Nick Crowley

RESUME

January 2025

Address:

Laurits R. Christensen Associates, Inc.
800 University Bay Drive, Suite 400
Madison, WI 53705-2299
Telephone: 608.216.7170
Email: nacrowley@caenergy.com

Academic Background:

Master of Science – University of Wisconsin-Madison, 2014, Economics
Bachelor of Arts – University of Wisconsin-Madison, 2012, Economics
Chartered Financial Analyst - Charter Awarded in October 2024

Positions Held:

Vice President, Laurits R. Christensen Associates, Inc., Jan. 1, 2024-present
Senior Economist, Laurits R. Christensen Associates, Inc., Sept. 1, 2021-Dec. 2023
Economist, Laurits R. Christensen Associates, Inc., 2019-Aug. 31, 2021
Staff Economist, Laurits R. Christensen Associates, Inc., 2016-2018
Economist, Federal Energy Regulatory Commission, 2015-2016

Professional Experience:

I am an expert witness on issues in utility regulation, with an emphasis on rate design, regulatory finance, and productivity measurement. In my time as a consultant, I have testified on behalf of major public utilities in rate proceedings, measured cost of capital and assembled corresponding reports, developed alternative rate designs, and forecasted electricity load for supply planning purposes. I have also performed extensive research for benchmarking purposes using publicly available data. My work includes marginal cost estimation and the development of marginal cost models for major electric utilities. My reports have been filed before regulatory authorities across North America. Prior to joining Christensen Associates Energy Consulting, I served as an Economist at the Federal Energy Regulatory Commission, where I assisted with energy industry benchmarking, market power studies, and the review and evaluation of natural gas pipeline rate cases. I have deep facility with Stata and Excel, in addition to other software packages used in quantitative analysis.

PUBLIC TESTIMONY

"Pre-filed Direct Testimony of Nicholas A. Crowley," Florida Public Utilities Commission, Docket No. 20240099-El, August 22, 2024.

"Rebuttal Testimony of Mark E. Meitzen and Nicholas A. Crowley," Massachusetts D.P.U., D.P.U. 23-150, April 26, 2024.

"Direct Testimony of Nicholas A. Crowley," Nicholas A. Crowley, MS, New Hampshire Department of Energy, Docket DE 23-039, December 13, 2023.

"Direct Testimony of Nicholas A. Crowley," Nicholas A. Crowley, MS, Michigan Public Service Commission, Case No. U-21488, December 11, 2023.

"Direct Testimony of Mark E. Meitzen and Nicholas A. Crowley," Nicholas A. Crowley, MS, Massachusetts D.P.U., D.P.U. 23-150, August 17, 2023.

"Direct Testimony of Nicholas A. Crowley," Nicholas A. Crowley, MS, Massachusetts D.P.U., D.P.U. 23-80 AND D.P.U. 23-81, August 17, 2023.

"Rebuttal Evidence," Mark E. Meitzen, Ph.D. and Nicholas A. Crowley, MS, Alberta Utilities Commission, Proceeding 27388, April 28, 2023.

"Determination of the Third-Generation X Factor for the AUC Price Cap Plan," Mark E. Meitzen, Ph.D. and Nicholas A. Crowley, MS, Alberta Utilities Commission Proceeding 27388, January 20, 2023.

"Rebuttal Testimony of Mark E. Meitzen Ph.D. and Nicholas A. Crowley, MS," Massachusetts D.P.U. 22-22, June 10, 2022.

"Direct Testimony of Mark E. Meitzen Ph.D. and Nicholas A. Crowley, MS," Massachusetts D.P.U. 22-22, January 14, 2022.

"Rebuttal Testimony of Mark E. Meitzen Ph.D. and Nicholas A. Crowley, MS," Massachusetts D.P.U. 20-120, April 23, 2021.

"Direct Testimony of Mark E. Meitzen Ph.D. and Nicholas A. Crowley, MS," Massachusetts D.P.U. 20-120, November 13, 2020.

PUBLICATIONS

"Trends and Drivers of Distribution Utility Costs in the United States: A Descriptive Analysis from 2008 to 2022." *Electricity Journal.* 37 (2024) 107397.

"2022 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark and Aidan Glaser-Schoff)

"2021 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark and Aidan Glaser-Schoff)

"Measuring the Price Impact of Price-Cap Regulation Among Canadian Electricity Distribution Utilities." *Utilities Policy.* Vol. 72, October 2021. (with Dr. Mark Meitzen)

"2020 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark and Navya Kataria)

"2019 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark)

"2018 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark)

"2017 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report." (with Michael Ty Clark and Dan Hansen)

"2017 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark and Dan Hansen)

"2016 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-Based Pricing Programs: Ex-post and Ex-ante Report for Customers with Net Energy Metering." (with Michael Ty Clark and Dan Hansen)

"2016 Load Impact Evaluation of Pacific Gas and Electric Company's Mandatory Time-of-Use Rates for Small, Medium, and Agricultural Non-residential Customers: Ex-post and Ex-ante Report." (with Michael Ty Clark and Dan Hansen)

REPORTS AND WORKING PAPERS

"Evaluation of Reopener Remedy Options," with Dr. Daniel McLeod, Alberta Utilities Commission, Proceeding 29064, November 29, 2024.

"Making Sense of Multi-Year Rate Plans," with Dr. Daniel McLeod, Technical Brief, October 2024.

"Cost of Capital Study," for Grand Bahama Power Company, Ltd. August 15, 2024.

"BC Hydro Performance-Based Regulation Framework," for the British Columbia Hydro and Power Authority." With Dr. Daniel McLeod and Dr. Mark Meitzen. December 21, 2023.

"Long Term Avoided Costs, for assessment of Resource Options Including Conservation Programs and LED Lighting." For Florida Public Utilities Company. 2021.

"Cost of Capital Study," For Grand Bahama Power Company, Ltd. April 15, 2021.

"Cost of Capital Study," St. Croix Valley Natural Gas Company, Inc. June 20, 2019.

"Methodology and Cost Estimates for Generation and Transmission Services, 2021-2029."

For Newfoundland and Labrador Hydro. November 15, 2018.

"Cost of Capital Study," Grand Bahama Power Company, Ltd. October 17, 2018.

"Common Metrics Report: Performance Metrics for Regional Transmission Organizations, Independent System Operators, and Individual Utilities for the 2010-2014 Reporting Period." *Federal Energy Regulatory Commission Staff Report,* 2016.

CONFERENCE PRESENTATIONS

"Dynamic, Tailored, and Niche Rate Design." With Bruce Chapman. Wisconsin Public Utility Institute. *Energy Utility Basics.* October 8, 2024.

"Introduction to Alternative Regulation." Edison Electric Institute. Hosted at the University of Wisconsin-Madison. July 2024.

"Avoided Costs of Electricity Services." With Michael Clark and Michael Vigdor. EUCI Workshop. March 19, 2024.

"Essentials of Costing: Embedded and Marginal Cost." With Bruce Chapman. Wisconsin Public Utility Institute. *Energy Utility Basics.* October 10, 2023.

"Rate Design for Revenue Adequacy and Price Efficiency." With Bruce Chapman. Edison Electric Institute. Hosted at the University of Wisconsin-Madison. July 2023.

"Marginal Costs of Electricity Services." Edison Electric Institute. Hosted at the University of Wisconsin-Madison. July 2023.

"Introduction to Performance-Based Regulation." EUCI Workshop. Virtual. May 2023.

"Introduction to Retail Electricity Regulation for FERC Staff." Federal Energy Regulatory Commission, Office of Energy Market Regulation Training Council. Virtual. February 2023.

"Marginal Costs of Electricity Services." EUCI Workshop. Virtual. February 2023.

"Rate Design for Revenue Adequacy and Price Efficiency." Wisconsin Public Utility Institute. *Energy Utility Basics.* October 4, 2022.

"Rate Innovation for Cooperatives and Public Power." EUCI Workshop. Virtual. March 2022.

"Marginal Costs of Electricity Services." EUCI Workshop. Virtual. March 2022.

"Ratemaking Under Performance-Based Regulation." EUCI Workshop. Virtual. February 2022.

"Ratemaking Under Performance-Based Regulation." EUCI Workshop. Virtual. November 2021.

"Rate Design for Revenue Adequacy and Price Efficiency." Wisconsin Public Utility Institute. *Energy Utility Basics.* October 2, 2021.

"Rate Design and the Potential Impacts of Covid-19." EUCI Workshop. Virtual. November 17, 2020.

"Ratemaking Under Performance-Based Regulation." EUCI Workshop. Atlanta, Georgia. March 9, 2020.

"Load Impact Evaluation: *Base Interruptible Program*." DRMEC Spring Workshop, California Public Utilities Commission. April 26, 2019.

"FERC Regulatory Policy and Relevant Environmental Issues, Focusing on the United States Natural Gas Grid," 2015 Energy Hub Conference. Hosted at the University of Wisconsin-Madison.

COMPUTER/PROGRAMMING SKILLS: Deep knowledge of Excel and STATA for data analysis; experience with R, SAS, and Python for API data acquisition and manipulation.

Daniel McLeod

RESUME

December 2024

Address:

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Academic Background:

PhD, University of Wisconsin-Madison, 2021, Economics
MS, University of Wisconsin-Madison, 2014, Economics
BA, University of Wisconsin-Madison, 2013, Economics

Positions Held:

Economist, Laurits R. Christensen Associates, Inc., July 2021-present
Staff Economist, Laurits R. Christensen Associates, Inc., 2015

Professional Experience:

I have worked in the areas of antitrust and competition, economic cost measurement in the airline and railroad industries, and productivity measurement in the postal and electric utility industries. Additionally, in the energy practice, I have been involved in the calibration of price and revenue caps, helped design and evaluate incentive regulation plans, performed and critiqued cost benchmarking studies, and estimated the load impacts of EV smart charging algorithms and critical peak pricing demand response programs.

My academic background is in empirical industrial organization and applied econometrics. In addition to teaching introductory microeconomics to undergraduate students, I have taught introductory econometrics for five semesters and a course in machine learning to graduate students. My research proposed a novel econometric approach to estimating marginal costs in the airline industry and quantified the impacts of airline mergers using both structural models of the industry and emerging deep learning algorithms.

Articles

"Trends and Drivers of Distribution Utility Costs in the United States: A Descriptive Analysis from 2008 to 2022, *Electricity Journal*, 37 (2024) 107397.

Reports and Working Papers:

"Evaluation of Reopener Remedy Options," with Mr. Nicholas Crowley, Alberta Utilities Commission, Proceeding 29064, November 29, 2024.

"Making Sense of Multi-Year Rate Plans," with Mr. Nicholas Crowley, Technical Brief, October 2024.

"Approaches for Establishing Indexed Cap Stretch Factors" (with Nick Crowley and Kevin Roth)

"Structural Estimation in the Airline Industry with Markup Restrictions"

"Cost Sharing During Periods with Low Airline Passenger Demand" (job market paper)

"Predicting the Price Effect of Horizontal Mergers" (with Lorenzo Magnolfi)

Programming Skills:

R, Stata, Python, Excel

Public Service Company of New Hampshire d/b/a Eversource Energy
Docket No. DE 24-070

Date Request Received: September 06, 2024 | **Date of Response: September 26, 2024**
Data Request No. DOE 6-126 | **Page 1 of 1**

Request from: Department of Energy

Witness: Horton, Douglas P.

Request:

Reference Principle (sic) Report, Mr. Mark Kolesar, Attachment ES-MK-1. The text states:

> It is noteworthy that the proposed trigger would not apply in the first four years of the plan [...] (p. 22) (Bates 01795).

Please confirm that the proposed Minimum Return on Equity Trigger does not apply to the PBR framework between the years 2025 and 2029. In other words, there is no off ramp proposed for the initial four-year PBR term.

Response:

Confirmed. The proposed Minimum Return on Equity Trigger does not apply to the PBR framework between the years 2025 and 2029. There is no "off ramp" proposed for the initial four-year PBR term.

Regulatory Reconciliation Adjustment Mechanism (RRA)			
Component	**Current Mechanism**	**Proposed DE 24-070 Test Year Baseline Includes:**	**Company Proposal**
Regulatory Assessments and Consultant Costs	Regulatory Commission annual assessments and consultants hired or retained by the Commission and OCA.	1) Regulatory assessments for the most recent FY 2) Consultant costs incurred during the test year	Eliminate annual reconciliation of over/under through RRA; Annual amount to be recovered through base rates, subject to reconciliation at the Company's next rate case.
Property Tax	Property tax expenses, as compared to the amount in base rates (DE 19-057)	2024 Tax Year property expense	Eliminate annual reconciliation of amount over/under base rates
Vegetation Management	Vegetation management program variances as compared to the amount in base rates (DE 19-057)	2023 actual plus post-TY adjustment for $2m budget increase	Eliminate annual reconciliation of amount over/under base rates
Storm Cost LTD True-Up	Storm cost amortization final reconciliation and annual reconciliation updated for actual cost of long-term debt	Proposed LTD cost in proceeding	Eliminate annual reconciliation of amount over/under base rates
Lost Base Revenues - Net Metering	Lost-base distribution revenues associated with net metering, as calculated consistent with RSA 362-A:9, VII and the Commission’s approved method in Order No. 26,029 (June 23, 2017) in Docket No. DE 16-576.	Not Included	Eliminate annual recovery for expenses incurred after August 1, 2024
Rate Case Expense	Order No. 26,634 (May, 27, 2022) at 1. The Commission approved a settlement agreement relating to Eversource's motion to recover rate case expenses for DE 19-057. Pursuant to that agreement, Eversource is authorzied to collect $1,762,807 through its Regulatory Reconciliation Adjustment mechanism over five years, beginning August 1, 2022.	1) Recover remaining balance of approved rate case expense from DE 19-057 over 5 years 2) DE 24-070 rate case expense over 5 years	Eliminate annual reconciliation of over/under through RRA, subject to reconciliation at the Company's next rate case.

Pole Plant Adjustment Mechanism			
Component	**Current Mechanism**	**Proposed DE 24-070 Test Year Baseline Includes:**	**Company Proposal**
Pole Replacement O&M Transfer costs	The actual costs associated with replacement poles for the prior calendar year based on the actual number of poles replaced and the actual Eversource cost to transfer the conductor from the old to the new poles.	Actual expenses for 2023 Test Year	Eliminate annual recovery for expenses incurred after August 1, 2024
Annual Inspection Costs	The actual inspection costs and other upfront costs for the prior calendar year consisting of the number of poles inspected in the former Consolidated maintenance area and the per pole rate in effect. Upfront costs of $250,000 in years 1 and 2 and $75,000 in year 3 will also be included.	Actual expenses for 2023 Test Year	Eliminate annual recovery for expenses incurred after August 1, 2024
Pole Attachment Revenue	Incremental third-party pole attachment revenues is applied as an offset to the items in (a) and (b). Pole attachment revenues for formerly Consolidated owned poles will be tracked separately and billed at the Consolidated rate at the time of closinguntil a full pole attachment survey is conducted and, or a single, unified rate is applied to all poles.	Not Included - amount not known and measurable at this time	Eliminate annual recovery for expenses incurred after August 1, 2024
Vegetation Management Expense	The incremental vegetation management expense is calculated as the vegetation management expenses formerly billed to Consolidated.	Normalized actual expenses for 2023 Test Year by reflecting a monthly average of CCI vegetation management billings from November 2017 through December 2023 annualized to reflect a twelve-month period. This resulted in a <u>decrease</u> to the actual test year vegetation management expense of $902,206.	Eliminate annual recovery for expenses incurred after August 1, 2024

Other			
Component	**Current Mechanism**	**Proposed DE 24-070 Test Year Baseline Includes:**	**Company Proposal**
Lost Base Revenues - Energy Efficiency	Systems Benefits Charge	Not Included	Eliminate annual recovery for expenses incurred after August 1, 2024

Public Service Company of New Hampshire d/b/a Eversource Energy
Docket No. DE 24-070

Date Request Received: September 19, 2024 **Date of Response: October 03, 2024**
Data Request No. DOE 8-183 **Page 1 of 1**

Request from: Department of Energy

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Public Service Company of New Hampshire provides the information contained in this response to the Department of Energy and Office of Consumer Advocate confidentially pursuant to Puc 203.08 and RSA 363:28, as the response includes proprietary formulas and information, the public disclosure of which could put the witness at a competitive disadvantage and which the Commission routinely treats as confidential. Please do not include this in any public filing to Docket No. DE 24-070 or otherwise disclose to the public

Public Service Company of New Hampshire d/b/a Eversource Energy
Docket No. DE 24-070

Date Request Received: September 19, 2024 **Date of Response: October 03, 2024**
Data Request No. DOE 8-182 **Page 1 of 1**

Request from: Department of Energy

Witness: Ros, Augustin

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Public Service Company of New Hampshire provides the information contained in this response to the Department of Energy and Office of Consumer Advocate confidentially pursuant to Puc 203.08 and RSA 363:28, as the response includes proprietary formulas and information, the public disclosure of which could put the witness at a competitive disadvantage and which the Commission routinely treats as confidential. Please do not include this in any public filing to Docket No. DE 24-070 or otherwise disclose to the public.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

ILLUSTRATIVE K-BAR PLANT ADDITIONS
($, Millions)

Cumulative K-Bar Capital Investment Variance to Forecast

Line #	Description	For Rates Effective: August 1, 2026	August 1, 2027	August 1, 2028	Reference
1	**K-Bar, 3-Year Average (As Proposed)**				
2	Capital Investment Per Forecast	(45)	(63)	(68)	Page 2, Line 12
3	Capital Investment Per Forecast, plus 20%	(68)	(90)	(95)	Page 3, Line 12
4	Capital Investment Per Forecast, plus 30%	(80)	(104)	(109)	Page 4, Line 12
5	Capital Investment Per Forecast, minus 20%	(22)	(37)	(40)	Page 5, Line 12
6	Capital Investment Per Forecast, minus 30%	(10)	(23)	(26)	Page 6, Line 12
7	**K-Bar, 4-Year Average**				
8	Capital Investment Per Forecast	(59)	(95)	(105)	Page 2, Line 13
9	Capital Investment Per Forecast, plus 20%	(92)	(145)	(157)	Page 3, Line 13
10	Capital Investment Per Forecast, plus 30%	(108)	(170)	(183)	Page 4, Line 13
11	Capital Investment Per Forecast, minus 20%	(27)	(45)	(53)	Page 5, Line 13
12	Capital Investment Per Forecast, minus 30%	(11)	(20)	(27)	Page 6, Line 13
13	**K-Bar, 5-Year Average**				
14	Capital Investment Per Forecast	(74)	(123)	(149)	Page 2, Line 14
15	Capital Investment Per Forecast, plus 20%	(111)	(187)	(226)	Page 3, Line 14
16	Capital Investment Per Forecast, plus 30%	(130)	(219)	(265)	Page 4, Line 14
17	Capital Investment Per Forecast, minus 20%	(36)	(59)	(71)	Page 5, Line 14
18	Capital Investment Per Forecast, minus 30%	(17)	(27)	(32)	Page 6, Line 14

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

ILLUSTRATIVE K-BAR PLANT ADDITIONS
($, Millions)

Capital Investment, Per Company Forecast

		For Rates Effective:		
Line #	Description	August 1, 2026	August 1, 2027	August 1, 2028
1	**Annual Investment**			
2	Company Forecast	296	303	305
3	K-Bar, 3-Year Average (As Proposed)	251	284	301
4	K-Bar, 4-Year Average	237	267	295
5	K-Bar, 5-Year Average	222	253	280
6	**Cumulative Investment**			
7	Company Forecast	296	599	904
8	K-Bar, 3-Year Average (As Proposed)	251	536	836
9	K-Bar, 4-Year Average	237	504	799
10	K-Bar, 5-Year Average	222	476	755
11	**Cumulative Variance to Forecast**			
12	K-Bar, 3-Year Average (As Proposed)	(45)	(63)	(68)
13	K-Bar, 4-Year Average	(59)	(95)	(105)
14	K-Bar, 5-Year Average	(74)	(123)	(149)

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

ILLUSTRATIVE K-BAR PLANT ADDITIONS
($, Millions)

Capital Investment, Per Company Forecast, Plus 20%

		For Rates Effective:		
Line #	Description	August 1, 2026	August 1, 2027	August 1, 2028
1	**Annual Investment**			
2	Company Forecast Plus 20%	355	364	366
3	K-Bar, 3-Year Average (As Proposed)	287	341	361
4	K-Bar, 4-Year Average	264	310	354
5	K-Bar, 5-Year Average	244	287	327
6	**Cumulative Investment**			
7	Company Forecast Plus 20%	355	719	1,085
8	K-Bar, 3-Year Average (As Proposed)	287	629	990
9	K-Bar, 4-Year Average	264	574	927
10	K-Bar, 5-Year Average	244	531	858
11	**Cumulative Variance to Forecast**			
12	K-Bar, 3-Year Average (As Proposed)	(68)	(90)	(95)
13	K-Bar, 4-Year Average	(92)	(145)	(157)
14	K-Bar, 5-Year Average	(111)	(187)	(226)

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

ILLUSTRATIVE K-BAR PLANT ADDITIONS
($, Millions)

Capital Investment, Per Company Forecast, Plus 30%

		For Rates Effective:		
Line #	Description	August 1, 2026	August 1, 2027	August 1, 2028
1	**Annual Investment**			
2	Company Forecast Plus 30%	385	394	397
3	K-Bar, 3-Year Average (As Proposed)	305	370	391
4	K-Bar, 4-Year Average	277	331	383
5	K-Bar, 5-Year Average	255	304	351
6	**Cumulative Investment**			
7	Company Forecast Plus 30%	385	779	1,175
8	K-Bar, 3-Year Average (As Proposed)	305	675	1,066
9	K-Bar, 4-Year Average	277	608	992
10	K-Bar, 5-Year Average	255	559	910
11	**Cumulative Variance to Forecast**			
12	K-Bar, 3-Year Average (As Proposed)	(80)	(104)	(109)
13	K-Bar, 4-Year Average	(108)	(170)	(183)
14	K-Bar, 5-Year Average	(130)	(219)	(265)

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

ILLUSTRATIVE K-BAR PLANT ADDITIONS
($, Millions)

Capital Investment, Per Company Forecast, Minus 20%

		For Rates Effective:		
Line #	Description	August 1, 2026	August 1, 2027	August 1, 2028
1	**Annual Investment**			
2	Company Forecast Minus 20%	237	242	244
3	K-Bar, 3-Year Average (As Proposed)	215	228	241
4	K-Bar, 4-Year Average	209	225	236
5	K-Bar, 5-Year Average	201	219	233
6	**Cumulative Investment**			
7	Company Forecast Minus 20%	237	479	723
8	K-Bar, 3-Year Average (As Proposed)	215	442	683
9	K-Bar, 4-Year Average	209	434	670
10	K-Bar, 5-Year Average	201	420	652
11	**Cumulative Variance to Forecast**			
12	K-Bar, 3-Year Average (As Proposed)	(22)	(37)	(40)
13	K-Bar, 4-Year Average	(27)	(45)	(53)
14	K-Bar, 5-Year Average	(36)	(59)	(71)

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

ILLUSTRATIVE K-BAR PLANT ADDITIONS
($, Millions)

Capital Investment, Per Company Forecast, Minus 30%

		For Rates Effective:		
Line #	Description	August 1, 2026	August 1, 2027	August 1, 2028
1	**Annual Investment**			
2	Company Forecast Minus 30%	207	212	214
3	K-Bar, 3-Year Average (As Proposed)	197	199	211
4	K-Bar, 4-Year Average	196	203	206
5	K-Bar, 5-Year Average	190	202	209
6	**Cumulative Investment**			
7	Company Forecast Minus 30%	207	419	633
8	K-Bar, 3-Year Average (As Proposed)	197	396	607
9	K-Bar, 4-Year Average	196	399	606
10	K-Bar, 5-Year Average	190	392	601
11	**Cumulative Variance to Forecast**			
12	K-Bar, 3-Year Average (As Proposed)	(10)	(23)	(26)
13	K-Bar, 4-Year Average	(11)	(20)	(27)
14	K-Bar, 5-Year Average	(17)	(27)	(32)

Public Service Company of New Hampshire d/b/a Eversource Energy
Docket No. DE 24-070

Date Request Received: September 06, 2024 **Date of Response: September 26, 2024**
Data Request No. DOE 6-125 **Page 1 of 1**

Request from: Department of Energy

Witness: Horton, Douglas P.

Request:

Reference Principle (sic) Report, Mr. Mark Kolesar, Attachment ES-MK-1. The text states:

> The Commission will thereby be provided with oversight of the investments and related costs as part of the annual PBR filing proceeding. (p. 19) (Bates 01792)

Will this require the Department to evaluate and determine eligibility for cost recovery of each customer-driven expenditure during each year of the PBR term?

Response:

Please see the Company's responses to DOE 6-120 and DOE 6-121.

As described therein, the intent of the K-bar mechanism and the PBR proposal is to provide revenue support for capital additions during the PBR term, under a mechanism that retains the incentive properties of a PBR ratemaking framework, and without the administrative review process associated with an annual capital cost recovery mechanism or step adjustment process. Under this framework, the prudence review would continue to be required and would be conducted at the time of the Company's next rate case for investments made during the PBR term. Adjustments, if any, would take effect prospectively.

As noted in the testimony of Company witnesses Foley, Coates, and Horton at page 60 (bates 1404), the Company proposes to notify the Commission of any known co-optimized reliability projects that the Company intends to undertake as part of its annual PBR adjustment filings, so that it has a line-of-sight into the potential for this occurrence during the course of the PBR plan. In order for the costs of any co-optimized reliability projects to flow through the K-bar mechanism, the Commission would be required to first determine and approve their eligibility for inclusion in the mechanism. This would not require a prudency review at that point in time, however. As noted in this proceeding, the Company does not anticipate large volumes of these projects to occur, and therefore be reviewed for eligibility during the proceeding. However, the dollar amounts can be significant when they do occur, warranting consideration of the costs through a regulatory process and allowance in the K-bar, absent the cap.

Public Service Company of New Hampshire d/b/a Eversource Energy
Docket No. DE 24-070

Date Request Received: September 06, 2024 **Date of Response: September 26, 2024**
Data Request No. DOE 6-121 **Page 1 of 4**

Request from: Department of Energy

Witness: Horton, Douglas P.

Request:

Reference Principle (sic) Report, Mr. Mark Kolesar, Attachment ES-MK-1. The text states, I consider that the three-year rolling average base K-Bar amount proposed by the Company is reasonable. (pp. 18-19) (Bates 01791-01792)
(And also, with reference to): Attachment ES-DPH-1 and Attachment ES-DPH-2.

For purposes of comparison, please provide estimated K-bar capital spending limits using a 4-year and 5-year rolling average base K-bar.

Response:

For clarification, the function of the average is not to establish a limit against which K-bar plant additions are measured. Rather, to develop a representative distribution rate base for a given rate year, the K-bar relies upon the average of recent actual plant additions, escalated to rate-year dollars, ***in lieu of*** actual plant additions made in the rate year, which would be known after the fact (as would be consistent with a capital tracker) or forecast plant additions, which are not certain. The limit on capital investment eligible for inclusion in K-bar can be established as part of the current proceeding, as took place during the rate case in which the Company's affiliate NSTAR Electric Company received approval for its K-bar.

To demonstrate the impact that varying the number of years averaged in the function of the K-bar, the Company has produced the estimates shown in the table below. Table DOE 6-121(a) shows what the estimated plant additions reflected in K-bar rate base would be if a four-year or five-year average were used rather than the three-year average as proposed.

Public Service Company of New Hampshire d/b/a Eversource Energy
Docket No. DE 24-070

Date Request Received: September 06, 2024 **Date of Response: September 26, 2024**
Data Request No. DOE 6-121 **Page 2 of 4**

Table DOE 6-121(a):
K-bar Estimated Plant Additions
($ Millions)

		For Rates Effective:		
Line #	Description	August 1, 2026	August 1, 2027	August 1, 2028
1	**Annual Investment**			
2	Company Forecast	296	303	305
3	K-Bar, 3-Year Average (As Proposed)	251	284	301
4	K-Bar, 4-Year Average	237	267	295
5	K-Bar, 5-Year Average	222	253	280

The adoption of an averaging methodology that relies upon four or five years of historical plant additions, rather than three, would produce a K-bar capital revenue requirement that is less responsive to increases or decreases in the investment needs of the system. That is, where system investment needs are expected to increase to meet the reliability needs of the system and replace aging infrastructure, the three-year average methodology is more likely to yield an estimated distribution investment base that is more closely representative of the Company's true distribution investment base. In contrast, the K-bar distribution investment base that is estimated using a five-year average is more likely to deviate from the Company's true distribution investment base. That is, the capital revenue requirement reflected in rates is more likely to be deficient, increasing the likelihood of larger subsequent rate increases following the PBR term, or the likelihood of the Company being unable to commit to stay out of a rate case for the full four years as reflected in the Company's proposal.

The Company tested the impact that varying levels of future capital investment have on K-bar plant addition estimates, as well as varying the period of time incorporated in the moving average for purposes of the K-bar adjustment. The results of this analysis is shown in Attachment DOE 6-121. Page 1 summarizes the variance that each K-bar averaging methodology (three-year, four-year, or five-year) has versus actual plant additions at different levels of investment, all relative to the Company's current infrastructure investment forecasts, including:

- Per the Company Forecast (Page 2)
- Per the Company Forecast plus an additional 20% investment (Page 3)
- Per the Company Forecast plus an additional 30% investment (Page 4)
- Per the Company Forecast less 20% investment (Page 5)
- Per the Company Forecast less 30% investment (Page 6)

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The Company evaluated each change to the level of capital listed above, all under different assumptions of using the 3-year moving average, 4-year moving average and 5-year moving average. As summarized in Attachment DOE 6-121, Page 1, as well as pictured below in Table DOE 6-121(b), the three-year average is consistently more representative of actual investment levels.

Please note that the dollar amounts in the table below reflect the cumulative amounts of capital additions that are *not* covered by the K-bar adjustment under the various assumptions. For example, by the third year of the PBR term, under the Company's proposal and assuming the Company's current capital forecast is sufficient over the term of the plan, the Company will have spent $68 million of capital that is not covered by the K-bar mechanism, reflecting that regulatory lag persists under the Company's proposal.

By way of additional example, under a three-year average K-bar, and assuming the Company's actual spending is 30 percent greater than forecast today, the Company will have invested $109 million (Line 4 in Table 2 below) more than what is covered by the K-bar mechanism. Note that, for purposes of this illustrative analysis, the Company has not applied the 10 percent cap to the level of additions allowed under the K-bar mechanism. Meaning that, with the application of the cap, the amount of capital *not* covered by the K-bar would be even greater than the amounts shown in the attachment and the table, below. By comparison, with the four-year average K-bar, $183 million of investment (Line 10) would not be supported by K-bar revenues, which increases further to $265 million (Line 16) with the five-year average. Conceptually, the larger the cumulative investment that K-bar is *not* supporting, the larger the Company's revenue deficiency that would be reflected in the next rate case.

As shown below, the K-bar mechanism produces a level of revenue that supports less capital than is actually placed in service under any of the scenarios and sensitivities presented below.

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Table DOE 6-121(b):

($ Millions)
Cumulative K-bar Capital Investment *Variance* to Forecast

		For Rates Effective:			
Line #	Description	August 1, 2026	August 1, 2027	August 1, 2028	Reference
1	**K-Bar, 3-Year Average (As Proposed)**				
2	Capital Investment Per Forecast	(45)	(63)	(68)	Page 2, Line 12
3	Capital Investment Per Forecast, plus 20%	(68)	(90)	(95)	Page 3, Line 12
4	Capital Investment Per Forecast, plus 30%	(80)	(104)	(109)	Page 4, Line 12
5	Capital Investment Per Forecast, minus 20%	(22)	(37)	(40)	Page 5, Line 12
6	Capital Investment Per Forecast, minus 30%	(10)	(23)	(26)	Page 6, Line 12
7	**K-Bar, 4-Year Average**				
8	Capital Investment Per Forecast	(59)	(95)	(105)	Page 2, Line 13
9	Capital Investment Per Forecast, plus 20%	(92)	(145)	(157)	Page 3, Line 13
10	Capital Investment Per Forecast, plus 30%	(108)	(170)	(183)	Page 4, Line 13
11	Capital Investment Per Forecast, minus 20%	(27)	(45)	(53)	Page 5, Line 13
12	Capital Investment Per Forecast, minus 30%	(11)	(20)	(27)	Page 6, Line 13
13	**K-Bar, 5-Year Average**				
14	Capital Investment Per Forecast	(74)	(123)	(149)	Page 2, Line 14
15	Capital Investment Per Forecast, plus 20%	(111)	(187)	(226)	Page 3, Line 14
16	Capital Investment Per Forecast, plus 30%	(130)	(219)	(265)	Page 4, Line 14
17	Capital Investment Per Forecast, minus 20%	(36)	(59)	(71)	Page 5, Line 14
18	Capital Investment Per Forecast, minus 30%	(17)	(27)	(32)	Page 6, Line 14

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Date Request Received: November 15, 2024 **Date of Response: December 05, 2024**
Data Request No. DOE 14-263 **Page 1 of 2**

Request from: Department of Energy

Witness: Horton, Douglas P.

Request:

Reference DOE Data Request No. 6-121 at 3-4; Attachment DOE 6-121: In the response Mr. Horton states: "As summarized in Attachment DOE 6-121, Page 1, as well as pictured below in Table DOE 6-121(b), the three-year average is consistently more representative of actual investment levels." Mr. Horton further states: "Please note that the dollar amounts in the table below reflect the cumulative amounts of capital additions that are not covered by the K-bar adjustment under the various assumptions. For example, by the third year of the PBR term, under the Company's proposal and assuming the Company's current capital forecast is sufficient over the term of the plan, the Company will have spent $68 million of capital that is not covered by the K-bar mechanism, reflecting that regulatory lag persists under the Company's proposal."

Does this statement mean that Eversource's K-bar mechanism, as filed, provides insufficient revenue relative to the Company's capital forecast?

Response:

The Company's response to data request DOE 6-121 explains how the Company arrived at the three-year rolling average as the appropriate timeframe in its K-bar calculation. The purpose of the average is to develop a representative distribution rate base for a given rate year, such that the K-bar relies upon the average of recent actual plant additions, escalated to rate-year dollars, ***in lieu of*** actual plant additions made in the rate year, which would be known after the fact (as would be consistent with a capital tracker) or forecast plant additions, which are not certain.

This question is asking whether the Company's PBR proposal provides insufficient revenues related to the Company's capital forecast. The Company's PBR proposal, including the K-bar adjustment, as designed, preserves the concept of regulatory lag, while allowing a sufficient level of revenues to support the capital forecast, while also maintaining a level of flexibility (i.e., with application of the three-year moving average of actual plant additions) to support changing infrastructure needs over time. Table DOE 6-121(b), copied below, depicts the revenue deficiencies when compared to the actual revenue requirement for each year under differing capital forecast scenarios and averaging methodologies.

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The adoption of an averaging methodology that relies upon four or five years of historical plant additions, rather than three, would produce a K-bar capital revenue requirement that is less responsive to increases or decreases in the investment needs of the system. That is, where system investment needs are expected to increase to meet the reliability needs of the system and replace aging infrastructure, the three-year average methodology is more likely to yield an estimated distribution investment base that is more closely representative of the Company's true distribution investment base. In contrast, the K-bar distribution investment base that is estimated using a five-year average is more likely to deviate from the Company's true distribution investment base. That is, the capital revenue requirement reflected in rates is more likely to be deficient, increasing the likelihood of larger subsequent rate increases following the PBR term, or the likelihood of the Company being unable to commit to stay out of a rate case for the full four years as reflected in the Company's proposal.

Table DOE 6-121(b):
($ Millions)
Cumulative K-bar Capital Investment *Variance* to Forecast

		For Rates Effective:			
Line #	Description	August 1, 2026	August 1, 2027	August 1, 2028	Reference
1	**K-Bar, 3-Year Average (As Proposed)**				
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3	Capital Investment Per Forecast, plus 20%	(68)	(90)	(95)	Page 3, Line 12
4	Capital Investment Per Forecast, plus 30%	(80)	(104)	(109)	Page 4, Line 12
5	Capital Investment Per Forecast, minus 20%	(22)	(37)	(40)	Page 5, Line 12
6	Capital Investment Per Forecast, minus 30%	(10)	(23)	(26)	Page 6, Line 12
7	**K-Bar, 4-Year Average**				
8	Capital Investment Per Forecast	(59)	(95)	(105)	Page 2, Line 13
9	Capital Investment Per Forecast, plus 20%	(92)	(145)	(157)	Page 3, Line 13
10	Capital Investment Per Forecast, plus 30%	(108)	(170)	(183)	Page 4, Line 13
11	Capital Investment Per Forecast, minus 20%	(27)	(45)	(53)	Page 5, Line 13
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13	**K-Bar, 5-Year Average**				
14	Capital Investment Per Forecast	(74)	(123)	(149)	Page 2, Line 14
15	Capital Investment Per Forecast, plus 20%	(111)	(187)	(226)	Page 3, Line 14
16	Capital Investment Per Forecast, plus 30%	(130)	(219)	(265)	Page 4, Line 14
17	Capital Investment Per Forecast, minus 20%	(36)	(59)	(71)	Page 5, Line 14
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Date Request Received: September 06, 2024 **Date of Response: September 24, 2024**
Data Request No. DOE 6-114 **Page 1 of 2**

Request from: Department of Energy

Witness: Horton, Douglas P.

Request:

Reference Testimony of Douglas W. Foley, Robert S. Coates, and Douglas P. Horton. The text states, Under economic theory, the implementation of an earning-sharing mechanism is viewed as counteracting the cost-efficiency incentives inherent within a performance plan by sharing the cost savings with customers rather than allowing the Company to retain the fruits of its labor […] (p. 64) (Bates 01408) And

The Company is proposing an earning-sharing mechanism that would trigger sharing on a 75 percent (customer), 25 percent (Company) basis where the computed distribution return on equity (ROE) exceeds 25 basis points above the ROE authorized in this proceeding. (p. 64) (Bates 01408)

Does the Company view its ESM as reducing its own cost efficiency incentives?

Response:

As implied by the question, earnings sharing mechanisms ("ESMs") can have the potential to reduce the incentive for utilities to pursue cost-efficiencies because there may not be a sufficient benefit to the utility to motivate additional efforts (and associated costs) to achieve longer-term efficiencies where the benefit of those efficiencies are immediately passed through the customers by virtue of the ESM. In this case, the Company sought to assure that the proposed ESM would be designed to contemplate the balance of risks and rewards within the plan design. This balance is inherent in the design of the ESM, which seeks to balance the creation of incentives for the Company to pursue cost efficiencies with the need to assure affordability, rate stability and the sharing of cost savings with customers.

The implementation of the asymmetrical ESM proposed in Testimony of Foley, Coates, and Horton would allow the Company to retain a smaller portion of actual earnings above the authorized return, while customers would receive the larger portion, and would not allow the Company to recover additional revenues from customers where the earned return falls below the authorized return. Since the Company is proposing to split the earnings sharing mechanism 75 percent for customers and 25 percent for the Company where the return on equity exceeds 25-basis points above the authorized return on equity, the Company is encouraged to pursue cost-efficiencies and retain the savings up to threshold. Although the Company's incentive is lowered once it hits the 25-basis point threshold, the Company would still retain a portion of those savings,

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providing an incentive to pursue cost efficiencies, while providing customers with the bulk of those savings so that rates remain stable for customers.

The Company recognizes that ESMs are a necessary component of a PBR plan, particularly in the first generation of a PBR plan, because the ESM serves as an important guardrail and customer protection to assure that integrated functioning of the PBR Plan remains balanced.

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Date Request Received: September 06, 2024 **Date of Response: September 24, 2024**
Data Request No. DOE 6-127 **Page 1 of 1**

Request from: Department of Energy

Witness: Horton, Douglas P.

Request:

Reference Principle (sic) Report, Mr. Mark Kolesar, Attachment ES-MK-1. The text states, The Company is also requesting the opportunity for the Company to propose a continuation of the PBR Plan for a term up to and including four years beyond August 1, 2029. (p. 22) (Bates 01795)

1. Is this proposed extension requesting that PSNH could continue its proposed revenue cap plan from 2029 through 2032 with no general rate application until 2032, and with no changes to the parameters of the proposed PBR plan at the four-year mark?
2. If major changes occur to, for example, industry total factor productivity, will the Company seek a change in its X factor at the four-year mark?

Response:

1. The Company is proposing that it would have the opportunity to request to extend the PBR term for up to four years. If the Company requests, and the Commission approves, a four extension of the PBR term, starting on August 1, 2029, then the Company will file for a rate case for new permanent base distribution rates effective on August 1, 2033.

2. The Company expects that all parties and the Commission will be assessing – throughout the PBR Plan -- whether the PBR plan is working well and whether the proper balance between the Company's funding needs and customer affordability and rate stability are being served by implementation of the PBR Plan. If the Company's view is that an extension of the PBR term would be appropriate for the Company and for customers, it could ask for that extension for up to four years. The Company will file its request no later than December 1, 2028 and will request a Commission decision within 60 days of filing, in order to allow the Company to prepare a rate case filing in the event the Commission denies the request. The Company is proposing that the extension would be under the same structure approved in this proceeding, including the X factor, except for the ability for the Company to request a base rate adjustment by filing a base rate case if its earned ROE falls below seven percent for two consecutive quarters, after the PBR Plan is allowed to be extended beyond the initial four-year stay-out.

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Date Request Received: September 06, 2024 **Date of Response: September 20, 2024**
Data Request No. DOE 6-137 **Page 1 of 2**

Request from: Department of Energy

Witness: Renaud, Paul R, Dickie, Brian J, Coates Jr, Robert S

Request:

Reference Performance Based Ratemaking Metrics, Testimony of PBR Metrics Panel (Robert S. Coates, Paul R. Renaud, Brian J. Dickie, Warren R. Boutin, Shamus OBrien, and Amy J. Findlay) Table 1 and Table 2 (pp. 15-16) (Bates 01928-01929)Table 1 and Table 2 show improvements in both metrics in the past few years.

1. What have driven the improvements in SAIDI and MBI?
2. Did the company have a PIM for reliability metrics before? If not, why is a PIM necessary now?

Response:

1. Improvements in MBI and SAIDI have resulted from three factors which have fundamentally changed since 2012:
   a. Substantial investment in a Distribution Management System to improve the speed and accuracy of outage analysis, which in turned enhanced our ability to identify solutions and deploy resources;
   b. Substantial investment in Distribution Automation technology in the field—allowing automatic restoration of customer interruptions (either in full or in part), as well as remote switching;
   c. Changes in organizational structure and restoration philosophy (e.g., when possible making temporary repairs to restore power while waiting for materials to arrive for a permanent repair).

2. The Company has not been subject to a reliability penalty metric previously. In this proceeding, the Company is proposing its first performance-based ratemaking ("PBR") plan. While not required, utilities may include performance metrics as part of a PBR plan to provide transparency in relation to the utilities' performance. PBR metrics are a critical tool that can be used to promote the Company's focus on making contributions toward realizing energy goals. This will create greater alignment between the Company's business objectives and regional and state priorities as well as customer expectations. Specifically, the Company has proposed to implement enforceable reliability metrics, including corresponding penalties, as an incentive for the Company to continue improving service quality during the PBR term. The

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proposed metric will provide a financial penalty if the Company does not meet the proposed performance targets annually during the PBR term. If the Company exceeds the target, the Company will receive a credit (not a financial reward) that may be applied to offset a future penalty under the proposed metric.

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Date Request Received: September 06, 2024 **Date of Response: September 26, 2024**
Data Request No. DOE 6-132 **Page 1 of 2**

Request from: Department of Energy

Witness: Horton, Douglas P., Coates Jr., Robert S.

Request:

1. Reference Performance Based Ratemaking Metrics, Testimony of PBR Metrics Panel (Robert S. Coates, Paul R. Renaud, Brian J. Dickie, Warren R. Boutin, Shamus O'Brien, and Amy J. Findlay). The text states:

   > For each Service Quality metric, the Company proposes to apply a penalty equal to the Company's proposed exogenous cost threshold of $1.5 million. If the Company does not meet the target annually during the 4-year PBR Plan term, the Company would be assessed a penalty of $1.5 million for each year it does not meet the target. For any year the Company exceeds the target, the Company will receive a credit of $1.5 million that may be applied as an offset to any future penalty under this metric. (p. 17) (Bates 01930)

   In Table 1 and Table 2, both a maximum and a minimum target are calculated. Please clarify which target is used to determine whether the company will be subject to a penalty and which target is used to determine whether the company will receive a credit.

2. How is exogenous cost threshold of 1.5 million determined? Please provide the relevant analysis, if available.

Response:

1. SAIDI measures the number of minutes an average customer can expect to be without power during the year. Regarding Table 1, in the Testimony of PBR Metrics Panel (Bates Page 01928), as proposed, SAIDI below the "Max target" would result in the Company receiving a credit, while SAIDI above the "Min target" would result in the Company being subject to a penalty. In other words, the Company would be penalized for SAIDI above the proposed upper bound and credited for SAIDI below the proposed lower bound. Please see the Company's response to question DOE-6-128, providing clarity regarding how credits accrued under this metric, if any, would be utilized to offset potential future penalties.

   MBI measures the number of months between when an average customer could expect to experience a sustained power interruption. Regarding Table 2 on the Testimony of PBR Metrics Panel (Bates Page 01929), as proposed, MBI above the "Max target" would result in

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the Company receiving a credit, while MBI below the "Min target" would result in the Company being subject to a penalty. In other words, the Company would be credited for MBI above the proposed upper bound and penalized for MBI below the proposed lower bound.

2. Please also refer to the Company's response to DOE 1-005 and accompanying Attachment DOE 1-005. The Company explains the basis of the $1.5 million exogenous cost threshold in the Testimony of at the PBR Metrics Panel, at Bates Page 01412. The Commission previously established an exogenous cost threshold of $1 million (Order No. 25,123, at 38-39). Given recent experience with inflation, the previous threshold should be escalated for this PBR term. This threshold level for exogenous event costs is in line with the level previously accepted by the Commission for exogenous event costs. The Company is proposing that the exogenous event cost threshold of significance be set at $1.5 million for calendar 2025, but thereafter would be adjusted for inflation based on changes in GDP-PI, as measured by the U.S. Commerce Department. Attachment DOE 1-005 provides the supporting analysis, which escalates the $1 million threshold established in 2010 by changes in inflation based on GDP-PI through the end of the test year in 2023, producing $1,364,492. The Company rounded upwards to the nearest $0.5 million in its proposal to establish an exogenous cost threshold. As discussed in Attachment ES-MK-1 (Bates Page 01794), the proposed threshold of $1.5 million equates to approximately 10 basis points of the Company's initial return on equity amount in its going-in revenue requirement.

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Date Request Received: September 06, 2024 **Date of Response: September 24, 2024**
Data Request No. DOE 6-128 **Page 1 of 1**

Request from: Department of Energy

Witness: Renaud, Paul R., Dickie, Brian J., Coates Jr., Robert S.

Request:

Reference Principle (sic) Report, Mr. Mark Kolesar, Attachment ES-MK-1. The text states, Eversource is proposing several reliability metrics to allow the Commission and other stakeholders to assess the Companys performance during the stay-out period. (p. 22) (Bates 01795)

Please confirm that the reliability metrics are penalty-only, and that they do not provide a positive financial reward for service.

Response:

Please refer to Testimony of PBR Metrics Panel at Bates Page 01930. If the Company does not meet the target annually during the four-year PBR Plan term, the Company would be assessed a penalty of $1.5 million for each year it does not meet the target. For any year the Company exceeds the target, the Company will receive a credit of $1.5 million that may be applied as an offset to any future penalty under this metric. This credit would not be collected from customers, but would instead be used to offset future penalties under this metric. The Company would not be provided a financial reward for exceeding the target.

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Docket No. DE 24-070

Date Request Received: September 06, 2024 **Date of Response: September 20, 2024**
Data Request No. DOE 6-134 **Page 1 of 1**

Request from: Department of Energy

Witness: Renaud, Paul R., Dickie, Brian J., Coates Jr., Robert S.

Request:

Reference Performance Based Ratemaking Metrics, Testimony of PBR Metrics Panel (Robert S. Coates, Paul R. Renaud, Brian J. Dickie, Warren R. Boutin, Shamus O'Brien, and Amy J. Findlay) The text states, Major event days for the reporting year are days in which the daily system SAIDI exceeds a threshold value, the TMED, as defined in IEEE 1366-2012. The threshold is calculated annually at the end of the reporting period for the subsequent reporting period. (p. 14) (Bates 01927). Please explain the methodology used to calculate the threshold value.

Response:

Approximately 25 years ago, a working group of utilities under the auspices of the Institute of Electrical and Electronics Engineers ("IEEE") developed a methodology to calculate Electrical Reliability Metrics both all-in, and normalized to exclude exceptional events (e.g., storms or natural disasters). The standard has been updated multiple times over the years, most recently in 2022.

In layman's terms, the basic methodology can be explained as follows: each utility takes five years of its daily reliability data and subjects it to a complex statistical analysis[1] to identify so-called "Major Event Days" ("MEDs"). These are days on which the electrical system experienced outages significantly outside its normal operating performance. The calculation provides a "Major Event Day Threshold" ("T_{MED}"), which is expressed in minutes of SAIDI. Each day that exceeds the T_{MED} SAIDI value may be excluded from the IEEE Methodology results. T_{MED} values are recalculated each year using the most recent five years of data and can change based on either system improvement or degradation.

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1 These calculations are performed by IEEE-DRWG once data is uploaded through its submission portal.

Appendix 1: Treatment of Capital in Jurisdictions Under PBR

Different jurisdictions where utilities operate under indexed cap PBR plans have different ways to determine what capital should be recovered under a formula and different ways of managing capital recovery for capital recovered outside of the formula. We have reviewed capital plans from British Columbia, Quebec, Alberta, Ontario, Massachusetts, and Hawaii and found that capital needs present a widely acknowledged problem for PBR, though each jurisdiction has a unique way of handling the issue. Because every utility is different and many PBR regimes are relatively young, the industry has not settled on best practice approach to recovering capital under PBR frameworks.

Approaches have also differed across time within jurisdictions. For example, the first generation PBR plan for Alberta distribution utilities allowed for capital tracker filings, which generated excessive regulatory processing, leading ultimately to a change in the second generation PBR plan. Similarly, the British Columbia Utilities Commission (BCUC) found that FortisBC, Inc. could not sufficiently recover revenue for capital spending under its 2014-2018 plan, such that capital was removed from formula treatment under its 2018-2022 plan.

A lack of homogeneity across jurisdictions and across time means that although capital supplements are common across PBR plans, the design of capital supplements do not follow a prescribed approach.

British Columbia: Different Approaches to Gas vs. Electric at FortisBC

The British Columbia Utilities Commission (BCUC) ruled in 2020 that FortisBC's electric utility, FortisBC, Inc. (FBC), may handle capital recovery differently than its gas utility, FortisBC Energy Inc. (FEI). While FEI must recover at least a portion of its capital costs under the revenue cap formula, FBC forecasts all of its capital expenditures over the PBR term. This means that for FBC, no capital is recovered under the revenue cap formula. FBC's previous PBR plan placed "regular" capital, meaning all capital not related to major projects,[1] under the revenue cap formula, with non-regular capital recovered on a forecast basis. However, FBC demonstrated in its 2019 PBR filing that actual capital expenditures differed greatly from the amount of capital recoverable using the I-X+G formula over the 2014-2019 PBR term. FBC stated that the difference between capital needs and PBR revenues arose because discrete electric projects in the previous plan term were more sizeable than gas projects, leading to more variability and less alignment with an index-based approach. The company argued that going forward, this differential was expected to continue, meaning the revenue cap would be seriously deficient in meeting the company's capital needs.[2] The approved approach relies on a three-year forecast (2020-2022), with an update in the 2023 annual filing covering 2023 and 2024. The BCUC approved a plan for FortisBC to conduct its forecast of capital expenditures using a bottom-up forecast of individual asset needs, including contingency amounts which mitigate uncertainty.[3] The difference between revenue recovered and actual costs is adjusted through an earnings sharing mechanism.

FEI divides capital into two distinct categories and recovers costs differently for each category, while FBC demonstrates that under its current circumstances, it is appropriate to entirely exclude capital from the PBR mechanism, operating wholly under a forecast approach. The formula for FEI's growth capital applies to unit costs of growth capital, which is then multiplied by a forecast of customer additions. The customer additions forecast is updated in each annual review, during which the previous year's forecasts are trued-up to actual amounts.

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[1] "Major projects" for FortisBC refers to projects that exceed the Certificate of Public Convenience and Necessity (CPCN) threshold of $20 million.

[2] The BCUC provided the following statement on the issues with treating capital:

> "In the Panel's view, the challenges with the Current PBR Plans and consideration of the approach in other jurisdictions show there is no ready solution to address the issues of developing a formula for all capital expenditures. […] The panel finds that the proposed forecast approach for […] [Fortis BC] Regular capital expenditures is reasonable." (BC Utilities Commission, Decision and Orders G-165-20 and G-166-20, 131.)

[3] BC Utilities Commission, Decision and Orders G-165-20 and G-166-20, 127.

<u>Quebec: Different Approaches to Distribution vs. Transmission at Hydro Quebec</u>

Hydro Quebec is a vertically integrated utility and a Crown Corporation, but revenues have, in the past, been regulated under separate mechanisms by business segment. Both the distribution and transmission segments of Hydro Quebec's service recently operated under similar PBR mechanisms, although the treatment of capital under the distribution segment was different from the treatment of capital under the transmission segment.[4] The Regie De L'Energie (the Régie) determined that the distribution segment of the business, Hydro Quebec Distribution (HQD), should maintain all capital under the I-X formula. The Régie supported its finding by stating that the depreciation and return on rate base has a relatively smooth, indexable annual increase, and that, with a customer growth rate included in the PBR formula, HQD should have sufficient funding to recover its capital needs.[5]

The Hydro Quebec TransÉnergie (HQT) approach to capital recovery followed a different methodology and is more similar to the approach of FortisBC electric in that all capital is excluded from the PBR formula. In its 2018 decision regarding HQT's first generation PBR plan, the Régie determined that all of HQT's capital would be subject to cost-of-service regulation due to the lumpy nature of HQT's capital needs.[6] A major distinction between the HQT approach and the approach taken by FBC, however, is that HQT filed an annual cost-of-service application, while FBC operates under a forecast spanning multiple years.

In this sense, HQD and HQT demonstrated two different approaches to the treatment of capital under PBR. HQD recovered all capital needs through revenue escalation via the I-X formula.[7]

[4] It appears that the generation portion of Hydro Quebec's business operates in a competitive market, selling power in the New England Independent System Operator and New York Independent System Operator territories.
[5] "Décision finale et sur les frais de la phase 1 pour le distributeur d'électricité," *Régie de l'énergie,* D-2017-043, R-3897-2014 Phase 1, April 7, 2017.
[6] "Décision finale et sur les frais de la phase 1 pour le transporteur d'électricité," *Régie de l'énergie*, D-2018-001, R-3897-2014 Phase 1, January 5, 2018, p. 72.
[7] Unless those capital needs are eligible for Z factor or Y factor treatment.

HQT, on the other hand, removed all of its capital from the revenue requirement adjusted by I-X+G, instead recovering capital costs via cost-of-service filings.

Ontario: Incremental Capital Module (Distribution Utilities)

In Ontario, electric distribution utilities have a menu of PBR options under which they may operate, including price and revenue caps. The fourth-generation incentive regulation (IR) plan consists of a price cap determined by I-X, along with a mechanism for supplemental capital recovery. The Ontario Energy Board (OEB) allows two corresponding capital cost recovery mechanisms for utilities electing to operate under the fourth generation IR option. One, the incremental capital module (ICM), allows electric utilities to collect revenues for extraordinary and unanticipated capital spending requirements—something other than the normal course of business.[8] The second mechanism, known as the advanced capital module (ACM), focuses on longer term capital planning.[9] This second mechanism was added through a 2014 decision aimed at improving the efficiency of capital planning and regulatory proceedings related to capital spending. Costs approved for revenue recovery under both mechanisms may be collected via rate riders on customer bills. Capital not recovered under the ICM or ACM is recovered by the PBR formula. ICM treatment allows for cost recovery when the investment goes into service, rather than waiting until the next cost of service application to rebase rates. At the end of the PBR term, these costs are folded into the rate base in the next generation cost of service study.

Alberta Distribution Utilities: "K-Bar" Approach

Distribution utilities in Alberta have operated under a price cap governed by an I-X formula since 2014. In its first generation PBR decision, the AUC recognized that circumstances may arise in which distribution utilities operating under the PBR formula may require additional funding to

[8] Ontario Energy Board, *An Application by Hydro One Networks Inc. for [an order approving distribution rates]*, EB-2008-0187, May 13, 2009.
[9] Ontario Energy Board, *New Policy Options for the Funding of Capital Investments*, EB-2014-0219, September 8, 2014.

provide for necessary capital expenditures. The Commission established a "capital tracker" that would review, approve, and collect revenue from ratepayers in addition to the price adjustments related to the PBR formula.[10] The criteria and processes established for capital tracker approvals were designed to ensure only necessary, incremental capital funding was awarded. The capital tracker mechanism resulted in numerous, contentious annual proceedings that the Commission viewed as being inconsistent with the regulatory and administrative efficiency it considered to be integral to its PBR regime.

The Commission adopted a different approach in the second generation PBR term, which spanned 2018 through 2022, with the objective of reducing the regulatory burden related to capital supplements. For the province's second generation PBR framework, the AUC adopted a "K-bar" approach to supplemental capital funding for Alberta electric distribution utilities in its 2016 order approving the second-generation PBR plan for the utilities,[11] and amended the calculation methodology outlined in the AUC's 2016 order in 2018.[12] K-bar provides a formulaic and mechanized way of recovering capital. Under this approach, the I-X formula escalates historical average Type 2 capital additions to form the basis of future approved capital recovery for Type 2 capital. Recoverable capital expenditures are obtained from the differential between the utility's escalated historical capital needs and what each utility will actually collect for Type 2 capital under the I-X formula. The AUC calls this differential the "K-bar." The approach was outlined in the AUC's amended decision.[13]

Massachusetts Distribution Utilities: Cost Trackers and K-Bar

The two major gas distribution utilities in Massachusetts operate under a revenue cap. Until 2023, gas and electric utilities in Massachusetts operating under PBR were not able to recover additional

[10] Alberta Utilities Commission, Decision 2012-237.
[11] Alberta Utilities Commission, Decision 20414-D01-2016.
[12] Alberta Utilities Commission, Rebasing for the 2018-2022 PBR Plans for Alberta Electric and Gas Distribution Utilities, Decision 22394-D01-2018, February 5, 2018.
[13] ENMAX was on a different schedule than the other Alberta electric distribution utilities.

capital expenditures beyond the PBR formula.[14] However, a particular capital investment program, the Gas Safety Enhancement Program (GSEP), provided cost recovery for targeted capital projects related to gas safety. Costs associated with the GSEP program are recovered on a cost-of-service basis, trued up annually and added to customer bills using "gas system enhancement reconciliation adjustment factors." These factors are usage-based, charged in fractions of a cent per therm of gas usage.

In 2023, Eversource began operating under a second generation PBR framework that included a K-bar mechanism akin to the mechanism in use among Alberta utilities.[15]

Hawaii Integrated Utilities: Exceptional Project Recovery Mechanism (EPRM)

Hawaiian Electric Industries, Inc. owns three vertically integrated utilities that transitioned to a PBR framework beginning in 2021.[16] These utilities now operate under a PBR framework with a revenue cap escalated by an I-X formula. The PBR framework also provides some provisions for additional revenue beyond the escalation of the formula. With respect to capital, the Hawaiian Public Utilities Commission provided for an Exceptional Project Recovery Mechanism (EPRM).

The EPRM is a reconciled cost recovery mechanism filed for specific projects. It provides reasonable recovery of specifically allowed revenues for the net costs of approved "Eligible Projects" placed in service during HECO's multiyear rate period, provided that cost recovery is not already covered by another effective recovery mechanism.[17] The EPRM also recovers O&M expenses, meaning this mechanism is not exclusively used for capital expenditures.

[14] At the end of 2022, the Massachusetts Department of Public Utilities issued a decision on Eversource Electric's proposed PBR framework, in which Eversource was granted a K-bar capital supplement akin to the K-bar approach employed in Alberta.
[15] Massachusetts Department of Public Utilities, D.P.U. 22-22, November 30, 2022.
[16] These utilities are: Hawaiian Electric Company, Inc., Maui Electric Company, Limited, and Hawaii Electric Light Company.
[17] Hawaii Public Utilities Commission, *In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval to Commit Funds in Excess of $2,500,000 (excluding customer contributions) for the PZ.005125 – Kahe-Waiau 138 kV Undergrounding Project and to Recover Costs through the Exceptional Project Recovery Mechanism*, Decision and Order No. 38451 Docket No. 2021-0086, p. 62.

Summary of Capital Supplements

A review of capital treatment across North American PBR plans revealed that the industry has not reached a consensus on capital recovery under PBR. Each approach to capital recovery gives rise to a certain level of complexity, risk, regulatory burden, and incentive pressure.

Appendix 2: Corrected Cost Benchmarking Tables

This Appendix contains tables referenced in Section 4 of the Direct Testimony of Nicholas Crowley and Daniel McLeod.

Witness Ros estimated his econometric model using years 2000 through 2022, but then omitted the year 2000 from the average of the differences presented on the bottom line of his Table 6 and inappropriately adjusted the fitted values of his model. Table 3a shows Dr. Ros's cost benchmarking results for each company, corresponding to each company's performance relative to the average, when the year 2000 is included and no adjustment is made. These results show that a fixed effects model used in this way will always erroneously show a company to be an average performer, because the company's performance in a given year is being compared to its own average performance.

Table 3a: Average Relative Company Performance with Corrections to FE Approach

Company Name	Average % Difference (Fixed Effects)
Consumers Energy Company	0.0000%
Sierra Pacific Power Company	0.0000%
Arizona Public Service Company	0.0000%
Green Mountain Power Corporation	0.0000%
Entergy Mississippi, LLC	0.0000%
Pacific Gas and Electric Company	0.0000%
Union Electric Company	0.0000%
Connecticut Light and Power Company	0.0000%
Black Hills Power, Inc.	0.0000%
Central Maine Power Company	0.0000%
Southwestern Public Service Company	0.0000%
Cleveland Electric Illuminating Company	0.0000%
ALLETE (Minnesota Power)	0.0000%
Public Service Company of Oklahoma	0.0000%
Baltimore Gas and Electric Company	0.0000%
Duke Energy Carolinas, LLC	0.0000%
Public Service Company of New Mexico	0.0000%
Orange and Rockland Utilities, Inc.	0.0000%
Southwestern Electric Power Company	0.0000%
Tampa Electric Company	0.0000%
Public Service Company of Colorado	0.0000%
DTE Electric Company	0.0000%
El Paso Electric Company	0.0000%
Northern Indiana Public Service Company	0.0000%
United Illuminating Company	0.0000%
Duke Energy Progress, LLC	0.0000%
Evergy Metro, Inc.	0.0000%
Portland General Electric Company	0.0000%
Entergy Arkansas, LLC	0.0000%
Louisville Gas and Electric Company	0.0000%
Idaho Power Company	0.0000%
Monongahela Power Company	0.0000%
Indiana Michigan Power Company	0.0000%
Evergy Kansas South, Inc.	0.0000%
Indianapolis Power & Light Company	0.0000%
Wisconsin Electric Power Company	0.0000%
San Diego Gas & Electric Company	0.0000%
Potomac Edison Company	0.0000%
NSTAR Electric Company	0.0000%
Dominion Energy South Carolina, Inc.	0.0000%
MDU Resources Group Inc.	0.0000%
Dayton Power and Light Company	0.0000%

Appalachian Power Company	0.0000%
Virginia Electric and Power Company	0.0000%
Duke Energy Ohio, Inc.	0.0000%
PECO Energy Co.	0.0000%
Niagara Mohawk Power Corporation	0.0000%
Oklahoma Gas and Electric Company	0.0000%
Massachusetts Electric Company	0.0000%
Rochester Gas and Electric Corporation	0.0000%
New York State Electric & Gas Corporation	0.0000%
Delmarva Power & Light Company	0.0000%
Narragansett Electric Company	0.0000%
Duke Energy Kentucky, Inc.	0.0000%
Jersey Central Power & Light Company	0.0000%
Northern States Power Company - MN	0.0000%
Ohio Edison Company	0.0000%
Empire District Electric Company	0.0000%
Alabama Power Company	0.0000%
PacifiCorp	0.0000%
Public Service Company of New Hampshire	0.0000%
PPL Electric Utilities Corporation	0.0000%
Puget Sound Energy, Inc.	0.0000%
Duquesne Light Company	0.0000%
Duke Energy Florida, LLC	0.0000%
Commonwealth Edison Company	0.0000%
Kentucky Utilities Company	0.0000%
Tucson Electric Power Company	0.0000%
Metropolitan Edison Company	0.0000%
Avista Corporation	0.0000%
Public Service Electric and Gas Company	0.0000%
Mississippi Power Company	0.0000%
Pennsylvania Electric Company	0.0000%
Cleco Power LLC	0.0000%
Northern States Power Company - WI	0.0000%
Southern Indiana Gas and Electric Company	0.0000%
Florida Power & Light Company	0.0000%
Potomac Electric Power Company	0.0000%
Georgia Power Company	0.0000%
Atlantic City Electric Company	0.0000%
Southern California Edison Company	0.0000%
Nevada Power Company	0.0000%
Duke Energy Indiana, LLC	0.0000%
Consolidated Edison Company of New York, Inc.	0.0000%
West Penn Power Company	0.0000%
Wisconsin Public Service Corporation	0.0000%
Entergy New Orleans, LLC	0.0000%

Table 3b is identical to Table 3a except that Dr. Ros's adjustment to the fitted values is made. This shows that simply adding in the year 2000 into the analysis causes each company's average relative performance to be -0.51%. This demonstrates that the flaw in the fixed effects model is unrelated to Dr. Ros's adjustment, as it is not possible for each and every company to be exactly 0.51% more efficient than the average company.

Table 3b: Average Relative Company Performance with Year 2000 Included

Company Name	Average % Difference (Fixed Effects)
Consumers Energy Company	-0.507%
Sierra Pacific Power Company	-0.507%
Arizona Public Service Company	-0.507%
Green Mountain Power Corporation	-0.507%
Entergy Mississippi, LLC	-0.507%
Pacific Gas and Electric Company	-0.507%
Union Electric Company	-0.507%
Connecticut Light and Power Company	-0.507%
Black Hills Power, Inc.	-0.507%
Central Maine Power Company	-0.507%
Southwestern Public Service Company	-0.507%
Cleveland Electric Illuminating Company	-0.507%
ALLETE (Minnesota Power)	-0.507%
Public Service Company of Oklahoma	-0.507%
Baltimore Gas and Electric Company	-0.507%
Duke Energy Carolinas, LLC	-0.507%
Public Service Company of New Mexico	-0.507%
Orange and Rockland Utilities, Inc.	-0.507%
Southwestern Electric Power Company	-0.507%
Tampa Electric Company	-0.507%
Public Service Company of Colorado	-0.507%
DTE Electric Company	-0.507%
El Paso Electric Company	-0.507%
Northern Indiana Public Service Company	-0.507%
United Illuminating Company	-0.507%
Duke Energy Progress, LLC	-0.507%
Evergy Metro, Inc.	-0.507%
Portland General Electric Company	-0.507%
Entergy Arkansas, LLC	-0.507%
Louisville Gas and Electric Company	-0.507%
Idaho Power Company	-0.507%
Monongahela Power Company	-0.507%

Indiana Michigan Power Company	-0.507%
Evergy Kansas South, Inc.	-0.507%
Indianapolis Power & Light Company	-0.507%
Wisconsin Electric Power Company	-0.507%
San Diego Gas & Electric Company	-0.507%
Potomac Edison Company	-0.507%
NSTAR Electric Company	-0.507%
Dominion Energy South Carolina, Inc.	-0.507%
MDU Resources Group Inc.	-0.507%
Dayton Power and Light Company	-0.507%
Appalachian Power Company	-0.507%
Virginia Electric and Power Company	-0.507%
Duke Energy Ohio, Inc.	-0.507%
PECO Energy Co.	-0.507%
Niagara Mohawk Power Corporation	-0.507%
Oklahoma Gas and Electric Company	-0.507%
Massachusetts Electric Company	-0.507%
Rochester Gas and Electric Corporation	-0.507%
New York State Electric & Gas Corporation	-0.507%
Delmarva Power & Light Company	-0.507%
Narragansett Electric Company	-0.507%
Duke Energy Kentucky, Inc.	-0.507%
Jersey Central Power & Light Company	-0.507%
Northern States Power Company - MN	-0.507%
Ohio Edison Company	-0.507%
Empire District Electric Company	-0.507%
Alabama Power Company	-0.507%
PacifiCorp	-0.507%
Public Service Company of New Hampshire	-0.507%
PPL Electric Utilities Corporation	-0.507%
Puget Sound Energy, Inc.	-0.507%
Duquesne Light Company	-0.507%
Duke Energy Florida, LLC	-0.507%
Commonwealth Edison Company	-0.507%
Kentucky Utilities Company	-0.507%
Tucson Electric Power Company	-0.507%
Metropolitan Edison Company	-0.507%
Avista Corporation	-0.507%
Public Service Electric and Gas Company	-0.507%
Mississippi Power Company	-0.507%
Pennsylvania Electric Company	-0.507%
Cleco Power LLC	-0.507%
Northern States Power Company - WI	-0.507%
Southern Indiana Gas and Electric Company	-0.507%
Florida Power & Light Company	-0.507%
Potomac Electric Power Company	-0.507%

Georgia Power Company	-0.507%
Atlantic City Electric Company	-0.507%
Southern California Edison Company	-0.507%
Nevada Power Company	-0.507%
Duke Energy Indiana, LLC	-0.507%
Consolidated Edison Company of New York, Inc.	-0.507%
West Penn Power Company	-0.507%
Wisconsin Public Service Corporation	-0.507%
Entergy New Orleans, LLC	-0.507%

Table 3c presents our cost growth benchmarking results. The table shows that PSNH's inefficiency growth is higher than average at 1.2% over the 2000-2022 sample, which corresponds to a ranking of 78 out of 87.

Table 3c: Average Relative Company Inefficiency Growth

Company Name	Average % Difference (Growth)
Mississippi Power Company	-3.28%
Duquesne Light Company	-2.77%
Potomac Edison Company	-1.78%
ALLETE (Minnesota Power)	-1.49%
Tampa Electric Company	-1.43%
Entergy New Orleans, LLC	-1.25%
Florida Power & Light Company	-1.20%
Georgia Power Company	-1.20%
Sierra Pacific Power Company	-1.20%
PacifiCorp	-1.17%
Cleveland Electric Illuminating Company	-0.96%
Southwestern Public Service Company	-0.95%
Idaho Power Company	-0.95%
Wisconsin Public Service Corporation	-0.95%
Duke Energy Florida, LLC	-0.91%
Duke Energy Carolinas, LLC	-0.90%
Southwestern Electric Power Company	-0.77%
Wisconsin Electric Power Company	-0.75%
Commonwealth Edison Company	-0.75%
Indianapolis Power & Light Company	-0.75%
Northern States Power Company - MN	-0.70%
Evergy Metro, Inc.	-0.69%
Appalachian Power Company	-0.68%
Ohio Edison Company	-0.63%
Jersey Central Power & Light Company	-0.54%

DTE Electric Company	-0.54%
Public Service Company of New Mexico	-0.51%
MDU Resources Group Inc.	-0.49%
PPL Electric Utilities Corporation	-0.49%
Entergy Arkansas, LLC	-0.43%
Central Maine Power Company	-0.32%
Virginia Electric and Power Company	-0.31%
Arizona Public Service Company	-0.29%
Pennsylvania Electric Company	-0.27%
Delmarva Power & Light Company	-0.22%
NSTAR Electric Company	-0.22%
Indiana Michigan Power Company	-0.22%
Evergy Kansas South, Inc.	-0.22%
Duke Energy Indiana, LLC	-0.21%
Duke Energy Kentucky, Inc.	-0.13%
Alabama Power Company	-0.13%
Metropolitan Edison Company	-0.12%
Connecticut Light and Power Company	-0.09%
Dominion Energy South Carolina, Inc.	-0.03%
Duke Energy Ohio, Inc.	0.04%
Northern States Power Company - WI	0.08%
Baltimore Gas and Electric Company	0.10%
PECO Energy Co.	0.10%
Northern Indiana Public Service Company	0.14%
Public Service Electric and Gas Company	0.15%
Monongahela Power Company	0.15%
Cleco Power LLC	0.18%
Union Electric Company	0.20%
Potomac Electric Power Company	0.21%
Black Hills Power, Inc.	0.22%
Duke Energy Progress, LLC	0.27%
Puget Sound Energy, Inc.	0.27%
Public Service Company of Oklahoma	0.33%
Green Mountain Power Corporation	0.35%
Tucson Electric Power Company	0.35%
Entergy Mississippi, LLC	0.40%
West Penn Power Company	0.40%
Nevada Power Company	0.43%
Dayton Power and Light Company	0.45%
Narragansett Electric Company	0.50%
New York State Electric & Gas Corporation	0.53%
Kentucky Utilities Company	0.61%
Rochester Gas and Electric Corporation	0.63%
El Paso Electric Company	0.67%
Consolidated Edison Company of New York, Inc.	0.79%
Oklahoma Gas and Electric Company	0.81%

Louisville Gas and Electric Company	0.83%
Massachusetts Electric Company	0.85%
Atlantic City Electric Company	1.02%
Empire District Electric Company	1.02%
Orange and Rockland Utilities, Inc.	1.09%
Public Service Company of Colorado	1.10%
Public Service Company of New Hampshire	1.18%
Avista Corporation	1.39%
Niagara Mohawk Power Corporation	1.45%
United Illuminating Company	1.65%
Portland General Electric Company	1.72%
Southern California Edison Company	1.72%
Consumers Energy Company	2.00%
Southern Indiana Gas and Electric Company	2.30%
San Diego Gas & Electric Company	2.53%
Pacific Gas and Electric Company	2.71%