Canadian regulators tended to be lower than those set by U.S. regulators despite nearly equivalent riskless rates of return. An intermediate approach would be to require regulators to calculate and present a formulaic result, but then allow them the discretion to authorize deviations from such a result when circumstances justify such departures. In such cases, regulators could avoid anchoring on past results, and instead anchor on a theoretically-justifiable return, before adjusting for any mitigating factors. If regulator judgment is impaired or subject to bias, then minimizing the influence of judgment by deferring to models may be prudent. In the end, we may observe simply that what regulators *should* do, what regulators *say* they're doing, and what regulators *actually* do may be three very different things.

Conflicts of interest

The authors declare that they have no conflict of interest.

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Appendix A. Supplementary data

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Mark Ellis <mark.edward.ellis@gmail.com>

RE: Inquiry: How Value Line calculates beta
1 message

vlsoft@valueline.com <vlsoft@valueline.com> Wed, Oct 6, 2021 at 9:03 AM
To: mark.edward.ellis@gmail.com

Dear Mr. Ellis,

Value Line's Estimation of Beta

The return on security I is regressed against the return on the New York Stock Exchange

Composite Index in the following form:

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

Where:

p^{I}_{t} - The price of security I at time t

p^{I}_{t-1} - The price of security I one week before time t

p^{m}_{t} and p^{m}_{t-1} are the corresponding values of the NYSE Composite Index.

The natural log of the price ratio is used as an approximation of the return and no adjustment is made for dividends paid during the week.

The regression estimate of beta, B_I , is computed from data over the past five years, so that 259 observations of weekly price changes are used.

Value Line adjusts its estimate of beta for regression bind described by Blume (1971). The reported beta is the adjusted beta computed as:

$$\text{Adjusted } B_I = 0.35 + .67 * B_I$$

M. Blume, "On the assessment of risk," Journal of Finance, March 1971

There is nothing more recent.

Thanks,

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From: Mark Ellis [mailto:mark.edward.ellis@gmail.com]
Sent: Wednesday, October 06, 2021 10:48 AM
To: VLsoft <vlsoft@valueline.com>
Subject: Inquiry: How Value Line calculates beta

I am researching how different market data providers calculate beta. I could not find any details on your website but came across the attached, from a regulatory filing, which looks dated. Could you please provide an update of Value Line's beta calculation methodology or confirm that the method described in the attached is correct?

Thank you!

Mark Ellis

619 507 8892

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Fwd: Chat Question: Case 11968851 [ref:_00D30aXa._5006f1hy0ed:ref]

1 message

From: **Support - Primary Email Address** <support.capiqpro@spglobal.com>
Date: Wed, Nov 17, 2021 at 5:57 PM
Subject: Chat Question: Case 11968851 [ref:_00D30aXa._5006f1hy0ed:ref]

S&P Global
Market Intelligence

Thank you for your response. Yes, you are correct about all your questions related to beta; likewise, you are using CIQ Pro and are pulling 1 and 3-year betas from using this platform.

I hope this is helpful, and please let me know if you have any other questions. Thanks and have a great rest of your day!

Best,

Paul Cordle
Associate, Client Support

Please "Reply All" to this email to ensure you receive a timely response.

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--------------- Original Message ---------------
Sent: 11/17/2021 4:16 PM
To: support.capiqpro@spglobal.com
Subject: Re: Chat Question: Case 11968851 [ref:_00D30aXa._5006f1hy0ed:ref]
Sorry for the delay in getting back to you, Paul.

Just to confirm:

- I am using CIQ Pro
- When I download betas, they are "SNL" 1- and 3-year betas
- Regarding SNL betas --
    - They use daily returns
    - Returns are:
        - Price-only (not total return)
        - Absolute (not relative to the risk-free rate)
        - Simple (not logarithmic)
    - The S&P 500 is the proxy for the market
    - The betas are raw, not adjusted toward 1.0

Thanks for your patience and help!

Docket E-7, Sub 1276
Exhibit MEE-6

Richard A. Michelfelder *is Clinical Associate Professor of Finance at Rutgers University, School of Business, Camden, New Jersey. He earlier held a number of entrepreneurial and executive positions in the public utility industry, some of them involving the application of renewable and energy efficiency resources in utility planning and regulation. He was CEO and chairperson of the board of Quantum Consulting, Inc., a national energy efficiency and utility consulting firm, and Quantum Energy Services and Technologies, LLC, an energy services company that he co-founded. He also helped to co-found and build Comverge, Inc., currently one of the largest demand-response firms in the world, which went public in 2006 on the NASDAQ exchange. He was also an executive at Atlantic Energy, Inc. and Chief Economist at Associated Utilities Services, where he testified on the cost of capital for public utilities in a number of state jurisdictions and before the Federal Energy Regulatory Commission. He holds a Ph.D. in Economics from Fordham University.*

Panayiotis Theodossiou *is Professor and Dean of Faculty of Management at the Cyprus University of Technology. Previously he was Professor of Finance at Rutgers University, School of Business, Camden. Dr. Thedossiou has also held a number of other faculty positions in finance at Catholic University and Clarkson University. He has also provided consulting advice to national governments. He holds a Ph.D. in Finance from the City University of New York.*

This article has benefitted from participant comments at the Rutgers University Center for Research in Regulated Industries Eastern Conference in May 2011. The authors would also acknowledge the Whitcomb Center for Financial Research for funding the data acquisition from the WRDS database.

Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings

The Capital Asset Pricing Model (CAPM) is commonly used in public utility rate proceedings to estimate the cost of capital and allowed rate of return. The beta in the CAPM associates risk with estimated return. However, an empirical analysis suggests that the commonly used Blume CAPM beta adjustment is not appropriate for electric and electric and gas public utility betas, and may bias the cost of common equity capital in public utility rate proceedings.

Richard A. Michelfelder and Panayiotis Theodossiou

I. Introduction

Regulators, public utilities, and other financial practitioners of utility rate setting in the United States and other countries often use the Capital Asset Pricing Model (CAPM) to estimate the rate of return on common equity (cost of common equity).[1] Typically, the ordinary least squares method (OLS) is the preferred estimation method for the CAPM betas of public utilities. Although the CAPM model has been widely criticized regarding its validity and predictability in the literature, as summarized by Professors Fama and French in 2005,[2] many firms and practitioners extensively use it to obtain cost of common equity estimates; e.g., such as shown by Bruser et al. in 1998, Graham and Harvey in 2001, and Gray, et al. in 2005.[3] Michelfelder, et al. in 2013[4] in this

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journal presents a new model, i.e., the Predictive Risk Premium Model, to estimate the cost of common equity capital and compare and contrast the poor results of the CAPM to that model and the discounted cash flow model.

Major vendors of betas include, but are not limited to, Merrill Lynch, Value Line Investment Services (Value Line), and Bloomberg. These companies use Blume's 1971 and 1975[5] beta adjustment equation to adjust OLS betas to be used in the estimation of the cost of common equity for public utilities and other companies.

The premise behind the Blume adjustment is that estimated betas exhibit mean reversion toward one over time; that is, betas greater or less than 1 are expected to revert to 1. There are various explanations for the phenomenon first discussed in Blume's pioneering papers. One explanation is that the tendency of betas toward one is a by-product of management's efforts to keep the level of firm's systematic risk close to that of the market. Another explanation relates to the diversification effect of projects undertaken by a firm.[6]

While this may be the case for non-regulated stocks, regulation affects the risk of public utility stocks and therefore the risk reflected in beta may not follow a time path toward one as suggested by Peltzman in 1976, Binder and Norton in 1999, Kolbe and Tye in 1990, Davidson, Rangan, and Rosenstein in 1997, and Nwaeze in 2000.[7] Being natural monopolies in their own geographic areas, public utilities have more influence on the prices of their product (gas and electricity) than other firms. The rate setting process provides public utilities with the opportunity to adjust prices of gas and electricity to recover the rising costs of fuel and other materials used in the transmission and distribution of electricity and gas. Companies operating in competitive markets

The premise behind the Blume adjustment is that estimated betas exhibit mean reversion toward one over time.

do not have this ability. In this respect, the perceived systematic risk associated with the common stock of a public utility may be lower than that of a non-public utility. Therefore, forcing the beta of a utility stock toward one may not be appropriate, at least on a conceptual basis.

The explanations provided by Blume and others to justify the latter tendency are hardly applicable to public utilities. Unlike other companies, utilities can and do possess monopolistic power over the markets for their products. This power impacts the ''negotiation process'' for setting electric and gas prices. Furthermore, it provides them with the opportunity to raise prices to recover increases in operating costs without regard to competitive market pressure. Such price influence is rarely available to companies operating in competitive market environments for their products. In that respect, macroeconomic factors will have a greater impact on the earnings and stock prices of the non-utility companies resulting in larger systematic risk or betas.

The application of Blume's equation to public utility stocks generally results in larger betas, since most raw utility betas are less than 1. Therefore, applications of these betas to estimate the cost of capital and an allowed rate of return on common equity possibly biases the required rate of return or cost of common equity, leading to an over-investment of capital as predicted by Averch and Johnson in 1962,[8] which preceded the trend in prudency reviews that began to occur in the 1980s. Although reported public utility betas may have been biased upward by the vendors of beta that applied Blume's adjustment to public utility betas, ex post prudency reviews of ''used and useful'' assets defined and supported by the Duquesne 1989 US Supreme Court decision[9] resulted in an underinvestment of capital in generation and transmission assets, leading to electric brownouts and blackouts. This article examines the behavior of the betas of the population of publicly traded U.S. energy utilities. In

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addition to evaluating the stability of these betas over the period from the January 1962 to December 2007, we also test whether or not public utility betas are stationary or mean reverting toward 1 or perhaps a different level.

II. Background

Investor-owned public utility regulatory proceedings to change rates for service almost always involve contentious litigation on the fair rate of return or cost of common equity. Since the cost of common equity is not observable, it must be inferred from market valuation models of common equity. The differences in the recommended allowed rates of return resulting from necessary subjective judgments in the application of cost of common equity models can easily mean 500 basis points or more in the estimate. Therefore, both the impact on customer rates for utility service and the profits of the utilities are very sensitive to the methods used to estimate the cost of common equity and allowed rate of return. The two most commonly used models are the Dividend Discount Model (DDM) and the CAPM. We discuss the use of CAPM for estimating the cost of common equity for public utilities. Our focus is on the use of market-influential betas from the major vendors of betas: Merrill Lynch, Value Line, and Bloomberg. These vendors apply Blume's adjustment to raw betas to estimate forward-looking betas. Blume[10] performed an empirical investigation, finding that beta is non-stationary and has a tendency to converge to 1. Bey in 1983 and Gombola and Kahl in 1990[11] found that utility betas are non-stationary and concluded that each utility beta's non-stationarity must be viewed on an individual stock basis, unlike the recommendation of Blume which adjusts all betas for their tendency to approach 1. Similarly with Gombola and Kahl, we find that public utility betas have a tendency to be less than 1. They investigated the time series properties of public utility betas for their ability to be forecasted whereas we are concerned with the institutional reasons for the trends in beta, the bias instilled in cost of capital estimates assuming that utility betas converge to one and the widespread use and applicability of the Blume adjustment to public utility betas. McDonald, Michelfelder and Theodossiou in 2010[12] show that use of OLS is problematic itself for estimating betas as the nonnormal nature of stock returns result in beta estimates that are statistically inefficient and possibly biased.

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Blume's equation is:

$$\beta_{t+1} = 0.343 + 0.677\beta_t \qquad (1)$$

where β_{t+1} is the foreasted or projected beta for stock i based on the most recent OLS estimate of firm's beta β_t. For example if β_t is estimated using historical returns from the most recent five years, then the projected β_{t+1} may be viewed as a forecast of the beta to prevail during the next five years. As mentioned earlier, Blume's equation implies a long-run mean reversion of betas toward 1. The long-run tendency of betas implied by Blume's equation can be computed using the equation:

$$\overline{\beta} = \frac{0.343}{1-0.677} = 1.0619 \approx 1 \qquad (2)$$

The same result can be obtained by recursively predicting beta until it converges to a final value. This can only be appropriate for stocks with average betas, as a group, close to one. This is, however, hardly the case for public utility betas that are generally less than 1 (as discussed in detail below).

The magnitude of adjustment for Blume's beta equation is initially large and declines dramatically as the adjusted beta approaches 1 either from below (for betas lower than 1) or from above (for betas greater than 1). In this respect, the beta adjustment step (size) will be larger for betas further away from 1.

As we will see in the next section, the median beta of the public utilities studied ranges between 0.08 and 0.74 over time,

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depending upon the period used. Under the assumption that betas for public utilities are consistent with Blume's equation, the next period beta for a stock with a current beta of 0.5, will be $\beta_{t+1} = 0.343 + 0.677\ (0.5) = 0.6815$, implying a 36.3 percent (0.6815/0.5) upward adjustment. On the other hand a beta of 0.4 will be adjusted to $\beta_{t+1} = 0.343 + 0.677\ (0.4) = 0.6138$ which constitutes a 53.5 percent upward adjustment and a beta of 0.3 will be adjusted to 0.5461 or by 82.0 percent.

The beta adjustment method most widely disseminated by the major beta vendors is the Blume adjustment. Therefore, our focus is on the Blume adjustment for public utility betas and the public utility cost of common equity capital. Occasionally, an expert witness in a public utility rate case estimates their own betas, but they are quickly repudiated in rate proceedings since these betas are not disseminated by influential stock analysts and presumed not to be reflected in the stock price. Section III discusses the data and empirical analysis of the Blume adjustment and its impact on the cost of common equity for public utilities.

III. Data and Empirical Analysis

The data include monthly holding period total returns for 57 publicly traded U.S. public utilities for the period from January 1962 to December 2007 obtained from the University of Chicago's Center for Research in Security Prices (CRSP) database. The sample includes all publicly traded electric and electric and gas combination public utilities with SIC codes 4911 and 4931 listed in the CRSP database. All non-U.S. public utilities traded in the U.S. and non-utility stocks were not included in the dataset. The monthly holding period total returns for each stock as calculated in the CRSP database were used for estimating betas of varying periods. The monthly market total return is the CRSP value-weighted total return.

Occasionally, an expert witness in a public utility rate case estimates their own betas, but they are quickly repudiated in rate proceedings.

The computation of the betas is based on the single index model, also used in Blume:

$$R_{i,t} = \alpha_i + \beta_i R_{m,t} + e_{i,t}, \quad (3)$$

where $R_{i,t}$ and $R_{m,t}$ are total returns for stock i and the market during month t, α_i, and β_i are the intercept and beta for stock i and $e_{i,t}$ is a regression error term for stock i. As previously mentioned, OLS is the typical estimation method used by many vendors of beta and is used in this investigation.

Table 1 presents the mean and median OLS beta estimates for the 57 utilities using 60, 84, 96, and 108 monthly returns respectively over five different non-lapping periods between December 1962 and December 2007. We also performed the same empirical analysis for periods of 4, 6, 10, 11, 12 and 13 years and the results were similar; the results are not shown for brevity but available upon request. We used non-overlapping periods to avoid serial correlation and unit roots. If we take, for example, 360 months of time series of returns for a stock and estimate 60-month rolling betas moving one month forward for each beta, this would result in 300 betas. Since only two of 60 observations would be unique due to overlapping periods, the error term would be highly serially correlated. A Blume-type regression of these betas would have a unit root, a coefficient of one and an intercept near 0, and therefore appear to follow a random walk. Therefore, the empirical nature of beta requires that lags in the Blume equation involve no overlapping time periods.

The mean and median betas in Table 1 not only do not rise toward 1 as the time period moves forward; the betas generally decline. Table 2 includes OLS regressions of the Blume equation for the 5-, 7-, 8-, and 9-year betas. We estimated five sets of 4- through 13-year betas inclusively for each public utility then

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Table 1: Mean and Median Betas for Varying Time Periods.

9-Year Periods	12/62–12/71	12/71–12/80	12/80–12/89	12/89–12/98	12/98–12/07
Mean	0.69	0.60	0.41	0.40	0.27
Median	0.68	0.57	0.40	0.36	0.22
8-Year Periods	**12/67–12/75**	**12/75–12/83**	**12/83–12/91**	**12/91–12/99**	**12/99–12/07**
Mean	0.76	0.39	0.45	0.27	0.33
Median	0.74	0.37	0.43	0.23	0.27
7-Year Periods	**12/72–12/79**	**12/79–12/86**	**12/86–12/93**	**12/93–12/00**	**12/00–12/07**
Mean	0.68	0.40	0.40	0.09	0.50
Median	0.65	0.39	0.38	0.06	0.47
5-Year Periods	**12/77–12/82**	**12/82–12/87**	**12/87–12/92**	**12/92–12/97**	**12/97–12/02**
Mean	0.36	0.38	0.53	0.49	0.12
Median	0.35	0.38	0.50	0.45	0.08

The following model was estimated for the sample of public utility stocks for five 60-, 84-, 96-, and 108-month non-overlapping periods. The ordinary least squares method was used to estimate the parameters of the single index model: $R_{i,t} = \alpha_i + \beta_i R_{m,t} + e_{i,t}$

where $R_{i,t}$ and $R_{m,t}$ are total returns for stock i and the market during month t, α_i, and β_i is the intercept and capital asset pricing model beta for stock i, respectively, and $e_{i,t}$ is a regression error term for stock i. The entire data series ranges from December 1962 to December 2007. The stock returns are the monthly holding period total returns from the CRSP database. The market returns are the CRSP market value-weighted total returns.

regressed the latter beta on the previous period betas. The 5-, 7-, 8-, and 9-year equations are shown for brevity. The diagnostic statistics strongly refute the validity of the Blume equation for public utility stocks. Most of the R^2's are equal to or close to 0.00 and the largest is 0.09. Only one F-statistic (tests the significance of the equation estimation) is significant and all but two slopes are insignificant. Also shown is the long-run beta implied from each Blume model as shown in equation (2). They range from 0.08 to 0.59. Only one estimate, the first-period 9-year Blume equation, includes a positive and statistically significant slope and intercept. The implied long-term beta of that equation is 0.59, which is substantially below one and the largest value of all estimates. As a final and visual review of the trends in betas, we developed and plotted probability distribution box plots developed by Tukey in 1977[13] for the 4- through 13-year public utility betas. We have shown only the 4- and 5-year beta box plots as shown in Figures 1 and 2 for brevity (the 6- to 13-year plots are available upon request). Tukey box plots show the 25th and 75th percentiles (the box height), the 10th and 90th percentiles (the whiskers), the median (the line inside the box), and the dispersion of the outlying betas. The box plots should be viewed as looking down on the distributions of the betas. We developed 4- through 13-year beta box plots to review the trend in shorter-term versus longer-term betas. None of the 51 beta probability distributions display any tendency for betas to drift toward one. The 5-, 6- and 7-year betas have higher variances in the last period relative to all other periods. A few outlying betas are greater than 2.0. This pattern is consistent with the notion that utility holding companies are investing in risky ventures of affiliates that can retain excess returns should they be realized. Note that the mean beta in Figures 1 and 2 show the cyclical nature of short-term utility betas with a severe downturn in the late 1990s and a severe upswing in the early 2000s. Generally, the box plots show a long-term downward trend in public utility betas.

It is interesting to note that the drop in beta occurred just after

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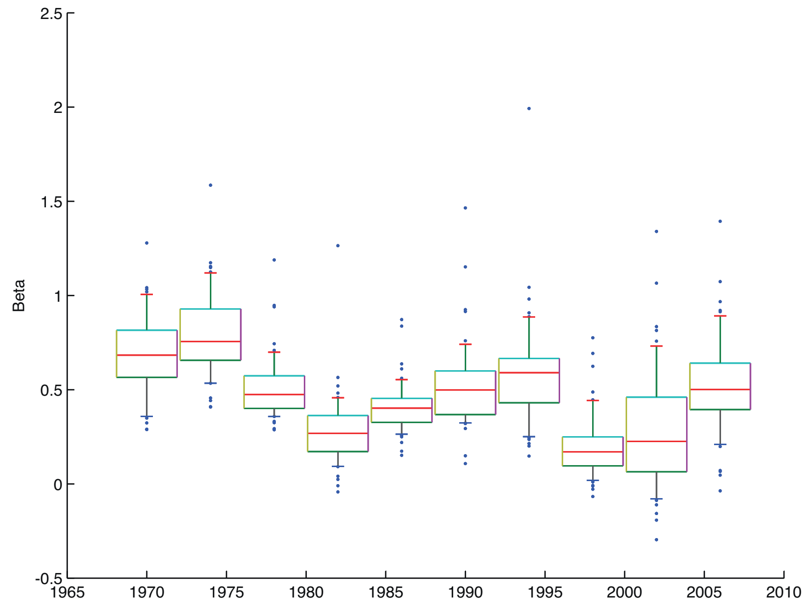
Table 2: Public Utility Blume Equation Estimates.

9-Year Betas	$\beta_2 = f(\beta_1)$	$\beta_3 = f(\beta_2)$	$\beta_4 = f(\beta_3)$	$\beta_5 = f(\beta_4)$
γ_0	0.463***	0.318***	0.480***	0.235***
	(0.074)	(0.062)	(0.096)	(0.080)
γ_1	0.214**	0.153	−0.186	0.800
	(0.102)	(0.099)	(0.227)	(0.179)
Long Run β	0.59	0.38	0.41	0.26
R^2	0.09	0.04	0.01	0.00
F-Statistic	4.43**	2.36	0.67	0.20
p-Value	0.04	0.13	0.42	0.65
8-Year Betas	$\beta_2 = f(\beta_1)$	$\beta_3 = f(\beta_2)$	$\beta_4 = f(\beta_3)$	$\beta_5 = f(\beta_4)$
γ_0	0.341***	0.464***	0.184**	0.321***
	(0.083)	(0.047)	(0.088)	(0.070)
γ_1	0.058	−0.034	0.193	0.035
	(0.106)	(0.115)	(0.189)	(0.220)
Long Run β	0.36	0.45	0.23	0.33
R^2	0.01	0.00	0.02	0.00
F-Statistic	0.30	0.09	1.04	0.02
p-Value	0.58	0.76	0.31	0.88
7-Year Betas	$\beta_2 = f(\beta_1)$	$\beta_3 = f(\beta_2)$	$\beta_4 = f(\beta_3)$	$\beta_5 = f(\beta_4)$
γ_0	0.370***	0.375***	0.074	0.491***
	(0.081)	(0.052)	(0.075)	(0.049)
γ_1	0.048	0.059	0.036	0.128
	(0.115)	(0.122)	(0.179)	(0.259)
Long Run β	0.39	0.40	0.08	0.56
R^2	0.00	0.00	0.00	0.00
F-Statistic	0.17	0.23	0.04	0.24
p-Value	0.68	0.63	0.84	0.62
5-Year Betas	$\beta_2 = f(\beta_1)$	$\beta_3 = f(\beta_2)$	$\beta_4 = f(\beta_3)$	$\beta_5 = f(\beta_4)$
γ_0	0.329***	0.474***	0.321***	0.106*
	(0.047)	(0.086)	(0.088)	(0.061)
γ_1	0.151	0.137	0.316**	0.019
	(0.119)	(0.213)	(0.157)	(0.111)
Long Run β	0.39	0.55	0.47	0.11
R^2	0.03	0.01	0.07	0.00
F-Statistic				
p-Value	1.62	0.41	4.07	0.03
	0.21	0.52	0.05	0.87

The following Blume equation was estimated using the betas of public utility stocks for five 60-, 84-, 96-, and 108-month non-overlapping periods. The ordinary least squares method was used to estimate the parameters of the following model: $\beta_{i,t+1} = \gamma_0 + \gamma_1\beta_{i,t} + \varepsilon_{i,t}$.
where $\beta_{i,t+1}$ is the OLS estimated CAPM beta for stock i, $\beta_{i,t}$ is the previous period beta for stock i, γ_0 and γ_1 are the intercept and slope of the Blume equation, and ε_t is the regression error term. The time subscripts on the betas refer to the time periods of estimation from Table 1. For example, β_5 in the 9 year panel refers to the beta estimated for each stock using the returns data from December 1998 to December 2007. The long-run $\beta = \gamma_0/(1 - \gamma_1)$; it can also be found by solving recursively for the next period beta until it converges on a final value. Newey-West autocorrelation and heteroskedasticity consistent standard errors are in parentheses.
* Significance at 0.10 level.
** Significance at 0.05 level.
*** Significance at 0.01 level.

deregulation of the wholesale electricity market in April 1996. This is inconsistent with the buffering theory of Peltzman and Binder and Norton[14] who found that regulation buffers the volatility of cash flows of public utilities from the vicissitudes of competition and business cycles and therefore reduces their systematic risk. However, this is consistent with Koble and Tye's 1990[15] theory of asymmetric regulation and the empirical findings of Michelfelder and Theodossiou in 2008,[16] who found that asymmetric regulation is associated with down-market public utility betas greater than their up-market betas. Adverse asymmetric regulation began in the 1980s and resulted in an upper boundary for public utilities' allowed rates of return equal to the cost of capital. If public utilities were granted an opportunity to earn their cost of common equity, regulators frequently would disallow specific investments *ex post* from earning the allowed rate of return if they were deemed ''not used and useful,'' even though they were deemed to be prudent when the decision was made to make these investments. The result was that utilities were not truly granted the opportunity to earn their allowed rate of return. If they happened to over-earn their allowed rate of return due to higher than anticipated demand forecasts, ''excess'' returns were taken away. This became known as regulatory risk, quantified as a risk premium in the cost of



Boxes give the 25th and 75th percentiles; line in the boxes is for the median; whiskers give the 10th and 90th Percentiles

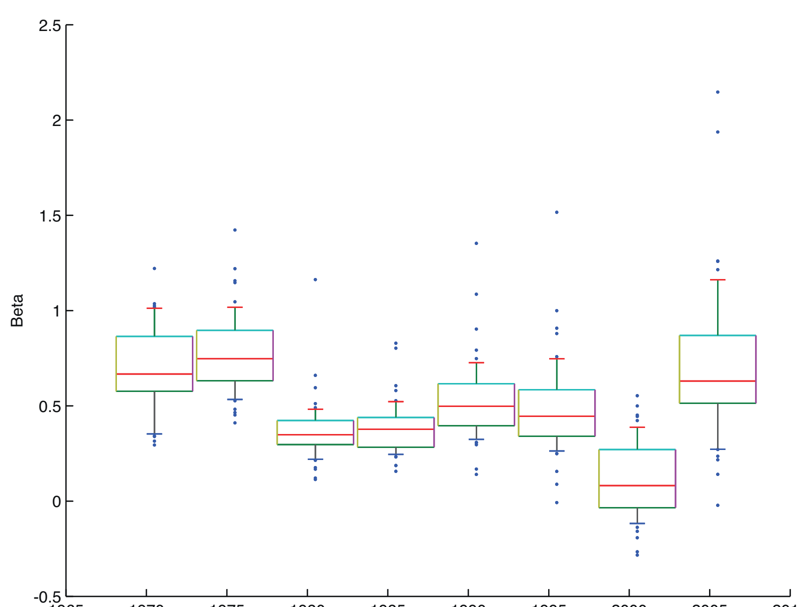
Figure 1: Boxplots of Utility Stock Betas Using 4 Year Periods Data

common equity. Michelfelder and Theodossiou in 2008[17] also concluded that public utility stocks are no longer defensive stocks dampening the downward behavior of otherwise less diversified portfolio returns in down markets.

Therefore, some suggest that *de*regulation may have ''buffered'' utility cash flows from regulatory risk, i.e., the chance that regulation would impose disappointing allowed rates of return in the manner described above. The advent of generation deregulation caused electric utilities with generating plants to no longer face regulatory risk on over 50 percent of their asset base. This is consistent with falling betas after deregulation of electric generation. The Brattle Group in 2004[18] found the same result in a research project for the Edison Electric Institute, an electric utility trade and lobbying organization. They found that electric utility betas fell after deregulation.

We suggest that it may be due to the relief of deregulation from asymmetric regulation. In any case, we find that the Blume adjustment toward 1 is not supported by our empirical results. This adjustment suggests that in the long run, all public utilities (and all firms) would gravitate toward the same risk and return. Our results herein suggest that the Blume adjustment is inappropriate for public utilities as it assumes that public utility betas are moving toward one in the long run as are non-utility company betas.

We perform a simple calculation to show the impact of a biased beta on public utility revenues. We calculate the common equity risk premium on the market as the annual total return for the CRSP market return from 1926 to 2007 to be approximately 12 percent and the average return on a three-month T-Bill to be about 4 percent. The long-term common equity risk premium is 8 percent. The difference between a beta of 0.50 and a Blume adjusted beta of .67 would result in a difference in cost of common equity



Boxes give the 25th and 75th percentiles; line in the boxes is for the median; whiskers give the 10th and 90th Percentiles.

Figure 2: Boxplots of Utility Stock Betas Using 5 Year Periods Data

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of 136 basis points. Using a common equity ratio of 0.50, this would impact the weighted average rate of return by 68 points. Assuming a rate base of $5 billion (the level for a moderately large electric utility), the difference in ''allowed'' net income would be 0.0068 × $5 billion, or, $34 million. Assuming a 37.5 percent income tax rate, the increase in revenues required to earn the additional $34 million would be $54 million. This is obviously a substantial difference. It is important for us to stress in this example that we do not necessarily advocate these inputs for the recommended cost of common equity for a utility with a raw beta of 0.50. The deliberation in recommending the cost of common equity is performed with a careful and detailed analysis of the company and stock, referral to more than one valuation model of the cost of common equity estimation and expert judgment.

IV. Conclusion

Major vendors of CAPM betas such as Merrill Lynch, Value Line, and Bloomberg distribute Blume-adjusted betas to investors. We have shown empirically that public utility betas do not have a tendency to converge to 1. Short-term betas of public utilities follow a cyclical pattern with recent downward trends, then upward structural breaks with long-term betas following a downward trend. We estimate the Blume equation for electric and gas public utilities, finding that all but one equation is statistically insignificant. The single significant equation implies a long-term convergence of beta to approximately 0.59. During our nearly 45-year study period, the median beta ranged from 0.08 to 0.74. Therefore the Blume equation overpredicts utility betas and Blume-adjustments

of utility betas are not appropriate.

We are not suggesting that betas should not be adjusted for prediction. Rather, the measurement period and subjective adjustment to beta should be based upon the likely future trend in peer group or *public utility betas*, or the specific utility's beta, not the trend in betas for all stocks in general. The time pattern of utility betas is obviously more complex than a smooth curvilinear adjustment, or for that matter, any adjustment toward one. Nor do we suggest as an alternative the use of raw or unadjusted betas in an application of the CAPM to estimate a public utility's cost of common equity.■

Endnotes:

1. D.R. Harrington, *The Changing Use of The Capital Asset Pricing Model in Utility Regulation*, PUB. UTIL. FORTNIGHTLY 105 (1980), at 28.

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Major vendors of CAPM betas such as Merrill Lynch, Value Line, and Bloomberg distribute Blume adjusted betas to investors.

Secular Mean Reversion and Long-Run Predictability of the Stock Market*

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Abstract

Empirical financial literature documents the evidence of mean reversion in stock prices and the absence of out-of-sample return predictability over periods shorter than 10 years. The goal of this paper is to test the random walk hypothesis in stock prices and return predictability over periods longer than 10 years. Specifically, using 141 years of data, this paper begins by performing formal tests of the random walk hypothesis in the prices of the real S&P Composite Index over increasing time horizons up to 40 years. Even though our results cannot support the conventional wisdom which says that the stock market is safer for long-term investors, our findings speak in favor of the mean reversion hypothesis. In particular, we find statistically significant in-sample evidence that past 15-17 year returns are able to predict future 15-17 year returns. This finding is robust to the choice of data source, deflator, and test statistic. The paper continues by investigating the out-of-sample performance of long-horizon return forecast based on the mean-reverting model. These latter tests demonstrate that the forecast accuracy provided by the mean-reverting model is statistically significantly better than the forecast accuracy provided by the naive historical-mean model. Moreover, we show that the predictive ability of the mean-reverting model is economically significant and translates into substantial performance gains.

Key words: predictability, stock returns, long-run, random walk, mean reversion, bootstrap simulation

JEL classification: C12, C14, C22, G12, G14, G17.

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1 Introduction

Until the late 1980s there was a widespread agreement in the academic community that stock prices follow a random walk. Indeed, a large body of empirical literature seemed to support this point of view (see Fama (1970) and Leroy (1982) for surveys). The efficient market hypothesis is strongly associated with the idea of a random walk in stock prices and loosely says that stock returns are unpredictable. However, during the late 1980s there appeared a series of papers where the authors challenged the random walk hypothesis (see, for example, Summers (1986), Campbell and Mankiw (1987), Fama and French (1988b), Lo and MacKinlay (1988), and Poterba and Summers (1988)). In particular, these authors considered the time series properties of stock returns over increasing time horizons up to 10 years and found the indications of mean reversion[1] and return predictability. For example, Fama and French (1988b) discovered a substantial negative autocorrelation in returns over periods of 3-5 years and concluded that past 3-5 year returns are able to predict future 3-5 year returns. Poterba and Summers (1988) found that stock returns exhibit positive and statistically significant autocorrelation in returns over periods shorter than one year and negative, though not statistically significant at conventional levels (1% or 5%), autocorrelations over longer periods.

However, the conclusions reached in these earlier papers were strongly criticized on statistical grounds. For example, Kim, Nelson, and Startz (1991) demonstrated that due to the small-sample bias the statistical significance of the test statistics in Fama and French (1988b) and Poterba and Summers (1988) was overstated and there was no predictability of future 3-5 year returns on the basis of past 3-5 year returns. Similarly, Richardson and Stock (1989) and Richardson (1993) showed that correcting for the small-sample bias may reverse the results obtained by Fama and French (1988b) and Poterba and Summers (1988).

[1]Mean reversion is an ambiguous concept and exists in several different forms. Most often, the concept of mean reversion can be expressed by the common investment wisdom which says that "over time markets tend to return to the mean". For example, when stocks go too far in one direction, they will eventually come back. Another type of mean reversion, which is studied in this paper, implies that the reversion is much more than just returning back to the mean. In reality the movement is far greater. This type of mean reversion incorporates another common investment wisdom which says that "an excess in one direction will lead to an excess in the opposite direction". That is, when stocks go too far in one direction, they will not just come back to the mean, but overshoot in the opposite direction. For example, a period of above average returns tends to be followed by a period of below average returns and vice versa. Throughout the paper, the term "period" is used to denote the period of mean reversion. The term "horizon" is mainly used to denote the average length of a complete cycle of reversion which consists of two periods: a period of higher than average returns and a period of lower than average returns (or vice versa).

Apparently, the statistical power of earlier tests was insufficient to reject the random walk hypothesis. Jegadeesh (1991) suggested a new more powerful test and detected statistically significant evidence of mean reversion in stock prices (over periods of 4-8 years). In addition, Jegadeesh found evidence of mean reversion not only for the US stock market, but also for the UK stock market. Later on based on a panel approach Balvers, Yangru, and Gilliland (2000) found statistically significant evidence of mean-reverting behavior (over periods of 3-3.5 years) in many international stock indices. Thus, mean reversion in stock prices seems to be an international phenomenon. Using the same technique as in Balvers et al. (2000), Gropp (2003) and Gropp (2004) found statistically significant evidence of mean reversion in the prices of portfolios of small cap stocks (over periods of 3.5 years) and industry-sorted portfolios (over periods of 4.5-8 years). Moreover, Balvers et al. (2000), Gropp (2003), and Gropp (2004) showed that parametric contrarian investment strategies that exploit mean reversion outperform buy-and-hold and standard contrarian strategies. This provides further support for the mean reversion findings in these papers.

Thus, nowadays the evidence of mean reversion in the prices of some stock portfolios over periods of 3-8 years seems to have been manifested. In contrast, the predictability of stock returns is still a source of heated debate within the academic community. Earlier papers, that demonstrated the existence of in-sample stock return predictability, include, among others, Fama (1981), Campbell (1987), Fama and French (1988b), Fama and French (1988a), Campbell and Shiller (1988), and Fama and French (1989). Again, the conclusions reached in these earlier papers were strongly criticized on statistical grounds. For example, Richardson and Stock (1989) and Nelson and Kim (1993) pointed to the small-sample bias problem, whereas Cavanagh, Elliott, and Stock (1995), Stambaugh (1999), and Lanne (2002) pointed to a neglected near unit root problem. Responding to the critique, Torous, Valkanov, and Yan (2004), Lewellen (2004), Rapach and Wohar (2005), and Campbell and Yogo (2006) developed new tests, that are free from the discovered flaws in the earlier tests, and again found some evidence of in-sample predictability. Yet, Bossaerts and Hillion (1999), Goyal and Welch (2003), and Welch and Goyal (2008) demonstrated that, despite evidence of in-sample predictability, the predictive models have no out-of-sample forecasting power. These authors therefore argued that in-sample predictability appears as a result of data mining. It should be noted, however, that in all these tests the longest forecast horizon was 10 years. Consequently, the results of these tests imply that the predictive models fail to demonstrate statistically significant predictive ability over short-term and medium-term horizons.

To the best knowledge of the author, no one has ever tested the random walk hypothesis in stock prices over periods longer than 10 years. Yet, anecdotal evidence suggests the presence of mean reversion in stock prices over very long horizons. Probably the best known evidence is presented by Siegel (2002) in his famous book "Stocks for the Long Run". In particular, using a historical sample that covers nearly 200 years, Siegel computed the standard deviation of average real annual returns on a broad US stock market index over increasing horizons up to 30 years. Siegel found that the standard deviation declines far faster than predicted by the random walk hypothesis. This led many to conclude that stocks are less risky in the long run. However, so far there have been no studies conducted on whether the decline in the standard deviation over very long horizons is statistically significant.

Another well-known anecdotal evidence, explicitly related to the mean reversion in stock prices over very long horizons, suggests the existence of long-lasting alternating periods of bull and bear markets. These long-lasting bull and bear markets are often termed as "secular" bull and bear markets. Alexander (2000), Easterling (2005), Rogers (2005), Katsenelson (2007), and Hirsch (2012), among others, analyzed the dynamics of the real S&P Composite Index since 1870 and found the indications of existence of secular stock market trends that last from 5 to 25 years, with average duration of about 15 years. Motivated by the seeming regularity in the reversion of secular trends, some authors made quite successful forecasts for the long-run US stock market outlook. For example, Alexander (2000) predicted that during the period from 2000 to 2020 the stock market will not beat the money market. So far, this forecast seems to come true. This anecdotal evidence suggests, among other things, that a price change over a given long-run period may be able to predict the price change over the subsequent long-run period. This idea motivates to re-examine the predictive performance of the model introduced by Fama and French (1988b). Even though Kim et al. (1991) demonstrated that this model has no predictive power on increasing periods up to 10 years, as far as the author knows, no one has ever tested this model on periods longer than 10 years. This paper aims to fill these gaps in scientific knowledge about the stock market dynamics over very long horizons.

The first contribution of this paper is to provide, for the first time, statistically significant evidence against the random walk hypothesis over periods longer than 10 years. Even though our results cannot support the anecdotal evidence which says that the stock market is safer for long-term investors, our findings do speak in favor of mean reversion in stock prices over periods of 15-17 years. In particular, using the whole sample of data, we find statistically significant evidence that a given change in price over 15-17 years tends to be reversed over the next 15-17 years by a predictable change in the opposite direction. This implies the existence of in-sample long-horizon predictability. Since the conventional wisdom says that in-sample evidence of stock return predictability might be a result of data mining, we investigate the performance of out-of-sample long-horizon return forecast. Besides the mean-reverting model, we investigate the out-of-sample forecast accuracy of a few other competing models which employ, as a predictor for long-horizon returns, the cyclically adjusted price-to-earnings ratio, the price-to-dividends ratio, and the long-term bond yield.

The second contribution of this paper is to demonstrate that the out-of-sample long-horizon forecasts provided by the mean-reverting model and the models that employ the price-to-earnings and price-to-dividends ratios are statistically significantly better than the forecast provided by the historical-mean model. It is worth emphasizing that Welch and Goyal (2008) also used the price-to-earnings and price-to-dividends ratios in their study and found that these models have no predictive ability over forecast horizons up to 5 years. Our results therefore advocate that these models do have predictive ability, but over forecast horizons longer than 10 years. We also demonstrate that the advantages of the models, that show the predictive ability, translate into significant performance gains. For example, we estimate that risk-averse investors would be willing to pay from 30 to 77 basis points fees per year to switch from the historical-mean model to a model with a superior forecast accuracy. Moreover, our tests suggest that over the recent past the out-of-sample forecast accuracy provided by the mean-reverting model was substantially better than that provided by the competing models. In addition, we find that the mean-reverting model delivers the highest performance gains when investors have to make long-term allocation decisions.

The rest of the paper is organized as follows. Section 2 presents the data for our study, namely, the returns on the real Standard and Poor's Composite Stock Price Index over the period from 1871 to 2011. In Section 3 we perform the tests of the random walk hypothesis using the S&P Composite Index. In Section 4 we study the out-of-sample predictability of multi-year returns on the S&P Composite Index. Finally, Section 5 summarizes and concludes the paper.

2 The Data

The data for the study in this paper are the annual log real returns on a broad US stock market index for the period from 1871 to 2011. The returns are adjusted for dividends and computed using the real (i.e., inflation-corrected) Standard and Poor's Composite Stock Price Index data and corresponding dividend data. The inflation adjustment is done using the Consumer Price Index (CPI) for the US. All the data are provided by Robert Shiller.[2] The Standard and Poor's Composite Stock Price index is a value-weighted stock index. The index for the period from 1871 to 1925 is constructed using the Cowles Commission Common Stock Index series. From 1926 to the present, the index data come from various reports of the Standard and Poor's. From 1957 this index is identical to the Standard and Poor's 500 Index which is intended to be a representative sample of leading companies in leading industries within the US economy. Stocks in the index are chosen for market size, liquidity, and industry group representation. For more details about the construction of the index and its dividend series see Shiller (1989), Chapter 26. Formally, let $(p_0, p_1, \ldots, p_n)$ be observations of the natural log of an inflation-corrected stock index price over $n+1$ years. Denote the one-year log return during year t, $1 \leq t \leq n$, by

$$r_t = p_t - p_{t-1}.$$

The resulting sample of n return observations is $(r_1, r_2, \ldots, r_n)$. The probability distribution of r_t is unknown, yet it is well-documented that stock returns are non-normal and heteroscedastic.

In order to check the robustness of findings, in particular, to see whether the results of

[2]See `http://www.econ.yale.edu/~shiller/data.htm`. The real dividend adjusted annual return series on the index are readily available in the file `chapt26.xls`. Robert Shiller stopped maintaining his database in 2012.

the testing the random walk hypothesis depend on a specific historical period, we divide the total sample period from 1871 to 2011 (141 annual observations) in two equal overlapping sub-samples, the first one is from 1871 to 1956 and the second one is from 1926 to 2011.[3] Both of these sub-samples cover a span of 86 years. Table 1 presents the descriptive statistics for the annual stock index returns, r_t, for the total sample and both sub-samples. Table 2 reports the results of the t-test on difference in mean returns and F-test on difference in standard deviations between the first and the second sub-sample. The descriptive statistics and the results of the tests suggest that the mean and variance of returns on the index were more or less stable during the total sample. Specifically, using a t-test for equal means we cannot reject the hypotheses that the mean returns are alike in both sub-samples. Similarly, using an F-test for equal variances we cannot reject the hypotheses that the variances are alike in both sub-samples. All the series exhibit negative skewness and positive excess kurtosis which indicates a deviation from normality. Observe also that the return series during the overall sample period exhibits a statistically significant negative autocorrelation at lag 2 (at the 5% level). There are no other indications of serial dependence in the return series.

3 Testing the Random Walk Hypothesis

3.1 Methodology

One of the main questions we want to study in this paper is whether the log of the real S&P Composite Stock Price Index follows a random walk. To answer this question we perform two well-known tests. The first test is based on the examination of the first-order autocorrelation function of k-year returns. This test is used by, for example, Fama and French (1988b), Fama and French (1989), and Fama (1990) and based on the computation of the following test statistic

$$AC1(k) = \frac{Cov(r_{t,t+k}, r_{t-k,t})}{\sqrt{Var(r_{t,t+k})Var(r_{t-k,t})}}, \tag{1}$$

[3]The reasons for using overlapping sub-samples are as follows. First, in order to perform statistical tests on the presence of long-run mean reversion we need longer time series. Second, the starting point of our second sub-sample coincides with the starting point of the database of historical stock market data provided by the Center for Research in Security Prices. Therefore the data on the stock market returns over the second sub-sample is much more accurate than that over the first sub-sample.

Statistics	Sample period		
	1871-2011	**1871-1956**	**1926-2011**
Mean, %	6.28	6.91	6.24
Std. dev., %	17.14	17.76	18.77
Skewness	-0.57	-0.48	-0.59
Kurtosis	3.41	3.32	3.24
ρ_1	0.02	0.04	0.04
ρ_2	**-0.19**	-0.20	-0.18
ρ_3	0.09	0.07	0.02
ρ_4	-0.08	-0.18	-0.14
ρ_5	-0.11	-0.10	-0.07
ρ_6	0.10	0.12	0.11
ρ_7	0.10	0.06	0.16
ρ_8	-0.08	-0.15	-0.02
ρ_9	-0.06	-0.04	0.04
ρ_{10}	0.02	0.06	0.06
ρ_{11}	0.02	0.06	-0.07
ρ_{12}	-0.08	-0.04	-0.10
ρ_{13}	-0.09	-0.15	-0.19
ρ_{14}	0.03	0.03	-0.14
ρ_{15}	-0.09	-0.07	-0.02
ρ_{16}	-0.09	-0.09	0.06
ρ_{17}	0.06	0.16	-0.02
ρ_{18}	-0.08	-0.06	-0.13
ρ_{19}	-0.17	-0.11	-0.21
ρ_{20}	0.06	0.09	-0.07

Table 1: Descriptive statistics of the annual log real returns on the Standard and Poor's Composite Stock Price Index. ρ_k denotes the autocorrelation between r_t and r_{t+k}. For each ρ_k we test the hypothesis $H_0 : \rho_k = 0$. Bold text indicates values that are statistically significant at the 5% level.

	Test statistic	**P-value**
t-test on difference in mean returns	0.24	0.81
F-test on difference in standard deviations	0.89	0.61

Table 2: Results of the t-test on difference in mean returns and F-test on difference in standard deviations between the first and the second sub-sample.

where $r_{i,j}$ is the compounded return from year i to year j, $r_{i,j} = p_j - p_i$, $Cov(\cdot, \cdot)$ and $Var(\cdot)$ denote the covariance and variance respectively, and $AC1(k)$ stands for the first-order autocorrelation function of k-year returns. The second test is based on the examination of the variance ratio. This test is very popular and used by Cochrane (1988), Lo and MacKinlay (1988), Poterba and Summers (1988), and many other afterwards. The test is based on the computation of the following test statistic

$$VR(k) = \frac{Var(r_{t,t+k})}{k \times Var(r_t)}. \tag{2}$$

Both the tests are motivated by the notion that if the stock returns are independent and identically distributed, then the first-order autocorrelation function is zero and the variance ratio is unity irrespective of the number of years k. In other words, without serial dependence in data, the variance of k-year returns equals k times the variance of one-year returns and there is no correlation between two successive non-overlapping k-year returns. The null hypothesis of a random walk is rejected if the first-order autocorrelation is significantly different from zero or the variance ratio is significantly different from unity.

We want to compute the variance ratio $VR(k)$ for return horizons k from 20 to 40 years and the first-order autocorrelation $AC1(k)$ for periods from 10 to 20 years (note that in the latter case we also study serial dependence in data over time horizons from 20 to 40 years). The fundamental problem with these computations is that we have only a few non-overlapping intervals of length 20-40 years. Therefore in the computations of the two test statistics we employ overlapping intervals (rolling k-year periods). To compute $AC1(k)$ we regress k-year returns $r_{t,t+k}$ on lagged k-year returns $r_{t-k,t}$. That is, we run the following regression

$$r_{t,t+k} = a(k) + b(k)\, r_{t-k,t} + \varepsilon_{t,t+k}. \tag{3}$$

Observe that the slopes of the regression, $b(k)$, $k \in [10, 20]$, are the estimated autocorrelations of k-year returns, $AC1(k)$. The variance of k-year returns is computed as

$$Var(r_{t,t+k}) = E\left[(r_{t,t+k} - E[r_{t,t+k}])^2\right].$$

The use of overlapping returns leads to some potentially very serious econometric issues which are commonly termed as "small-sample bias". In particular, when it comes to the estimation of regression (3), there are two econometric problems. First, the estimates for the slope coefficients are biased. The sources of this bias in the estimation of autocorrelation are described in details by Orcutt and Irwin (1948) and Marriott and Pope (1954). More specifically, these authors show that an estimate of autocorrelation obtained using overlapping blocks of data is downward biased. Therefore, the estimates must be corrected for the bias. The second problem is that the standard errors of estimation using overlapping blocks of data are also downward biased, see, for example, Nelson and Kim (1993). Both biases work in the direction of making the values of t-statistic too large so that standard inference may indicate dependence in return series even if none is present.[4]

Similarly, the estimate for the variance of multi-year returns, $Var(r_{t,t+k})$, is downward biased when one uses overlapping blocks of data.[5] As an immediate consequence, the estimate for the variance ratio $VR(k)$ becomes also downward biased. Therefore, the estimates for $VR(k)$ must be corrected for the bias. In addition, since the estimate for $VR(k)$ is a random variable, for the purpose of statistical inference we need to know the probability distribution of $VR(k)$. This is necessary in order to be able to estimate standard errors and confidence intervals for $VR(k)$. This is also necessary for performing hypothesis tests about the value of $VR(k)$.

When the nature of the data generating process is unknown, it is generally not possible to tackle the econometric problems described above. However, in the context of the null hypothesis our goal is primarily to test whether or not stock returns are distributed independently of their ordering in time. Since under the null there is no dependence in return series, in order to estimate the significance level and perform the bias correction of the test statistics, we follow closely Kim et al. (1991) and Nelson and Kim (1993) where the authors employ the randomization method. The randomization method is introduced by Fisher

[4]Specifically, in case where returns are independent, using overlapping blocks of data produces a negative value of the estimated slope coefficient in regression (3). In addition, the standard error of estimation of the slope coefficient using overlapping blocks of data is downward biased. That is, the estimated standard error is smaller than it is in reality. The higher the overlap, the more negative the slope coefficient and the smaller the estimated standard error. As a result, the values of t-statistic may falsely indicate the presence of dependence in return series when none is present.

[5]Note that this is also related to the second econometric problem in the estimation of regression (3). That is, the standard errors of estimation of slope coefficients using overlapping blocks of data are downward biased, because the estimates for variance using overlapping blocks of data are downward biased. For the sake of motivation, consider what happens to the estimate for $Var(r_{t,t+k})$ when $k \to n$. Obviously in the limit, when the length k converges to the sample length, there is only one available block of data to estimate $Var(r_{t,t+k})$. Therefore, regardless of the nature of the data generating process, $Var(r_{t,t+k}) \to 0$ as $k \to n$.

(1935) and provides a very general and robust approach for computing the probability of obtaining some specific value for an estimator under the null hypothesis of no dependence. We refer the interested readers to Noreen (1989) and Manly (1997) for extensive discussion of the randomization tests. In a nutshell, randomization consists of reshuffling the data to destroy any dependence and then recalculating the test statistics for each reshuffling in order to estimate its distribution under the null hypothesis of no dependence. The great advantage of the randomization method is that it is very simple and no assumptions are made about the actual distribution of stock returns.

To be more specific, consider the estimation of the significance level and the bias correction of the estimate for the autocorrelation of k-year returns $AC1(k)$. First, we run regression (3) using the original series $(r_1, r_2, \ldots, r_n)$ to obtain the actual historical estimates for $AC1(k)$. Then we randomize the original series to get a permutation $(r_1^*, r_2^*, \ldots, r_n^*)$. This is repeated 10,000 times, each time running regression (3) and obtaining an estimate for $AC1^*(k)$. In this manner we estimate the sampling distribution of $AC1(k)$ under the null hypothesis. Finally, to estimate the significance level for some particular k, we count how many times the computed value for $AC1^*(k)$ after randomization falls below the value of the actual historical estimate for $AC1(k)$. In other words, under the null hypothesis we compute the probability of obtaining a more extreme value for the autocorrelation of k-year returns than the actual historical estimate. Note that in this manner we compute p-values of one-tailed test. The estimation bias is defined as the difference between the expected and the true value of $AC1^*(k)$. Since the true value is zero under the null hypothesis, the bias correction is done by subtracting the expected value of $AC1^*(k)$ from the actual historical estimate for $AC1(k)$. That is, the bias adjusted values of the first-order autocorrelation of k-year returns are computed as $AC1(k) - E[AC1^*(k)]$.

The estimation of the significance level and the bias correction of the estimate for the variance ratio $VR(k)$ is done in a similar manner. First, we use the original series to obtain the actual historical estimates for $VR(k)$. Then we randomize the series and compute $VR^*(k)$ to obtain the sample distribution under the null hypothesis. Finally, to estimate the significance level for some particular k, we count how many times the computed value for $VR^*(k)$ after randomization falls below the value of the actual historical estimate of $VR(k)$. The estimation bias in this case is given by $E[VR^*(k)] - 1$ since the true value is unity under the null hypothesis. Finally, the bias adjusted values of the variance ratio are computed as $VR(k) - E[VR^*(k)] + 1$.

There is ample evidence that the series of stock returns is heteroscedastic, see, for example, Officer (1973) and Schwert (1989). In particular, many researchers document that the variance of stock returns is not constant, but time-varying. To see whether a change in the variance of returns might affect the sampling distribution of a test statistic, we follow closely Kim et al. (1991) and Nelson and Kim (1993) and use the stratified randomization. In the stratified randomization method the total sample (or a sub-sample) is divided into several separate bins (urns) and the randomization is performed within each bin. Such a stratified randomization allows us to see whether the sampling distribution of a test statistic is sensitive to the particular pattern of heteroscedasticity that occurred historically.

3.2 Empirical Results

Figure 1 plots the sample first-order autocorrelations and variance ratios of the k-year returns on the Standard and Poor's Composite Stock Price Index. The first-order autocorrelations and variance ratios are computed according to formulas (1) and (2) respectively using overlapping blocks of data. Apparently, for the total sample and both the sub-samples the first-order autocorrelations and variance ratios generally decline with increasing k. The indications against the null hypothesis on very long horizons are stronger (i.e., the declines in the first-order autocorrelations and variance ratios are larger) for the second sub-sample (1926 to 2011) than for the total sample or the first sub-sample (1871 to 1956).

Recall, however, that the estimates for both the first-order autocorrelations and the variance ratios presented in Figure 1 are downward biased. As a matter of fact, under the null hypothesis of no serial dependence in return series we expect to see declining first-order autocorrelations and variance ratios with increasing k. In order to find out whether the observed declines are statistically significantly different from the expected declines under the null hypothesis, and in order to correct for the estimation bias under the null, we perform the randomization method with and without the stratification. These results are reported in Tables 3 and 4 which show the estimates for the bias-adjusted first-order autocorrelations and variance ratios, respectively, with corresponding p-values. The estimates are based on 10,000 reshuffles and computed using different numbers of bins in the stratification. The

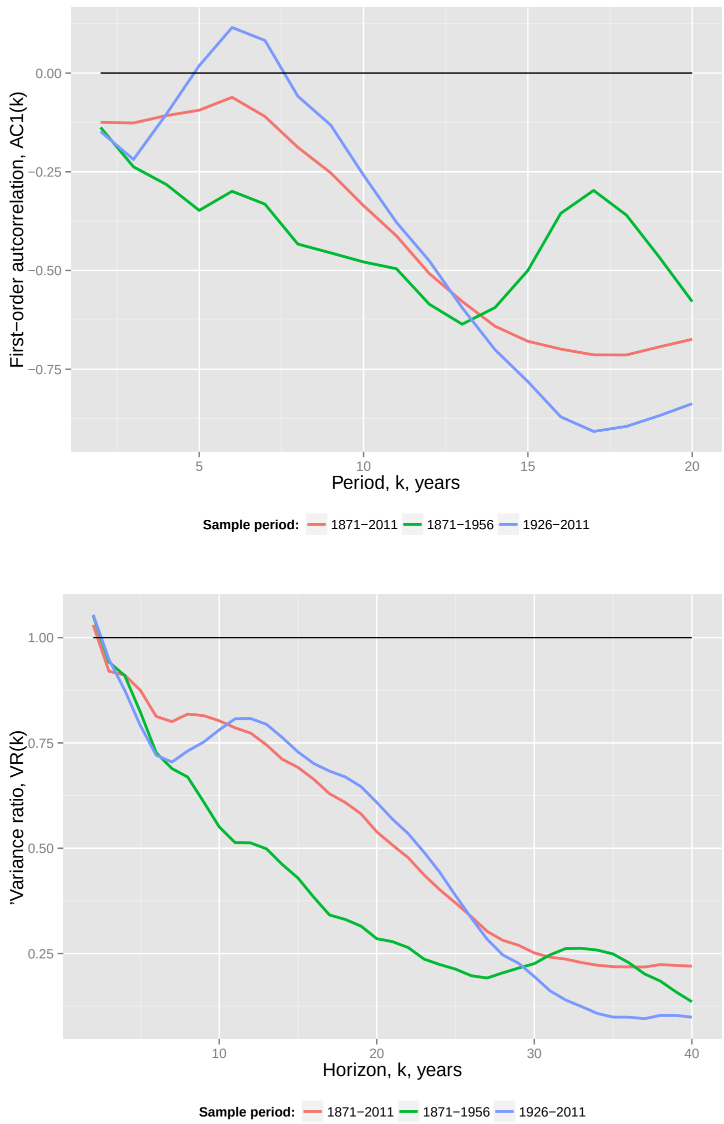

Figure 1: The sample first-order autocorrelations (top panel) and variance ratios (bottom panel) for the k-year log real returns on the Standard and Poor's Composite Stock Price Index. Neither the first-order autocorrelations nor the variance ratios are adjusted for the estimation bias.

number of bins varies from 1 (no stratification) to 5.

Without the stratification (that is, when the number of bins equals to one) both the test statistics suggest that the return series over the total sample (1871 to 2011) and the second sub-sample (1926 to 2011) exhibit clear evidence against the random walk on horizons of about 30-40 years. In particular, for the overall sample the values of the first-order autocorrelation are statistically significantly negative at the 5% level at periods 12-20 years (which indicates dependence over 24-40 year horizons). In addition, the values of the variance ratio are statistically significantly below unity at the 5% level at horizons 30-34 years. Thus, both the test statistics present evidence against the null hypothesis over horizons of 30-34 years. For the second sub-sample the values of the first-order autocorrelation are statistically significantly negative at the 5% level at periods 15-18 years (which indicates dependence over 30-36 year horizons), and the values of the variance ratio are statistically significantly below unity at horizons 34-36 years. For the first sub-sample the evidence against the random walk is weaker. Yet, if we use the 10% significance level, then we can reject the null hypothesis of no dependence in return series at several horizons.

Further, our results suggest that accounting for heteroscedasticity in stock returns does not influence the outcomes of the randomization tests on the first-order autocorrelations of k-year returns. Regardless of the number of bins in the stratified randomization, the first-order autocorrelation of k-year returns remains statistically significantly different from zero at the 5% level over periods of 15-17 years for the total sample and the second sub-sample. In contrast, stratification of the sample weakens the evidence against the null hypothesis for the value of the variance ratio. In particular, for the total sample and the stratification with either 2, 4, or 5 bins, the variance ratio is not statistically significantly below unity at conventional levels. Similarly, for the second sub-sample and the stratification with either 3 or 5 bins the variance ratio is not significantly below unity at conventional levels. For the first sub-sample the variance ratio is not significantly below unity regardless of the number of bins in the stratified randomization.

Consequently, we do not have strong enough evidence to claim that the variance ratio decreases with increasing investment horizon. Even though without stratification the variance ratio over horizons of 30-34 years is statistically significantly below unity, stratification of the sample suggests that this effect can be attributed to the historical pattern

Period, years	**Number of bins**				
	1	**2**	**3**	**4**	**5**
Panel A : Total sample 1871 to 2011					
10	-0.23 (0.14)	-0.15 (0.22)	-0.19 (0.16)	-0.10 (0.29)	-0.06 (0.36)
11	-0.29 (0.09)	-0.21 (0.15)	-0.25 (0.10)	-0.15 (0.20)	-0.11 (0.26)
12	**-0.38** (0.04)	-0.29 (0.08)	**-0.34** (0.05)	-0.23 (0.10)	-0.18 (0.13)
13	**-0.43** (0.03)	**-0.34** (0.04)	**-0.39** (0.03)	-0.28 (0.06)	-0.23 (0.07)
14	**-0.48** (0.02)	**-0.38** (0.03)	**-0.44** (0.02)	**-0.32** (0.03)	**-0.27** (0.04)
15	**-0.50** (0.01)	**-0.40** (0.02)	**-0.46** (0.01)	**-0.34** (0.03)	**-0.29** (0.03)
16	**-0.51** (0.01)	**-0.40** (0.02)	**-0.47** (0.01)	**-0.34** (0.02)	**-0.28** (0.03)
17	**-0.51** (0.02)	**-0.40** (0.02)	**-0.46** (0.01)	**-0.34** (0.02)	**-0.27** (0.02)
18	**-0.50** (0.02)	**-0.38** (0.03)	**-0.45** (0.02)	**-0.33** (0.03)	**-0.25** (0.03)
19	**-0.47** (0.03)	**-0.34** (0.04)	**-0.41** (0.03)	**-0.29** (0.04)	**-0.21** (0.05)
20	**-0.43** (0.05)	-0.30 (0.07)	**-0.37** (0.05)	-0.26 (0.06)	-0.17 (0.09)
Panel B : First sub-sample 1871 to 1956					
10	-0.25 (0.17)	-0.11 (0.32)	-0.10 (0.33)	-0.06 (0.39)	-0.26 (0.18)
11	-0.28 (0.15)	-0.13 (0.29)	-0.12 (0.31)	-0.10 (0.33)	-0.31 (0.14)
12	-0.36 (0.09)	-0.20 (0.21)	-0.20 (0.22)	-0.19 (0.20)	-0.41 (0.08)
13	-0.31 (0.13)	-0.13 (0.29)	-0.15 (0.29)	-0.15 (0.26)	-0.37 (0.09)
14	-0.22 (0.23)	-0.03 (0.46)	-0.06 (0.41)	-0.08 (0.37)	-0.27 (0.12)
15	-0.13 (0.32)	0.07 (0.60)	0.01 (0.52)	-0.01 (0.48)	-0.16 (0.20)
16	-0.03 (0.47)	0.19 (0.77)	0.11 (0.68)	0.10 (0.66)	-0.01 (0.47)
17	0.02 (0.52)	0.25 (0.83)	0.15 (0.74)	0.14 (0.72)	0.09 (0.74)
18	-0.07 (0.41)	0.19 (0.75)	0.06 (0.60)	0.06 (0.59)	0.07 (0.68)
19	-0.16 (0.32)	0.14 (0.66)	-0.03 (0.46)	-0.03 (0.46)	0.05 (0.62)
20	-0.17 (0.32)	0.16 (0.66)	-0.03 (0.45)	-0.03 (0.46)	0.11 (0.70)
Panel C : Second sub-sample 1926 to 2011					
10	-0.06 (0.41)	-0.05 (0.41)	0.09 (0.67)	-0.03 (0.45)	0.06 (0.64)
11	-0.16 (0.28)	-0.15 (0.27)	-0.00 (0.49)	-0.14 (0.27)	-0.02 (0.45)
12	-0.23 (0.20)	-0.23 (0.17)	-0.07 (0.35)	-0.22 (0.17)	-0.08 (0.33)
13	-0.32 (0.11)	-0.33 (0.09)	-0.17 (0.19)	-0.33 (0.08)	-0.16 (0.18)
14	-0.41 (0.06)	**-0.42** (0.05)	-0.27 (0.08)	**-0.42** (0.03)	-0.23 (0.07)
15	**-0.46** (0.04)	**-0.47** (0.03)	**-0.34** (0.05)	**-0.48** (0.02)	**-0.29** (0.03)
16	**-0.53** (0.03)	**-0.54** (0.01)	**-0.42** (0.03)	**-0.54** (0.01)	**-0.37** (0.01)
17	**-0.53** (0.04)	**-0.54** (0.02)	**-0.45** (0.03)	**-0.55** (0.01)	**-0.41** (0.01)
18	-0.50 (0.06)	**-0.51** (0.03)	**-0.43** (0.04)	**-0.51** (0.01)	**-0.42** (0.01)
19	-0.45 (0.09)	**-0.46** (0.05)	-0.40 (0.06)	**-0.46** (0.01)	**-0.43** (0.01)
20	-0.40 (0.13)	-0.43 (0.08)	-0.36 (0.09)	**-0.41** (0.03)	**-0.42** (0.02)

Table 3: First-order autocorrelations of the k-year log real returns on the Standard and Poor's Composite Stock Price Index ($AC1(k)$). These estimates are obtained using the randomization method with stratification (when the number of bins is greater than one). The estimates are corrected for the bias under the null hypothesis. The values in the brackets report the p-values of one-tailed test for the hypothesis $H_0 : AC1(k) = 0$. Bold text indicates values that are statistically significant at the 5% level.

Horizon, years	Number of bins 1	2	3	4	5
Panel A : Total sample 1871 to 2011					
20	0.75 (0.21)	0.87 (0.32)	0.80 (0.22)	0.93 (0.39)	1.00 (0.50)
22	0.71 (0.17)	0.84 (0.28)	0.77 (0.17)	0.90 (0.34)	0.97 (0.45)
24	0.66 (0.12)	0.79 (0.21)	0.71 (0.11)	0.86 (0.25)	0.93 (0.35)
26	0.62 (0.09)	0.76 (0.16)	0.67 (0.07)	0.83 (0.18)	0.90 (0.26)
28	0.58 (0.06)	0.73 (0.12)	**0.64** (0.04)	0.80 (0.12)	0.87 (0.19)
30	**0.58** (0.05)	0.73 (0.11)	**0.63** (0.03)	0.80 (0.10)	0.87 (0.16)
32	**0.59** (0.05)	0.75 (0.11)	**0.64** (0.03)	0.81 (0.11)	0.88 (0.17)
34	**0.60** (0.05)	0.76 (0.11)	**0.65** (0.03)	0.82 (0.11)	0.89 (0.17)
36	0.62 (0.06)	0.78 (0.13)	**0.67** (0.03)	0.83 (0.13)	0.91 (0.21)
38	0.65 (0.08)	0.81 (0.16)	**0.70** (0.04)	0.86 (0.18)	0.93 (0.28)
40	0.67 (0.09)	0.84 (0.18)	**0.72** (0.05)	0.87 (0.20)	0.95 (0.32)
Panel B : First sub-sample 1871 to 1956					
20	0.66 (0.11)	0.82 (0.21)	0.84 (0.18)	0.91 (0.30)	0.71 (0.07)
22	0.67 (0.10)	0.82 (0.20)	0.84 (0.16)	0.90 (0.27)	**0.69** (0.05)
24	0.65 (0.06)	0.81 (0.13)	0.82 (0.09)	0.87 (0.17)	**0.66** (0.02)
26	0.70 (0.09)	0.85 (0.18)	0.86 (0.14)	0.90 (0.25)	**0.69** (0.03)
28	0.74 (0.13)	0.89 (0.25)	0.90 (0.23)	0.94 (0.33)	**0.73** (0.04)
30	0.79 (0.18)	0.94 (0.34)	0.93 (0.31)	0.97 (0.40)	0.77 (0.06)
32	0.84 (0.26)	0.99 (0.46)	0.97 (0.43)	1.01 (0.53)	0.84 (0.12)
34	0.86 (0.26)	0.99 (0.48)	0.98 (0.43)	1.01 (0.53)	0.87 (0.13)
36	0.85 (0.21)	0.97 (0.40)	0.95 (0.34)	0.98 (0.42)	0.87 (0.08)
38	0.84 (0.16)	0.96 (0.33)	0.94 (0.27)	0.97 (0.33)	0.89 (0.08)
40	0.85 (0.14)	0.96 (0.31)	0.94 (0.24)	0.97 (0.30)	0.92 (0.11)
Panel C : Second sub-sample 1926 to 2011					
20	0.98 (0.48)	1.01 (0.51)	1.20 (0.79)	1.10 (0.67)	1.18 (0.81)
22	0.94 (0.44)	0.97 (0.46)	1.17 (0.76)	1.05 (0.59)	1.15 (0.77)
24	0.90 (0.38)	0.91 (0.38)	1.12 (0.71)	0.98 (0.47)	1.10 (0.69)
26	0.83 (0.28)	0.84 (0.26)	1.04 (0.59)	0.89 (0.30)	1.03 (0.56)
28	0.78 (0.19)	0.78 (0.15)	0.98 (0.44)	0.82 (0.18)	0.97 (0.42)
30	0.76 (0.14)	0.77 (0.10)	0.94 (0.32)	0.79 (0.13)	0.95 (0.34)
32	0.74 (0.07)	**0.74** (0.04)	0.90 (0.17)	0.76 (0.07)	0.92 (0.19)
34	**0.74** (0.04)	**0.74** (0.02)	0.88 (0.09)	**0.76** (0.04)	0.91 (0.11)
36	**0.76** (0.04)	**0.76** (0.01)	0.89 (0.09)	**0.78** (0.03)	0.92 (0.12)
38	0.79 (0.07)	**0.79** (0.02)	0.91 (0.14)	**0.81** (0.04)	0.93 (0.16)
40	0.82 (0.07)	**0.81** (0.02)	0.92 (0.15)	**0.84** (0.03)	0.93 (0.17)

Table 4: Variance ratios of the k-year log real returns on the Standard and Poor's Composite Stock Price Index ($VR(k)$). These estimates are obtained using the randomization method with stratification (when the number of bins is greater than one). The estimates are corrected for the bias under the null hypothesis. The values in the brackets report the p-values of one-tailed test for the hypothesis $H_0 : VR(k) = 1$. Bold text indicates values that are statistically significant at the 5% level.

of heteroscedasticity (that is, existence of periods of high and low variance). Thus, our results cannot support the anecdotal evidence which says that the stock market is safer for long-term investors. Nevertheless, we do have strong enough evidence that allows us to reject the random walk hypothesis in stock prices over periods of about 15-17 years. This evidence is based on the first-order autocorrelation of multi-year returns. Yet, our results suggest that the departure from the random walk on very long horizons has been primarily a phenomenon of the post-1926 period.

3.3 Robustness Tests

In order to check the robustness of our findings regarding the statistical significance of the secular mean reversion, we conducted a series of robustness checks which results are not reported in this paper in order to save the space. These additional robustness tests are described below.

First, the results reported in this section are obtained using the annual data provided by Robert Shiller. More specifically, these data are annual series of (average) January values of the real Standard and Poor Composite Stock Price Index. Hence, the results obtained in this section might be affected by seasonality.[6] To test the seasonality problem, we used the monthly data instead and obtained virtually the same levels of statistical significance of the mean-reverting behavior over very long horizons.

Second, Robert Shiller uses the CPI to adjust the nominal returns for inflation. We tested whether our evidence of mean reversion depends on the choice of deflator used to construct real stock returns.[7] For this purpose we constructed the real stock returns using the GDP deflator and value of the Consumer bundle.[8] We found that regardless of the choice of a deflator the evidence on mean reversion remains intact.

Third, since Kim et al. (1991) demonstrated that the mean-reversion in the study by Fama and French (1988b) is primarily a phenomenon of pre World War II period which is presented in both our sub-samples, we tested whether there is evidence of mean-reversion in the post 1940 period.[9] We found that the evidence is weaker (which is naturally to expect

[6]We thank Ole Gjølberg for pointing this.

[7]We thank an anonymous referee for pointing this.

[8]The data on the GDP deflator and the Consumer bundle are downloaded from `www.measuringworth.com`. The value of the consumer bundle is defined as the average annual expenditures of consumer units.

[9]We thank an anonymous referee for pointing this.

since the sample length becomes shorter), but is still statistically significant at the 10% level.

Fourth, instead of the first-order autocorrelation of multi-year returns test statistic, suggested by Fama and French (1988b), we used the test statistic suggested by Jegadeesh (1991). In particular, instead of regression (3), we used the following regression

$$r_t = a(k) + b(k)\, r_{t-k,t} + \varepsilon_{t,t+k}. \tag{4}$$

Note that in this regression the stock market return at year t is predicted using the aggregated return over the preceding k years. Using this regression we could also reject the random walk hypothesis in stock prices over very long horizons in the post-1926 period.

Finally, instead of using the data provided by Robert Shiller, we used the real annual returns on the large cap stocks provided by Kenneth French[10] over the period from 1927 to 2012. Again we found that the values of the first-order autocorrelation of multi-year returns are statistically significantly negative over periods of 15-18 years.

Thus, on the basis of the results from numerous robustness tests, we conclude that our evidence on the secular mean reversion is robust to the choice of data, deflator, sample period, and test statistics.

4 Testing the Long-Horizon Return Predictability

4.1 Motivation

The results of the tests performed in the preceding section allow us to reject the hypothesis that the S&P Composite Stock Price Index follows a random walk. Rather surprisingly, considering a seemingly insufficient span of available historical observations of the returns on the stock index, convincing evidence against the random walk is present over long-lasting periods of about 15-17 years. That is, our tests support the alternative hypothesis that there is serial dependence in stock returns. The question arises: what kind of serial dependence? In other words, what is the alternative hypothesis? Usually a statistically significant decrease in the variance ratio with increasing investment horizon (this effect is sometimes

[10]See `http://mba.tuck.dartmouth.edu/pages/faculty/ken.french/data_library.html`. We use the large-cap stocks because the S&P Composite is a large-cap index.

termed as the "variance compression") is interpreted as evidence of mean reversion. Unfortunately, the evidence of mean reversion based on the variance ratio test appears to be not strong enough under stratified randomization of data. However, variance compression seems to be the sufficient, but probably not necessary condition for mean reversion. Luckily, besides the variance ratio we have another test statistic, namely, the first-order autocorrelation of multi-year returns. The significance of this test statistic is unaffected by the choice of a randomization method. The presence of the values of the autocorrelation of k-year returns that are statistically significantly below zero suggests mean reverting behavior in stock prices. Specifically, a given change in price over first k years tends to be reversed over the next k years by a predictable change in the opposite direction. For the full sample period, evidence for mean reversion comes from the negative and statistically significant values of the first-order autocorrelations at periods of 15, 16, and 17 years particularly.

Considering the above mentioned, the results reported in the previous section suggest the presence of long-term mean reversion over periods of about 15-17 years in the real Standard and Poor's Composite Stock Price Index. In this case, if the pattern of the first-order autocorrelation of multi-year returns suggests the presence of mean reversion over the horizon of $2k$ years, there should be some degree of predictability of multi-year returns over a half-part of this horizon, that is, over a period of k years. Indeed, regression (3) is a predictive regression. To demonstrate the predictability of multi-year returns, Figure 2 presents a scatter plot of $r_{t,t+15}$ versus $r_{t-15,t}$ for the returns on the real Standard and Poor's Composite Stock Price Index for the total sample period from 1871 to 2011. In addition, a regression line is fitted through these data points. The scatter plot clearly suggests a tendency for the past 15-year returns to predict future 15-year returns. The regression line has a strongly negative slope, and R^2 statistic is 42%.

However, if we use the full sample period to estimate the first-order autocorrelation of multi-year returns, our estimate measures the degree of in-sample (IS) predictability. Yet it is known that in-sample predictability might be spurious (for example, it appears as a result of data mining) and not hold out-of-sample (OOS) (see, for example, Bossaerts and Hillion (1999), Goyal and Welch (2003), and Welch and Goyal (2008)). In order to guard against data mining, in this section we assess the performance of the OOS forecast based on the mean-revering model given by regression (3). Besides the mean-reverting model, we use

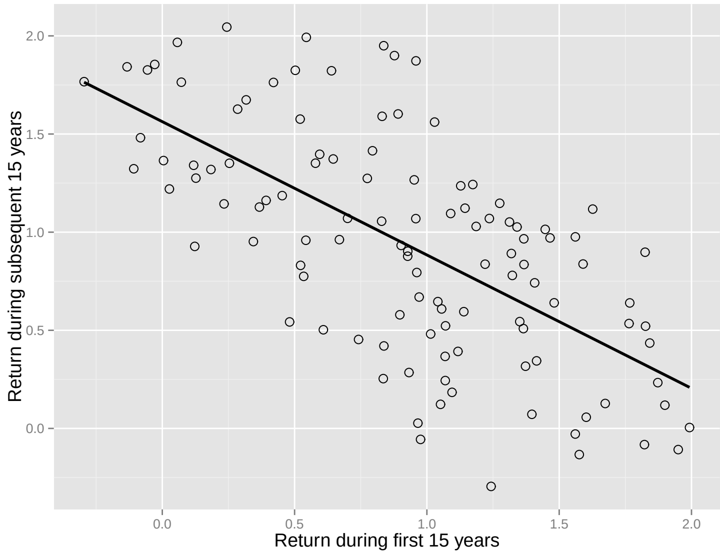

Figure 2: This figure shows a scatter plot of $r_{t,t+15}$ versus $r_{t-15,t}$ for the log real Standard and Poor's Composite Stock Price Index for the period from 1871 to 2011. In addition, a regression line is fit through these data points. The goodness of fit, as measured by R^2, amounts to 42%.

several other competing predictive models. We demonstrate that in the OOS tests the mean-reverting model and a few other predictive models perform statistically significantly better than the naive historical-mean model. In addition, we demonstrate that the advantages of the predictive models translate into significant utility gains.

4.2 Methodology of Assessing the Performance of OOS Forecasts

Our OOS recursive forecasting procedure is as follows. The initial IS period $[1, m]$, $m < n$, is used to estimate regression (3) for different period lengths $k \in [10, 20]$ years. In this manner we estimate a number of autocorrelations of k-year returns, $AC1(k)$. Then we perform the bias adjustment of $AC1(k)$. Next we select the value of $k = k_1$ which produces the lowest estimate of the bias-adjusted autocorrelation. That is,

$$k_1 = \arg \min_{k \in [10,20]} AC1(k).$$

Presumable, over the initial IS period the evidence of mean reversion is strongest over the period of k_1 years. Subsequently, the estimated coefficients from regression (3) with k_1 are used to compute the first k_1-year ahead return forecast for the period $[m + 1, m + k_1]$. We then expand our IS period by one year (it becomes $[1, m+1]$), perform the selection of k_2 at which the evidence of mean reversion is strongest over the second IS period, and compute the OOS forecast for the period $[m + 2, m + k_2 + 1]$. We repeat the procedure, increasing every time our IS window by one year, until we compute the last k_l-year ahead return for the period $[n - k_l + 1, n]$.

Observe that our OOS forecasting procedure is free from look-ahead bias, since to forecast the return for the period $[m+j, m+k_j+j-1]$, $j \geq 1$, we use only information that is available at time $m+j-1$. It is worth noting that since we are dealing with a long-horizon forecast, in performing the recursive forecasting procedure we need not just to update the estimates for the coefficients of regression (3), but first of all we need to update the optimal length of the prediction period k. Observe that, in order to avoid the look-ahead bias, the optimal length of the prediction period k is determined using only information that is available at the end of each IS period as well. Thus, our OOS recursive forecasting procedure updates all the values of the model parameters and is able to adapt to changing conditions in the time series. For example, it can accommodate the possibility that the period of mean reversion is monotonically changing over time.[11]

To assess the performance of OOS forecast, a common approach in the empirical literature is to run a "horse-race" among several competing predictive models. A standard criterion by which to compare two alternative predictive models is to compare their mean squared prediction errors (MSPE). As a matter of fact, the comparison of the mean squared prediction errors of two alternative models has a long tradition in evaluating which of the two models has a better ability to forecast, see McCracken (2007) and references therein. In our study, we run OOS horse races involving the mean-reverting model (MR), the historical-mean model (HM), Robert Shiller's model (PE10) that uses the cyclically adjusted price-to-earnings ratio as a predictor for long-horizon returns, the model that uses the price-to-dividends ratio (PD) as a predictor, and the model that uses the long-term bond yield

[11]Recall that the results presented in the previous section indicate that the period of the long-term mean reversion seems to have been increasing over time. In particular, during the first sub-sample the evidence of mean reversion is strongest over horizons of about 24-26 years (judging by the values of the most statistically significant first-order autocorrelation and variance ratio). In contrast, during the second sub-sample the evidence of mean reversion is strongest over horizons of about 34-36 years. Apparently this results in the fact that over the total sample period the evidence of mean reversion is strongest over horizons of about 30-34 years.

(LTY) as a predictor. These models are given by

$$\text{MR}: r_{t,t+k} = a(k) + b(k)\, r_{t-k,t} + \varepsilon_{t,t+k}, \tag{5}$$

$$\text{PE10}: r_{t,t+k} = a(k) + b(k)\, pe10_t + \varepsilon_{t,t+k}, \tag{6}$$

$$\text{PD}: r_{t,t+k} = a(k) + b(k)\, pd_t + \varepsilon_{t,t+k}, \tag{7}$$

$$\text{LTY}: r_{t,t+k} = a(k) + b(k)\, lty_t + \varepsilon_{t,t+k}, \tag{8}$$

$$\text{HM}: r_{t,t+k} = a(k) + \varepsilon_{t,t+k}, \tag{9}$$

where $pe10$ is the natural log of the ratio of price to 10-year moving average of earnings (this ratio is usually denoted as CAPE or PE10), pd is the natural log of the price-to-dividends ratio, and lty is the natural log of the long-term bond yield. The data for the price-to-earnings ratio, price-to-dividends ratio, and the long-term bond yield are also provided by Robert Shiller.

Robert Shiller's model was introduced by Campbell and Shiller (1998) and further popularized and developed by Shiller (2000) and Campbell and Shiller (2001). Shiller's model is based on a simple mean reversion theory which says that when stock prices are very high relative to recent earnings, then prices will eventually fall in the future to bring the price-to-earnings ratio back to a more normal historical level. Using this model Campbell and Shiller (1998) predicted the stock market crash of 2000 on the basis of an unreasonably high PE10 ratio. Since that time, Shiller's model has been extremely popular among practitioners. Originally, Campbell and Shiller (1998), Shiller (2000), and Campbell and Shiller (2001) used this model to forecast future 10-year returns. Yet, Asness (2003) demonstrated that the PE10 ratio is a good predictor of the future returns over periods from 10 to 20 years.[12] Thus, Shiller's model represents a natural competitor to our long-term mean-reverting model.

The model that uses the price-to-dividends ratio as a predictor for future returns was presented by Fama and French (1988a). This model is also based on a simple mean reversion theory which says that if the price-to-dividends ratio is unusually high or low, then this ratio tends to return to its long-run historical mean. The motivation for the model that

[12]This conclusion is made on the basis of studying R^2 of the predictive regression for different forecasting horizons. It should be noted, however, that in estimating the coefficient in front of the predictor and its significance level, Asness (2003) does not account for the estimation biases discovered by Cavanagh et al. (1995) and Stambaugh (1999).

uses the long-term bond yield as a predictor is based on a simple idea that stocks and long-term bonds are two major competing assets. Therefore simple logic suggests that the changes in the long-term bond yield must be highly correlated with the changes in the stock market earnings yield (earnings-to-price ratio). If, for example, the bond yield increases, stock prices should decrease and the stock market earnings yield increase. The so-called "Fed model" postulates that the stock's earnings yield should be approximately equal to the long-term bond yield. Empirical support for this model is found in the studies by Lander, Orphanides, and Douvogiannis (1997), Koivu, Pennanen, and Ziemba (2005), Berge, Consigli, and Ziemba (2008), and Maio (2013).

The historical-mean model can be interpreted as a reduced version of any other predictive model. This model uses the historical average of k-year returns to predict the return for the next k years. It is worth emphasizing that Welch and Goyal (2008) also employed in their study the predictive models that use the price-to-earnings ratio, price-to-dividends ratio, and the long-term bond yield. They found that in out-of-sample tests these models perform worse than the historical-mean model. However, these authors used an increasing forecast horizon up to 5 years only. In our study the goal is to compare the out-of-sample forecast accuracy from these models on horizons longer than 10 years.

Now we turn to the formal presentation of our test statistic that is employed to assess the performance of OOS forecasts provided by two competing models. Let $r^{AC}_{t,t+k}$, $t > m$, be the actual k-year returns and $r^{mod_1}_{t,t+k}$ and $r^{mod_2}_{t,t+k}$ be the OOS forecast of the k-year returns provided by models 1 and 2. To compute the test statistic, we first compute the OOS prediction errors of the two competing models

$$\varepsilon^{mod_1}_{t,t+k} = r^{mod_1}_{t,t+k} - r^{AC}_{t,t+k}, \quad \varepsilon^{mod_2}_{t,t+k} = r^{mod_2}_{t,t+k} - r^{AC}_{t,t+k}.$$

Our test statistic is the ratio of the MSPE of model 1 to the MSPE of model 2

$$\text{MSPE-R} = \frac{\frac{1}{T-m}\sum_{t=m+1}^{T}\left(\varepsilon^{mod_1}_{t,t+k}\right)^2}{\frac{1}{T-m}\sum_{t=m+1}^{T}\left(\varepsilon^{mod_2}_{t,t+k}\right)^2},$$

where $T-m$ is the number of OOS forecasted k-year returns.[13] The null hypothesis in this

[13]Note that k is not constant, but a variable which is exogenously determined by our recursive forecasting procedure. We suppress its dependence on time in order to simplify the notation.

test is that the forecast provided by model 2 is not better than the forecast provided by model 1. Formally, under the null hypothesis the MSPE of model 1 is less than or equal to the MSPE of model 2. Formally, H_0 : MSPE-R ≤ 1. Consequently, we reject the null hypothesis when the actual estimate for the MSPE ratio is significantly above unity. In our tests, the model 1 is always the historical-mean model. Therefore the outcome of our tests is whether a predictive model can "beat" the historical-mean model (a similar approach is used by Goyal and Welch (2003), Welch and Goyal (2008), and many others).

If two alternative prediction errors are assumed to be Gaussian, serially uncorrelated, and contemporaneously uncorrelated, then an MSPE-R statistic under the null hypothesis has the usual F-distribution.[14] However, in our case the assumptions listed above are not met. First, because of using overlapping multi-year returns, the prediction errors of all our models are serially correlated. Second, since the historical-mean model is the reduced version of any other predictive model, the prediction errors of the historical-mean models and any other predictive model are contemporaneously correlated. Finally, the assumption of Gaussian errors also seems to be unpalatable. One potential possibility to obtain correct statistical inference in this case is to perform asymptotically valid tests in the spirit of the seminal tests by Diebold and Mariano (1995). However, because we use relatively small samples, and because of the variable length k of the prediction horizon in our forecasting procedure, in order to compute the p-value of the MSPE ratio we employ a bootstrap method.

Our bootstrap method follows closely Welch and Goyal (2008). In this method we assume that the returns are serially independent, whereas the log of the PE10, the log of the PD, and the log of LTY follow the first-order autoregressive (AR(1)) process. Therefore the data generating process is assumed to be

$$\begin{aligned}
r_t &= \mu + u_t, \\
pe10_t &= \alpha_1 + \beta_1 \, pe10_{t-1} + w_t, \\
pd_t &= \alpha_2 + \beta_2 \, pd_{t-1} + z_t, \\
lty_t &= \alpha_3 + \beta_3 \, lty_{t-1} + e_t.
\end{aligned} \tag{10}$$

[14]In this case testing the null hypothesis largely corresponds to the standard F-test of equal forecast error variances.

In this case the return series r_t follows the random walk[15] and a bootstrapped resample is generated using the nonparametric bootstrap method. In particular, a random resample $(r_1^*, r_2^*, \ldots, r_n^*)$ is generated by drawing with replacement from the original series $(r_1, r_2, \ldots, r_n)$. In contrast, a bootstrapped resample of any other predictive variable is generated using the semi-parametric bootstrap method. The construction of a bootstrapped resample for the log of the PE10 series, $pe10_t$, is performed as follows. First of all, the parameters α_1 and β_1 are estimated by OLS using the full sample of observations, with the residuals stored for resampling. Afterwards, to generate a random resample $(pe10_1^*, pe10_2^*, \ldots, pe10_n^*)$ we pick up an initial observation $pe10_1^*$ from the actual data at random. Then a series is generated using the AR(1) model and by drawing w_t^* with replacement from the residuals.[16] The construction of a bootstrapped resample for the log of the PD and the LTY series is done in a similar manner.

Now we turn to the description of how we compute the MSPE-R statistic and its p-value. First, using the original series $(r_1, r_2, \ldots, r_n)$ we employ the recursive forecasting procedure described above to obtain the OOS forecasts of the mean-reverting model. Note that one of the outcomes of our recursive forecasting procedure is a sequence of lengths of prediction periods $(k_1, k_2, \ldots, k_l)$. Second, using the same sequence of lengths of prediction periods we obtain the OOS forecasts of all the other models. Afterwards we compute the mean squared prediction errors, and after that the MSPE-R statistic. Then we bootstrap the original series to get random resamples. The next crucial step is to generate a sequence of lengths of prediction periods $(k_1^*, k_2^*, \ldots, k_l^*)$. All this is repeated 10,000 times, each time running the recursive forecasting procedures[17] and obtaining an estimate for MSPE-R*. In this manner we estimate the sampling distribution of the MSPE-R statistic under the null hypothesis. Finally, to estimate the significance level, we count how many times the computed value for the MSPE-R* after bootstrapping happens to be above the value of the actual estimate for the MSPE-R. In other words, under the null hypothesis we compute

[15]Note that is this case the historical-mean model is a version of the random walk hypothesis.

[16]It should be noted, however, that our data generating process assumes no contemporaneous correlation between the stock return and a predictive variable. In the actual data there is a small but statistically significant correlation between the returns and the price-to-earnings (as well as the price-to-dividends) ratio. To check the robustness of our findings, we also implemented another bootstrap method which retains the historical correlations between the data series. We found that both the bootstrap methods deliver similar p-values of our test statistic.

[17]Note that this time the recursive forecasting procedures for all the models use the exogenously determined sequence of lengths of prediction periods.

the probability of obtaining a more extreme value for the MSPE ratio than the actual estimate.[18]

It is not clear what method should be used to generate a sequence of lengths of prediction periods for each bootstrap simulation. To the best of the author's knowledge, there are no similar forecasting procedures in the relevant scientific literature. Therefore we entertain four different methods listed below. In the first method we always use the original sequence of lengths of prediction periods $(k_1, k_2, \ldots, k_l)$. In the second and third methods a generated sequence $(k_1^*, k_2^*, \ldots, k_l^*)$ is a bootstrapped version of the original sequence. Whereas in the second method we use the nonparametric bootstrap, in the third method we use the semi-parametric bootstrap. In the semi-parametric bootstrap we assume that the length of a prediction period is a linear function of time.[19] In the fourth method a sequence of lengths of prediction periods is endogenously determined by the recursive forecasting procedure on the basis of the bootstrapped series $(r_1^*, r_2^*, \ldots, r_n^*)$. We find that the first three methods produce virtually similar p-values, whereas the fourth method produces notably lower p-values. Therefore when we report the p-values of the MSPE-R statistic we use the highest p-values. Thus, our statistical inference is based on the "worst case scenario" for the rejection of the null hypothesis. In other words, if we can reject the null in the "worst case scenario", we would reject it for any other case.

4.3 Empirical Results on Performance of OOS Forecasts

Our OOS forecast begins 50 years after the data are available, that is, in 1921, and ends in 1997 with the last forecast for the 15-year period from 1997 to 2011. To check the robustness of findings, we split the total OOS period in two equal OOS subperiods, the first one from 1921 to 1959, and the second one from 1959 to 1997. As in Goyal and Welch (2003), we employ a simple graphical diagnostic tool that makes it easy to understand the relative performance of two competing forecasting models. In particular, in order to monitor the predictive power of the unrestricted model relative to the predictive power of

[18] Note again that in this manner we compute p-values of one-tailed test.

[19] Indeed, for our OOS period from 1921 to 1997 the length of a prediction period is almost monotonically stepwise increasing from 10 to 15 years. The goodness of fit to the linear function, as measured by R^2, amounts to 73%. To perform the semi-parametric bootstrap, first of all we estimate the simple linear trend model for the original sequence of lengths of prediction periods $(k_1, k_2, \ldots, k_l)$ with the residuals stored for resampling. Afterwards, to generate a random resample of the sequence of lengths of prediction periods, we pick up the original initial prediction period k_1. The rest of the sequence is generated using the estimated linear trend model by drawing the error terms from the residuals with replacement.

the restricted model, Goyal and Welch (2003) suggested using the cumulative difference between the MSPE of the restricted model (the HM model in our case) and the MSPE of the unrestricted model:

$$CUDIF_t = \sum_{i=m}^{t} \left(\varepsilon_{i,i+k}^{mod_1}\right)^2 - \left(\varepsilon_{i,i+k}^{mod_2}\right)^2.$$

By visual examination of the graph of $CUDIF_t$ it is easy to understand in which periods the unrestricted model predicts better than the restricted model. Specifically, in periods when the cumulative MSPE difference increases, the unrestricted model predicts better, in periods when it decreases, the unrestricted model predicts worse than the restricted model.

Figure 3 shows the performance of the unrestricted models versus the performance of the restricted (historical-mean) model. Specifically, left panels in the figure plot the actual k-year ahead returns versus the OOS forecasted k-year ahead returns produced by the unrestricted and restricted models. Right panels in the figure plot the cumulative difference between the MSPE of the restricted model and the MSPE of the unrestricted model. The results of the estimations of the MSPE-R test statistic with corresponding p-values are reported in Table 5.

The p-values of the MSPE-R statistic demonstrate that over the total OOS period 3 out of 4 unrestricted models performed statistically significantly better (at the 5% level) than the restricted model. These unrestricted models are: the mean-reverting model, the price-earnings model, and the price-dividends model. However, over the first OOS subperiod only the price-dividends model performed statistically significantly better than the historical-mean model. In contrast, over the second OOS subperiod only the mean-revering and the price-earnings models showed the evidence of superior forecasting accuracy as compared to that of the historical-mean model. Our results advocate that the model, which uses the long-term bond yield as predictor, performed substantially worse than all the other competing models. Our results on the predictive ability of the long-term bond yield support the conclusions reached in the studies by Estrada (2006) and Estrada (2009). Specifically, Estrada argued that the predictive ability of the long-term bond yield is supported by data in the post 1960 period only.[20] Prior to 1960, there is no empirical support for the model

[20] In all empirical studies that demonstrate the predictive ability of the long-term bond yield the sample period starts after 1960. In this case if, for example, the initial IS period is chosen to be 1960-1980, then over the OOS period 1980-2010 one finds the evidence of OOS predictability of stock return using the long-term

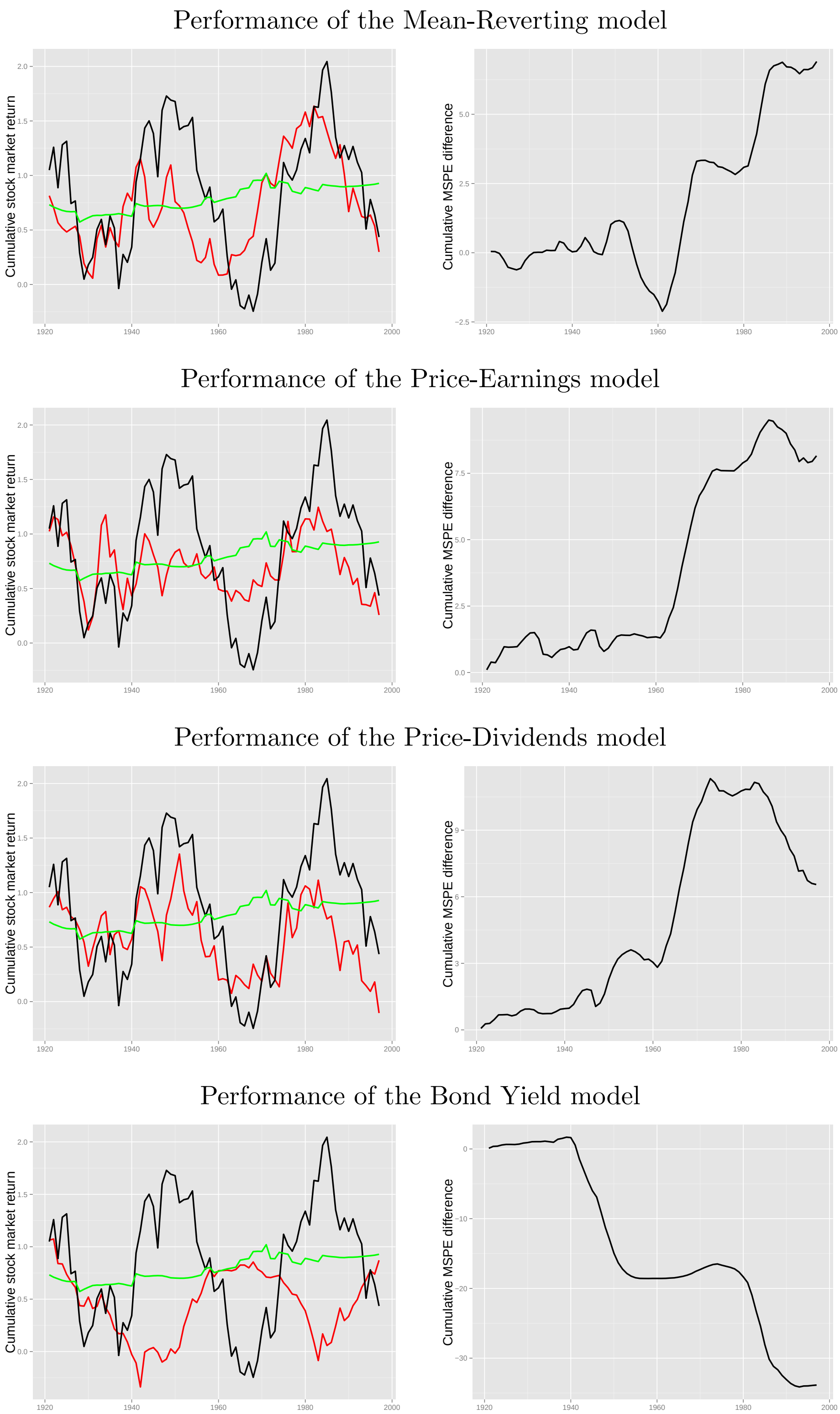

Figure 3: Performance of the unrestricted models versus the performance of the restricted (historical-mean) model. Left panels plot the actual k-year ahead returns (black line) versus the k-year ahead returns forecasted OOS by the unrestricted (red line) and restricted (green line) models. The initial IS period is from 1871 to 1920 which covers a span of 50 years. The OOS forecast begins in 1921 and ends in 1997 with the last forecast for the 15-year period from 1997 to 2011. Right panels plot the cumulative difference between the MSPE of the restricted model and the MSPE of the unrestricted model.

OOS period	HM to MR	HM to PE10	HM to PD	HM to LTY
1921-1997	**1.35** (0.01)	**1.44** (0.01)	**1.33** (0.03)	0.44 (0.98)
1921-1959	0.86 (0.38)	1.14 (0.10)	**1.38** (0.04)	0.37 (0.97)
1959-1997	**2.14** (0.01)	**1.78** (0.01)	1.28 (0.09)	0.50 (0.92)

Table 5: The values of the MSPE-R statistic with corresponding p-values (in brackets). A MSPE-R statistic is a ratio of the mean squared prediction error of the restricted (historical-mean) model to the mean squared prediction error of an unrestricted model. The four competing unrestricted models are: the mean-reverting (MR) model, the price to 10-year moving average of earnings (PE10) model, the price-dividends (PD) model, and the long-term bond yield model (LTY). For example, the column **HM to MR** reports the values of the ratio of the MSPE of the historical-mean model to the MSPE of the mean-reverting model. The estimated p-values of the MSPE ratios are based on performing 10,000 bootstraps. Bold text indicates values that are statistically significantly above unity at the 5% level.

that uses the long-term bond yield as a predictor for stock returns.

The graphs of the cumulative difference between the MSPE of the restricted (historical-mean) model and the unrestricted model allow us to see in which historical periods one model performed better than the other. Visual monitoring of these graphs reveals the following observations. The price-dividends model performed relatively well until about 1970 only. After that, the accuracy of the forecast provided by the price-dividends model was substantially worse than that of the historical-mean model. Both the mean-reverting and price-earnings models performed significantly better than the historical-mean model over 1960-1990. From about 1990 the price-earnings model lost its advantage over the historical-mean model. Starting from about 1980 the mean-revering model performed substantially better than all the other competing models. Only over the decade of 1950s the mean-reverting model performed notably worse than the historical-mean model.

4.4 Economic Significance of Return Predictability

In the preceding subsection we found a statistically significant evidence of long-term predictability of stock returns. This evidence was obtained by comparing the MSPE of the predictive model with the MSPE of the historical-mean model. However, over the total OOS period the ratios of the MSPE of the restricted model to the MSPE of the unrestricted model are not substantially above unity. This raises the important question of whether they are economically meaningful. Put it differently, statistical significance is not the same thing as economic significance.

bond yield.

To estimate the economic significance of return predictability, we follow closely the methodology employed in the studies by Fleming, Kirby, and Ostdiek (2001), Campbell and Thompson (2008), and Kirby and Ostdiek (2012). We consider an investor who, at time t, allocates the proportion y_t of his wealth to the stock market index and the proportion $(1 - y_t)$ to the risk-free asset. The investor revises the composition of his portfolio at time $t + q$; that is, after q years, $q \geq 1$. The investor's return over period $(t, t + q)$ is given by

$$R_{t,t+q} = y_t r_{t,t+q} + (1 - y_t) r^{free}_{t,t+q},$$

where $r_{t,t+q}$ and $r^{free}_{t,t+q}$ are the stock market return and the risk-free rate of return over period $(t, t + q)$.

We assume that the investor is equipped with the mean-variance utility function which can be considered as a second-order approximation to the investor's true utility function. As a result, the investor's *realized* utility over period $(t, t + q)$ can be written as

$$u(R_{t,t+q}) = y_t \left(r_{t,t+q} - r^{free}_{t,t+q} \right) - \frac{1}{2} \gamma y_t^2 \sigma^2_{t,t+q},$$

where $\sigma_{t,t+k}$ is the volatility of the stock market index over period $(t, t + q)$ and γ is the investor's coefficient of risk aversion. The total investor's realized utility is found as the sum of single-period utilities

$$U(R) = \sum_{i=1}^{n} u(R_{t,t+q}), \quad t = (i - 1) \times q,$$

where $n = \frac{T}{q}$ is the number of periods of length q from time 0 to time T (the end of the investment horizon).

The investor's optimal proportion y_t, which maximizes the expected utility, is given by (see Bodie, Kane, and Marcus (2007), Chapter 7)

$$y_t = \frac{1}{\gamma} \left(\frac{E[r_{t,t+q}] - r^{free}_{t,t+q}}{\sigma^2_{t,t+q}} \right),$$

where $E[r_{t,t+q}]$ and $\sigma_{t,t+q}$ are the expected return and volatility over $(t, t + q)$ that need to be forecasted at time t. The forecasting of expected returns is done using two competing models, 1 and 2. Specifically, $\hat{r}^{mod_1}_{t,t+q}$ and $\hat{r}^{mod_2}_{t,t+q}$ denote the return forecasts provided by models 1 and 2 respectively. Since we do not have a specific predictive model to forecast the volatility, the volatility over $(t, t+q)$ is forecasted using the historical-mean model for volatility. Formally,

$$y_t^{mod_1} = \frac{1}{\gamma}\left(\frac{\hat{r}_{t,t+q}^{mod_1} - r_{t,t+q}^{free}}{\hat{\sigma}_{t,t+q}^2}\right), \quad y_t^{mod_2} = \frac{1}{\gamma}\left(\frac{\hat{r}_{t,t+q}^{mod_2} - r_{t,t+q}^{free}}{\hat{\sigma}_{t,t+q}^2}\right),$$

where $\hat{\sigma}_{t,t+q}$ denotes the forecasted volatility.

It is important to observe that our predictive models forecast the stock market returns for a period of $k \geq 10$ years. Since generally $q \neq k$ (most often $q < k$), the q-year forecasted returns for model $i \in \{1, 2\}$ are computed as

$$\hat{r}_{t,t+q}^{mod_i} = \hat{r}_{t,t+k}^{mod_i} \times \frac{q}{k},$$

where $\hat{r}_{t,t+k}^{mod_i}$ is the k-year return forecast provided by model i.

As before, the model 1 in our study is the historical-mean model. The economic significance of return predictability is measured by equating to total realized utilities associated with two alternative forecasting models

$$\sum_{i=1}^{n} u\left(R_{t,t+q}^{mod_1}\right) = \sum_{i=1}^{n} u\left(R_{t,t+q}^{mod_2} - q \times \Delta\right),$$

where Δ denotes the annual fees the investor is willing to pay to switch from predictive model 1 to predictive model 2. Whereas Fleming et al. (2001) and Kirby and Ostdiek (2012) used the equation above to compute the annual fees, Campbell and Thompson (2008) demonstrated that the total realized investor's mean-variance utility can alternatively be measured by means of the Sharpe ratio. That is, the computation of the annual fees can be done using

$$SR\left(R_{t,t+q}^{mod_1}\right) = SR\left(R_{t,t+q}^{mod_2} - q \times \Delta\right),$$

where $SR(\cdot)$ denotes the Sharpe ratio.

In our computations we assume that the investor's risk aversion $\gamma = 5$ (as in Kirby and Ostdiek (2012)). Since we do not have data for the real risk-free rate of return, to perform the computations we assume that the nominal annual risk-free rate of return equals the annual inflation rate. Therefore, in real terms, $r_{t,t+p}^{free} = 0$. We measure the annual

Forecasting model	Sharpe ratio	Basis point fees
Panel A : Portfolio rebalancing once a year		
Historical-Mean	0.35	0
Mean-Reverting	0.42	46
Price-Earnings	0.45	77
Price-Dividends	0.39	30
Bond Yield	0.32	-20
Panel B : Portfolio rebalancing once in 15 years		
Historical-Mean	0.35	0
Mean-Reverting	0.40	47
Price-Earnings	0.35	1
Price-Dividends	0.39	37
Bond Yield	0.21	-129

Table 6: The table reports the performance of alternative predictive models and the annual fees the investor is willing to pay to switch from the historical-mean model to another predictive model. The performance is measured by means of the Sharpe ratio. The annual fees are measured in basis points.

performance fees over our total OOS period 1921-2011. Table 6 reports the Sharpe ratios associated with each predictive model and the estimated annual fees measured in basis points. The results are reported for two values of q: $q = 1$ and $q = 15$. In the first case the investor rebalances his portfolio once a year, in the second case the investor rebalances his portfolio once in 15 years.

First we consider the case where the investor rebalances his portfolio once a year. In this case the Sharpe ratios of all predictive models, which perform statistically significantly better than the historical-mean model, are higher than the Sharpe ratio of the historical-mean model. The advantages of these predictive models translate into significant utility gains. Specifically, risk-averse investors would be willing to pay from 30 to 77 basis points fees per year to switch from the historical-mean model to a model with a superior forecast accuracy. In contrast to these models, our results indicate that the model that uses the long-term bond yield as a predictor demonstrates an inferior forecast accuracy as compared with that of the historical-mean model. As a result, not only the Sharpe ratio of this model is lower than that of the historical-mean model, but also the investor would require to be paid 20 basis points fees per year to switch from the historical-mean model to the bond yield model.

When the investor can rebalance his portfolio once a year, the price-earnings model performs best while the mean-reverting model performs second best. However, when the investor decreases the portfolio revision frequency, the performance gains delivered by the price-earnings model diminish whereas the performance gains provided by the mean-reverting model remains rather stable. When the investor rebalances his portfolio once in 15 years, the performance gains of the price-earnings model virtually disappear. In contrast, the performance gains of the mean-reverting model (as measured in annual fees) remain virtually intact. Therefore in cases where the investor has to make long-term allocation decisions, the mean-reverting model delivers the highest performance gains.

5 Summary and Conclusions

We started the paper by performing two tests of the random walk hypothesis using the real Standard and Poor's Composite Stock Price Index data for the period from 1871 to 2011. In particular, we investigated the time series properties of the index returns at increasing horizons up to 40 years. In our tests of the random walk hypothesis we used two well-known test statistics: the autocorrelation of multi-year returns and the variance ratio. In the context of the null hypothesis our goal was to test whether the index returns are distributed independently of their ordering in time. In order to estimate the significance level of the test statistics under the null hypothesis, we employed the randomization methods which are free of distributional assumptions.

Rather surprisingly, considering a seemingly insufficient span of available historical observations of the returns on the stock index, either of the test statistic allowed us to reject the random walk hypothesis at conventional statistical levels over very long horizons of about 30-34 years. By studying the impact of sample period on the test statistics we concluded that mean reversion seems to be an extraordinary strong phenomenon of the post-1926 period. Having performed the same randomization tests with stratification we found that the results based on the use of the variance ratio are sensitive to the particular pattern of heteroscedasticity that occurred historically,[21] while the results based on the use of the autocorrelation of multi-year returns are not.

[21] A similar conclusion is drawn by Nelson and Kim (1993).

Consequently, we do not have strong enough evidence to claim that the variance ratio decreases with increasing investment horizons. In other words, our results cannot support the conventional belief that the stock market is safer for long-term investors. In contrast, we do have convincing evidence that suggests that a given change in price over 15-17 years tends to be reversed over the next 15-17 years by a predictable change in the opposite direction. Overall, our findings support the mean reversion hypothesis as the alternative to the random walk hypothesis. Our evidence of secular mean reversion in stock prices is robust to the choice of data source, deflator used to compute the real prices and returns, sample period, and test statistic.

The results of our tests demonstrated the evidence of in-sample predictability. However, conventional wisdom says that in-sample evidence of stock return predictability might be a result of data mining. In order to guard against data mining, we investigated the performance of out-of-sample forecast of multi-year returns. We demonstrated that the out-of-sample forecast provided by the mean-reverting model is statistically significantly better than the forecast provided by the historical-mean model. Moreover, the out-of-sample forecast accuracy of the mean-reverting model is comparable to that of very popular (among practitioners) Robert Shiller's model that uses the cyclically adjusted price-earnings ratio as a predictor for long-horizon returns, and of the model that uses the price-dividends ratio as a predictor for long-horizon returns. In addition, we demonstrated that the advantages of these three predictive models translate into significant utility gains. We found that in cases where the investor has to make long-term allocation decisions, the mean-reverting model delivers the highest performance gains. Besides, in the post-1960 period the mean-reverting model showed the best forecast accuracy among all competing model.

Given the main result of our study, it is natural to ask the following question. What causes this long-lasting mean reversion in the stock market prices? Put it differently, what is the economic intuition behind this result? One possible answer is suggested by previous research on the link between the demography and stock market returns and on the long-term variations in the birth rates and population growth in the US. In particular, on the one hand, Bakshi and Chen (1994), Dent (1998), Geanakoplos, Magill, and Quinzii (2004), and Arnott and Chaves (2012) observe the interrelationship between the demography and the US stock market returns and argue that the demography determines the stock market returns. On the other hand, the evidence presented by Kuznets (1958), Dent (1998), Berry (1999), and Geanakoplos et al. (2004) suggests the presence of secular trends in birth rates in the US that last from 10 to 20 years. Thus, if the population growth goes through long-term alternating periods of above-average and below-average rates, and it is the demography that determines the stock market returns, then it is naturally to expect that the stock market also goes through long-term alternating periods of above-average and below-average returns.

A more elaborate model of cyclical dynamics of economic activity, interrelated with similar movements in other elements, is presented by Schlesinger (1949), Schlesinger (1986), Berry (1991), Berry, Elliot, Harpham, and Kim (1998), and Alexander (2004). These authors argue that the dynamics of economic activity in the US has a long-term rhythm (with a period of 12-18 years) of accelerated and retarded secular growth. This cyclical fluctuation in economic activity, in particular the alternation of long-term periods of good and bad economic times, gives rise to similar long-term fluctuations in social and political activities. In brief, a long-term period of rapid economic growth and technological development coincides with a conservative political wave (era). The conservative politics reduces the scope and the role of government in the life of the nation and frees up business and capital. Such a period is also characterized by a higher population growth, increase in inequality, and deflationary conditions. Yet inevitably a long-term period of economic growth comes to a long-term stagflationary crisis. During such a crisis conservative leaders are replaced by liberal leaders committed to business regulation, social innovation, equity, and redistribution via an enhanced role of government. A liberal era is usually characterized by a lower population growth, decrease in inequality, and inflationary conditions. In our opinion, the secular mean-reverting behavior of the stock market fits nicely into this model of socioeconomic dynamics. It seems to be possible to demonstrate that the conservative political waves are usually associated with above average stock market returns, whereas during the liberal political waves the stock market returns are below average.

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Duke Energy Carolinas
Response to NCJC, et al.
Data Request No. 5

Docket No. E-7, Sub 1276

Date of Request: June 2, 2023
Date of Response: June 12, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCJC, et al. Data Request No. 5-2, was provided to me by the following individual(s): Spencer Heuer, Treasury Manager, and was provided to NCJC, et al. under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

Request:

5-2. On page 7 of witness Roger A. Morin's Direct Testimony, he asserts that "low allowed ROEs can increase the future cost of capital and ratepayer costs." Is witness Morin aware of any empirical data, academic studies (conducted by witness Morin or others), or other evidence that supports this claim with respect to utilities specifically? If so, please provide any and all such supporting evidence.

Response:

The underlying premise of the referenced question and answer is that if a utility is authorized a ROE below the level required by equity investors, the result is a decrease in the utility's market price per share of common stock, thus increasing the cost of procuring common equity capital. As a result, the utility has to rely more on debt financing to meet its capital needs, its capital structure becomes more leveraged, hence increasing financial risk, and the cost of debt increases as well. The final result is an increase in the cost to the utility for both debt and equity financing, and by extension, the rates charged to consumers. This raises the broader issue of regulatory risk.

Several empirical studies have documented the impact of regulatory climate on utility cost of capital and de facto on revenue requirements. These empirical studies are summarized in Chapter 4 of Dr. Morin's regulatory finance textbook Modern Regulatory Finance. Not surprisingly, the preponderance of the empirical evidence supports the notion that a favorable regulatory climate decreases a utility's risk and capital costs and ratepayer burden. High ratings result in low capital costs (lower ratepayer costs) and low ratings in high capital costs (high ratepayer costs).

The bottom line is that capital suppliers, both debt and equity, will require a higher rate of return in the presence of low regulatory quality which in turn is highly dependent on the reasonableness of allowed ROEs. Low regulatory quality leads to an increase in the cost of capital and, by extension, the rates charged to consumers, and conversely.

To illustrate, a typical instance of the impact of regulatory decisions on capital costs, hence on ratepayers, occurred on 11/9/21 as a result of a negative ROE decision rendered by the Arizona Public Service Commission in an Arizona Public Service (APS) docket. (Docket No. E-01345A-22-0144). Moody's and S&P both downgraded Pinnacle West and APS from A- to BBB+, with a Negative outlook.

In summarizing its decision to downgrade, S&P explained: "The downgrade and negative outlook reflects higher regulatory risk in Arizona. The downgrade on PWCC and its subsidiary reflects the ACC's final order, including lower authorized ROE to 8.7%......". (Standard & Poors Ratings Direct, Pinnacle West Capital Corp. Downgraded To 'BBB+', Outlook Negative, On Arizona Rate Reduction, Nov. 9, 2021).

In summarizing its decision to downgrade, Moody's explained: "The rate case decision will result in a base rate decrease of $119.8 million and a substantive decline in the authorized ROE to 8.7% from 10%, which is well below the national average of 9.5%. (Moody's

Investor Services Credit Opinion, Rating Action: Moody's downgrades Pinnacle West to Baa1 and Arizona Public Service to A3; outlook negative, Nov. 17, 2021).
A downgrade of a company's bonds and subsequent negative stock price reaction inexorably leads to higher debt costs and equity costs and perforce to higher ratepayer burdens.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
	)	
Application of Duke Energy Carolinas, LLC, for and Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina and Performance-Based Regulation	)	**Docket No. E-7, Sub 1276**

DIRECT TESTIMONY AND EXHIBITS OF

Gennelle Wilson, RMI

ON BEHALF OF

NORTH CAROLINA JUSTICE CENTER,
NORTH CAROLINA HOUSING COALITION,
NATURAL RESOURCES DEFENCE COUNCIL,
SOUTHERN ALLIANCE FOR CLEAN ENERGY,
AND VOTE SOLAR

July 19, 2023

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Exhibits

Exhibit GW-1 – Resume of Gennelle Wilson

I. Introduction & Summary

Q: PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A: My name is Gennelle Wilson. I am a Senior Associate at RMI. RMI is an independent, non-partisan, nonprofit organization of experts across disciplines working to accelerate the clean energy transition and improve lives. My business address is 2490 Junction Pl #200, Boulder, CO 80301

Q: PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A: I graduated from North Carolina State University in 2013 with a Bachelor of Arts degree in International Studies and a minor in French. In 2020, I received a Master of Environmental Management degree from Duke University where my studies focused on energy policy and economics. A copy of my current resume is included as Exhibit GW-1.

Q: PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A: Since 2018, I have been employed as an energy analyst by three non-profit organizations focused on energy economics and policy, including RMI, the Nicholas Institute for Environmental Policy Solutions at Duke University, and Southern Environmental Law Center. I was a contributor to RMI's testimony in the first Carbon Plan proceeding in 2022. This is my first time offering testimony in an electric utility rate case before a public utilities commission.

At RMI, I have supported the Hawaii Public Utilities Commission as a consultant in its investigation into performance-based regulation (PBR) since January 2021 and have contributed to the design of performance incentive mechanisms (PIMs), scorecards, and tracking metrics, amongst other PBR mechanisms. I have also engaged with or provided consulting support to a variety of other organizations – including advocates and commissions – to support increased knowledge of PBR mechanisms and improve understanding of how to design effective PBR frameworks. I have presented to a variety of organizations on PBR, including the National Association of Regulatory Utilities Commissioners' (NARUC) state working group for PBR. Further, I have published several articles and research reports on various elements of the PBR toolbox, which are listed in Exhibit GW-1.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION.

A: As a Senior Associate in RMI's Carbon-Free Electricity practice, I perform financial, policy, and regulatory analysis focused primarily on supporting the uptake of well-designed PBR frameworks that will enable an affordable and just transition to a clean energy economy.

I also manage a variety of client- and donor-supported projects to support the design of effective PBR frameworks as well as individual PBR mechanisms. I am currently leading a project to develop a database of innovative PIMs that are intended to support an affordable, equitable, and rapid transition of the electricity sector to a decarbonized future (to be published later this year). I likewise support projects that convene regulators and their staff from across the U.S., and globally, to explore regulatory issues of mutual interest, PBR among them. I regularly consult with advocacy organizations and commissions across the U.S. to equip them with knowledge and awareness of the trade-offs in the shift from traditional cost-of-service regulation to a PBR framework.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A: No.

Q: WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A: The purpose of my direct testimony is to provide:

1) An in-depth analysis of the PBR framework as enabled by North Carolina law (NC PBR framework),
2) An analysis on the application filed by Duke Energy Carolinas (DEC or the Company), specifically whether DEP's PBR application aligns with sound economic theory and state policy; and
3) A recommendation to the North Carolina Utilities Commission (Commission or NCUC) on process changes that can support more robust PBR applications and mechanism proposals in the future.

Q: PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A: In Section II of my testimony, I evaluate the NC PBR framework and explain how it creates a set of incentives that work against the interests of ratepayers and the policy goals of the state. I also describe the core elements of DEC's PBR application that underscore my recommendation to reject the DEC PBR application.

In Section III of my testimony, I discuss how PIMs can be leveraged to overcome some of the shortcomings of the NC PBR framework and discuss illustrative PIMs that may be good accompaniments to the NC PBR framework, considering the investments proposed in DEC's PBR application.

In Section IV of my testimony, I discuss processes employed in other jurisdictions that yield robust PBR frameworks and mechanisms and contrast those approaches with the processes employed in the Commission's first electric public utility PBR applications in North Carolina. I offer these reflections on practices in other jurisdictions with the hope that it will foster future PBR applications and mechanism proposals that better support the interests of ratepayers and the policy goals of the State.

Q: PLEASE STATE YOUR PRIMARY RECOMMENDATION TO THE COMMISSION REGARDING DEC'S PBR APPLICATION.

A: It is my position that the Commission should not approve DEC's PBR application, which includes a multi-year rate plan (MYRP), an earnings sharing mechanism (ESM), PIMs, a revenue decoupling mechanism, and tracking metrics.

As I discuss throughout my testimony, DEC's PBR application would not result in just and reasonable rates and therefore is not in the public interest.

Moreover, the core regulatory mandate of economical utility service[1] is threatened by DEC's proposed PBR application, as it would, by the Company's own assertion, result in significant increases in average residential ratepayer bills during the MYRP compared to a traditional rate case.[2]

The proposed rate and bill increases associated with DEC's PBR application would come at a time when fuel price volatility and inflation have surged and are adversely affecting ratepayers. This macroeconomic context, in conjunction with the heightened potential for a recession in the near future, underscores the importance of ensuring economical utility service to all. Any PBR application that the Commission approves, especially in this economic environment, should be one that (a) strongly incentivizes the utility to reduce its costs while achieving operational efficiency and (b) proposes investments that are consistent with facilitating a clean energy transition at least cost.

Q: PLEASE ELABORATE ON WHY YOU DO NOT RECOMMEND COMMISSION APPROVAL OF DEC'S PBR PROPOSAL?

A: At a fundamental level, the purpose of PBR is to better align utility incentives with the best interests of customers and society. Moreover, N.C.G.S. § 62-133.16(a)(8) established that it is a policy goal of the state for PBR to support "expected or anticipated achievement of operational efficiency,

[1] N.C.G.S. § 62-2(a)(3) states that it is the public policy of the State of North Carolina "to promote adequate, reliable, and **economical** utility service to all of the citizens and residents of the state" (emphasis added).
[2] Application and Request for an Accounting Order, 5.

cost-savings, or reliability of electric service that is greater than that which already is required by State or federal law or regulation, including standards the Commission has established by order prior to and independent of a PBR application…" (emphasis added).

DEC's PBR application fails to support cost-savings and better align utility incentives with the best interests of customers, implicating affordability concerns. Instead, DEC's PBR application:

- requests a return on equity (ROE) increase despite the risk reduction that the Company would enjoy from an MYRP and the potential earnings benefit from PIMs. The attainment of these earnings benefits is by design substantially controllable by the Company, further reducing the risk faced by the Company;
- conservatively estimates the value of the new and expanded tax credits in the Inflation Reduction Act of 2022 (IRA) by excluding:
  - the tax credit adder for the use of U.S.-produced steel and iron and partial usage of U.S.-made components for solar and storage projects; and
  - the tax credit adder for locating projects in "energy communities" for all solar projects and all storage projects except Allen;[3]

[3] Direct Testimony of Laurel M. Meeks and Evan W. Shearer for Duke Energy Carolinas, 11. DEC witness John Panizza does not indicate that either the domestic content or energy community bonus has been added to the Production Tax Credit assumed for solar at the 2022 level of 2.75 cent per kWh (and inflation adjusted afterward); *see* Direct Testimony of John R. Panizza for Duke Energy Carolinas, 11-12 (Panizza DEC Direct Test.).

- proposes to create a regulatory asset that will increase rate base to account for carrying costs of Production Tax Credits (PTCs) and Investment Tax Credits (ITCs) that the Company expects to credit to ratepayers during the MYRP, but which the Company contends will not be monetizable until the next decade.[4] While the Company acknowledges that the tax credit transferability provisions of the IRA may one day allow for more rapid monetization, it substantially undercuts this acknowledgment by arguing that "until a stable market for transfer credits materializes the potential benefits of transfer (should they ultimately materialize) are too uncertain and speculative at this point to permit DEC to include potential impacts of transferability upon its revenue requirement in this case." But, in fact, tax credit transfers are already being contracted with pricing between 90 and 92 cents on the tax credit dollar, and many industry experts expect prices to rise, perhaps to as much as 98 cents on the dollar.[5]
- puts forward PIMs that are unlikely to align its performance with the public's interest in receiving affordable electric service, achieving operational efficiency, and facilitating the clean energy transition at least cost.

[4] Panizza DEC Direct Test. at 20.
[5] Keith Martin, *Transferability: Selling tax credits*, NORTON ROSE FULBRIGHT PROJECT FINANCE NEWSWIRE (Mar. 6, 2023), at 14.

DEC's PBR application notably lacks key elements that will complement the NC PBR framework in supporting affordable decarbonization. Specifically, the NC PBR framework includes an incentive to inflate cost forecasts, a muted cost containment incentive, a partial throughput incentive, and the absence of any incentive to control fuel costs. DEC's PBR application omits mechanism proposals (i.e., PIMs) that could have helped, where applicable, to, either counter or advance these incentives. In addition, failure to incorporate achievable IRA tax credit bonuses or to reasonably assess and pursue the potential of tax credit transferability – in tandem with the NC PBR framework - will reduce the ratepayer benefits of the clean energy transition. As such, DEC's PBR application will likely yield higher ratepayer costs in terms of bill increases than a traditional cost-of-service rate case would without providing sufficient corresponding benefits.

Q: WHAT ADDITIONAL RECOMMENDATIONS DO YOU OFFER FOR THE COMMISSION'S CONSIDERATION WITH RESPECT TO FUTURE PBR PROPOSALS?

A: Though I recommend rejecting this PBR application, better designed PIMs *can* be an avenue for the Commission to remedy the NC PBR framework dynamics that I flag in this testimony as inconsistent with the state's policy goals.

In order to support the design of more effective mechanisms and utility PBR applications that are better aligned with the Commission's regulatory objectives, I recommend the Commission initiate a PBR goal and outcome setting and prioritization process. If implemented, these process-oriented recommendations are more likely to empower the Commission with a broad spectrum of PIM, scorecard, and metric proposals which could better align utility incentives with policy priorities in the next MYRP.

Additionally, when the Commission next evaluates a PBR framework, it should prioritize approval of PIMs that aim to contain costs and maximize affordability such as the ones I discuss later on. PIMs focused on cost reduction can be another means of compensating for the flawed incentives of the NC PBR framework, which motivates the utility to inflate costs in its proposal while offering little incentive to contain those costs during the MYRP.

I also urge the Commission to consider the allowed ROE and PBR in tandem. PBR reduces utility business and regulatory risk exposure, which should in turn reduce the authorized ROE. Furthermore, PBR incentives create additional earnings opportunities that will impact the realized ROE. As such, the ROE proposed for a traditional rate case should normally not be the same at the ROE proposed with a PBR application.

Lastly, when the Commission next reviews a PBR application, it should require a financial and management audit to be completed prior to the utility's filing. This will ensure that the utility is operating cost effectively at baseline, and any savings will be reflected in the base rates of a prospective MYRP.

II. Analysis of North Carolina's PBR Framework and DEC's PBR Application

Q: PLEASE EXPLAIN THE PROBLEMATIC INCENTIVES PRESENT IN, AND SUBOPTIMAL OUTCOMES ASSOCIATED WITH, COST-OF-SERVICE RATEMAKING.

A: "All regulation is incentive regulation," meaning that all regulation, by impacting revenue-making opportunities, provides companies with the motivation to perform in certain ways (and not in others).[6] In traditional cost-of-service ratemaking, a variety of problematic incentives are present that can lead to suboptimal outcomes.

First, utilities earn a substantive return for their investors on capital expenditures (capex) but only a minimal return on operational expenses (opex).[7] This creates an incentive known as "capex bias," which motivates the utility to invest in infrastructure (e.g., power plants, transmission, and distribution plant) even if there are cost-effective opex alternatives (e.g., non-wires alternatives).[8] Relatedly, there is an incentive to build infrastructure even when it may not be necessary; this is known as "gold

[6] This quote is attributed to Alfred Kahn, a former chair of the New York Public Service Commission in the 1970s. *See* Gavin Purchas & Elizabeth B. Stein, Utility 2.0: New York Draws Lessons on Utility Regulation from Across the Pond, BREAKING ENERGY (Dec. 8, 2014), https://breakingenergy.com/2014/12/09/utility-2-0-new-york-draws-lessons-on-utility-regulation-from-across-the-pond/.

[7] Although utilities do not earn a return on opex itself, they do typically earn a return on the working capital that funds opex. Working capital is the funding needed to bridge the gap between when costs are incurred and when revenues are received from customers. Since the utility needs working capital to run its business, regulators include an allowance for working capital in rate base, which means the utility earns a return on it. However, because opex is treated as a pass-through item, customers soon pay for it and the need for working capital is therefore brief. As a result, the total return generated for shareholders from a dollar of opex is minimal compared with the return generated from a dollar of capex. In fact, utilities can generally increase their profits in the short term by cutting opex relative to the baseline that was used when setting rates.

[8] DAN CROSS-CALL ET AL., RMI, NAVIGATING UTILITY BUSINESS MODEL REFORM: A PRACTICAL GUIDE TO REGULATORY DESIGN (2018), www.rmi.org/insight/navigating-utility-business-model-reform.

plating."[9] This works counter to the goal of affordable, equitable decarbonization by biasing the utility in favor of (1) more costly investments (ensuring a relatively higher financial return), and (2) capital investments that could potentially be cost-effectively avoided by operational changes.

Together, the capex bias and the gold plating incentives can lead utilities to be resistant to third-party and customer-owned solutions. Any investments not owned by the utility represent missed opportunities to earn a return. The utility prefers investing its own capital even when there are cheaper alternatives that leverage resources owned by other entities. This incentive can work counter to least-cost decarbonization by making the utility resistant to operational practices that would leverage customer-owned, distributed assets to help manage the grid, for example.

Volumetric charges are typically calibrated to recover a share of the utility's fixed costs. If sales are less than forecasted, a utility can fail to recover its costs, and if they exceed forecasts, the utility can earn windfall profits. This creates what is known as the "throughput incentive," which motivates utilities to sell more energy and resist conservation efforts.[10] Utilities that operate in regulatory contexts where the throughput incentive is present can be unambitious in their energy efficiency and demand-side

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[9] *See* Averch-Johnson effect in JIM LAZAR, RAP STAFF, *ELECTRICITY REGULATION IN THE US: A GUIDE*, RAP 87 (2016), http://www.raponline.org/knowledge-center/electricity- regulation-in-the-us-a-guide-2.

[10] *Id.* at 88.

management efforts.[11] In combination with the capex bias, this can yield capital intensive investment proposals (which are also often carbon intensive) to serve increasing peak load, which could otherwise be avoided by greater emphasis on demand-side management.

Cost-of-service regulation thus encourages several suboptimal outcomes that are at cross-purposes with the public interest and policy goal of affordable decarbonization. And since utilities usually know much more about how to keep their systems running smoothly, how to locate cost-saving opportunities, and how best to manage other aspects of their businesses than regulators and stakeholders do, there is "information asymmetry" between utilities and those responsible for providing oversight.[12] This information asymmetry is particularly problematic when these parties' objectives are at odds, since it limits the ability of the regulator to mandate that the utility take actions that advance the public interest. For example, when regulators attempt to improve energy affordability through reduced capital spending, information asymmetry with respect to the necessity of certain capital spending projects can limit their ability to prevent capex bias and gold plating (which increase costs).

[11] Sanem Sergici, *Which States Are Leading the Charge in Energy Efficiency Programs? Sanem Sergici Discusses in Public Utilities Fortnightly Article,* BRATTLE (Mar. 1, 2020), https://www.brattle.com/insights-events/publications/which-states-are-leading-the-charge-in-energy-efficiency-programs-sanem-sergici-discusses-in-public-utilities-fortnightly-article/

[12] MELISSA WHITED & CHERYL ROBERTO, SYNAPSE, MULTI-YEAR RATE PLANS: CORE ELEMENTS & CASE STUDIES (2019), https://www.synapse-energy.com/sites/default/files/Synapse-Whitepaper-on-MRPs-and-FRPs.pdf.

Finally, since utilities operating under cost-of-service regulation are compensated based on their costs (rather than the value they provide) — and these costs are potentially at risk of being deemed imprudent by regulators — there is an incentive toward risk aversion.[13] With innovation discouraged, opportunities to produce better results are often left unexplored.

When designed properly, PBR can address these problematic incentives.

Q: PLEASE EXPLAIN WHAT PBR IS AND HOW PBR IS INTENDED TO OVERCOME THE SHORTCOMINGS OF TRADITIONAL COST-OF-SERVICE REGULATION.

A: In principle, PBR is a regulatory approach that seeks to better align utility incentives with both customer and societal interests. It does this by compensating utilities based on desired outcomes rather than on costs incurred, and by removing existing perverse incentives. There are several main tools in the PBR toolbox that are designed to address the problematic incentives and outcomes associated with cost-of-service regulation. I will address each briefly.[14]

Multi-year rate plans (MYRPs) are intended to encourage cost efficiency and keep customer rates affordable.[15] When MYRPs are designed well, they encourage utilities to invest in clean energy and embrace distributed energy resources (DERs) where cost saving

[13] CROSS-CALL supra note 8.

[14] I will not address capex-opex equalization mechanisms (e.g., opex capitalization, totex ratemaking) or benchmarking here since these PBR tools were not enabled by North Carolina law, nor are they present in this case.

[15] WHITED & ROBERTO supra note 12.

opportunities exist. MYRPs also have the benefit of enhancing utility revenue stability, which makes the firms attractive to investors. However, it is important to note that MYRPs do not automatically result in savings for ratepayers; poorly designed MYRPs can reduce the risk associated with utility earnings, inflate shareholder profits, and fail to share utilities' efficiency gains with customers. Moreover, the extent to which DER adoption is encouraged may depend on whether the utility can substitute cost-effective opex for capex and retain a portion of the savings in lieu of the lost opportunity for a return.

PIMs focus the utility's attention and creativity on outcomes that would not otherwise be incentivized. When PIMs are tied to a substantial share of a utility's revenue requirement, they can realign its incentives to pursue key policy goals and objectives, such as rapid decarbonization and promoting equitable outcomes. Metrics tied to PIMs that track outcomes (e.g., the results of a program) rather than intermediate utility actions (e.g., customer enrollment in a program) are an accepted best practice.

Revenue decoupling is intended to remove the throughput incentive and make the utility whole for "lost revenues" from energy efficiency, demand-side management, and DERs. Often there is a concern that revenue decoupling will reduce the utility's incentive to pursue end-use electrification because it reduces the profit opportunity associated with increased sales. To address this concern, other tools (such as PIMs) can be used alongside revenue decoupling to incentivize the pursuit of end-use electrification. Pairing such PIMs with revenue decoupling can help encourage efficient electrification rather than electrification that wastes energy and thus customers' money.

Tracking metrics and scorecards provide an opportunity to increase visibility into aspects of utility performance that are opaque to regulators, customers, and the public, and they can also help focus utility attention on desired outcomes. Tracking metrics are also helpful for creating baselines that can be used to support future PIM design, and for understanding the parameters of burgeoning issues (e.g., equitable reliability on all circuits as opposed to system averages).

Q: PLEASE EXPLAIN YOUR PERSPECTIVE ON TRADEOFFS ASSOCIATED WITH THE NC PBR FRAMEWORK AS ADOPTED IN NORTH CAROLINA LAW (N.GS. § 62-133.16).

A: North Carolina electric public utilities have an incentive to inflate their cost forecasts. The statute requires that a PBR application include an MYRP with costs based upon "projected incremental Commission authorized capital investments"[16] — in other words, forecasted capital costs.[17] Much like traditional cost-of-service ratemaking, this requirement creates an incentive for the utility to exaggerate the expected levels of both

[16] N.C.G.S. § 62-133.16 (c)(1)a.

[17] The forecasted cost approach is in contrast to the method of indexing allowed revenues to external indices.

capital spending and fixed opex to secure a higher approved revenue requirement than what it may need.[18]

North Carolina electric public utilities have a muted incentive to reduce their actual spending. N.C.G.S. § 62-133.16 establishes a muted incentive to reduce the actual costs utilities incur through a narrowly defined ESM. While refunding excessive earnings to customers is generally desirable, there is a balance between protecting customers from paying for excessive earnings and maintaining the strength of the cost-containment incentive created by a revenue cap. The ESM established under G.S. § 62-133.16 removes much of the incentive created by the MYRP for the utility to seek cost efficiencies, since it prevents the utility from earning an ROE that exceeds the approved ROE by more than 50 basis points each year. As a result, a utility with an approved MYRP in North Carolina will be motivated to pursue only modest cost-efficiencies relative to its approved revenue requirement, while deeper cost efficiencies are unlikely to be leveraged because they will not benefit the utility.

DEC witnesses Laura Bateman and Phillip Stillman assert that the "PBR approach to ratemaking is better than frequent rate cases for addressing" the challenge of customer affordability. Further, they argue that "cost containment incentives would be reinforced under the Company's

[18] An MYRP based on forecasts still typically incentivizes cost containment better than traditional cost-of-service regulation because a MYRP reduces regulatory lag, *see* note 25 for a definition of regulatory lag. However, these benefits are diminished when 1) an ESM is in place that limits the utility's ability to benefit from cost savings and 2) the utility is allowed to file an early rate case if it spends too much. Both of these limitations are features of North Carolina law.

PBR proposal … In particular, …the statutory asymmetrical sharing of earnings surpluses (but not deficits) are significant benefits to customers."[19] However, in reality, the proposed PBR framework creates very weak cost-containment incentives. First, operating under an ESM that shares all surplus earnings that exceed 50 basis points of the approved ROE undermines the utility's incentive to pursue any substantial savings opportunities. Second, DEC can file a new rate case if its earnings fall short of expectations, so the fact that earnings deficits are not shared by the ESM will not create as strong a cost-containment incentive as witnesses Bateman and Stillman claim.

The incentive to inflate forecasted costs combined with the muted incentive to reduce spending during the plan render any MYRPs proposed in North Carolina less effective at encouraging cost efficiency. However, the utility's revenue stability and attractiveness to investors are maintained. In short, the NC PBR framework preserves the MYRP's benefits to investors but not to customers, and DEC's PBR application does not do all it could to leverage additional PBR tools that could bring more balance to this asymmetrical structure. Before approving any PBR application, the Commission should carefully consider whether the utility has:

(a) done its due diligence to find opportunities to reduce costs,

[19] Direct Testimony of Laura A. Bateman and Philip O. Stillman for Duke Energy Carolinas, 12 (DEC PBR Panel Direct Test.).

(b) considered a range of alternatives to proposed investments, in order to identify the least-cost method to meet grid needs, and

(c) included reforms that incentivize cost efficiency (e.g., well-designed PIMs) as elements of the PBR application.

North Carolina electric public utilities have no financial incentive to reduce fuel purchases or consumption. With fuel costs remaining as a 100% pass-through to customers, DEC's investors are insulated from fuel-price volatility and the utility gains nothing if it successfully reduces its overall fuel spending. Motivating the utility to carefully manage its fuel costs (by negotiating better fuel-supply contracts or by reducing its reliance on fuel-based generation resources, for example) could reduce the size and variability of customer bills — disproportionately benefiting low- and middle-income residential customers, as these customers are particularly vulnerable to high and variable bills — and also contribute to achieving the state's carbon reduction targets.[20]

In a parallel proceeding, Duke Energy Progress argues that utility and customer interests with respect to fuel cost are "inextricably linked."[21] While utilities do have some reputational incentive to reduce fuel costs

[20] In reply comments filed on December 17, 2021, in the PBR Rulemaking Proceeding, Docket No. E 100, Sub-178, North Carolina Sustainable Energy Association and the North Carolina Attorney General's Office both urged the Commission to consider ways to shift some risk of fluctuating fuel costs to the utility. *See* NCSEA's Reply Comments, Docket No. E-100, Sub 178, at 21 (Dec. 17, 2021); Reply Comments and Related Proposed Rules of the Attorney General's Office, Docket No. E-100, Sub 178, at 24 (Dec. 17, 2021).
[21] Rebuttal Testimony of Laura A. Bateman and Phillip O. Stillman for Duke Energy Progress, Docket No. E-2, Sub 1300, 49-53 (Apr. 14, 2023) (DEP PBR Panel Rebuttal Test.).

under a 100% pass-through (e.g., to maintain customer satisfaction and regulatory goodwill), that is far from sufficient to focus utility attention on reducing spending. The absence of a financial incentive to reduce fuel costs is at odds with the fundamental regulatory objective of affordable electric service, as well as with the objectives of encouraging carbon reductions and utility-scale renewable energy and storage and reducing low-income energy burdens.

A fuel cost PIM is one approach that the Commission could employ to support affordability. However, a recently published RMI paper, *Strategies for Encouraging Good Fuel-Cost Management; A Handbook for Utility Regulators* outlines five additional regulatory strategies that are available to reduce utility fuel costs which may be of interest to the Commission.[22]

North Carolina electric public utilities have a throughput incentive for commercial and industrial customer classes. By law, revenue decoupling is applicable only to the residential class, and not even to all sales to that class. In addition, while the Net Lost Revenue (NLR) adjustment mechanism is in place for non-residential customers, it does not de-link sales from revenues as fully as decoupling could (since the NLR only applies to demand side management/energy efficiency (DSM/EE) revenues, and it also relies on potentially inaccurate savings estimates).[23]

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[22] Kaja Rebane et al., RMI, Strategies for Encouraging Good Fuel- Cost Management: A Handbook for Utility Regulators (2023), https://rmi.org/insight/strategies-for- encouraging-good-fuel-cost-management/.

[23] It is important to note that a substantial portion of non-residential customers opt out of DEC's DSM/EE programming.

As a result, the utility still has an incentive to increase energy sales to non-residential customers, as well as (in a limited fashion) to residential customers.[24]

Ultimately, my position on the tradeoffs between a traditional rate case and a MYRP according to the NC PBR framework is summarized in Table A below.

Table A.

Comparison of trade-offs between a traditional rate case versus an MYRP in NC

	Traditional rate case	**MYRP**
Advantages	• Based on *actual* costs that were incurred (as opposed to prospective costs) which avoids the cost inflating incentive associated with the MYRP.	• Reduces regulatory burden and lag[25] on rates by reducing the frequency of rate cases. • Provides better revenue certainty, which will reduce risk and potentially decrease the utility's cost of capital. • Might give the utility better certainty on cost recovery for desirable actions like EE/DSM adoption, larger DER penetration, affordability measures, and decarbonization.

[24] DEC has a limited incentive to increase sales to residential customers because it is permitted to omit any kilowatt-hours attributable to electric vehicles from the revenue decoupling calculation.

[25] Regulatory burden refers to the "costs" that frequent general rate cases impose upon public utility commissions. Regulatory lag refers to the span of time between when (1) a utility incurs costs providing electric services to its customers and (2) recovers those costs through rates that are approved in its next general rate case proceeding. This gap in cost recovery can impact utility earnings if a utility incurs more costs than it can recover through the rates then in effect.

Disadvantages	• Might require more frequent rate cases to support achievement of Carbon Plan requirements, which may contribute to regulatory lag and burden. • Has all the standard incentive issues associated with cost-of-service regulation.	• Maintains or only minimally mitigates many of the same incentive issues as traditional cost of service. • Incentivizes utility to inflate costs, which may yield higher customer bills than otherwise necessary. • Provides the utility a substantial opportunity to grow shareholder value without commensurate ratepayer or societal benefit.

Q: GIVEN THE CONCERNS YOU HAVE OUTLINED, PLEASE EXPLAIN YOUR PERSPECTIVE ON THE OPTIONS THE COMMISSION HAS AT ITS DISPOSAL TO IMPLEMENT PBR IN A WAY THAT IS CONSISTENT WITH THE GOALS OF AFFORDABILITY.

A: N.C.G.S. § 62-133.16 prescribes the design of PBR applications. As a result, the Commission has two fundamental choices: to either approve a PBR framework within the limits set by law, or to stick with traditional cost-of-service regulation.

Despite this constraint, it is possible for the Commission to implement PBR in a way that is supportive of affordability and decarbonization. The Commission has three strategies available to do this. It can:

(1) **Modify the inputs to the MYRP.** This strategy focuses on “inputs," which are the cost assumptions, investments, and cost treatments (e.g., tax credit monetization approach that provide the foundation for the MYRP. The Commission can adjust these inputs as needed to reflect factors in the PBR application itself. For example, the Commission could approve an MYRP without approval

for a regulatory asset associated with the monetization of IRA tax credits, with more aggressive assumptions regarding the eligibility of certain adders or deny approval of certain investments which the Company has not demonstrated to be cost-efficient strategies to upgrade the grid.

(2) **Approve PIMs that incent cost containment and authorize an appropriate ROE.** This second strategy leverages the incentive power of PIMs in tandem with an authorized ROE that acknowledges the reduction of risk associated with PBR. PIMs and a lower ROE can be pursued in concert with the first strategy.

(3) **Reject any PBR application that does not sufficiently support Commission goals.** If the application does not appropriately support affordability and decarbonization, the Commission has the power to reject it. This strategy can be pursued if the other two are not sufficient. For this strategy to be most effective, the Commission should communicate clearly to the utility why the application does not meet the minimum threshold for approval, so it knows what it must change in future applications to garner approval.

To support the Commission in leveraging these options, I will elaborate on how DEC's PBR application is insufficient with respect to affordability, starting with the inputs to the MYRP that should be changed. Then, in Section III of my testimony I will analyze the extent to which DEC's proposed PIMs support affordability and offer illustrative PIM concepts that would better complement the DEC application.

Q: WHAT CONCERNS DO YOU HAVE REGARDING THE INPUTS TO THE DEC MYRP?

A: There are two primary input concerns with respect to the DEC PBR application, and more specifically, the costs outlined in its proposed MYRP.[26]

First, the proposed ROE is not adjusted for the decreased risk the utility would enjoy under a MYRP, nor the additional earning potential offered by the PIMs it proposed.

Second, DEC is not fully leveraging the benefits of the IRA to maximize ratepayer savings.

Ultimately, these concerns, and the NC PBR framework incentives I enumerated above, would work in tandem to exacerbate affordability issues during the MYRP and beyond, and are not supportive of the least-cost path to the state's decarbonization requirements.

Q: PLEASE EXPLAIN YOUR CONCERNS REGARDING RISK AND ROE SETTING IN THE CONTEXT OF PBR.

A: DEC's proposed ROE increase fails to account for the decreased financial risk to the utility under PBR. DEC's requested ROE at 10.40% with a 53%

[26] Assessing the capital projects DEC has planned in the MYRP is beyond the scope of my testimony. NCJC et al. witnesses David Hill and Jake Duncan have reviewed DEC's investments in distribution plant and outline their concerns with the level and types of spending DEC has planned in terms of supporting affordable decarbonization. Those are also important inputs that are driving affordability concerns associated with DEC's PBR application.

equity layer, when compared with its current allowed ROE of 9.6% with a 52% equity layer, will result in significant cost increases for ratepayers. Both the *reduction in risk* associated with operating under an MYRP and the opportunity for earnings gains and losses through PIMs should be considered when setting an authorized ROE. I address each of these elements in turn.

I will start first with a discussion of two different types of risk, which have a significant impact on a utility's achieved ROE: (1) business risk and (2) regulatory risk. Business risk is the "fluctuation in cash flows resulting from operations" and is dependent upon a variety of factors such as "the variability in demand, sales price, and input costs, the ability to adjust output prices to reflect cost conditions, and the degree of operating leverage."[27] Under a MYRP, DEC's business risk associated with demand will be buffered by the residential revenue decoupling mechanism, which mitigates the extent to which the utility will be vulnerable to residential electricity sales falling short of projections.

Utilities will never have full control over all input costs, but they are protected from major input cost increases (e.g., fuel) through cost trackers, which are directly passed through to customers. This is true for both cost-of-service rate case and a MYRP. However, unlike passing through fuel

[27] Maryam Ghadessi & Marzia Zafar, Carolina Public Utilities Commission Policy & Planning Division, An Introduction to Utility Cost of Capital (2017), https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/about_us/organization/divisions/policy_and_planning/ppd_work/ppd_work_products_-2014_forward-/ppd-general-rate-case-manual-1-.pdf.

costs in a standard rate case, a MYRP provides the utility with protection against a far wider range of cost increases. If for some reason the input costs increase to a level that the utility underearns relative to its authorized ROE and below the ESM's lower threshold, (i.e., the risk is not manageable), the NC PBR framework provides an offramp for the utility to file a new general rate case. The offramp is likewise a counter point to DEC's argument that a MYRP increases its risk in cost management under inflationary pressures.[28] The option to file a new rate case if earned ROE falls below 50 basis points (bps) of the authorized ROE means that the utility can fully avoid inflationary risks.

Generally, regulatory lag can be thought of as the difference in time between when a utility's cost to provide service increases and when the utility is granted approval to charge new rates to recover the higher cost of service. Regulatory risk is associated with regulatory lag and the risk that the costs the utility incurs will not be recoverable.[29] Under a MYRP, the risk of regulatory lag is diminished by approval of costs on a longer time horizon, which reduces the frequency of rate cases. Moreover, cost recovery risk is minimized by having advanced approval of all the new investments the utility intends to make for the next 36 months. Ultimately, less frequent instances of retrospective approval results in a reduction in regulatory risk.

For these reasons, the utility's authorized ROE when operating under a MYRP should be lower than its authorized ROE when operating

[28] Direct PBR Panel Direct Test. at 13.
[29] *Id.*

under traditional cost-of-service rate. The authorized ROE should be further adjusted downwards to account for any opportunities for additional earnings (e.g., through upside only or symmetrical PIMs) and reductions in risk exposure (e.g., through the ESM).

In the DEP proceeding, DEP witness Roger Morin conceded that an electric utility under regulation with fewer "risk mitigators" than its peers should be deemed riskier and accordingly be approved for a higher ROE. Witness Morin stated that "most electric utilities have a portfolio of risk mitigators. They have riders and trackers and deferrals and decoupling, but if a Company only had, let's say, one, that would be considered riskier than the peer group on average."[30] As such, it follows from Mr. Morin's oral testimony that the NC PBR framework, which possesses a variety of "risk mitigators," should be associated with a lower ROE when compared to a jurisdiction with fewer risk mitigators, and certainly lower than the ROE associated with a traditional cost of service rate case.

Additionally, it is worthwhile to draw attention to some logical inconsistencies in Morin's arguments on the sufficiency of "PBR peer groups" to determine ROE. Witness Morin submitted rebuttal testimony in the DEP case that sought to uniformly characterize the risk profile to the adduced peer group, insisting that "[a]s a matter of fact, most of the electric utilities in the industry possess risk-mitigators such as decoupling, riders,

[30] Witness Morin made these comments in response to questions from Chair Mitchell during the expert witness hearing in the Duke Energy Progress rate case. Docket No. E-2 Sub 1300, tr. vol. 9, 55.

adjustment clauses, to name a few. The omnipresence of risk mitigators is well documented in a 2022 comprehensive study by Regulatory Research Associates (RRA), an operating division of S&P Global Intelligence, entitled 'Adjustment clauses: A State by State Overview'."[31]

However, the RRA study cited by Witness Morin does not support the contention that the risk mitigations in the DEC PBR application (or by DEP in its parallel case) are the norm. The RRA study (which surveys regulation of electric utilities in the fifty states and the District of Columbia) looks only at adjustment clauses (one of which, is revenue decoupling); it makes no mention of MYRPs and references performance incentive mechanism only with regard to energy efficiency savings.[32]

Not only is Morin's assertion based on a misinterpretation of the source material, it also argues from a flawed assumption that all alternative regulation frameworks are the same and all risk mitigators are created equal. If two utilities operate under different PBR frameworks, comprising different mechanisms of varying strengths, it logically follows that the risks the two utilities face may be different. Given the highly unique approach to PBR enshrined in NC law, it should not be assumed that the ROEs employed in other jurisdictions are appropriate in NC just because risk mitigators are present.

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[31] Rebuttal Testimony of Roger A. Morin for Duke Energy Progress, Docket No. E-2 Sub 1300, 4:16-21 (Apr. 14, 2023).

[32] REGULATORY RESEARCH ASSOCIATES, REGULATORY FOCUS TOPICAL SPECIAL: ADJUSTMENT CLAUSES: A STATE BY STATE OVERVIEW ESP. 22 (2022).

Q: PLEASE EXPLAIN YOUR CONCERNS REGARDING UNDERLEVERAGED/UNDERESTIMATED IRA SAVINGS OPPORTUNITIES IN THE MYRP.

A: DEC is underleveraging/underestimating the benefits and cost saving opportunities of the IRA in its proposed MYRP.

The IRA has created a new possibility for increasing the net present value for ratepayers of clean energy tax credits: tax credit transferability. There is increasing evidence that transfer transactions will result in a relatively small "haircut" as they allow tax credits to be monetized in the same tax year in which they are first available.

In contrast, DEC argues that the benefits of monetizing on the basis of the tax credit transferability section of the IRA, Internal Revenue Code Section (IRC) 6418, are too uncertain to be relied upon at this point. As such, DEC proposes an approach to amass a regulatory asset during the MYRP and beyond to cover the carrying costs of unmonetized tax credits. [33] The Commission should be skeptical of this downplaying of the customer value of transferability. The IRA has made all the ITCs and PTCs for the Company's proposed storage and solar projects eligible for transfer. In June, the Internal Revenue Service issued a notice of proposed rulemaking with proposed guidance issued for IRC 6418 and set August 14, 2023, as the deadline for comments. Industry experts welcomed the proposed guidance and have indicated that transfers have already been selling at 90-

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[33] Direct Testimony of Kathryn S. Taylor for Duke Energy Carolinas, Exhibit 4, 1:12-13.

92 cents on the dollar and many experts expect the price to settle at 95-96 cent or even higher.[34] Adjusting the assumptions for potential savings from the ITC and PTC benefits and avoided regulatory asset balances should reduce the total Company ratepayer costs associated with solar and battery storage projects during the MYRP. The Commission should demand the company pursue transferability and robustly justify any proposal to self-monetize to ensure that customers are getting the most benefit from the tax credits earned by the assets for which they are paying.

Additionally, the Company should attempt to maximize the use of bonus adders as much is possible with respect to the solar generation and battery storage credits. For example, the IRA provides an adder for use of U.S.-produced steel and partial usage of U.S.-produced components, which can increase the PTC for solar generation by 10% and the new stand-alone ITC for storage (with the tax credit normalization opt-out) by 10 percentage points. Additionally, the IRA adder for locating assets in "energy communities," should be examined closely for applicability within DEC's territory. This adder can also raise the value of both the PTC and the ITC by 10 percentage points. While the U.S. Department of Treasury is still preparing final regulations for the energy community adder, there are credible reports suggesting that locations covering half of North Carolina may be eligible. According to experts from Resources for the Future, as much as 53.6% of the state might be covered by the "energy communities"

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[34] Keith Martin et al., *IRS Transferability Guidance*, NORTON ROSE FULBRIGHT (June 19, 2023), https://www.projectfinance.law/publications/2023/june/irs-transferability-guidance/

definition, even without including "brownfield sites."[35] Leveraging these adders will require some additional effort on the part of the utility, but should be incorporated into near-term investment plans to yield significant savings for ratepayers.

Similarly, DEC's treatment of costs associated with coal unit retirement may be ignoring real near-term MYRP and long-term potential cost savings from the IRA. The increase in depreciation expenses to recover capital from plants whose closure dates have been pushed forward neglects the low-cost refinancing opportunities possible through the Energy Infrastructure Reinvestment (EIR) Program that the IRA created, and which is being managed by the Department of Energy's Loan Programs Office.

Nationwide, EIR is authorized to provide up to $250 billion in federal loans at rates equal to 37.5 bps above relevant Treasury yields for terms up to 30 years. If DEC were to apply for and receive this funding to refinance at least 50% of the remaining net plant balance of coal assets, it could: (a) lower the rate spike during the MYRP period and (b) save ratepayers money over the next 20 years. The total savings are reasonably estimable *now* and will vary depending on the balance that is refinanced (i.e., the larger portion of the balance that is refinanced will avoid the more expensive cost of capital associated with keeping a regulatory asset on the Company's books pending a future securitization). Although finalized EIR guidance is still

[35] DANIEL RAIMI & SOPHIE PESEK, WHAT IS AN "ENERGY COMMUNITY"? ALTERNATIVE APPROACHES FOR GEOGRAPHICALLY TARGETED ENERGY POLICY, RESOURCES FOR THE FUTURE REPORT 22-12 Appendix, Table 10, 31 (2022), https://media.rff.org/documents/Report_22-12_AxXwJqy.pdf.

forthcoming and DEC cannot guarantee that any EIR application it submits will be approved, deducting potential EIR savings from the MYRP revenue requirement would incentivize DEC to make a good faith effort to submit a high-quality application for federal financing to help unlock these savings for ratepayers.

Q: PLEASE EXPLAIN YOUR RATIONALE FOR RECOMMENDING THAT THE DEC PBR APPLICATION BE REJECTED IN FAVOR OF A TRADITIONAL RATE CASE.

A: The knock-on effects of the inputs I listed above (i.e., a higher than necessary ROE, potentially higher than necessary costs, and underleveraged savings opportunities relative to what the IRA credits and programs enable) together with the embedded NC PBR framework incentives to exaggerate cost projections and a muted cost containment mechanism (i.e., ESM) are not supportive of ensuring affordability of electric service under an MYRP in North Carolina.

III. DEC PIM Analysis and Opportunities for PIMs to Complement the NC PBR Framework

Q: WHY ARE PIMS AN EFFECTIVE STRATEGY TO BETTER ALIGN THE UTILITY'S INCENTIVES WITH THE PUBLIC INTEREST, CONSIDERING THE CONSTRAINTS IMPOSED BY N.C.G.S. § 62-133.16?

A: Given the shortcomings of the NC PBR framework I described above, PIMs may represent the *best* strategy for remedying the muted cost containment incentive of PBR.[36] This is because the earnings from PIMs are not subject to the ESM.[37] Instead, any earnings from PIMs would be additional to (and not affected by) the earned ROE calculated in each annual review. Therefore, if PIMs are carefully designed to create a stronger incentive for the utility to seek cost efficiencies, they could bolster the muted incentive to reduce costs under the ESM. This could put downward pressure on costs during the MYRP.

In the long run, PIMs can also provide downward pressure on base rates by incentivizing operational and investment efficiencies that lower a utility's overall cost of service. If and when the Commission resets rates in a future MYRP, well-designed PIMs from the prior MYRP can provide clarity on the utility's ability to contain costs for certain expenditures, such as fuel expenses, generation and storage assets net of IRA benefits, and T&D investments.

Scorecards and tracking metrics can also elucidate how various outcomes are being affected by the MYRP. For example, metrics that could help the Commission understand cost containment over time may include:

- Annual costs for cost categories not under the MYRP, such as annual revenues collected under cost trackers,

[36] This is a general statement and does not otherwise constitute an endorsement of DEC's PIMs nor a recommendation that the Commission should approve DEC's PBR application.
[37] G.S. § 62-133.16(4)(c)(1) states that any penalties or rewards from PIM incentives and any incentives related to demand-side management and energy efficiency measures will be excluded from the determination of any refund pursuant to earnings sharing mechanism.

- Rate base per customer, as measured by total rate base divided by total number of customers,
- O&M costs per customer, as measured by total O&M expenses divided by total number of customers, and
- annual revenue growth, as measured by total electric revenue minus revenues for fuel and purchased power expenses.[38]
- Though scorecards and metrics can be useful additions to any PBR framework, they create less potent incentives, which is why the following discussion is focused on PIMs.

Q: WHY ARE THE PIMS DEC HAS PROPOSED INSUFFICIENT TO ALIGN THE UTILITY'S INCENTIVES WITH THE PUBLIC INTEREST, CONSIDERING THE CONSTRAINTS IMPOSED BY N.C.G.S. § 62-133.16?

A: Given the affordability concerns I have outlined with respect to both the NC PBR framework and the inputs to the DEC PBR application, I have prioritized analyzing the merits of the DEC PIM proposals through the lens of affordability through cost containment.[39] DEC acknowledges that, "a PIM must be consistent with a policy goal, which is defined in N.C.G.S. § 62-133.16(a)(8) as "the expected or anticipated achievement of operational

[38] *See PBR Scorecards and Metrics: Cost Control*, HAWAIIAN ELECTRIC, https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/cost-control (last visited July 18, 2023).

[39] I note that the PIMs proposed in the DEP case are very similar to those proposed by DEC. As such, I fully endorse the testimony that my colleague and NCJC et al. witness David Posner filed in Docket No. E-2, Sub 1300, which provides a more holistic analysis of the same PIM concepts originally proposed by DEC. Some of that analysis is applicable to the DEC PIMs, but I will not reiterate the relevant portions here where my goal is to focus on the extent to which the DEC PIMs are explicitly supportive of affordability, and decarbonization where relevant.

efficiency, ***cost-savings***, or reliability of electric service." (emphasis added).[40] As such, DEC is likely to agree that assessment of its own PIMs through these lenses is worthwhile.

Additionally, I will focus my analysis on the PIMs that are a component of the DEC application, as reflected in Direct and Supplemental Direct Testimony of Bateman and Stillman for DEC. DEC initially proposed four PIMs but has since rescinded one (the Affordability/LMI PIM) and modified the baseline for two (the Reliability PIM and Renewables Integration Encouragement PIM). As such, I will address analyzing the three remaining PIM proposals in turn.

<u>DEC's proposed Peak Load Reduction PIM</u>. DEC asserts that its Peak Load Reduction PIM advances cost savings by pointing to the linkage between winter peak and cost savings; to the extent that winter peak can be reduced, it may reduce the need for additional capacity investment, which in turn will save ratepayers money.[41] Moreover, DEC argues that the PIM will prompt it to develop innovative, dynamic, time-differentiated rates and engage customers to participate in these rates, which "would reduce utility earnings." Though DEC's premise is reasonable and peak load reductions through rates and programs are important tools for potential cost reduction, DEC has not provided any analysis to show that (1) the estimated customer enrollment due to this PIM will be sufficient to forestall any grid investments that would otherwise be necessary, or that (2) the proposed incentive value

[40] DEC PBR Panel Direct Test. at 23.
[41] *Id.* at 28.

will outweigh the utility's foregone earnings associated with the grid investment. Such an analysis may be prospective, but analyses to approximate the potential benefits of prospective PIMs are necessarily prospective.

DEC's proposed Renewables Integration & Encouragement PIM. DEC suggests that this PIM advances operational efficiency and cost-savings but fails to substantiate this argument beyond that it "strengthen[s] the Company's incentive to integrate DERs located on customer premises and to offer and subscribe customers to cost-competitive and convenient alternative green power programs." DEC offers that the DER Integration Metric (Metric A) "helps to decrease total generation demand, thereby reducing the need for generation investment." However, the linkage between Metric A and cost-savings is tenuous; beyond the customers who directly benefit from the DERs interconnected, the primary benefit to customers generally will depend on the extent to which these assets are managed by the utility as supply side resources to meet load and reduce peak. For this reason, Metric A is not explicitly designed to support cost-containment. For illustrative purposes, Metric A would support cost-containment if the metric were changed to the number of DER projects that are interconnected in a year *and* enrolled in a utility or third-party program demand side management program.

DEC also fails to make a connection between cost savings and either of the other two metrics (i.e., the Large Customer Renewable Program

Encouragement Metric B and Residential Customer Shared Solar Program Encouragement Metric C). As was true in the DEP case, the programs that would be eligible under these metrics are already part of the utility's procurement plan (meaning these programs provide no additional benefits or regulatory surplus to ratepayers).I cannot identify how either of these metrics supports cost savings beyond the cost savings that individual customers may experience from participation in the eligible programs. [42]

DEC's proposed Reliability PIM. This PIM's connection to affordability and cost containment is immaterial because reliability is an outcome that is not intended to align with cost savings. As such, I do not think it warrants analysis from an affordability lens.

Finally, I note that the scaling factor DEC applied to its PIMs relative to the incentives proposed for the same mechanisms in the DEP case is inconsistent. For example, the tiered incentives associated with the DEP Reliability PIM are $1 million, $2 million, and $6 million respectively, whereas DEC has proposed $1.5 million, $3 million, and $9 million. This suggests that DEC increased the incentives for this PIM by a factor of two-thirds for the first tier, and then doubled the prior tier for the second and third tiers. Similarly, the DEC Peak Load Reduction PIM's annual reward caps are $600 thousand for RY1, $1.1 million for RY2, and $1.6M for RY3. The corresponding proposed caps for the DEP PIM are 1.5x lower for RY1,

[42] Please see the comprehensive analysis of the Renewables Integration & Encouragement PIM contained in NCJC et al. witness David Posner's Testimony in the DEP rate case proceeding. *See* Direct Testimony of David B. Posner on behalf of NCJC et al., Docket No. E-2, Sub 1300, 22 (Mar. 27, 2023).

1.57x lower for RY2, and 1.45x lower for RY3. It is unclear why the PIMs scaled differently for each PIMs.

Ultimately, I raise this matter because, absent explanation, the Commission is left to assume that PIM values were arbitrarily set in order to achieve an even $12M upside and downside total potential impact for the DEC PIM portfolio. This is a concern for affordability because it suggests that the value of PIM incentives is not based on the benefit that achieving the PIM targets will create for ratepayers. Consequently, if the underlying PIM targets are achieved, ratepayers may be required to pay more to incentivize the utility than the benefit ratepayers will accrue from the performance that is achieved. Moreover, this variance in scaling between the two utilities and even amongst the PIMs introduces concerns about uneven marginal incentives in different rate years and between the two utilities.

Ultimately, none of the PIMs proposed by DEC provide a strong linkage to cost savings, though the Peak Load Reduction PIM proposal has a stronger connection than the others. For this reason, I do not believe the DEC proposed PIMs can support the Commission in ensuring that the DEC PBR application will support affordability.

Q: WHAT ADDITIONAL, GENERAL CRITERIA – BEYOND SERVING THE POLICY GOAL OF AFFORDABILITY – DO YOU RECOMMEND THE COMMISSION USE WHEN EVALUATING AN ELECTRIC UTILITY'S PIM PROPOSALS UNDER N.C.G.S. § 62-133.16 IN THE FUTURE?

A: First, I recommend assessing whether the PIM is outcome oriented and clearly serving an explicit policy goal. Outcome-based PIMs focus on the achievement of a policy goal or desirable outcome rather than the specific actions taken to deliver that outcome. Outcome-based PIMs are generally preferrable because they allow the utility flexibility to choose which portfolio of programs and investments best produce desired outcomes most cost-effectively. The drawback of alternatives — activity-based or program-based PIMs — is that they may not support the development of effective programs that support the desired policy outcome.[43]

Second, I recommend examining whether the PIMs will support new or improved services that the utility would not otherwise pursue. PIMs are widely used to motivate a utility to act in a manner consistent with the public interest when it would otherwise not be incented to do so.[44] Given this, having historical data to benchmark what level of performance would constitute an improvement of the utility's performance is incredibly important.

Third, a PIM's targets should be sufficiently *ambitious* – meaning that the target should not be set to a level that history suggests will be easily achieved, nor to a level that is likely to be achieved without utility effort. A

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[43] CARA GOLDENBERG ET AL., ROCKY MOUNTAIN INSTITUTE, PIMS FOR PROGRESS: USING PERFORMANCE INCENTIVE MECHANISMS TO ACCELERATE PROGRESS ON ENERGY POLICY GOALS (2020), https://rmi.org/insight/pims-for-progress/.

[44] *See* RHODE ISLAND AND PROVIDENCE PLANTATIONS PUBLIC UTILITIES COMMISSION, GUIDANCE ON PRINCIPLES FOR DEVELOPMENT AND REVIEW OF PERFORMANCE INCENTIVE MECHANISMS, Microsoft Word - 4943_Staff_Memo_GD_Approved (ri.gov).

good example of this would be a PIM that rewards the utility for maintaining status quo annual growth rates in interconnection of distributed resources (DERs) when new federal tax incentives for customer sited DERs have just been announced.

While targets should be ambitious, the inverse is also true – they should be achievable. Navigating the balance of ambitious but achievable is challenging when historical performance data is not available, and in some cases, even when it is. When in doubt, establishing a scorecard can be a low-risk way to ascertain whether a metric and target are appropriate for use in a future PIM.

Finally, any PIM should create net benefits for ratepayers. When considering a potential PIM, evidence — either qualitative or quantitative — should be made available that suggests that the new or improved services which the PIM will motivate will provide benefits that outweigh the PIM's costs. Generally, a PIM incentive should be large enough to motivate the desired performance and no larger, in order to prevent imposing unnecessary costs on customers. Cost-benefit analyses, where possible, can support the rightsizing of incentives.

Given the affordability concerns of the NC PBR framework, a PIM design that fails any of these criteria should be dismissed or approved only as a scorecard or tracking metric. This will ensure that ratepayers are not burdened with the potential cost of a PIM incentive that is misaligned or disproportionate to the benefit they will incur.

Q: CONSIDERING THESE RECOMMENDATIONS, WHAT FOCUS AREAS MIGHT BE IDEAL FOR PIMS WITH THE DEC PBR APPLICATION IN MIND?

A: Though I recommend that the Commission reject DEC's proposed PBR application, I offer some illustrative PIM concepts that would provide stronger incentives to align the NC PBR framework with the outcomes of affordability and cost containment, since these are its most notable failings. PIMs structured as follows could partially address these concerns and support other NC policy goals:

- A balanced incentive to reduce fuel costs.
- A reward to invest in non-wires alternatives that defer or avoid costlier and outdated approaches to improving the grid.
- A penalty for failing to maximize federal tax credits, credit adders (e.g., for utilizing domestic materials in asset construction and siting in designated energy communities), and net present value of credits through transferability when the utility's tax capacity is not sufficient to efficiently self-monetize.

I mention these PIM concepts with the current DEC PBR Application in mind. However, some of these PIMs may not be appropriate for a future MYRP (e.g., one that spends much more on generation or opex investments rather than distribution plant) and/or if the Commission were to establish a process to set priority PBR goals and outcomes with which these concepts are misaligned. In other words, these PIM concepts are offered specifically in response to this current PBR application.

Q: PLEASE EXPLAIN WHY A FUEL COST INCENTIVE WOULD BE SUPPORTIVE OF COST CONTAINMENT AND OTHER NORTH CAROLINA POLICY GOALS.

A: A well-designed PIM to incentivize the fuel costs reductions could create a financial incentive for DEC to better manage its fuel expenditures and optimize its operations to rely more heavily on cost-effective non-fuel resources.

At present, fuel costs are treated as a 100% pass-through to customers. This means that while the Company does not directly profit from fuel usage, it does not have any financial incentive to reduce its usage. Said another way, if fuel costs fell, DEC would gain nothing from the lower costs, and if they rose, DEC would not be responsible for footing the bill because customers will pay them. Since fuel costs are not a profit center for the utility, the ESM would not affect fuel-cost recovery either.

However, fuel costs matter a great deal to customers, as they make up a large share of total bills. Fuel prices can also be volatile (particularly for natural gas).[45] This makes it hard for customers to predict the size of their bills from month to month — and for fixed income customers to pay them when fuel prices spike. A PIM that encouraged the Company to contain its fuel costs could therefore contribute substantially to ensuring affordable service for DEC's most vulnerable customers.

[45] *See* Joseph Daniel, *Electricity Customers Are Getting Burnt by Soaring Fossil Fuel Prices*, RMI (June 23, 2022), https://rmi.org/electricity-customers-are-getting-burnt-by-soaring-fossil-fuel-prices/.

While the Company does not have total control over fuel costs, there are various actions it can take to contain them. In a parallel proceeding, Duke Energy Progress witnesses outline various "creative and proactive measures" the Company has taken to reduce fuel costs, such as financial hedging, the Duke Energy/Progress Energy merger joint dispatch agreement system fuel savings effort, novel market engagement strategies, and energy trading.[46] Though it is beyond the scope of my testimony to evaluate the efficacy of the Company's fuel cost containment efforts, to the extent DEC's fuel cost containment strategies mirror DEP's, they are an insufficient substitute for a financial incentive to reduce fuel costs.

Moreover, to the Company's list of activities it can take to reduce fuel costs for ratepayers, I would add a few additional ones: negotiating more favorable fuel-price contracts, optimizing generation resources and market purchases to minimize costs (which DEP has suggested that it will be able to do through the Southeast Energy Exchange Market), employing batteries to store power during low-cost hours and export it during high-cost hours, and reducing reliance on fuel by investing in fuel-free resources (e.g., wind, solar, energy efficiency, demand flexibility). Investment in fuel-free resources has the added benefit of supporting the carbon emission reduction outcome.

DEP further argues that a PIM for fuel cost containment implies that "existing regulatory processes and Commission oversight are insufficient."[47]

[46] Rebuttal Testimony of Bateman and Stillman, Docket No. E-2, Sub 1300, 50-51
[47] *Id.* at 50

To the extent DEC seeks to preempt a fuel cost PIM in this proceeding on similar grounds, not only is this assertion untrue, but it is also logically inconsistent with the Company's own proposals for other PIMs (i.e., by proposing a reliability PIM, the Company does not imply that Commission oversight of reliability is insufficient). Ultimately, a PIM proposal is agnostic of the sufficiency of Commission oversight, but rather a tangible *financial* incentive to motive utility performance in a certain way.

Q: HOW WOULD A HYPOTHETICAL FUEL COST PIM WORK?

A: A fuel cost PIM would allow the utility to capture a share of the benefits if fuel costs ended up being lower than expected and require it to bear the same share of the cost if they ended up being higher than expected. The reward or penalty would be calculated by comparing the Company's actual fuel-cost spending with the expected level of spending at the end of each rate year and multiplying the difference by the same fixed percentage (a "sharing factor").

The annual reward and penalty could be capped at a certain level (e.g., $20 million) to ensure the utility is not burdened with undue financial risk. While a cap of ±$20 million may seem high, it is important for the cap to be substantial so that the incentive remains consistent throughout the year. The lower the cap, the more probable that it will be reached in times of high price volatility, which would have the effect of nullifying the incentive to restrain fuel costs for the remainder of the year.

There are a few things to keep in mind when setting a sharing percentage: first, the sharing factor should be high enough to incent DEC to aggressively seek ways to reduce fuel costs. However, it should not be so large that the annual cap is frequently triggered, since this would reduce the incentive power of the PIM. For example, the Commission could use historical data to set the sharing factor at a level that would have triggered the cap 20% of the time if the PIM had been in place over the past ten years.

Other states have adopted similar PIMs. For example, Hawaii employs a 2% sharing factor for the Hawaii Electric Companies,[48] Idaho uses a 5% sharing factor for Idaho Power,[49] and Wyoming uses a 20% sharing factor for Rocky Mountain Power.[50]

To design the PIM I describe will require selecting a method for setting the expected costs to which actual fuel costs are compared. There are two basic methodological choices for setting a baseline: forecasts and historical actuals. The main benefit of forecasts is that they can be tailored to reflect changing conditions, though this is of limited benefit because the accuracy of fuel-cost forecasts tends to be low (particularly for natural gas, which is subject to substantial price volatility that is hard to predict). Utility fuel cost forecasts are typically based on market fuel price forecasts. The

[48] Final Decision and Order No. 35545, Docket No. 2016-0328 (Haw. Pub. Util. Comm'n., June 22, 2018).

[49] Order No. 35421, Case No. IPC-E-22-11 (Idah. Pub. Util. Comm'n., May 31, 2022), *available at* https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE2211/OrdNotc/20220531Final_Order_No_35421.pdf.

[50] ROCKY MOUNTAIN POWER, ENERGY COST ADJUSTMENT MECHANISM, SCHEDULE 95, https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/wyoming/rates/095_Energy_Cost_Adjustment_Mechanism.pdf.

industry has recognized, however, the fallibility of fuel price forecasts for more than a decade.[51]

Moreover, using forecasts to set the baseline for a PIM of this type can invite gaming; the utility can increase the size of its reward (or reduce the size of its penalty) if it is able to inflate the fuel-cost forecast. This problem can be avoided by instead using actual historical fuel-cost spending to set the baseline (for example, a five-year rolling average could be used that excludes any major outlier years). I flag this issue for the Commission to consider in the future. However, if the Commission were to adopt such a PIM today, the gaming concern would be moot in this single instance because the Company has already submitted its fuel cost forecasts. Once such a PIM is adopted, all future fuel-cost forecasts would present an opportunity to game the PIM baseline.

Unintended consequences should be considered when designing a PIM, and a fuel cost PIM is no different. With respect to owned generation and purchased power, a fuel cost PIM provides an illustrative example of unintended consequences that warrants close consideration. Specifically, a fuel cost PIM that incents the utility to reduce the cost of one but not the other could encourage the utility to make uneconomic substitutions (i.e., to reduce fuel costs by purchasing pricier power from other suppliers). This gaming incentive could be addressed by also applying the PIM to purchased

[51] Gabrielle Wong-Parodi et al., Comparing price forecast accuracy of natural gas models and futures markets, Energy Policy, Volume 34, Issue 18, 2006, at 4115-4122, https://eta.lbl.gov/publications/comparing-price-forecast-accuracy-0.

power; if this is done, care should be taken to create a level playing field between generated and purchased kWhs (e.g., by basing the PIM on net power costs instead of fuel costs alone). However, while including purchased power in this PIM could be beneficial, it would also dilute the financial incentive for the Company to reduce its own fuel costs (which it has more control over than purchased power prices). This consideration should be carefully weighed in the design process.

If designed well, a balanced fuel cost PIM would benefit both customers and Duke Energy. As the Company finds ways to reduce fuel costs, customers would reap most of the savings through lower bills. If the Company is lax in its efforts to find savings, customers will still benefit from receiving a refund that will offset a portion of the past year's bill. Meanwhile, this PIM would turn fuel costs from a pass-through item to an earnings opportunity for the Company. Finally, the PIM would also yield societal benefits by incenting the Company to reduce its reliance on costly (and volatile) fossil fuels over time, supporting its efforts to reduce emissions by 70% by 2030. This PIM, if implemented in tandem with a MYRP, could be a win-win for North Carolina.

Table B summarizes the key attributes of the proposed Fuel Cost PIM.

Table B.

Fuel Cost PIM Design Proposed Design

Name	Fuel Cost PIM
Perverse incentive or problem PIM would address	DEC has no incentive to contain fuel costs during the MYRP. Customers pay these costs and bear the full risk of fuel-price volatility, but compared to the utility they have few options (beyond conservation and efficiency) to reduce fuel costs.
Illustrative metric	Annual fuel cost spending ($)
Illustrative incentive	DEC will earn or cover a certain percentage of the difference between projected total fuel costs and actual total fuel costs.
H 951 policy goal(s) addressed	• Achieves operational efficiency and cost-savings that are greater than required by existing law. • Reduces low-income energy burdens. • Encourages utility-scale renewable energy and storage. • Encourages DERs. • Encourages energy efficiency. • Encourages peak load reduction or efficient use of the system. • Encourages carbon reductions.

Q: PLEASE EXPLAIN WHY A PIM FOCUSED ON INCENTIVIZING NON-WIRES ALTERNATIVE PROJECTS WOULD BE BENEFICIAL.

A: A significant portion of the costs forecasted in the DEC proposed MYRP are T&D investments. The average bill impact of these investments alone would be significant. While investments in T&D infrastructure are necessary to support attainment of the least-cost pathway to reduce carbon emissions from the power sector, it is nevertheless important to ensure that the investments being made are cost-effective and supportive of the state's policy goals.

Non-wires alternatives (NWA) investments in some circumstances can defer or avoid traditional T&D investments and better support customer affordability and carbon reduction outcomes. However, as I explain below, the NC PBR framework creates a disincentive to pursue NWAs. As such, it is highly unlikely that DEC will identify or propose NWAs if its proposed MYRP is approved.

Cost-effective NWAs would reduce the utility's rate base relative to what it has proposed in the MYRP because: (a) by definition, cost-effective NWAs would be *lower cost* relative to DEC's proposed T&D investment, and (b) NWA investments can be capex, opex, or a combination of both. Lower capital spending and less capex-intensive projects represent a diminished opportunity for utility earnings. Moreover, the lower cost of NWAs adopted during the MYRP would increase the likelihood of the utility over-earning relative to its approved ROE, which might trigger the ESM and a refund to ratepayers.

However, a shared savings mechanism (SSM) focused on incentivizing NWA investment could be designed to counteract the PBR framework's embedded disincentive to meaningfully pursue NWAs during a MYRP.

Q: PLEASE EXPLAIN HOW AN ILLUSTRATIVE NON-WIRES ALTERNATIVE SHARED SAVINGS MECHANISM COULD WORK.

A: A SSM is a PIM through which the utility's role in realizing savings for ratepayers is rewarded by allowing the utility to keep a portion of the total savings. An appropriately sized NWA SSM could incentivize DEC to identify, seek approval for, and deploy cost-effective NWA investments that meet the needs of the transmission and distribution grid, and have the additional benefit of supporting customer affordability and carbon reduction.

Like a symmetrical PIM for fuel costs, a SSM for NWAs would require a sharing factor. It would be important to balance the sharing factor with an overarching cap on the annual PIM reward. For example, if the sharing factor is too high, the utility could pursue fewer NWA solutions and max out the annual reward. Alternatively, if the sharing factor is too low, the incentive may not be sufficient to overcome the lost earnings from reduced capital expense. However, as a point of reference, electric distribution companies in Connecticut are allowed to keep 25% of total annual customer savings associated with approved NWAs.[52]

To effectively implement an NWA SSM, the Commission will likely need to establish a process through which it (or another independent party) would approve the savings in total ratepayer costs attributable to each NWA solution deployed in a rate year relative to the traditional T&D investment it is delaying or replacing.

It is important to note that though an NWA SSM may slow the growth of the rate base in the long-term, it would not necessarily result in immediate savings for ratepayers during a MYRP in North Carolina. Per the NC PBR framework, ratepayers would pay the full approved revenue requirement

[52] Final Decision: Appendix A, Docket No. 17-12-03RE07 (Conn. Pub. Reg. Auth., Nov. 9, 2022), *available* at https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/59e888f10a5de7d2852588f5005b106c?OpenDocument.

plus any reward claimed by the utility. NWA savings would not accrue to ratepayers until the end of the MYRP when base rates would be reset.

However, Commission Rule R1-17B(e)(4) provides an out in this respect; the Commission has the prerogative to claw back approved revenues if spending is less than the amount projected by "adjusting base rates as necessary" throughout the MYRP. This is a mechanism through which savings from NWA projects could be passed through to ratepayers more quickly.

Table C.

Non-wires Alternative Projects Shared Savings Mechanism Proposed Design

Name	Non-wires Alternative Projects Shared Savings Mechanism (NWA SSM)
Perverse incentive or problem PIM would address	Muted cost containment of the ESM and capex bias.
Illustrative metric	Total ratepayer cost savings associated with an NWA solution that replaces a more costly T&D investment.
Illustrative incentive	Utility would be eligible to keep a share of the savings in total ratepayer costs (sharing factor percentage) up to an annual cap.
H 951 Policy Goal(s) addressed	• Achieves anticipated operational efficiency, cost-savings, and reliability that are greater than required by existing law. • Promotes resilience and security of the electric grid. • Maintains adequate levels of reliability and customer service. • Cost containment. • Customer affordability. • Decarbonization.

Q: PLEASE EXPLAIN WHY A PENALTY FOR FAILING TO LEVERAGE FEDERAL SAVINGS OPPORTUNITIES WOULD BE COMPLIMENTARY TO A MYRP APPROVED IN NORTH CAROLINA.

A: There are a variety of recently established savings opportunities that utilities can take advantage of to improve grid reliability and deliver more affordable electric service to customers. In addition to the ITC, PTC and their respective adders, the IRA also offers the potential to save ratepayers money and support the clean energy transition through the Energy Infrastructure Reinvestment (EIR) low-interest loan program, the program guidance for which is available from the U.S. Department of Energy.[53,54,55]

The Infrastructure Investment and Jobs Act (IIJA) also offers a variety of direct-to-utility loan programs that can be leveraged to reduce the costs associated with investments that: increase resiliency in the face of extreme weather, represent innovative T&D and storage applications for resiliency, facilitate the construction of transmission, and increase grid flexibility and/or "smarten" the grid.[56] Given the affordability crisis that ratepayers across the country and in North Carolina[57] are facing, it is incumbent upon commissions and utilities to leverage every opportunity to save them money.

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[53] U.S. DEPARTMENT OF ENERGY LOAN PROGRAMS OFFICE, PROGRAM GUIDANCE FOR TITLE 17 CLEAN ENERGY FINANCING PROGRAM (2023), https://www.energy.gov/lpo/articles/program-guidance-title-17-clean-energy-program#page=1

[54] *See* Christian Fong et al., *The Most Important Clean Energy Policy You've Never Heard About,* RMI (2022), https://rmi.org/important-clean-energy-policy-youve-never-heard-about/; Jessie Ciulla et al., *What Utility Regulators Needs to Know about the Inflation Reduction Act: How to Ensure the Biggest Boon to the Energy System in US History Supports Affordable, Reliable Electric Service*, RMI (2022), https://rmi.org/insight/what-utility-regulators-need-know-about-ira/.

[55] *See* Jessie Ciulla et al., *What Utility Regulators Needs to Know about the Inflation Reduction Act: How to Ensure the Biggest Boon to the Energy System in US History Supports Affordable, Reliable Electric Service*, RMI (2022), https://rmi.org/insight/what-utility-regulators-need-know-about-ira/.

[56] Indeed, these savings opportunities, among others, were identified by the Commission, utilities, and stakeholders in Docket No. M-100, Sub 164 and synthesized in the Commission's resulting Order Directing North Carolina Public Utilities to Take Reasonable and Prudent Action to Obtain Federal Funding and to File Reports, issued November 11, 2022.

[57] The Low-Income Affordability Collaborative's final assessment found that prior to the COVID pandemic, 16% of residential customers met the "arears definition" for struggling to pay their bills. *See* Low-Income Affordability Collaborative Final Report, Docket Nos. E-7, Subs 1187, 1213, and 1214 and E-2, Subs 1193 and 1219 (Aug. 12, 2022), https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=fa412421-a3d5-4635-813c-7eda2e534934

DEC has partially taken the IRA into account in forecasting MYRP period costs. However, the IRA offers a variety of bonuses that could significantly increase the value of tax credits contingent upon construction and siting decisions that are within the Company's discretion but whose attainment the Company deems too uncertain to be included in estimates at this point in time. While the Company recognizes that any IRA clean energy tax provision benefits(s) may well differ from its estimates and that variances will ultimately flow through to customers, that is by no means a commitment to maximize the value of the IRA for ratepayers. It is for this reason that a PIM ensuring that these savings opportunities are maximized would be valuable. A PIM could be designed to incentivize the utility to capture "adders" specifically, or it could be designed more broadly to reflect other IRA and IIJA programs and provisions.

The ability to capture the ITC/PTC adders rest squarely within the utility's control. By choosing to use U.S.-sourced materials and locate facilities in designated energy communities, the value of the PTC can be increased 20% over the "bonus" level available when prevailing wage and apprenticeship requirements are satisfied, while the ITC's value can increase 20 percentage points (or 66.7%) over the bonus level.

Decisions by the company to forego these adders should be justified by the Company with detailed cost comparisons that assess locational/operational values of projects, cost differentials for domestic and foreign materials, and the potential value of the tax credit adders. A PIM could deny the company the benefit of excess costs when alternative projects with alternative tax credits assumptions are evaluated in a comprehensive fashion.

With regard to tax credit monetization, a PIM could be designed to incentivize DEC to presume monetization at no less than the rates prevailing in the tax credit transfer market when the credits are earned and cap the cost to ratepayers from the Company's use of a regulatory asset until self-monetization at that level.

Q: HOW WOULD THESE PIMS IMPACT RATEPAYER COSTS?

A: A fuel cost PIM could potentially lower the portion of ratepayers' bills that is associated with the fuel cost rider. If costs exceed DEC's projections during the MYRP, then the portion of the fuel cost increase that ratepayers would be responsible for would be reduced by the proposed sharing factor or the PIM's total annual cap.

An NWA SSM could lower the total ratepayer cost associated with T&D projects slated to go into service during the MYRP period. If the savings realized in response to this PIM are significant enough, it may trigger a refund to customers under the ESM. The refund would be equal to the difference between total capital costs net of incremental operating costs minus the PIM reward. If the savings are not substantial enough to trigger a refund under the ESM, ratepayers will realize the savings from NWAs when base rates are reset in the next rate case. However, as I note above, the Commission has the discretion to ensure ratepayers are refunded more immediately during the MYRP.

Likewise, a penalty-only PIM for failing to take advantage of taxpayer-funded cost savings offered by the IRA could, similar to the NWA SSM, lower total ratepayer costs associated with new solar and battery storage projects going into service during the MYRP period. Each year in which this PIM is triggered, ratepayers would receive a refund on bills through the proposed PIM rider equal to the amount of unleveraged savings.

IV. DEC PBR Design Process & National Best Practice

Q: WHY IS THE PROCESS A CRITICAL FACTOR TO CONSIDER WHEN DESIGNING PBR APPLICATIONS AND MECHANISMS?

A: Though PBR tools *can* be leveraged to overcome the problematic incentives associated with cost-of-service regulation, the design of the overarching PBR framework[58] is of critical importance to realizing the desired outcomes. As such, PBR outcomes are a direct reflection of design; poorly designed PBR mechanisms and frameworks will fail to achieve the desired outcomes. In contrast, well-designed PBR is more likely to support progress toward the desired outcomes. That said, "good PBR" should be thought of as a continuous *process* of implementation, evaluation, and refinement.

[58] Here I use the term "PBR framework" to refer generally to the collection of PBR mechanisms that comprise the regulatory model in which a utility operates. While reflecting on the design and efficacy of individual PBR mechanisms (e.g., MYRPs, PIMs, scorecards, revenue decoupling, etc.) is important, it is equally important to reflect on how the individual mechanisms work together to ensure they work in harmony rather than at cross-purposes.

Q: RECOGNIZING THAT PROCESS DESIGN IS NOT THE FOCUS OF THIS PROCEEDING, WHY IS IT IMPORTANT TO REFLECT AT THIS TIME ON THE PROCESSES THAT YIELD PBR APPLICATIONS IN NORTH CAROLINA?

A: The quality of North Carolina electric public utility PBR applications is – and will continue to be – a direct result of the process that led to their creation. As such, analyzing the processes that yielded DEC's PBR application, and comparing it to the processes in other jurisdictions, can illuminate a set of future steps the Commission might consider taking to support the submission of PBR applications that serve the outcomes of affordability and least-cost decarbonization.

Well-designed PBR mechanisms and frameworks tend to be the result of robust and inclusive processes. Any process to design PBR should aim to support the design of mechanisms that are responsive to the overarching regulatory framework. As such, a PBR process that fails to meaningfully engage the perspectives of a variety of stakeholders, set a foundation of shared understanding about the issues in the business model that PBR applications should solve for, and articulate a clear set of policy objectives against which the success of PBR can be measured, is unlikely to succeed. This is especially true in North Carolina given the shortcomings of the PBR framework discussed above.

Q: WHAT ARE THE HALLMARKS OF ROBUST PBR PROCESSES THAT YIELD WELL-DESIGNED MECHANISMS AND FRAMEWORKS?

A: Processes that yield well-designed PBR mechanisms -- and thus, are better positioned to achieve the desired policy goals – tend to have some common features:

1. An **assessment of the incentives created by the current regulatory framework**, which usually takes the form of an intentional effort to ensure all stakeholders have an opportunity to comment on and understand the incentives associated with the current regulatory framework and how PBR can remedy problematic incentives.
2. An **explicit, preliminary period focused on goal setting and outcome prioritization**, which will later provide the foundation upon which the design and selection of proposed mechanisms can be based.
3. An **invitation to stakeholders to contribute** perspectives and proposals for PBR mechanisms to be considered on an equal footing with those offered by the utility.

PBR processes that include all these elements can be likened to planning a journey with a destination clearly in mind. Stakeholders and utilities can better propose appropriate PBR applications and PIMs if they have a sense of the destination; otherwise, they may end up packing a parka to head to the Caribbean, or booking tickets for sea travel when what they needed was airfare.

These common elements have been incorporated into multiple state processes that have culminated in (or are expected to) the implementation of PBR frameworks.

Q: PLEASE PROVIDE SOME EXAMPLES OF OTHER JURISDICTIONS THAT HAVE DEMONSTRATED THESE BEST PRACTICES IN PBR DEVELOPMENT PROCESSES AND HOW THEY HAVE BEEN INCORPORATED.

A: Several states have paid specific attention to the assessment and evaluation of the existing regulatory framework to support identification of goals and priority outcomes for a new PBR framework, including Hawaii, Connecticut, and Nevada. In its Alternative Ratemaking proceeding, the Public Utilities Commission of Nevada (PUCN) developed and provided stakeholders with a template for evaluating whether the existing regulatory system achieved or helped advance priority regulatory goals.[59] This same template could be adapted and leveraged by North Carolina stakeholders and the Commission to assess the mechanisms DEC proposes against the policy goals they purport to serve, and with emphasis on the broader policy and regulatory context of North Carolina.

[59] Concept Paper 2: Assessment of the Nevada Electric Utility Regulatory Framework, Docket No. 19-06008 (Pub. Util. Comm'n of Nev., July 13, 2020), *available at* https://puc.nv.gov/uploadedFiles/pucnvgov/Content/Utilities/Electric/PUCN%20Second%20Concep t%20Paper_FINAL.pdf.

Minnesota is a good example of a state that has both given explicit attention to goal setting and invited ideas and mechanism proposals from all stakeholders. The 2017 Xcel MYRP application included proposed performance metrics, but stakeholders in the proceeding advocated for a distinct proceeding in which the utility's proposed metrics could be systematically evaluated, new metric concepts could be explored and created, and PIMs developed. The Minnesota Public Utilities Commission agreed that there was benefit to creating a separate venue for this purpose, and initiated an investigatory proceeding toto "identify and develop performance metrics, and potentially, incentives" for Xcel Energy.[60] In the context of that proceeding, the Commission invited the perspectives of a variety of stakeholders on key issues, such as:

- Goals that should be elevated for the development of performance metrics;
- How performance with respect to goals should be measured and quantified;
- Discussion on the extent to which goals are already measured or evaluated, and whether existing evaluation practices were sufficient; and
- Identification of areas of utility performance that would require further study to measure or set reasonable targets.[61]

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[60] Order Establishing Performance-Incentive Mechanism Process, Docket No. E-002/CI-17-401 (Minn. Pub. Util. Comm'n, Jan. 8, 2019).
[61] *Id.*

Connecticut is an example of a state in the midst of a multi-proceeding process to develop a comprehensive PBR framework for the states' electric distribution utilities. The Connecticut Public Utility Regulatory Authority (PURA) issued a decision in April 2023 which adopted four goals, five "foundational considerations," and prioritized nine outcomes to guide the development of PBR reforms which will be implemented as soon as mid-2024.[62] The forthcoming phase of PBR design activities will focus on revenue adjustment mechanisms, performance mechanisms (including PIMs, reported scorecards, and tracking metrics), and integrated distribution system planning. The emphasis PURA places on diverse stakeholder contributions is evident in the process and in its communications as "PURA will solicit participant comments and proposals, encouraging robust stakeholder engagement to ensure inclusive, thorough, and deliberative investigations."[63]

Minnesota, Nevada, and Connecticut are just three examples of states that have demonstrated these best practices, but there are others. Many of these processes draw on foundational PBR resources, such as Synapse's *Utility Performance Incentive Mechanisms: A Handbook for Regulators,* RMI's *Process for Purpose* and *PIMs for Progress* reports, and many other reports that synthesize lessons learned from PBR experiences in other jurisdictions, (e.g., *Next Generation Performance-Based*

[62] *PURA Resets Electric Utility Regulatory Framework to Better Serve the Public*, CONNECTICUT PUBLIC UTILITIES REGULATORY AUTHORITY (Apr. 26, 2023), https://portal.ct.gov/PURA/Press-Releases/2023/PURA-Resets-Electric-Utility-Regulatory-Framework-to-Better-Serve-the-Public
[63] *Id*.

Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation written by the Regulatory Assistance Project and the National Renewable Energy Laboratory).

Q: PLEASE DESCRIBE YOUR ASSESSMENT OF THE EXTENT TO WHICH THESE BENEFICIAL PROCESS FEATURES ARE PRESENT IN NORTH CAROLINA'S PBR PROCEEDINGS TO DATE.

A: While the North Carolina Energy Regulatory Process (NERP)[64] engaged in an evaluation of PBR, the NERP process was instituted and concluded prior to the passage of HB 951. Consequently, NERP represents an evaluation of PBR that is not specific to the unique framework adopted in North Carolina legislation, which has several elements that diverge from national PBR best practice. The PBR framework represented in HB 951 – specifically, G.S. 62-133.16 – is a unique and customized approach to PBR not yet deployed in another jurisdiction, and as such, it has not been evaluated publicly or collaboratively by stakeholders.

The North Carolina process has also not focused on goal setting and outcome prioritization, though here again, the Duke Energy subsidiaries have offered a different perspective. In a parallel proceeding, Duke Energy Progress asserted that its PIM proposals reflect broad stakeholder input from:

[64] *North Carolina Energy Regulatory Process*, NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY, https://www.deq.nc.gov/energy-climate/climate-change/nc-climate-change-interagency-council/climate-change-clean-energy-plans-and-progress/clean-energy-plan/north-carolina-energy-regulatory-process#:~:text=The%20NERP%20Development%20Process%20proceeded,and%20(3)%20Policy%20Development (last visited July 17, 2023).

(a) the NERP process (which again, concluded prior to the passage of HB 951),

(b) its own review of PIMs in place in other jurisdictions,

(c) the Order Adopting Rule R1-17B, which summarized intervenor positions in Docket No. E-100, Sub 178, and

(d) a "PIMs stakeholder process in the Summer of 2022, which was attended by representatives of thirteen organizations or agencies, representing several additional stakeholders."[65]

While these efforts were undoubtedly worthwhile, they are an insufficient substitute for a robust, inclusive, and impartially stewarded process in which all parties' perspectives and proposals are considered on an equal footing. As such, parties have not had an opportunity to advocate for prioritization of certain goals over others, or reflect upon the unique temporal needs, regulatory context, and policy goals of the state. Nor have they had the benefit of learning about the Commission's priorities and goals through a healthy debate.

In the PBR rulemaking docket, the Commission declined several interveners' request to initiate a new docket identifying PBR policy goals, concluding that "the PBR Statute itself establishes initial policy goals and requires that a minimum of one PIM be included in a utility MYRP."[66] While

[65] DEP PBR Panel Rebuttal Test. at 13-14.
[66] Order Adopting Rule, Docket No. E-100, Sub 178, at 24 (Feb. 10, 2022).

the 11 policy goals the NCUC is *allowed* to consider in reviewing a PBR application as outlined in G.S. 62-133.16(d)(2) provide a framework to evaluate the sufficiency of PBR application, it is an imperfect substitute for the Commission's own assessment of the *priorities* that a PBR application should address. Some of these outcomes may be more important in the near-term than others given the current state of the power sector and the requirement to meet the 70% carbon emission reduction by 2030 at least cost.

Further, the Commission stated that in rejecting intervenors' request to initiate a policy docket, it was seeking "to preserve flexibility and the ability for the Commission and all parties to learn and adapt as policy issues evolve."[67] Now that the Commission and stakeholders have had the opportunity to review two PBR applications from DEP and DEC, the time prior to the next PBR application will be an opportune window to leverage these learnings and adapt to the policy issues that have been surfaced in both proceedings.

Finally, while DEC should be commended for inviting input from various stakeholders, inviting input and *incorporating* it are entirely different, and it is the latter upon which greater value should be placed. Utilities are unlikely to propose PBR mechanisms that threaten their profitability – it would be akin to a baker proposing to count your calories. All utilities – not just DEC – are therefore not well suited to be the primary, initial arbiters of

[67] *Id.*

ideas for PIMs, scorecards, and metrics. Instead, diverse stakeholders should be given the opportunity to offer their ideas in a dedicated design process led by the Commission.

Furthermore, utilities are disincentivized to foster an "equal playing field" between themselves and other intervenors when it comes to rate cases. It is no secret that rate cases tend to have adversarial dynamics. As the first mover in rate cases, utilities are motivated to offer opening gambits that are close as possible to their desired outcome, which often has the effect of skewing the focus and energy of debate to focus on improving the "worst" elements rather than coming up with "the best possible" concepts. This is a nuanced framing difference – which is the result of process design -- with profound implications for the quality of the final result.

This analysis is not intended to diminish the efforts or intention of Duke Energy. Rather, this is offered as a frank evaluation of the incentives created by the processes and frameworks within which utilities operate and have evolved to exist within.

Q: ARE THERE ANY ADDITIONAL PROCESS ELEMENTS YOU WOULD LIKE TO EMPHASIZE THAT MAY BE RELEVANT FOR THE CONTEXT OF THE NC PBR FRAMEWORK?

A: Yes. Given the affordability concerns implicated by the NC PBR framework (namely, the incentive to inflate forecasted costs and the muted incentive to contain costs associated with the ESM), an independent management and financial audit may prove to be an indispensable tool for the Commission.

Because utilities are insulated from the cost pressures firms in competitive markets face, they have muted incentives to continually identify structural and operational improvements to improve their bottom line. Over time, the lack of competition works in tandem with business model incentives to increase spending and will frequently result in utility over-investment.[68]

A financial audit can provide visibility into a utility's performance, including its fuel-cost management, fuel procurement practices, and risk-reduction strategies. In contrast, a management audit may focus on multiple dimensions of utility operations and decision-making and include auditor recommendations for regulatory and utility action.[69]

Management audits have been employed in other jurisdictions prior to the implementation of MYRPs, such as in Hawaii and Illinois. In Hawaii, the PUC required an independent management audit of Hawaiian Electric (HECO) as part of HECO's most recent rate case. The audit identified operational inefficiencies amounting to annual savings of roughly $25 million, which were incorporated in the rates set under the new PBR framework. The audit was an important tool in identifying opportunities for the utility to realize cost savings that could be returned to customers through the PBR framework.

[68] Cara Goldenberg, *Five Lessons from Hawaii's Groundbreaking PBR Framework*, RMI (2021), https://rmi.org/five-lessons-from-hawaiis-groundbreaking-pbr-framework/

[69] Kaja Rebane et al., *Strategies for Encouraging Good Fuel Cost Management: A Handbook for Utility Regulators*, RMI (2023), https://rmi.org/insight/strategies-forencouraging-good-fuel-cost-management/.

More recently, Illinois passed climate legislation (which also enabled PBR) that requires audits for each major utility to be completed in a 6-month timeframe. The audits focus on the following: capital projects placed into service since 2012; utility efforts to optimize reliability and resiliency; a data baseline to inform utility MYRPs; and deficiencies that could impact the planning process.[70]

A management audit modeled after these examples and others could help provide transparency into DECs operations and could ensure that base rates proposed in future PBR applications are as low as possible.

Q: IN LIGHT OF THE PROCESS SHORTCOMINGS YOU HAVE IDENTIFIED, WHAT ARE YOUR ADDITIONAL RECOMMENDATIONS TO THE COMMISSION TO IMPLEMENT IN A FUTURE PROCEEDING?

A: As a first priority, prior to approving a PBR application, the Commission should require an independent and comprehensive financial audit of the utility's operations. Such an audit may reveal operational cost savings that would lower the baseline revenue requirement prior to implementing the PBR framework for the first time, which possess weak cost containment incentives. Further, it will help provide a measure of confidence that any approved PBR application will support affordability.

Second, I recommend that the Commission initiate a proceeding to outline a set of priority goals and outcomes against which it will judge any PBR application it receives in the next two to three years.

[70] Illinois Compiled Statutes Sec. 16-105.10.

Third, upon receipt of the next PBR application from an electric public utility, I urge the Commission to consider issuing a procedural order that would invite PIMs, scorecards, and metrics proposals from all stakeholders (not just the utility) that enables proposed PIMs to be evaluated on a fair and equal footing.

Finally, when the Commission reviews PBR applications in the future, I encourage it to continuously pay particular attention to the cost forecasts employed by the utility in MYRPs as a countermeasure to the NC PBR framework incentive to inflate costs.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of Gennelle Wilson on Behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Southern Alliance for Clean Energy, Natural Resources Defense Council, and Vote Solar either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 19th day of July, 2023.

/s/ Munashe Magarira

Munashe Magarira

Gennelle Wilson

Boulder, CO | Ph: (252) 458-5356 | gwilson@rmi.org

EXPERIENCE

RMI Boulder, CO

Senior Associate, Carbon-Free Electricity January 2021 - Present

- Analyzes state-level regulatory policy reforms and changes to the utility business model needed to support the integration of clean energy.
- Provides analysis, strategic guidance, and stakeholder facilitation support to the Hawaii Public Utilities Commission in support of market reforms to achieve the Hawaii state goal for 100% renewable electricity by 2045.
- Facilitated an assembly of thought leaders and decision makers from across the U.S. electricity sector to collaboratively innovate on ways to address the critical institutional, regulatory, business, economic, and technical barriers that cause and prevent solutions to energy burden and disparity of access to clean distributed resources in the U.S.

Nicholas Institute for Environmental Policy Solutions Durham, NC

Climate & Energy Policy Associate August 2020 – December 2020

- Provided research, analysis, and report writing support to a portfolio of projects focused on state- level environmental policy work in the Southeast.
- Engaged and coordinated with stakeholders on energy efficiency, electrification, and equity policies.
- Co-authored *Power Sector Carbon Reduction: An Evaluation of Policies for North Carolina* report, which outlined policy options to support achieving the Clean Energy Plan targets.

Graduate Research Assistant September 2018—May 2019, August 2019–June 2020

- Provided research and advisory support to help inform North Carolina policymakers on the most appropriate avenues for the implementation of a recommendation from the Clean Energy Plan.
- Conducted data analysis on the spread and intensity of energy burden across North Carolina.
- Supported state-initiated stakeholder working group focused on carbon policy exploration and design with research and analysis.
- Supported a year-long, collaborative and inclusive process to create a set of energy efficiency (EE) recommendations for a state-wide policy roadmap for North Carolina.
- Designed meeting agendas and collaborative exercises to extract actionable insight and expertise from 40+ NC stakeholders, and derive agreement on top priorities for the state.
- Researched EE targets, measures, challenges and successes as implemented by other states.

Southern Environmental Law Center (SELC) Chapel Hill, NC

Solar & Energy Efficiency Policy Intern June 2019 – August 2019

- Conducted research and assisted with the crafting of cross-examination questions for a utility's expert witness in avoided cost hearings before the NC Utilities Commission.
- Wrote official comment letters on behalf of SELC's clients regarding:
  - A utility's EE and Demand Side Management mechanism and what changes are necessary to improve the mechanism for greater implementation of EE; and,
  - The rationale for excluding swine-to-waste biogas production from inclusion in the Clean Energy Plan for North Carolina.
- Researched the status of community solar across the Southeast and wrote an internal report on the adequacy of existing programs for reaching low-income and rural customers.

RTI International Durham, NC

Senior Strategy Analyst December 2017 – July 2018

- Provided critical strategic advisory to organizational leadership to support creation and evaluation of business cases and plans to help reach desired business goals.
- Lead corporate strategic & planning processes to develop and implement strategies that would enable RTI to successfully tackle social and scientific challenges and expand its service offerings to meet future client needs.
- Designed and facilitated strategic working sessions focused on ideation, prioritization, codification, and consensus finding, with groups ranging in size from 10 – 45 staff.
- Lead and coordinated analyses of un-tapped markets and assessed potential for RTI to gain market share.

Strategy Analyst March 2016 – November 2017
Project Management Associate December 2014 – February 2016

- Responsible for the financial and operational management of three large, early grade reading projects in Sub-Saharan Africa and Southeast Asia per strict budgets and government regulation.
- Supervised the sourcing, selection, on-boarding and ongoing management of 30+ consultants and subcontractors.
- Ensured the development and timely submission of project deliverables.

Market Research Analyst June 2013 – November 2014
Intern June 2012 – May 2013

EDUCATION

Master of Environmental Management (MEM) May 2020
Duke University, Durham, NC
Nicholas School of the Environment
Energy Economics & Policy focus

B.A. International Studies, summa cum laude
May 2013
North Carolina State University, Raleigh, NC
International Studies – Sub-Saharan Africa Concentration
Political Science & French Minors

PUBLICATIONS (reverse chronological order)

Jessie Ciulla, Gennelle Wilson, and Rachel Gold, *What Utility Regulators Needs to Know about the Inflation Reduction Act: How to Ensure the Biggest Boon to the Energy System in US History*

Supports Affordable, Reliable Electric Service, RMI, 2022, https://rmi.org/insight/what-utility-regulators-need-know-about-ira/

Rachel Gold, Gennelle Wilson, *Rewarding What Matters in Energy Efficiency: Shifting Utility Performance to Focus on Climate*, RMI, 2022, https://rmi.org/rewarding-what-matters-in-energy-efficiency/

Rachel Gold, Weston Berg, and Gennelle Wilson, "Climate-Forward Efficiency Performance Incentives: Rewarding What Matters," ACEEE Summer Study on Energy Efficiency in Buildings, 2022, https://www.aceee.org/sites/default/files/pdfs/20220810190543432_9f62dfcf-14c7-4fc4-9601-58055a933493.pdf

Cara Goldenberg and Gennelle Wilson, *Shining a Light on Utility Performance in Hawaii's Clean Energy Transition,* RMI, 2022, https://rmi.org/shining-a-light-on-utility-performance-in-hawaii/

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Gennelle Wilson, "Wholesale Decarbonization: An Assessment of RTO Options to Advance Carbon Objectives in the Carolinas," 2021, Energy Transition Institute, https://energytransitions.org/report%3A-wholesale-decarb

Kate Konshnik, Martin Ross, Jonas Monast, Jen Weiss, and Gennelle Wilson, "Power Sector Carbon Reduction: An Evaluation of Policies for North Carolina," 2021, Nicholas Institute for Environmental Policy Solutions at Duke University, https://nicholasinstitute.duke.edu/publications/power-sector-carbon-reduction-evaluation-policies-north-carolina

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
	)	
Application of Duke Energy Carolinas, LLC, for and Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina and Performance-Based Regulation	)	**Docket No. E-7, Sub 1276**

DIRECT TESTIMONY AND EXHIBITS OF

DAVID HILL

AND

JAKE DUNCAN

ON BEHALF OF

NORTH CAROLINA JUSTICE CENTER,
NORTH CAROLINA HOUSING COALITION,
NATURAL RESOURCES DEFENCE COUNCIL,
SOUTHERN ALLIANCE FOR CLEAN ENERGY,
AND VOTE SOLAR

July 19, 2023

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EXHIBITS

DH-JD-1 David Hill Resume

DH-JD-2 Jake Duncan Resume

DH-JD-3 Comparison of Duke's Grid Modernization Spending

I. Introduction and Qualifications

A. DAVID HILL

Q: PLEASE STATE YOUR NAME, JOB TITLE, EMPLOYER, AND BUSINESS ADDRESS.

A: My name is David G. Hill. I am a Managing Consultant at Energy Futures Group, Inc., and my business address is P.O. Box 587, Hinesburg, Vermont 05461.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A: I am submitting testimony on behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, Southern Alliance for Clean Energy, and Vote Solar (NCJC et al.).

Q: PLEASE SUMMARIZE YOUR QUALIFICATIONS AND WORK EXPERIENCE.

A: Exhibit DH-JD-1 sets forth my educational background and professional experience.

Q: HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A: I pre-filed direct testimony on behalf of NCJC et. al. before the North Carolina Utilities Commission (Commission or NCUC) in Docket No. E-2, Sub 1300 on March 27, 2023.

Q: HAVE YOU SERVED AS AN EXPERT WITNESS BEFORE OTHER PUBLIC UTILITY COMMISSIONS?

A: Yes, I provided testimony related to the Duke Energy Progress (DEP) proposed grid improvement plan (GIP) in Docket #2022-254-E before the South Carolina Public Service Commission. I have testified on related matters including integrated resource planning, efficiency programs for electric and gas utilities, advanced metering infrastructure, net metering, and interconnection on more than two dozen occasions in a dozen jurisdictions. My resume, which is attached as DH-JD-1, provides additional details.

B. JAKE DUNCAN

Q: PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A: My name is Jake Duncan, and I am a Southeast Regulatory Director for Vote Solar. My business mailing address is 360 22nd St, Suite 730, Oakland, CA 94612.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A: I am submitting testimony on behalf of NCJC et al.

Q: PLEASE SUMMARIZE YOUR QUALIFICATIONS AND WORK EXPERIENCE.

A: Exhibit DH-JD-2 sets forth my educational background and professional experience.

Q: HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A: I pre-filed direct testimony on behalf of NCJC et. al. before the North Carolina Utilities Commission in Docket No. E-2, Sub 1300 on March 27, 2023.

C. ESTABLISHING JOINT TESTIMONY

Q: DOES EACH SPONSORING WITNESS ADOPT THE WHOLE OF THIS TESTIMONY?

A: Yes.

II. <u>Testimony Overview</u>

Q: PANEL, WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of our testimony is to review and analyze Duke Energy Carolina's (the Company or DEC) approach to distribution grid investments as reflected in the Direct and Supplemental Testimony of Witness Brent Guyton. We will also identify environmental justice concerns related to distribution system planning and investments.

Q: HOW IS THIS TESTIMONY RELATED TO THE TESTIMONY SUBMITTED IN DOCKET NO. E-2, SUB 1300?

A: Our testimony in both dockets addresses each Duke subsidiary's fundamental approach to grid modernization and distribution investment. As described below, while some program level specifics may vary, both DEP and DEC share the same fundamental approach to grid modernization and distribution investment. Therefore, the principles and policy critiques we offer in Docket No. E-2, Sub 1300 remain consistent with the testimony that we offer in Docket No. E-7, Sub 1276.

Q: HOW IS YOUR TESTIMONY ORGANIZED?

A: Our testimony is organized as follows:

- Section II provides a summary of our conclusions and our recommendations to the Commission.
- Section III reviews the Company's grid modernization filing.
- Section IV provides a summary of our policy positions and updates to the substantive content provided in our testimony in Docket No. E-2, Sub 1300.
- Section V concludes our testimony.

Q: PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR TESTIMONY.

A: We conclude the following:

- The Company plans to increase revenue requirements by over $5.6 billion by 2026 to cover distribution system investments, including grid modernization programs.
- The Company's cost-benefit analysis overstates the benefits of the proposed multi-year rate plan (MYRP) programs by analyzing the benefits of each program in isolation, and by placing too much weight on the value of marginal reliability improvements.

- The Company's proposed MYRP distribution projects represent a continuation of the GIP and Power/Forward (P/F) proposals.
- The Company's proposed MYRP distribution projects related to grid modernization represent a larger per year spending rate than the Company's 2017 P/F proposal and 2019 GIP proposal, levels of spending that risk making DEC's bills unaffordable.
- The Company's stakeholder engagement process on grid modernization since the Power/Forward proposal has been insufficient. The Company's stakeholder engagement has largely consisted of the Company presenting what are effectively pre-determined outcomes, which stakeholder input has little to no opportunity to meaningfully change.
- The Company has not fundamentally changed its approach to grid modernization since its first grid modernization plan eight years ago, despite significant technological, market, social, and policy changes.
- Grid modernization and environmental justice (EJ) are linked as grid modernization has an impact on energy burden, reliability, and grid access.
- The Company does not currently produce and/or share sufficient data to analyze whether, and how, the proposed grid

modernization spending will impact disparities in reliability, grid access, and energy burden metrics across North Carolina.

- Preliminary data from analyses conducted in California and Michigan reveal that access to hosting capacity can vary between EJ and non-EJ communities. In its current iteration, Duke Energy's Grid Hosting Capacity (GHC) analysis is unlikely to provide sufficient data to analyze whether such a disparity in service exists in North Carolina.
- Grid modernization planning and investments in many jurisdictions from around the country are incorporating EJ, equity impacts, and consideration of multiple distributed energy resource (DER) solutions as alternatives to traditional grid investments. Active and collaborative stakeholder engagement is critical to such efforts.
- While the Company recently applied for some Infrastructure Investment and Jobs Act (IIJA) funds, by and large, DEC's planning and proposed MYRP investments for grid modernization fail to fully capitalize on the federal funds available to North Carolina through the IIJA and Inflation Reduction Act (IRA); to the extent the Company has sought to secure funding, most of its funding proposals center on traditional grid solutions to the detriment of customers.

Q: WHAT RECOMMENDATIONS DO YOU HAVE FOR THE COMMISSION?

A: We recommend the following:

- The Commission should initiate a working group to redesign the Company's benefit-cost analysis for grid modernization and DERs.
- The Commission should require the Company to conduct at least two non-wires alternative (NWA) pilot projects that leverage multiple DERs, including customer-sited resources, to defer distribution-level projects. One of these pilot projects should focus on an environmental justice community.
- The Commission should initiate an investigation into distribution system planning to establish stakeholder supported 1) grid modernization objectives, 2) reporting and data sharing requirements for regulated electric utilities, 3) NWA methodology and proposal requirements, 4) a community engagement plan, and 5) an exploration of the EJ aspects of grid modernization.
- The Commission should establish a tracking metric for the Company to report reliability data at the census tract and nine-digit zip code level – comprised of aggregated and anonymized customer premise level data – in order to investigate potential disparities in reliability services.

- Regarding the Company's Grid Hosting Capacity analysis, the Commission should require the Company to 1) use its existing GHC stakeholder process to evaluate the fourteen decision points for an effective hosting capacity analysis as described by Interstate Renewable Energy Council (IREC), 2) collaborate with stakeholders to add sociodemographic, energy burden, and other environmental justice indicators as layers on top of its planned GHC map and 3) include load hosting capacity in addition to generation hosting capacity in its GHC.
- The Commission should require the Company to update the proposed grid modernization plan investments to better account for federal funds through the IRA and IIJA. As part of this update, the Company should be required to work with stakeholders to identify at least two target initiatives that address environmental justice through multiple DERs as non-wire solutions.

III. <u>Analysis of The Company's Grid Modernization Efforts</u>

Q: PLEASE BRIEFLY DESCRIBE GRID MODERNIZATION AND EXPLAIN WHY IT IS IMPORTANT.

A: Broadly speaking, grid modernization refers to a range of utility upgrades, including but not limited to technical, engineering, planning, process, and policy changes, to the distribution (and transmission) grid for the purpose of responding to or addressing modern needs concerning electricity generation, transmission, and/or distribution.

Grid modernization is critical given the opportunity (and challenge) presented by integrating increasing levels of utility, third-party, and customer owned renewables, increasingly extreme weather impacts to the grid due to climate change, potential service disparities in communities of color and low-income communities (and increasingly powerful technical and engineering tools to identify and alleviate these disparities), and emerging physical and cybersecurity threats, along with other emerging trends and developments.

Q: HOW IS THE COMPANY'S APPROACH TO GRID MODERNIZATION RELATED TO HOUSE BILL 951'S GOALS?

A: The rapid deployment of DERs is a critical component to meeting the statutory requirements of House Bill 951 (HB 951), which direct Duke Energy to reduce its carbon emissions by 70% from a 2005 baseline by 2030 and achieve carbon neutrality by 2050. Grid modernization efforts, if done well, can facilitate the integration of DERs and lower the overall cost of HB 951 compliance. If done poorly, grid modernization efforts may increase HB 951 compliance costs without delivering comparable benefits to ratepayers.

Q: PLEASE DESCRIBE HOW GRID MODERNIZATION INVESTMENTS ARE RECOVERED.

A: A utility will typically seek to compensate the equity and debt investors who provided the necessary capital for significant, long-lived grid modernization investments by requesting that they be included in rate base. A rate of return would apply to those investments if a public utility commission determined that they were in fact part of rate base. Most often, grid modernization cost recovery is sought in traditional, cost of service general rate case proceedings according to traditional cost of service principles. However, there can be utility earnings impacts if there is a considerable gap between when a utility invests in grid modernization and when those investments are reflected in and recovered through customer rates, a phenomenon observers refer to as "regulatory lag." For this reason and others, many utilities have sought, with varying levels of success, non-traditional rate recovery approaches to obtain quicker (and/or more certain) rate recovery of these grid modernization investments, including deferral accounting, riders, and performance-based ratemaking (PBR).

Q: PLEASE PROVIDE A HIGH-LEVEL REVIEW OF THE COMPANY'S PROPOSED SPENDING AND ITS IMPACTS ON REVENUE REQUIREMENTS FOR GRID MODERNIZATION.

A: The application includes spending and rate recovery for distribution system grid improvements concerning recent GIP expenditures and for proposed distribution grid expenditures over the course of the MYRP. The impacts of these are additive (*e.g.*, the retrospective GIP expenditures and the prospective MYRP expenditures need to be considered together), and cumulative (the rate increases for each year are on top of those proposed for prior years). The additive and cumulative nature of the spending, and the related rate impacts are not concisely or clearly presented in the application. Therefore, in Figure 1 we present a summary based on our best understanding of the application and the Company's response to data requests.[1]

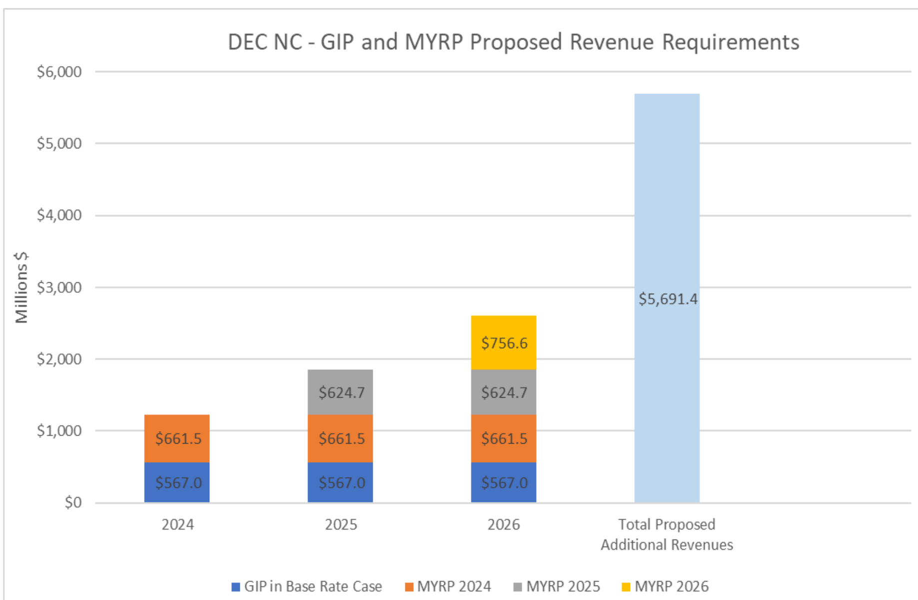

Figure 1: Revenue Impacts from Grid Improvement Plan and MYRP Distribution System Spending

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[1] DEC's response to NCJC et.al.'s DR 7-1. DEC's response indicates the spending includes the substation and line, and the integrated volt var control scopes, however, it does not appear to include the "other projects" described by Witness Guyton on pages 49 through 52 of his direct testimony.

From June 2020-2026, the distribution system spending for the GIP and the MYRP results in revenue requirements increasing by more than $5.6 billion, comprised of $1.228 billion in year 1 of the MYRP, $1.853 billion in year 2, and $2.609 billion in year 3. Each of these years includes an adjustment to "traditional base rate retail revenues" of $567 million.[12] The proposed MYRP additions for each year are added to the traditional base rate revenue increase, and to the MYRP step ups from prior years. Thus, in Year 3 of the MYRP, the total additional revenue requirements for the distribution system spending are $2.609 billion.

The Company's anticipated increase in the total electric distribution plant assets from the proposed spending is presented in Figure 2.[2]

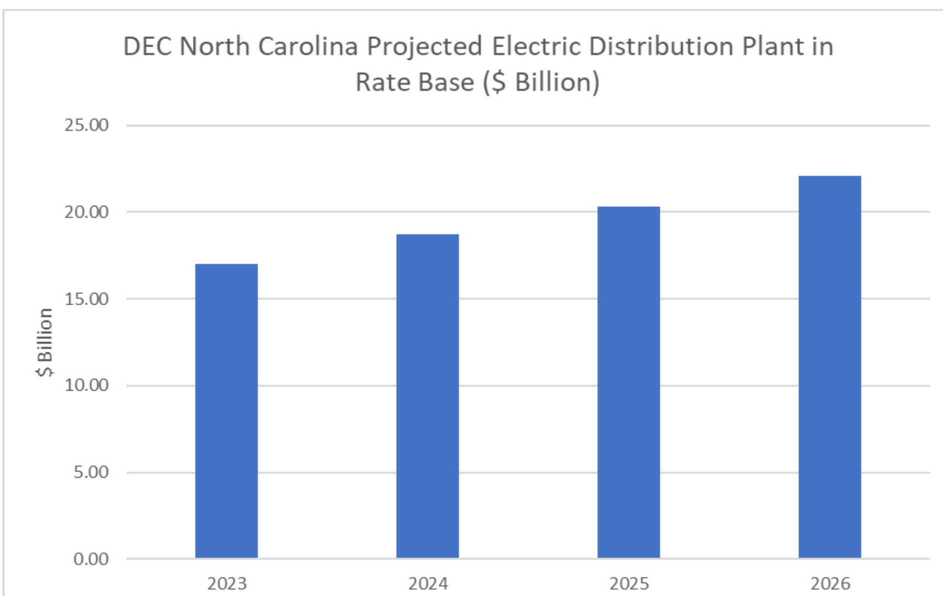

Figure 2: Rate Base Increase from Distribution Assets

[2] DEC's response to NCJC et al.'s DR 7-2.

From 2023 to 2026, the distribution plant assets are expected to increase $5.1 billion or 30%. Figures 1 and 2 highlight how the completed and proposed grid modernization investments in the GIP and MYRP are increasing revenue requirements and the distribution system assets in the rate base. By any measure these are significant expenditures, deserving careful regulatory oversight, and comparison with alternatives. Considerations that should inform the Commission's review of grid modernization investments include but are not limited to the following:

- The level of proposed grid modernization spending has commensurate impacts on customer's rates and bills and can be particularly challenging for fixed-income households.
- Opportunities for NWA[3] and for projects funded (in part or whole) from non-utility sources are increasingly available and can lower system costs and ratepayer impacts.
- There is an opportunity for the design, review, and implementation of grid modernization initiatives to be informed by and consider environmental justice and equity-based metrics and impacts.
- This is the Company's third grid modernization proposal in a rate case, and stakeholders have heavily contested each of the Company's proposals.

[3] The Company uses the term "Non-traditional solutions (NTS)" to refer to NWA.

- The Company continues to argue that marginal reliability improvements are the chief justification (or benefit) for this significant distribution grid spending at the same time it affirms that it is maintaining adequate, reliable service for its customers. The material benefits for marginal reliability improvements—particularly for residential customers—do not appear to be worth the substantial costs.

Our testimony addresses shortcomings in the Company's application in these areas, and we provide recommendations on how the grid modernization initiatives can and should be improved.

Q: PLEASE COMPARE AND CONTRAST THE GRID MODERNIZATION PROPOSALS IN THIS CASE AND DOCKET NO. E-2 SUB 1300.

A: The proposals in this case and in Docket No. E-2, Sub 1300 are generally very similar in approach, structure, and outcomes. See Exhibit DH-JD-3 for a comparison of grid modernization spending. This is not surprising, and it means that many of the issues and opportunities we identified in Docket No. E-2, Sub 1300 are also present in this case.

For example, DEC and DEP's proposals in these two proceedings focus on the need for substantial increases in utility investments (and therefore substantial additional costs to ratepayers) for grid improvement and grid modernization driven by so-called "megatrends," while paying less attention to ways in which evolving technologies and markets offer opportunities to avoid and defer utility grid investments. The language in both cases, highlighting grid "improvement" and "modernization" contrasts with the term "integrated distribution planning" (IDP), which is based on a holistic assessment of how investments on the customer's and utility's side of the meter can be optimized to provide desired levels of service and reliability. We encourage the Company to develop and the Commission to review proposed grid investments from the more holistic, integrated planning perspective.

Q: PLEASE COMPARE THE PROPOSED LEVEL OF DISTRIBUTION SPENDING WITH PREVIOUS GRID MODERNIZATION REQUESTS.

A. DEC requests $3.056 billion in distribution spending over three years[4]. We estimate that at least $1.8 billion of this spending is aligned with grid modernization programs associated with P/F or GIP. This amount could be higher due to inconsistencies in Duke's reporting. This amounts to at least $617 million per year in grid modernization spending. This is higher than both the 2017 P/F proposal of $581 million per year and the 2019 GIP proposal of $498 million per year (see Exhibit DH-JD-3).

[4] DEC's response to NCJC et al. DR 6-15.

IV. Summary of Policy Positions and Updates since the Duke Energy Progress Testimony

Q: IN JUNE 2023, THE LAWRENCE BERKELEY NATIONAL LABORATORY AND THE NATIONAL RENEWABLE ENERGY LABORATORY ISSUED A REPORT TITLED "DUKE ENERGY'S INTEGRATED SYSTEM AND OPERATIONS PLANNING: A COMPARATIVE ANALYSIS OF INTEGRATED PLANNING PRACTICES." PLEASE SUMMARIZE THIS REPORT AND HOW IT SHOULD INFORM THE ASSESSMENT OF THE COMPANY'S MYRP DISTRIBUTION PROPOSAL.

A: Lawrence Berkeley National Laboratory (LBNL) and National Renewable Energy Laboratory's (NREL) report aims to compare Duke's Integrated System and Operations Planning (ISOP) approach with Integrated Distribution Planning (IDP, which is interchangeable with distribution system planning) best practices.[5] The report is authored for the South Carolina Office of Regulatory Staff (SCORS). The authors interviewed staff from the SCORS, the North Carolina Public Staff, and Duke Energy. While state law and regulatory policy differ between North Carolina and South Carolina, it is our understanding that neither state has a distribution system planning requirement. Given that ISOP governs Duke Energy's distribution system planning framework for both North Carolina and South

[5] U.S. DEPARTMENT OF ENERGY, GRID MODERNIZATION INITIATIVE, DUKE ENERGY'S INTEGRATED SYSTEM AND OPERATIONS PLANNING: A COMPARATIVE ANALYSIS OF INTEGRATED PLANNING PRACTICES (2023), https://eta-publications.lbl.gov/sites/default/files/gmlc_4.2.2_memo_20230628_final.pdf.

Carolina,[6] the results of this report are broadly applicable to North Carolina and should provide helpful guidance to DEC on how to improve its distribution system planning.

The report first reviews the various elements of Duke's ISOP practice, including Morecast, Advanced Distribution Planning and NWA Screening, its relationship to Integrated Resource Planning (IRP), and its relationship to transmission planning, hosting capacity and the ISOP Data System, and then assesses the elements of ISOP against IDP best practices.

The report singles out Duke's development of granular load forecasts through Morecast, its progress removing barriers between planning departments, and its creation of a centralized data repository for Duke engineers as accomplishments. We applaud Duke for these efforts as well.

In addition, the report identifies the following opportunities for improvement:

- Methodological changes to Duke's NWA analysis.
- Metric tracking – "Duke Energy does not include metrics that can be used to measure the predicted or realized success of a given ISOP investment."7

[6] *See ISOP Reference Information Portal*, DUKE ENERGY, https://www.duke-energy.com/our-company/isop (last visited July 13, 2023).
[7] *Id.* at 27.

- Clear objectives – "it is unclear how ISOP prioritizes investments related to state objectives expressed in legislation or in PSCSC [or NCUC] regulations and orders in related matters."8

Notably, many of the LBNL/NREL recommendations to improve ISOP are in line with our recommendations regarding Duke Energy's distribution system planning approach and highlight, among other things, the critical role DERs can play in maintaining and improving system reliability and resiliency, reducing costs, and providing several other system, customer, and societal benefits. The authors recommend the following:

- Deeper stakeholder engagement.
- Include discussion of ISOP in IRP.
- Provide more information on how ISOP identifies investment decisions that are least cost and risk for maintaining a reliable and resilient distribution system.
- Move towards a spatially explicit forecast that predicts load distributed throughout the circuit based on advanced metered infrastructure (AMI) and supervisory control and data acquisition (SCADA) data.

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[8] *Id.* at 20.

- Integrate NWA analysis into a capacity expansion optimization model.
- Incorporate other DERs (beyond utility-owned battery storage), including managed electric vehicle (EV) charging, in NWA analysis.
- Account for all value streams in NWA analysis.
- Explore the screening approach used by peer utilities to successfully identify NWA projects.
- Continue to develop and enhance the GHC process.
- Improve distribution planning analytics and GHC capabilities to help inform customers and developers about where smaller capacity distributed generation projects may be limited by the constraints shown in Duke Energy's distributed generation (DG) Locational Guidance Map.
- Explore best practices for maintaining accurate GHC maps.

Q: PLEASE SUMMARIZE YOUR POSITION ON THE "SEVEN MEGATRENDS" CITED BY THE COMPANY AND OFFER ANY UPDATES.

A: Section IV of DEC witness Guyton's testimony presents the seven megatrends, noting these were initially described by DEP witness Oliver in the previous rate case.[9] The trends described by Witness Oliver adopted and expanded on the rationale for the P/F proposal.[10] While the megatrends overlap with some of the factors we have previously identified, and provide some relevant context reflecting changes in technology, risk profiles, and the environment, the Company's perspective appears to be limited in some key respects. For example:

Under megatrend 2, increases in DERs are classified as “new types of loads and resources impacting the grid”. This phrasing could be helpfully expanded by highlighting the potential for DERs to provide NWAs to reduce the need for traditional grid investments. As stated, and treated throughout the application, the Company’s perspective highlights the growth of DER’s as creating impacts that require traditional grid investments. This is sometimes, but certainly not always, the case. For instance, a planned combination of customer sited solar paired with storage (solar+storage), energy efficiency, and demand flexibility can simultaneously reduce circuit level capacity constraints and serve as a system level asset.

Megatrend 3 indicates that there are increasing public and private incentives and requirements for clean energy sources, which Guyton’s

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[9] Direct Testimony of Brent C. Guyton for Duke Energy Carolinas, LLC, Docket No. E-7, Sub 1276, pp. 24-25 (Guyton DEC Direct Test.).

[10] Direct Testimony of David B. Fountain for Duke Energy Progress, Docket No. E-2, Sub 1142 (June 1, 2017), *available at* https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=2e602d93-a288-4a6f-8c7c-d8684a747d91 (Fountain DEP Direct Test.).

testimony suggests will therefore increase system costs (and by extension customer costs). The grid modernization plan focuses on utility owned assets and investments, rather than examining the ways in which the combination of utility and non-utility investments and assets can be used to provide grid services at the lowest total cost.

Similarly, megatrend 5 indicates that technical advances have given "***utilities*** alternatives to traditional grid infrastructure options" (emphasis added). Here, we see an opportunity for the Company's application and proposed plans to be improved in how they identify and analyze NWAs, and particularly in how they consider the potential for non-utility parties to participate in the identification, funding, development, and benefits of NWAs.

Megatrend 7 indicates customer expectations are changing with respect to solar, EVs (we would add on-site storage), and control over their energy usage. As indicated above with respect to megatrends 3 and 5, the Company's plan and grid modernization initiatives can be improved by more actively recognizing and engaging higher levels of customer expectations, engagement, and investment as resources to increase NWAs and to reduce the overall system costs that would be borne by ratepayers.

While not identified in Guyton's testimony, consideration of equity or environmental justice impacts in energy planning and regulation is a megatrend that should be included.

We provided these megatrend observations in our testimony in Docket No. E-2, Sub 1300. As the Company's megatrend discussion and analysis mirrors DEP's, our comments are germane to and applicable in the instant case.

Q: WHAT ARE THE FOUR CRITICAL CAPABILITIES THE COMPANY IDENTIFIES TO ADDRESS THESE MEGATRENDS?

A: Witness Guyton states that reliability, capacity, automation and communication, and voltage regulation are the four critical grid capabilities needed to address the megatrends and thus deliver customer benefits.[11]

Q: DO YOU HAVE ANY COMMENTS REGARDING HOW THE COMPANY CONSIDERS THE FOUR CRITICAL CAPABILITIES IN ITS GRID MODERNIZATION PLANNING?

A: The four capabilities are essential to grid functioning and reliability. The Company tends, however, to view the capabilities from a narrow perspective, missing the opportunity to consider how DER technologies can improve capabilities and reduce impacts in each area of concern. For example, customer sited storage and on-site solar can increase resilience

[11] Guyton DEC Direct Test., p. 26:5 - 7.

and improve system reliability, reduce peak-power demands, defer investments driven by capacity constraints, and provide voltage regulation through enhanced grid edge automation and communication. The Company's perspective and proposed grid modernization plan has historically, and in this application continues to, overlook the valuable role DERs can play in modern grid and system planning, tending instead to treat the growth of DERs as a negative impact, for which the sole solution is direct utility investment to enhance grid capabilities. This fundamentally overlooks the potential value to the system and to customers of a more integrated and holistic approach to grid planning based on a more balanced portfolio of utility and customer sited assets.

Q: PLEASE SUMMARIZE YOUR POSITION ON COST-BENEFIT ANALYSIS AND OFFER ANY UPDATES.

A: Exhibit 10 from Witness Guyton provides an overview of the Company's cost-benefit methodology, with results in Exhibit 8. The Company also provides summary cost-benefit results in the DEP MYRP Technical Conference Presentation conducted on November 2, 2022.

In a similar fashion to its consideration of megatrends, and grid capabilities, DEP's cost-benefit analysis is unduly limited in four respects.

First, in response to NC Justice Center et al. data request 2.14 in Docket No. E-2 Sub 1300, DEP confirmed that program outage benefits are considered in isolation, and there is no indication that DEC's approach differs on this issue. This means that the avoided outage benefits from programs such as the self-optimizing grid (SOG), and distribution hardening and resiliency (DHR) as presented are not considered as interactive and are instead treated as if other program investments were not occurring. This suggests the summary cost-benefit ratios presented in the 2022 MYRP Technical Conference Presentation count avoided outage benefits more than once, resulting in more favorable cost-benefit ratios than would result if the combined and interactive impacts on avoided outages were estimated.

Second, the Company's cost benefit analysis continues to fail in acknowledging the undue burden grid modernization programs impose on residential customers. In the Duke Energy Carolinas' P/F rate case,[12] NCJC et al.[13] showed that although the majority of the benefits from reliability focused spending accrues to commercial and industrial (C&I) customers, residential customers would be required to pay for the majority of the program. This would be the case because the Company's cost-benefit analysis is based primarily on the Interruption Cost Estimate (ICE) tool, which levies a "cost" that can be avoided by Duke for momentary residential outages, even though these sorts of outages impose little to

[12] We discuss the DEC rate case on P/F because DEP did not present any cost-benefit analysis for P/F in its rate case, which was filed before DEC's rate case.

[13] Post-Hearing Brief of North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy, Docket No. E-7, Sub 1146 (Apr. 27, 2018), *available at* https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=51e296ec-b706-465b-8760-8aeef939f34b.

no monetary cost on residential customers. Similarly, in DEP's 2019 rate case, Public Staff Witness Jeff Thomas testified that "87% of the benefits of DEP's GIP were customer reliability benefits and that where reliability benefits were broken out by customer class about 97% of those benefits would accrue to commercial and industrial customers."[14] The same principle is at play in the Company's PBR proposal and the Company continues to use a cost-benefit analysis that relies on the flawed ICE tool.

Third, it does not consider the potential for third party NWAs to defer or completely avoid the need for at least some of the Company's proposed projects. The Company's cost-benefit framework accounts for the Company's capital costs and avoided operational costs as well as the benefit to customers from avoided outages. Potential customer investments, the ability for utility programs to leverage customer investments, and customer savings on utility bills, say for example through on-site solar generation, flexible load management or the use of on-site storage are not considered in the Company's current cost-benefit framework.

Finally, the Company's cost benefit analysis does not fully incorporate important options for downward pressure on rates through

[14] Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice, Docket No. E-2, Sub 1219, at 122 (Apr. 16, 2021).

increased customer sited investments or from leveraging federal funds like the IRA.

To most effectively assess grid modernization options and opportunities to address the megatrends Witness Guyton identified, we recommend the Commission create a working group to develop a stakeholder-driven approach to grid modernization cost-benefit analysis. This process should investigate how benefit cost analysis can be designed to meet North Carolina's statutory requirements and policy goals.[15] The National Energy Screening Project (NESP) offers policy-neutral guidance, methods, tools, and resources for states to develop their own, jurisdiction specific, cost-screening process for DERs, which can also inform and be applied to grid modernization efforts broadly. NESP's guidance is currently or has been used in a total of eleven states to revamp their cost-benefit frameworks.

Q: PLEASE SUMMARIZE YOUR POSITION ON STAKEHOLDER ENGAGEMENT AND OFFER ANY UPDATES.

A: Our testimony in Docket No. E-7, Sub 1300 offers a detailed history of DEC and DEP's joint stakeholder engagement efforts. Duke Energy has conducted Power/Forward, Grid Improvement Plan, and ISOP meetings

[15] THE NATIONAL ENERGY SCREENING PROJECT, https://www.nationalenergyscreeningproject.org/ (last visited Mar. 26, 2023).

as a joint effort between the two subsidiaries. Therefore, the conclusions we previously reached are consistent for DEC.

In sum, the proposed MYRP distribution projects are, in large part, a continuation of the programs and underlying framework put forward first in the Power/Forward proposal and again in the Grid Improvement Plan. (Exhibit DH-JD-3). The vast majority of parties in the DEC P/F proceeding heavily opposed P/F proposal and DEC's proposed Grid Reliability and Resilience Rider funding mechanism (the Rider), which the Commission ultimately rejected.[16] Duke Energy then held a series of stakeholder meetings, in which many stakeholders reported feeling that the GIP was simply a re-branding of P/F and that Duke Energy was not materially changing its approach based on stakeholder input.[17] DEC and several intervenors entered into a partial stipulation, which permitted deferral accounting for a narrow scope of GIP programs and expressed support for GIP programs that helped integrate DERs, and which the Commission ultimately approved.[18]

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[16] *See* Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, Docket No. E-7, Sub 1146, at 19, 133-37 (June 22, 2018), *available at* https://starw1.ncuc.gov/ncuc/ViewFile.aspx?NET2022&Id=80a5a760-f3e8-4c9a-a7a6-282d791f3f23.

[17] *See, e.g.*, Direct Testimony of Kevin W. O'Donnell on behalf of CUCA, Docket No. E-2, Sub 1219, p. 20
(Apr. 13, 2020), *available at* https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=1fa904ee-408e-4773-a82c-1f3f7f0a8bbe.

[18] Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice, Docket No. E-7, Sub 1214, at 16, 119-41 (Mar. 31, 2021).

Since the proposed MYRP distribution projects are largely a continuation of GIP programs, it is evident that the Company's grid modernization plans remain static, despite continued efforts by intervenors and informal stakeholders to improve the Company's distribution planning to better match the needs of the current energy and policy environment.

There have been no substantial changes to the Company's distribution planning process or stakeholder engagement process since we filed testimony in Docket No. E-2, Sub 1300.

We recommend that the Commission open an investigation into distribution system planning to establish stakeholder supported 1) grid modernization objectives, 2) reporting and data sharing requirements for regulated electric utilities, 3) non-wires alternative methodology and proposal requirements, 4) community engagement plan, and 5) an exploration of the EJ aspects of grid modernization.

Q: PLEASE SUMMARIZE YOUR POSITION ON NON-WIRES ALTERNATIVES AND PROVIDE ANY UPDATES.

A: Ultimately, identifying cost-effective NWAs is a product of the method chosen to analyze each NWA. The categories of costs and benefits included and how analyses compare these benefits and costs are, to a degree, subjective choices. In our DEP testimony, we demonstrate that DEP is using a methodology that may limit the cost-effectiveness of analyzed NWA, and that stakeholders have had limited to no input on this methodology. The same trend holds true for DEC.[19]

We make two recommendations here. First, the Commission should require the Company to directly collaborate with stakeholders on an updated NWA methodology. Second, the Commission should require the Company to conduct at least two NWA demonstration projects. The purpose of these projects would be to uncover important engineering, economic, policy, and customer engagement learnings about how to design and operate a customer-focused NWA. The consideration of NWA's should include more than utility owned battery storage systems. NWA options include customer sited storage and on-site generation, expanded efficiency and demand response, and rate design. One of these NWA projects should be conducted with an environmental justice focus to understand how targeted intervention can simultaneously achieve grid and social needs.

As stated in our DEP testimony, DEP South Carolina reached a settlement with the Coastal Conservation League, Southern Alliance for Clean Energy and Vote Solar to conduct one such project.[20] While this project is still in a very early stage, DEP South Carolina staff, including

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[19] NCJC et al. responses to DR. 6-12 and 6-13.

[20] Order Approving Comprehensive Settlement Agreement, Adjusting Base Rates, and Continuing Grid Improvement Plan Cost Deferral Accounting, Dockets Nos. 2022-254-E and 2022-281-E (S.C. Pub. Serv. Comm'n., Mar. 8, 2023) *available at* https://dms.psc.sc.gov/Attachments/Order/d62cf2f9-b260-4a3c-acfe-6a2c816d7b6d.

Witness Guyton, have started the process to develop an equity lens to analyze distribution projects and associated NWA. We believe this investigation could deliver significant benefits to the most underserved ratepayers and should extend to North Carolina.

In addition, Duke Energy has sought IIJA funding, which, if awarded, would entail tracking grid impacts on disadvantaged communities.[21] This funding support could be used to identify and demonstrate the types of DER, NWA projects we have recommended, particularly projects benefitting EJ communities.

Finally, we note that NCJC et al. witness Gennelle Wilson's testimony, which we strongly endorse, proposes an NWA performance incentive mechanism (PIM). We believe that demonstration projects and the proposed PIM are complementary. Demonstration projects provide important learnings about a technology or practice that could not otherwise be obtained. A PIM on the other hand, is built to address the Company's fundamental incentive of whether to pursue an NWA or traditional solution.

[21] DEC's confidential response and attachment provided in response to NCJC et al. DR 7-3. To avoid any doubt, no confidential information is included in, cited, or referenced to in this pre-filed testimony.

Q: PLEASE SUMMARIZE YOUR POSITION ON ENVIRONMENTAL JUSTICE AS IT RELATES TO GRID MODERNIZATION AND PROVIDE ANY UPDATES.

A: The Environmental Protection Agency defines environmental justice as:

> .... the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. Achievement of this goal requires that everyone enjoy: the same degree of protection from environmental and health hazards, and equal access to the decision-making process to create and maintain a healthy environment in which to live, learn, and work.[22]

Environmental Justice relates to grid modernization in that the Company's grid modernization efforts have a direct and significant impact on energy burden and affordability, local pollution, carbon emissions, access to reliable services, and access to grid capacity for EJ communities to enact their visions of local resilient energy systems.

The Company's MYRP distribution projects do not address environmental justice. The terms "environmental justice," "energy justice," "justice," and "energy burden" did not appear in the Direct or Supplemental Testimony of Witness Guyton. The term "equity" as it would apply to customers appears only once, under customer expectations in

[22] *Environmental Justice: Learn about Environmental Justice*, EPA, https://www.epa.gov/environmentaljustice/learn-about-environmental-justice (last updated Sept. 6, 2022).

Exhibit 2 of Guyton's Direct Testimony.[23] Table 4 and Exhibit 10 of our testimony in Docket No. E-2, Sub 1300 cite more than twenty legislative, regulatory and grid planning examples from around the country illustrating how justice and equity impacts are being incorporated into grid planning and investments.

We also made the case in Docket No. E-2, Sub 1300 that if different customer segments within the residential class experience substantially worse reliability experiences, it is the duty of both the Company and the Commission to investigate and address this disparity. We provided evidence that such disparities do exist in Michigan and Illinois. We summarized the Michigan and Illinois public utility commissions' responses to this evidence, which included requiring regulated utilities to report reliability metrics at a level more granular than the system and comparing these data with environmental justice indicators. In the DEP rate case hearing in Docket No. E-2, Sub 1300, Witness Guyton testified that DEP's current reliability reporting would not enable the Commission and other stakeholders to evaluate whether or not certain communities might experience more frequent or longer outages than other communities, despite the Company recording reliability data down to the protective device level.[24] DEC's discovery

[23] Guyton DEC Direct Test., Guyton Direct Ex. 2, p. 10.
[24] Transcript of Hearing Held in Raleigh on Friday, May 5, 2023, Volume 10 – Public, Docket No. E-2, Sub 1300, tr. vol. 10, 316-317 (May 10, 2023).

responses[25] and pre-filed testimony in this docket, along with DEC and DEP sharing data strategies, indicate the same holds true for DEC.

In Docket No. E-2, Sub 1300, DEP entered into a proposed partial stipulation with the Public Staff – North Carolina Utilities Commission and CIGFUR II on PIMs and tracking metrics (PIMs Settlement).[26] With respect to monitoring service reliability, DEP under the PIMs Settlement agrees to track the "top ten worst performing circuits." The Supplemental Direct Testimony of DEC witnesses Laura Bateman and Phillip Stillman[27] updates most of DEC's proposed PIMs to match the PIMs Settlement. Considering that Witness Guyton testified that DEP tracks reliability metrics down to the protective device and DEC and DEP share data strategies, DEC almost certainly can report performance on all circuits as well. Reporting on all circuits at the zip code or census tract would be well within DEC's capabilities, directionally align with the reliability reporting requirements in the PIMs Settlement, and enable the Commission, Public Staff, the Company, and other stakeholders to determine whether or not reliability disparities exist.

In our direct testimony in Docket No. E-2, Sub 1300, we reference Case No. U-21297 at the Michigan Public Service Commission in which

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[25] DEC's responses to NCJC et al. DR 6-1, 6-2, 6-3, 6-10, and 8-1.

[26] Agreement and Stipulation of Settlement on Performance Incentive Mechanisms, Tracking Metrics, and Decoupling Mechanism, Docket E-2 Sub 1300 (May 1, 2023), *available at* https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=3f4f45d2-3065-497e-9381-81079a29932b.

[27] Supplement Direct Testimony of Laura A. Bateman and Phillip O. Stillman, *available at* https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=22031ccc-78d3-40eb-88fe-46d7c841646e.

DTE Energy agreed to report reliability data at the census block level. Since then, Vote Solar submitted testimony in this case using a regression analysis with census block level reliability data.[28] The results are telling. The model revealed that demographic information is highly correlated with grid reliability. Witness Tan testified that "[m]y regression of the SAIDI data demonstrates that census tracts with more people in poverty experience longer outage durations. This suggests that those least able to adapt to an outage are those most likely to experience the longest outages."[29] This demonstrates the usefulness of geographic reliability reporting requirements.

Furthermore, in our testimony in Docket No. E-2, Sub 1300, we cited the example of Portland General Electric (PGE) as evidence of how a utility can further environmental justice through a robust hosting capacity analysis that incorporates sociodemographic layers and contrasted PGE's hosting capacity analysis with the insufficient, current version of the GHC.

Since then, there have been several GHC developments. First, Duke Energy held a GHC update meeting on May 24, 2023, at the request of stakeholders. We commend Duke for providing the requested

[28] Testimony on Behalf of The Ecology Center, The Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar, Case No. U-21297 (Michigan Pub. Serv. Comm'n., June 13, 2023), *available at* https://mipsc.force.com/sfc/servlet.shepherd/version/download/0688y0000086QbKAAU.
[29] *Id.* at 17.

information on the GHC and for extending the GHC analysis beyond the initial scope of a representative sample of feeders to all North Carolina and South Carolina feeders. However, Duke Energy representatives stated that they believe layering EJ datapoints on the GHC is not within the scope of the original GHC settlement agreement.[30] We disagree. Although we are not lawyers, there does not appear to be any language in the agreement that precludes Duke Energy from adding these data points to the GHC. Moreover, in response to discovery questions[31] and in an EJ Stakeholder meeting held by Duke on May 31, 2023, Duke Energy stated that it is in the process of evaluating and using several EJ screening tools. As noted previously, Duke Energy has applied for IIJA funding which, if awarded, would entail tracking grid impacts for disadvantaged communities. Combining the GHC and EJ datapoints is feasible.

Lastly, DEP suggests in pre-filed rebuttal testimony in Docket No. E-2, Sub 1300[32] that our recommendation that Duke Energy collaborate with stakeholders to overlay sociodemographic data on the GHC is an

[30] Duke Energy Progress, LLC's Agreement and Stipulation of Settlement with Stipulating Parties, Docket No. E-2, Sub 1219 (Jul. 23, 2020), *available at* https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=2d59661b-3d53-43d0-965f-82eb2db1c0d0.

[31] DEC's confidential response to NCJC et al. DR 7-3 and response to NCJC et al. DR 8-2. To avoid any doubt, the information included, cited, or referenced in this testimony is not confidential.

[32] Rebuttal Testimony of Brent C. Guyton for Duke Energy Progress, LLC, Docket E-2 Sub 1300 (April 14, 2023), *available at* https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=d1c3bd89-2683-4af3-a321-13c73ed3a8b1.

attempt to unilaterally impose changes on a stakeholder process. We would note that a recommendation to work with stakeholders is by definition, not an attempt to unilaterally change a stakeholder process. Furthermore, as our testimony has demonstrated, Duke's ISOP engagement process has not produced enough constructive dialogue on this topic or on others. Proposing that Duke Energy collaborate with stakeholders is entirely appropriate.

We recommend that:

- The Commission should require the Company to report reliability data at the census tract and nine-digit zip code level – comprised of aggregated and anonymized customer premise level data – to investigate potential disparities in reliability services. We recommend the tracking and reporting of both census tract and nine-digit zip code data so that this data can be combined with national data sets that primarily use census tracts and with existing Duke customer billing data that use zip codes. This should be established as a PBR tracking metric.
- The Commission should require the Company to propose a PIM in its next PBR application focused on improving reliability in the census tracts or zip codes experiencing lower reliability metrics.

- DEC should use its existing GHC stakeholder process to evaluate the fourteen decision points for an effective hosting capacity analysis as described by IREC.
- DEC should collaborate with stakeholders to overlay sociodemographic, energy burden, and other environmental justice indicators on its planned GHC map.
- DEC should include load hosting capacity in addition to generation hosting capacity in its GHC.

Q: PLEASE SUMMARIZE YOUR POSITION ON FORMAL DISTRIBUTION PLANNING AND PROVIDE ANY UPDATES.

A: The Company's disparate filings and stakeholder sessions across ISOP, rate cases, and other processes do not constitute a distribution system plan.

In our pre-filed testimony in Docket No. E-2, Sub 1300, we reviewed formal utility distribution system plans from PGE and Xcel Energy Minnesota. The key takeaways from this review include the following:

- Both the Oregon Public Utility Commission and Minnesota Public Utility Commission initiated formal distribution system planning dockets, with OPUC explicitly initiating its DSP docket through its existing authority to investigate utility operations and require reporting. Both commissions took action to advance energy equity, both inside and outside the DSP.

- PGE's Phase Two Distribution System Plan demonstrates that a utility can address environmental justice through a distribution system plan.
- Establishing a grid modernization vision and process that is co-developed by the Commission, utilities, and stakeholders yields robust, actionable, and flexible outcomes.
- PGE and Xcel shared significant information about their NWA analyses. Stakeholder feedback actively shaped their NWA approaches, and the utilities have proposed concrete projects as a result.

V. <u>Conclusion and Recommendations</u>

Q: PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR TESTIMONY.

A: We conclude the following:

- The Company plans to increase revenue requirements by over $5.6 billion by 2026 to cover distribution system investments, including grid modernization programs.
- The Company's cost-benefit analysis overstates the benefits of the proposed MYRP programs by analyzing the benefits of each program in isolation and over-valuing marginal reliability benefits.

- The Company's proposed MYRP distribution projects represent a continuation of the Company's GIP and P/F proposals, which have faced consistent criticism over the last 8 years.
- The Company's proposed MYRP distribution projects related to grid modernization represent a larger per year spending rate than the Company's 2017 P/F proposal and 2019 GIP proposal.
- The Company's stakeholder engagement process on grid modernization since the P/F proposal has been insufficient. The Company's stakeholder engagement has largely consisted of the Company presenting what are effectively pre-determined outcomes, which stakeholder input has little to no opportunity to meaningfully change.
- The Company has not fundamentally changed its approach to grid modernization since its first grid modernization plan eight years ago, despite significant technology, market, social, and policy changes.
- Grid modernization and environmental justice are linked in that grid modernization has an impact on energy burden, reliability, and grid access.
- Analyses in Illinois and Michigan reveal preliminary data that reliability metrics can vary between EJ and non-EJ communities. The Company does not currently produce and/or share sufficient

data to analyze whether such a disparity in service exists in North Carolina.

- Analyses in California and Michigan reveal preliminary data that access to hosting capacity can vary between EJ and non-EJ communities. As it is currently portrayed, the GHC analysis is unlikely to provide sufficient data to analyze whether such a disparity in service exists in North Carolina.
- Grid modernization planning and investments in many jurisdictions from around the country are incorporating environmental justice, equity impacts, and consideration of multiple DER solutions as alternatives to traditional grid investments. Active and collaborative stakeholder engagement is critical to such efforts. Specifically, we have demonstrated that robust stakeholder processes in distribution system planning dockets in Oregon and Minnesota result in collaborative methodologies, clear data sharing, and concrete changes to utility distribution investment.
- The Company's planning and proposed MYRP investments for grid modernization do not adequately account for federal funds available to North Carolina through the IRA and IIJA.

Q: WHAT RECOMMENDATIONS DO YOU HAVE FOR THE COMMISSION?

A: We recommend the following:

- The Commission should initiate a working group to redesign the Company's benefit-cost analysis for grid modernization and DERs.
- The Commission should require the Company to conduct at least two NWA pilot projects that leverage multiple DERs, including customer-sited resources, to defer distribution-level projects. One of these pilot projects should focus on an environmental justice community.
- The Commission should initiate an investigation into distribution system planning to establish stakeholder supported 1) grid modernization objectives, 2) reporting and data sharing requirements for regulated electric utilities, 3) NWA methodology and proposal requirements, 4) community engagement plan, and 5) an exploration of the EJ aspects of grid modernization.
- The Commission should require the Company to report reliability data at the census tract and nine-digit zip code level – comprised of aggregated and anonymized customer premise level data – in order to investigate potential disparities in reliability services.
- Regarding the Company's GHC analysis, the Commission should require the Company to 1) use its existing GHC stakeholder process to evaluate the fourteen decision points for an effective hosting capacity analysis as described by IREC, 2) collaborate with stakeholders to add sociodemographic, energy burden, and other

environmental justice indicators on top of its planned GHC map and 3) include load hosting capacity in addition to generation hosting capacity in its GHC.

- The Commission should require the Company to update the proposed grid modernization plan investments to better account for federal funds through the IRA and IIJA. As part of such an update, the Company should be required to work with stakeholders to identify at least two target initiatives that address environmental justice through multiple DERs as non-wire solutions.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of Direct Testimony and Exhibits of David Hill and Jake Duncan on behalf of North Carolina Justice Center, North Carolina Housing Coalition, Southern Alliance for Clean Energy, National Resources Defense Council, and Vote Solar, either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 19th day of July, 2023.

s/ David L. Neal
David L. Neal

David Hill
Managing Consultant

ENERGY FUTURES GROUP

DOCKET E-7, Sub 1276
EXHIBIT DH-JD-1

Professional Summary

David Hill joined EFG as a Managing Consultant at the start of 2020, after 22 years of employment with VEIC, most recently as Director of Distributed Resources and a VEIC Policy Fellow. He is known nationally for his advancement of sustainable energy program design and evaluation, and renewable energy policy. David has been the principal investigator and led analysis teams for multi-year stakeholder informed studies on solar market and decarbonization pathways and scenarios. David provides expert testimony and regulatory support; participates in international, national, and state boards; leads policy committees and conferences; provides comprehensive studies of the economic, technical, and achievable potentials for sustainable energy programming; and supports program budget planning and implementation. He has led or significantly contributed to the design and development of efficiency and renewable energy programs with annual budgets of $100+ million for initiatives in New Jersey, Washington DC, New York, Vermont, Arizona, and Maryland. Recent work includes expert testimony and whitepaper analyses related to gas infrastructure investments, pilot programs and planning. He has clients in more than a dozen states and six countries; several of them are international organizations.

Experience

January 2020 – present: Managing Consultant, Energy Futures Group, Hinesburg, Vermont (VT)

2014 – 2019: Director, Distributed Energy Resources, Policy Fellow, VEIC, Burlington, VT

2010 – 2014: Managing Consultant, VEIC, Burlington, VT

2008 – 2010: Deputy Director, Planning and Evaluation, VEIC, Burlington, VT

2000 – 2008: Senior Consultant, VEIC, Burlington, VT

1998 – 2000: Consultant, VEIC, Burlington, VT

1993 – 1998: Research Associate, Tellus Institute and the Boston Center of the Stockholm Environment Institute

Testimony as Expert Witness

Expert witness and reports for technical working groups and before commissions on renewable energy, energy efficiency, and gas infrastructure, in Illinois, Vermont, New York, Rhode Island, New Jersey, Maryland, Pennsylvania, South Carolina, for the Federal Energy Regulatory Commission, Nova Scotia and Ontario.

Energy Futures Group, Inc
PO Box 587, Hinesburg, VT 05461 – USA | 802-482-4874 | dhill@energyfuturesgroup.com

2022 In the Matter of: Application of Duke Energy Progress, LLC for Authority to Adjust and Increase its Electric Rate Schedules and Charges Docket No. 2022-254-E, on behalf of South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and Vote Solar, South Carolina Public Service Commission, December 1, 2022.

2022 In the Matter of the Merger of South Jersey Industries, Inc. and Boardwalk Merger Sub, Inc. in Docket No. GM22040270, on behalf of Environmental Defense Fund, State of New Jersey Board of Public Utilities, November 10, 2022.

2022 *GTN Xpress Project: A Critical Review of Need, Cost and Impacts*, prepared for the Washington State Office of the Attorney General, and filed with the Federal Energy Regulatory Commission in Docket No.CP22-2-00, on behalf of the States of Washington, California, and Oregon.

2022 In the Matter of Avoided Costs for EfficiencyOne's 2023-2025 Demand Side Management Plan Application, before the Nova Scotia Utility and Review Board, on behalf of EfficiencyOne. February 11, 2022.

2022 Appearance before the Rhode Island Energy Facilities Siting Review Board, Docket SB-2021-03, regarding a declaratory Order filed by Sea 3 Providence. LLC. Hearing appearance in support of Direct Testimony of Gabrielle Stebbins of Energy Futures Group, on behalf of the Conservation Law Foundation.

2021 Nicor Smart Neighborhood and Total Green Pilots. Expert witness testimony on behalf of Citizens Utility Board, Environmental Defense Fund and Natural Resources Defense Council, Docket 21-0098 before the Illinois Commerce Commission.

2021 Nicor Renewable Natural Gas Pilot. Expert witness testimony on behalf of Citizens Utility Board and Natural Resources Defense Council, Docket 20-0722 before the Illinois Commerce Commission.

2020 *NH Saves 2021-2023 Triennial Plan.* Expert witness testimony reviewing joint gas and electric triennial efficiency plan before the New Hampshire Public Service Commission submitted on behalf of Clean Energy New Hampshire, DE 20-092.

2020 *Dominion Energy South Carolina, 2020 Integrated Resource Plan*. Expert witness testimony before the South Carolina Public Service Commission submitted on behalf of Southern Alliance for Clean Energy and the South Carolina Coastal Conservation League on the characterization and analysis of energy efficiency and demand response in Dominion's 2020 IRP. Docket No. 2019-226-E.

2019 *Efficiency One 2020-2022 DSM Plan: Portfolio Diversification and Lighting Transition*. Expert Witness Testimony submitted on behalf of Efficiency Nova Scotia, to the Nova Scotia Utility and Review Board, Matter 09096.

2018 *In the Matter of an Application by Nova Scotia Power for Approval of its Advanced Meter Infrastructure Project*. Expert Witness Testimony submitted on behalf of Ecology Action Center, to the Nova Scotia Utility and Review Board, Matter 08349.

2018 *Becoming an Advanced Solar Economy.* Testimony before the Vermont House Committee on Energy and Technology, Montpelier.

2017 Maryland Public Service Commission. On behalf of Office of People's Counsel on EmPOWER Maryland Utilities 2018-2020 plans. Presentation and testimony, October 25-26, 2017.

2016 Maryland Office of People's Counsel, EmPOWER Maryland. *Written Comments on 2015 Semi Annual (Q3 and Q4) Review.* Presentation and testimony, May 4, 2016.

2015 Maryland Office of People's Counsel, EmPOWER Maryland. *Written Comments on 2015 Semi Annual Review.* Presentation and testimony, October 14-15, 2015.

2014 Maryland Office of People's Counsel, EmPOWER Maryland. *Written Comments on 2015-2017 Utility Proposed Plans.* Presentation and testimony, October 21-22, 2014.

2014 Maryland Office of People's Counsel, EmPOWER Maryland. Evaluation of Semi-Annual Reports - Case Nos. 9153-9157. Presentation and testimony, April 7, 2014.

2013 Pennsylvania Public Utility Commission. On behalf of the Office of Consumer Advocate, regarding Petitions of the Pennsylvania Power Company for Approval of its Act 129 Phase II Energy Efficiency and Conservation Plan (Docket Nos. M-2012-2334395 and M-2012-2334392); Petition of Metropolitan Edison Company (Docket No, M-2012-2334387); and Petition of West Penn Power Company (Docket No. M-2012-2334398). Written testimony. January 8, 2013.

2013 Maryland Office of People's Counsel, EmPOWER Maryland. *Written comments on 2012 Q3-Q4 Semi-Annual Report.* Presentation and testimony, October 2-3, 2013.

2011 Maryland Office of People's Counsel. *Utility-Specific Comments on the 2012-2014 EmPOWER Maryland Program Plans*. Case Nos. 9153-9157. Written testimony. October 19, 2011.

2011 Maryland Office of People's Counsel. *Written Comments on 2010 Annual Reports, and Q4 2010 reports*. Case Nos. 9153-9157. Presentation and testimony. March 31, 2011.

2011 Maryland Public Service Commission. On behalf of the Maryland Office of People's Counsel. *Comments on the 2012-2014 EmPOWER Maryland Utility Program Plans.* October 2011.

2009 Pennsylvania Public Utility Commission. On behalf of the Office of Consumer Advocate, regarding Petition of Duquesne Light Company for Approval of Its Energy Efficiency and Conservation and Demand Response Plan, Docket No. M-2009-2093217. August 7, 2009.

2005 Ontario Energy Board. On behalf of Green Energy Coalition, regarding Hydro One Networks and Brampton Conservation and Demand Management Plans. February 4, 2005 (written comments) and February 17-18, 2005 (testimony).

2005 Pennsylvania Public Utility Commission. On behalf of Penn Future, regarding net metering standards. Written comments and testimony. June 2005.

2005 Pennsylvania Public Utility Commission. On behalf of Penn Future. Written testimony and comments on interconnection standards. April 2005.

2005 Testimony to the Vermont State Legislature House Committee on Energy and Natural Resources on Vermont's Solar and Small Wind Incentive Program. February 9, 2005.

David Hill
Managing Consultant

Selected Projects (from more than 100)

Vermont Agency of Natural Resources. Co-leader of Vermont Pathways Analysis team providing technical support and quantitative modeling to the Vermont Climate Council, leading to adoption of Vermont Climate Action Plan.

Conservation Law Foundation. Lead author, for "*Rhode Island's Investments in Gas Infrastructure A Review of Critical Issues*", discussing renewable gas potential, gas planning in relation to greenhouse gas reduction goals and, depreciation periods for gas new infrastructure.

Institute for Energy Economics and Financial Analysis. Lead author, for "*Critical Elements in Short Supply: Assessing the Shortcomings of National Grid's Long-Term Capacity Report*", study calling into question proposed natural gas pipeline investment for New York City region.

Massachusetts Executive Office of Energy and Environmental Affairs. Senior advisor for team creating Low Emissions Analysis Platform (LEAP) integrated scenario modeling to inform Massachusetts efforts to reach greenhouse gas reduction targets.

Pennsylvania Department of Environmental Protection. Led team creating scenario modeling using the Low Emissions Analysis Platform (LEAP) model in support of two- and half-year study "*Pennsylvania's Solar Future*". Presentations for modeling review and collaborative stakeholder feedback at more than half a dozen stakeholder meetings and webinars.

U.S. Department of Energy. Principal Investigator for a three-year SunShot Initiative Solar Market Pathways study, investigating the technical, regulatory, and business model implications of getting 20 percent of Vermont's total electric supply from solar by 2025.

Sun Shares. Created and launched, and responsible for management and business development of, a community solar business subsidiary to provide "Easy and Affordable Solar for Employers and their Employees," 2015 – present.

New Jersey Clean Energy Program. Program design and policy advisor for the renewable energy program for more than a decade.

Rhode Island Office of Energy Resources. Strategic Advisor on State Energy Plan and System Reliability Procurement and Distributed Generation programs.

Alaska Energy Authority. Principal consultant for two studies on renewable and energy efficiency financing and funding strategies.

New York State Energy Research and Development Authority (NYSERDA). Twice led the renewable energy analysis for 20-year forecast of energy efficiency and renewable energy potential, 2003 and 2012.

World Bank. Expert consultant on a short-term study of efficiency and micro- / mini-grid opportunities in Tanzania, 2014.

Arizona Public Service. Managed a rapid assessment and redesign of PV and solar hot water incentives, 2009.

Selected Presentations

2017 Sun Shares, Easy and Affordable Solar for Employers and their Employees, American Solar Energy Society, Solar 2017, Denver.

2017 Vermont Solar Market Pathways, American Solar Energy Society, Solar 2017, Denver.

Energy Futures Group, Inc

PO Box 587, Hinesburg, VT 05461 – USA | 802-482-4874 | dhill@energyfuturesgroup.com

2016 *Oxymoron: Harmonizing Distributed Energy Integration Realities with Policy Frameworks*. Solar Power International.

2015 World Bank, International Conference on Energy Efficiency in Cities, Puebla New Mexico. Invited Panel speaker on Efficiency Vermont and Third-Party Administration Model. February, 2015.

2015 *Vermont Solar Market Pathways.* Presentations at Solar 2015 (State College, Pennsylvania), and Renewable Energy Vermont Conference.

2014 New York State Energy Research and Development Authority (NYSERDA), Renewable Energy Potential Study Results, Albany, NY.

2013 *Transformative Energy Planning*. Invited speaker at Innovations in Renewable Energy Symposium, Metcalf Institute for Marine and Environmental Reporting, Narragansett, Rhode Island.

2012 World Renewable Energy Forum, 2012 – Welcome Address and Introduction of Keynote Plenary Speakers. American Solar Energy Society, Denver.

2012 *Efficiency Vermont: A Successful Statewide Clean Energy Utility Model.* Presented at the 2012 Business of Clean Energy in Alaska Conference, Anchorage.

2011 Nova Scotia Feed In Tariff Forum: Invited speaker for two panels addressing Regional Coordination and Export Potential and International Feed-in Tariffs.

2011 *Integrating Renewable Energy and Efficiency Services.* Presentation to the Clean Energy States Alliance Fall 2011 Meeting, Washington, DC.

2010 *The Potential for Energy Efficiency and Renewables as Resources in Wholesale Capacity Markets,* Presentation at EUEC 2010 Conference, Phoenix, AZ.

2008 "Technology and Policy; Getting it Right." Solar Power International, Invited panel speaker. San Diego, California.

2008 *Solar Market Transition in New Jersey: Promise and Progress towards Sustained Growth*. Solar 2008, American Solar Energy Society.

2008 *Review of Efficiency Vermont Administrative Structure and Experience*. Penn Future 2008 Clean Energy Conference, May 2008.

2006 *Scoping Analysis of Potential Photovoltaic Contributions Towards Offsetting Transmission System Upgrades in Southern Vermont.* Solar 2006, American Solar Energy Society.

2006 *Growing New Construction Markets for Photovoltaics: Recent Strategies and Activities from LIPA's Solar Pioneer Program.* Solar 2006, American Solar Energy Society, 2006.

2005 *Market Response to Photovoltaic Incentive Offerings: An Analysis of Trends and Indicators*. Presented at the International Solar Energy Society Solar World Congress, 2005.

2003 *Solar Energy Value and Opportunities in Vermont*, Invited Session Panel Moderator and Speaker, 2nd Annual Power for a New Economy Conference, Burlington, Vermont, October 8, 2003. Renewable Energy Vermont.

2003 *Renewable Energy Case Studies: Redefining the Models, Refining the Messages, and Getting the Word Out*, Invited Session Panel Moderator, Solar 2003 National Solar Energy Conference, Austin, Texas June 22, 2003. American Solar Energy Society.

2002 *Transforming Markets for Customer Sited Clean Renewable Energy: Connecting Field Experience with Lessons from the Efficiency World*, Invited Session Panel Moderator, Solar 2002 National Solar Energy Conference, Reno, Nevada June 18, 2002. American Solar Energy Society.

1997 *IDENTIFY: Improving Industrial Energy Efficiency and Mitigating Global Climate Change.* Software and paper prepared for the United Nations Industrial Development Organization, presented at the 1997 ACEEE Summer Study on Energy Efficiency in Industry.

1997 *E2/FINANCE: A Software System for Evaluating Industrial Eco-Efficiency Opportunities*, sponsored by the U.S. Department of Energy. ACEEE 1997 Summer Study on Energy Efficiency in Industry.

1995 *Process Evaluation of Three Gas Utility Commercial Industrial Demand Side Programs.* Prepared for the Colonial Gas Company, and presented at ACEEE 1995 Summer Study on Energy Efficiency in Industry.

Selected Publications

2017 Smart Electric Power Alliance, 51st State Initiative, *Role of Utilities in the Transforming Energy Economy of the 51st State*, September 2017.

2016 *Vermont Solar Market Pathways: From a Developed to an Advanced Solar Economy*. A Phase II Roadmap document prepared for the *Smart Electric Power Alliance 51st State Initiative*.

2016 *Vermont Solar Market Pathways,* Vols. 1-4. U.S. Department of Energy, Sun Shot Initiative, Office of Energy Efficiency and Renewable Energy. Award DE-EE-0006911. www.Vermontsolarpathways.org.

2016 *Energy Efficiency Program Evaluation and Financing Needs Assessment*. Report prepared for the Alaska Energy Authority, May 2016.

2015 *Michigan Renewable Resource Assesment*. Final Report, prepared for the Michigan Public Service Commission Staff under agreement with the Clean Energy States Alliance. April 2015.

2012 *Renewable Energy Grant Recommendation Program: Process and Impact Evaluations.* Principal in Charge for comprehensive two-volume study. Alaska Energy Authority.

2011 "Solar in Nepal: Small Systems, Big Benefits." *Solar Today.* July / August 2011.

2011 "National Clean Energy Standard: Congress Needs to Design It Properly." Perspective with Shaun McGrath and Jeff Lyng. *Solar Today.* July / August 2011.

2010 "National RPS Now!" *Solar Today*. July / August 2010.

2009 "Carbon Regulation: What's the Most Effective Path?" *Solar Today*. June 2009.

2009 "Policy Recommendations for the 111th Congress: Tackling Climate Change and Creating a Green Economy." Prepared by the American Solar Energy Society Policy Committee.

2008 "Pennsylvania Solar Assessment." Final Report, November 25, 2008. Incorporated into American Council for an Energy-Efficient Economy, *Potential for Energy Efficiency, Demand Response, and Onsite Solar Energy in Pennsylvania.* ACEEE Report No. E093. Washington, DC: ACEEE, April 2009.

2008 "Solar Market Transition in New Jersey: Promise and Progress towards Sustained Growth." *Proceedings of Solar 2008*, American Solar Energy Society.

2004 "Cost Effective Contributions to New York's Greenhouse Gas Reduction Targets from Energy Efficiency and Renewable Energy Resources." *Proceedings of 2004 ACEEE Summer Study on Energy Efficiency in Buildings.*

2002 "The Ten Percent Challenge: A Participatory Community Scale Climate Campaign." *Proceedings of 2002 ACEEE Summer Study on Energy Efficiency in Buildings.* Volume 9, (with Tom Buckley, Jennifer Green, and Debra Sachs).

2000 "Implementing and Monitoring Community-Based Climate Action Plans." *Proceedings of 2000 ACEEE Summer Study on Energy Efficiency in Buildings.* Volume 9, pp. 149-160 (with Tom Buckley, Mark Eldridge, Debra Sachs, and Abby Young).

1998 *Eco-Efficiency Financing Resource Directory*. Electronic web-site, and printed directory prepared for the Environmental Protection Agency, Region I, New England.

Regulatory and Other Governmental / NGO Documents

2000 – 2012 *New Jersey's Clean Energy Programs – Honeywell Team Program Plans.* Led team on designing and implementing of Renewable Energy Program plans and initiatives. Many program plans and strategies for transition to market-based incentives.

1998 – 2008 *Long Island Power Authority's Clean Energy Initiative.* Lead Technical and Senior Advisor on Renewable Energy Plans, including the Solar Pioneer Initiative and Residential Energy Efficiency Programs.

2000 *The Climate Action Plan: A Plan to Save Energy and Reduce Greenhouse Gas Emissions*, Lead author for the Burlington (Vermont) Climate Protection Task Force.

1998 *Home Weatherization Assistance Program Environmental Impact Analysis*. Prepared for the Ohio Department of Development, Office of Energy Efficiency.

1997 *Achieving Public Policy Objectives Under Retail Competition: The Role of Customer Aggregation*. Prepared for the Colorado Governor's Office of Energy Conservation.

1997 *IDENTIFY: Improving Industrial Energy Efficiency and Mitigating Global Climate Change*, software and paper. For the United Nations Industrial Development Organization.

1997 *Review of the Swaziland Energy Information System and Report on LEAP Training Activities*. Prepared for the Ministry of Natural Resources and Energy, Government Kingdom of Swaziland.

1996 *Evaluation of the IDB's Policies and Practices in Support of Renewable Energy and Energy Efficiency: A Report to the Inter-American Development Bank*. Brower and Company and Tellus Institute.

1996 *Action Plan for the Massachusetts' Industrial Services Program (ISP)*, prepared for the Sustainable Industries Initiative of the Corporation for Business Work and Learning.

1995 *Framework for National Energy Planning: Mission Report*, The Republic of Maldives. United Nations Department for Development Support and Management Services.

1994	*The SEI / UNEP Fuel Chain Project: Methods, Issues, and Case Studies in Developing Countries. Venezuela Case Study*.
1994	*Future Energy Requirements for Africa's Agriculture (Sudan Case Study)*. Report to the African Development Bank by the UN Food and Agriculture Organization.
1994	Report to the Idaho Public Utility Commission on Suggested Cost Allowances for the Idaho Power Company's DSM Programs. Prepared for the Idaho Public Utilities Commission, Tellus Report No. 94-177.
1994	Review of Pennsylvania Electric Company's 1995 Demand Side Management Filing. Prepared for: Pennsylvania Office of Consumer Advocate. Tellus Study No. 94-071.
1994	Review of Union Electric Company's Electric Utility Resource Planning Compliance Filings. Prepared for: The Missouri Office of Public Counsel. Tellus Study No. 93-300.
1994	*Incorporating Environmental Externalities in Energy Decisions: A Guide for Energy Planners*. A Report to the Swedish International Development Agency. SEI-B Report No. 91-157.

Leadership

2017 – 2019	Energy Coop of Vermont, Board Member and Treasurer.
2013	Solar 2013, "Power Forward, Baltimore Maryland." Chair of Conference Advisory Committee responsible for recruiting and coordinating four main conference plenary sessions.
2012 – 2013	American Solar Energy Society (ASES), Chair of the Board.
2012	Policy Track Chair for the World Renewable Energy Forum, Denver, Colorado, May.
2009 – 2012	ASES Policy Committee, Board Member and Chair.
2007	Vermont Governor's Climate Change Committee, Member of the Plenary Working Group.
2000 – 2010	Renewable Energy Vermont, Founding Board Member, Past Board Chair.

Education

Ph.D., Energy Management and Policy Planning, University of Pennsylvania, Philadelphia, Pennsylvania (PA), 1993.

- Fulbright Scholar: Research on energy decision-making in rural Nepal, 1991 – 1993.

Master's, Appropriate Technology and International Development, University of Pennsylvania, Philadelphia, PA, 1989.

B.A., Geography and Political Science, Middlebury College, Middlebury, VT, 1986.

Other Qualifications

Nepal, Himalayan Light Foundation. Installed solar lighting systems in 3 remote health clinics and 3 homes, 2010.

Advanced PV Installation certificate. Solar Energy International, 2010.

Peace Corps volunteer. Sierra Leone, 1984 – 1986.

Languages

- Nepali: ILR Level 3, speaking; ILR Level 2, reading
- Krio and Mende (Sierra Leone): ILR Level 2, speaking

Software competency

- LEAP (Low Emissions Analysis Platform), Stockholm Environment Institute. Former trainer and current Principal Investigator of team using scenario modeling on three projects.
- NREL System Advisor Model. Financial and technical modeling tool for renewable energy systems.

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DOCKET E-7, Sub 1276
EXHIBIT DH-JD-2

JAKE DUNCAN

Jduncan@votesolar.org | Chattanooga, TN

PROFESSIONAL EXPERIENCE

Vote Solar, Southeast Regulatory Director
Remote June 2022 - Present

- Leads regulatory and legislative efforts in North and South Carolina to advance a rapid, cost-effective, equitable transition to a carbon free power system.
- Engages in rate cases, resource plans, grid plans, and program design efforts.
- Develops testimony, comments, and coalition positions through qualitative and quantitative analysis.

Institute for Market Transformation, Senior Associate August 2018 – May 2022
Washington, DC

- Co-developed IMT's power sector strategy, which focuses on supporting broader regulatory engagement, expanding utility regulator's legislative mandate to include climate and equity, and using building performance policies to advance utility reform.
- Supported local government and community partner's engagement in regulatory proceedings with a focus on climate and equity, including intervention in utility resource planning, distribution planning and data access proceedings; co-authoring comments; co-creating and supporting two advocacy coalitions.
- Managed two peer-learning groups within the Urban Sustainability Director's Network on grid flexibility and data access.
- Directly assist local governments as they design, pass, and implement building performance policies.
- Managed a Department of Energy sponsored field study on building codes in the Southwest.
- Led the development of several proposals, including a $9 million, multi-year proposal to the Department of Energy's Connected Communities program.
- Developed a spreadsheet-based model to assess the impact of building performance standards on the national building stock.
- Supported the Green Lease Leaders program and Small Business Energy Initiative.
- Represented IMT at conferences and through speaking engagements.
- Developed written resources, including reports and blogs.

Resources for the Future, Future of Power Fellow June - August 2018
Washington, DC

- Published a report on how utility planning processes view and integrate demand side management approaches compared to supply side investments.

Natural Capitalism Solutions, Policy and Research Intern March - August 2016

- Supported the Presidential Climate Action Project, which advanced opportunities for climate action using executive authority under the Obama Administration.

Solar Energy Industries Association, Research Intern Summer 2015
Washington, DC

- Managed the National Solar Database.
- Collected and organized data about solar industry growth.
- Contributed to the Solar Market Insight Report.

RELEVANT FILINGS

- Oregon Public Utilities Commission (Docket UM 2005, 2197, and 2198). Investigation into Distribution System Planning, Comments of Verde, Coalition of Communities for Color, and Institute for Market Transformation. Dec 3, 2021.
- Minnesota Public Utilities Commission (Docket No. E-002/M-21-694). Xcel Energy's 2021 Integrated Distribution Plan, Comments of the City of Minneapolis. February 25, 2022.
- Minnesota Public Utilities Commission (Docket No. E002/RP-19-368). 2020-2034 Xcel Energy Upper Midwest Integrated Resource Plan, Comments of the City of Minneapolis. Feb 11, 2021.
- Minnesota Public Utilities Commission (Docket No. E002/RP-19-368). 2020-2034 Xcel Energy Upper Midwest Integrated Resource Plan, Comments of the Coalition of Minnesota Local Governments and the Suburban Rate Authority. March 12, 2021.

RELEVANT PUBLICATIONS

- Duncan, J and Eagles, J. 2022. Public Utility Commissions and Consumer Advocates: Protecting the Public Interest. *National Association of Utility Regulatory Commissioners.*
- Duncan, J., Eagles, J., Farnsworth, D., Shenot, J., & Shipley, J. 2021. Participating in Power: How to Read and Respond to Integrated Resource Plans. *The Institute for Market Transformation and the Regulatory Assistance Project.*
- Debelius, H., Duncan, J., Gahagan, R., Kirby, K. & White, A. 2020. New Leasing Languages - How Green Leasing Programs Can Help Overcome the Split Incentive. *American Council for an Energy Efficient Economy*.
- Crandall, K. and Duncan, J. 2019. Local Government Engagement with Public Utility Commissions. *National Association of Utility Regulatory Commissioners.*
- Bonulgi, C., Crandall, K., Duncan, J, & Etter-Wenzel, C. 2019. Utilizing City-Utility Partnership Agreements to Achieve Climate and Energy Goals. *The Institute for Market Transformation and the World Resources Institute.*
- Burtraw, D. and Duncan, J. 2018. Does Integrated Resource Planning Effectively Integrate Demand-Side Resources? *Resources for the Future.*

RELEVANT PRESENTATIONS

- National Association of Utility Regulatory Commissioners Fall Meeting. Nov 2022. Federal Funding for Energy Justice Has Arrived! Everything You Need to Know to Ensure Consumers Receive the Benefits.
- Cincinnati 2030 District. May 2021. Building Electrification and the Grid 101.
- Urban Sustainability Directors Network. September 2020. Balancing Efficiency, Renewables, Storage, and Electrification.
- Building Performance Standard Coalition Summit. March 2020. How to Achieve Demand Flexibility through a Building Performance Standard.

EDUCATION

MS in Climate Science and Policy — May 2019
Bard College, Annandale-on-Hudson, NY

BS in Economics — December 2015
Georgia College, Milledgeville, GA

Comparison of Duke’s Grid Modernization Spending

DOCKET E-7, Sub 1276
EXHIBIT DH-JD-3

	P/F	2019 GIP	GIP Report	2022 GIP	MYRP	2017 GRC (P/F)			
						DEP		DEC	
						P9+		Testimony of Simpson, p 38	
						Total (M)	Total per year (M)	Total (M)	Total per year (M)
Stated Total cost						$5,400.0	$540.0	$7,800.0	$780.0
Calculated total cost						$5,378.0	$537.8		
Time period						10 years		5 years	
AMI	x					$289	$29		
Enterprise System Upgrades / commun	x	x				$39	$4	$108	$22
System Intelligence and Communicatioı	x					$176	$18	$120	$24
Transmission Improvements	x					$761	$76	$634	$127
Distribution Hardening and Resilience	x				x	$1,565	$157	$822	$164
Targeted Undergrounding	x	x			x	$2,066	$207	$870	$174
SOG	x	x	x	x	x	$482	$48	$351	$70
Distribution Automation		x	x	x	x				
Distribution DR			x						
Capacity					x				
ISOP		x	x	x					
Long Duration Interruption		x			x				
Equipment retrofit		x			x				
Tree Hazard					x				
Distribution infrastructure integrity	0-2 in E-2 Sub 1300				x				
Integrated Volt Var Control		x	x		x				
Voltage Regulation and Management					x				
Power Electrocnis for Volt Var			x						
Physical and Cyber Security		x	x	x					
ADMS					x				
Land Mobile Radio					x				
Tower Shelter and Power Supplies					x				
Mission critical transport					x				
facilities					x				
EVSI		x			x				
Enterprise Applications		x							
DER Dispatch Tool		x	x						
Transmission system intelligence				x					
Energy Storage		x		x					
Transmission H&R		x							
T Transformer Bank Replacement		x		x					
Oil Breaker Replacement		x		x					
T System Intelligence		x	x						
Retail and Sytem Capacity									
Next gen GIS									
Grid Hosting Capacity									
Total program						$5,378	$538	$2,905	$581
Total GIP or P/F like									
Combined Duke Total									
Combined Grid Mod Total									

* Note: NCJC et al DR 6-15 states that the up to date MYRP distribution project request total is $3,056.1 million. Duke did not break out the substation and line project cost updates, therefore we are unable to accurately update this table with the final cost estimates.

Comparison of Duke's Grid Modernization Spending

	P/F	2019 GIP	GIP Report	2022 GIP	MYRP	2019 GRC (GIP)			
						DEP		DEC	
						P 154 exhibit 10		P 154 exhibit 10	
						Total (M)	Total per year (M)	Total (M)	Total per year (M)
Stated Total cost						$988	$329	$1,300.0	$433.3
Calculated total cost						$1,130	$377	$1,493.0	$497.7
Time period						3 years 2020-2022		3 years 2020-2022	
AMI	x								
Enterprise System Upgrades / commun	x	x				$108	$36	$104	$35
System Intelligence and Communicatioi	x								
Transmission Improvements	x								
Distribution Hardening and Resilience	x				x				
Targeted Undergrounding	x	x			x	$55	$18	$60	$20
SOG	x	x	x	x	x	$302	$101	$402	$134
Distribution Automation		x	x	x	x	$79	$26	$115	$38
Distribution DR			x						
Capacity					x				
ISOP		x	x	x		$2	$1	$4	$1
Long Duration Interruption		x			x	$158	$53	$6	$2
Equipment retrofit		x			x	$110	$37	$8	$3
Tree Hazard					x				
Distribution infrastructure integrity	0-2 in E-2 Sub 1300				x				
Integrated Volt Var Control		x	x		x	$11	$4	$207	$69
Voltage Regulation and Management					x				
Power Electrocnis for Volt Var			x					$1	$0
Physical and Cyber Security		x	x	x		$69	$23	$65	$22
ADMS					x				
Land Mobile Radio					x				
Tower Shelter and Power Supplies					x				
Mission critical transport					x				
facilities					x				
EVSI		x			x	$25	$8	$38	$13
Enterprise Applications		x				$11	$4	$107	$36
DER Dispatch Tool		x	x			$3	$1	$5	$2
Transmission system intelligence				x					
Energy Storage		x		x		$73	$24	$56	$19
Transmission H&R		x				$31	$10	$102	$34
T Transformer Bank Replacement		x		x		$83	$28	$34	$11
Oil Breaker Replacement		x		x		$85	$28	$116	$39
T System Intelligence		x	x			$24	$8	$63	$21
Retail and Sytem Capacity									
Next gen GIS									
Grid Hosting Capacity									
Total program						$1,130	$377	$1,493	$498
Total GIP or P/F like									
Combined Duke Total									
Combined Grid Mod Total									

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Comparison of Duke's Grid Modernization Spending

	P/F	2019 GIP	GIP Report	2022 GIP	MYRP	GIP Biannual Report Dec 2022			
						DEP		DEC	
						source			
						Total (M)	Total per year (M)	Total (M)	Total per year (M)
Stated Total cost						$363.3		$735.0	
Calculated total cost									
Time period						Jan 1, 2020 - Dec 31 2022 ACTUALS			
AMI	x								
Enterprise System Upgrades / commun	x	x							
System Intelligence and Communicatioı	x								
Transmission Improvements	x								
Distribution Hardening and Resilience	x				x				
Targeted Undergrounding	x	x			x				
SOG	x	x	x	x	x	$249		$376	
Distribution Automation		x	x	x	x	$76		$110	
Distribution DR			x			$0.014			
Capacity					x				
ISOP		x	x	x		$3		$4	
Long Duration Interruption		x			x				
Equipment retrofit		x			x				
Tree Hazard					x				
Distribution infrastructure integrity	0-2 in E-2 Sub 1300				x				
Integrated Volt Var Control		x	x		x			$154	
Voltage Regulation and Management					x				
Power Electrocnis for Volt Var			x			$0		$1	
Physical and Cyber Security		x	x	x		$6		$8	
ADMS					x				
Land Mobile Radio					x				
Tower Shelter and Power Supplies					x				
Mission critical transport					x				
facilities					x				
EVSI		x			x				
Enterprise Applications		x							
DER Dispatch Tool		x	x			$2		$3	
Transmission system intelligence				x					
Energy Storage		x		x					
Transmission H&R		x							
T Transformer Bank Replacement		x		x					
Oil Breaker Replacement		x		x					
T System Intelligence		x	x			$27		$79	
Retail and Sytem Capacity									
Next gen GIS									
Grid Hosting Capacity									
Total program						$363	$121	$735	$245
Total GIP or P/F like									
Combined Duke Total						$1,098			
Combined Grid Mod Total									

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Comparison of Duke’s Grid Modernization Spending

	P/F	2019 GIP	GIP Report	2022 GIP	MYRP	2022 GRC (historical)			
						DEP		DEC	
						DEP Source p 22		DEC Source p 22	
						Total (M)	Total per year (M)	Total (M)	Total per year (M)
Stated Total cost						$52.6	$33.2	$134.0	$84.6
Calculated total cost									
Time period						Jun 1, 2020 - Dec 31, 2021		Jun 1, 2020 - Dec 31, 2021	
AMI	x								
Enterprise System Upgrades / commun	x	x							
System Intelligence and Communicatioi	x								
Transmission Improvements	x								
Distribution Hardening and Resilience	x				x				
Targeted Undergrounding	x	x			x				
SOG	x	x	x	x	x	$31	$19.3	$44	$27.8
Distribution Automation		x	x	x	x	$18	$11.6	$26	$16.4
Distribution DR			x						
Capacity					x				
ISOP		x	x	x		$2	$1.4	$4	$2.3
Long Duration Interruption		x			x				
Equipment retrofit		x			x				
Tree Hazard					x				
Distribution infrastructure integrity	0-2 in E-2 Sub 1300				x				
Integrated Volt Var Control		x	x		x			$42	$26.8
Voltage Regulation and Management					x				
Power Electrocnis for Volt Var			x						
Physical and Cyber Security		x	x	x		$1	$0.5	$4	$2.4
ADMS					x				
Land Mobile Radio					x				
Tower Shelter and Power Supplies					x				
Mission critical transport					x				
facilities					x				
EVSI		x			x				
Enterprise Applications		x							
DER Dispatch Tool		x	x						
Transmission system intelligence				x		$1	$0.5	$14	$8.9
Energy Storage		x		x					
Transmission H&R		x							
T Transformer Bank Replacement		x		x					
Oil Breaker Replacement		x		x					
T System Intelligence		x	x						
Retail and Sytem Capacity									
Next gen GIS									
Grid Hosting Capacity									
Total program						$53	$33	$134	$85
Total GIP or P/F like									
Combined Duke Total									
Combined Grid Mod Total									

* Note: NCJC et al DR 6-15 states that the up to date MYRP distribution project request total is $3,056.1 million. Duke did not break out the substation and line project cost updates, therefore we are unable to accurately update this table with the final cost estimates.

Comparison of Duke's Grid Modernization Spending

	P/F	2019 GIP	GIP Report	2022 GIP	MYRP	2022 MYRP			
						DEP		DEC	
						P 33+		p 35-39	NCJC DR 6-15
						Total (M)	Total per year (M)	Total (M)	Total per year (M)
Stated Total cost						$2,000.0	$666.7	$3,056	$1,019
Calculated total cost						$1,818.6	$606.2	$3,119	$1,040
Time period						3 Years		3 years	
AMI	x								
Enterprise System Upgrades / commun	x	x							
System Intelligence and Communicatio	x								
Transmission Improvements	x								
Distribution Hardening and Resilience	x				x	$271	$90	$584	$195
Targeted Undergrounding	x	x			x	$103	$34	$194	$65
SOG	x	x	x	x	x	$232	$77	$271	$90
Distribution Automation		x	x	x	x	$50	$17	$28	$9
Distribution DR			x						
Capacity					x	$461	$154	$522	$174
ISOP		x	x	x			$0		
Long Duration Interruption		x			x	$3	$1	$23	$8
Equipment retrofit		x			x	$80	$27		
Tree Hazard					x	$48	$16	$39	$13
Distribution infrastructure integrity	0-2 in E-2 Sub 1300				x	$366	$122	$447	$149
Integrated Volt Var Control		x	x		x			$194	$65
Voltage Regulation and Management					x	$205	$68		
Power Electrocnis for Volt Var			x						
Physical and Cyber Security		x	x	x					
ADMS					x			$109	$36
Land Mobile Radio					x			$94	$31
Tower Shelter and Power Supplies					x			$43	$14
Mission critical transport					x			$103	$34
facilities					x			$125	$42
EVSI		x			x			$17	$6
Enterprise Applications		x							
DER Dispatch Tool		x	x						
Transmission system intelligence				x		$86	$29		
Energy Storage		x		x		$63	$21		
Transmission H&R		x				$21	$7		
T Transformer Bank Replacement		x		x		$35	$12		
Oil Breaker Replacement		x		x		$189	$63		
T System Intelligence		x	x			$9	$3		
Retail and Sytem Capacity								$288	$96
Next gen GIS								$31	$10
Grid Hosting Capacity								$7	$2
Total program						$2,222	$741	$3,119	$931
Total GIP or P/F like						$1,310	$437	$1,851	$617
Combined Duke Total							$5,278		
Combined Grid Mod Total							$3,160		

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