pepco
A PHI Company

Kirk J. Emge
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July 8, 2011

Mr. Jesse P. Clay, Jr.
Acting Commission Secretary
Public Service Commission
of the District of Columbia
1333 H Street, N.W.
2nd Floor, West Tower
Washington, DC 20005

Dear Mr. Clay:

Potomac Electric Power Company, pursuant to the applicable rules of the Commission, hereby submits an original and twenty-five (25) copies of its Application for an increase in its retail rates for the distribution of electric energy and supporting Testimony and Exhibits.

Please feel free to contact me if you have any questions regarding this matter.

Sincerely,

Kirk J. Emge

KJE/mda

Enclosures

cc: Sandra Mattavous-Frye, Esq.

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF	)	
	)	
THE APPLICATION OF POTOMAC	)	
ELECTRIC POWER COMPANY FOR	)	**Formal Case No. _________**
AUTHORITY TO INCREASE EXISTING	)	
RETAIL RATES AND CHARGES FOR	)	
ELECTRIC DISTRIBUTION SERVICE	)	

VOLUME I of III: **Application, Direct Testimony and Exhibits of Potomac Electric Power Company Witnesses KAMERICK, LOWRY and CANNELL**

July 8, 2011

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF

THE APPLICATION OF	)	
POTOMAC ELECTRIC POWER COMPANY	)	
FOR AUTHORITY TO INCREASE	)	Formal Case No. _____
EXISTING RETAIL RATES AND CHARGES	)	
FOR ELECTRIC DISTRIBUTION SERVICE	)	

APPLICATION OF
POTOMAC ELECTRIC POWER COMPANY

Potomac Electric Power Company ("Pepco" or "the Company"), pursuant to Section 34-901 of the District of Columbia Official Code and Rules 101, 104, 200-207 and 211 of the Rules of Practice and Procedure of the District of Columbia Public Service Commission, 15 D.C.M.R. §§ 101, 104, 200-207 and 211 (1998), hereby respectfully requests authority for an increase in its electric distribution rates for service in the District of Columbia of $42,101,000. This translates to a 5.27% increase in a typical residential customer's bill.

In support of this Application, Pepco respectfully shows as follows:

I. The Applicant

Pepco is a wholly-owned subsidiary of Pepco Holdings, Inc. ("PHI") and is a District of Columbia and Virginia corporation having its principal place of business at 701 Ninth Street, N.W., Washington, D.C. 20068. Pepco is also licensed to do business in the State of Maryland and in the Commonwealth of Pennsylvania. Pepco provides retail electric distribution service in the District of Columbia as well as major portions of the surrounding Maryland suburbs in Montgomery County, and Prince George's County.

Pepco is subject to regulation by the Public Service Commission of the District of Columbia ("Commission") with respect to its public utility operations within the District of Columbia pursuant to the District of Columbia Public Utilities Act, as amended, D.C. Official Code §§ 34-101 *et seq.*

II. Service

All correspondence and communications concerning this Application should be sent to the following persons at the addresses specified:

Kirk J. Emge, Senior Vice President
and General Counsel
Deborah M. Royster, Deputy General Counsel
Marc K. Battle, Assistant General Counsel
Potomac Electric Power Company
701 Ninth Street, N.W., 10th Floor
Washington, DC 20068
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dmroyster@pepcoholdings.com
mkbattle@pepcoholdings.com

Grace Soderberg, Esq. Manager – Regulatory Affairs, Washington DC
Potomac Electric Power Company
701 Ninth Street, N.W., Room 9004
Washington, DC 20068
gdsoderberg@pepcoholdings.com

III. Need for a Rate Increase

Pepco requires an increase in its rates for providing electric distribution services to its customers in the District of Columbia in order to afford it the opportunity to cover its expenses of providing service and to earn a fair return on its investor-supplied capital. Based on a test year ending September 30, 2011, Pepco is requesting a $42,101,000 increase in its District of Columbia distribution rates. This increase translates to a 5.27% increase for a typical residential customer who uses 750 kWh per month. The Company is also asking for an increase in the authorized rate of return on equity ("ROE") from 9.625% to 10.75%. At current rates, Pepco's return on equity is just 6.46%, which is far short of the current 10.50% to 11.25% estimated cost of equity capital.[1]

As explained by Company Witness McGowan, the Company has proposed an overall rate of return ("ROR") of 8.64%, increased from the 8.01% authorized in the last rate case. Pepco is seeking an increase in distribution rates because its revenue growth has not kept pace with the growth in operating costs and rate base. Notwithstanding the Company's efforts to contain costs, this disparity will only increase as Pepco continues its efforts to improve the reliability of the distribution system.

In preparing its Application, Pepco has followed Commission rate making precedent, including a number of adjustments generally identified in the testimony of Company Witness Hook, and discussed in greater detail by other witnesses. The Company will also discuss several ratemaking mechanisms in use by state utility commissions around the country, the purpose of which is to address the problem of "regulatory lag." As identified in Part IV below, Pepco views it as critical that the Commission address the problem of the regulatory lag that has consistently resulted in denying the Company the opportunity to earn its Commission-authorized rate of return. In Part V below, Pepco identifies two regulatory lag mitigation mechanisms needed to allow Pepco the opportunity to earn its authorized rate of return, and these mechanisms are explained further in the testimony of Company Witness Lowry.

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[1] The Direct Testimony of Company Witness Hevert demonstrates that 10.75% represents a reasonable estimate of the cost of equity capital.

PHI, the parent company of Pepco, has sold its wholesale generation business and is winding down its retail gas and electric supply business. PHI, together with its subsidiary, Pepco, and its other utility subsidiaries, is now fundamentally a transmission and distribution company. Pepco's aging infrastructure requires replacement and repair in order to continue to supply safe and reliable service, as is the case with infrastructure across the country, such as other electric and gas distribution facilities, water systems, and federal, state, and local roads and bridges. Moreover, new technology is becoming available that will enable the Company to provide more reliable service in a cost-effective manner. However, in order to improve its infrastructure and implement cost-effective distribution technologies, the Company must make substantial investment in its utility plant and must have the opportunity to recover its costs.

IV. Regulatory Lag

The inability of a regulated utility to earn its authorized rate of return due to the differing conditions in the test period, as compared to the rate effective period, is commonly referred to as "regulatory lag." The amount of the shortfall in actual revenues due to regulatory lag can be calculated by comparing revenues obtained during the rate effective period to the revenues that the Company would have received during the rate effective period at the authorized rate of return. Other contributors to regulatory lag include the extended period required to conduct a base rate case and receive a final order, and the length of time between base rate cases.

Pepco has experienced the effects of regulatory lag following its most recent rate cases, and the problem is becoming particularly acute due to the Company's rising operating costs and capital investment. For example, in Case No. 1076, the Commission approved a rate of return on equity of 9.625% based on the test period presented in that case.[2] In fact, as demonstrated in

[2] Order No. 15710.

Company Witness Hook's testimony, on an adjusted basis for the six months actual, six months projected period ending September 30, 2011, the Company will realize a rate of return of only 6.53%, which translates to a return on equity of only 6.46%. Company Witness Hook will provide evidence that the Company is currently and will continue to experience exceptional levels of regulatory lag during the rate-effective period.

This lag arises because Pepco's rate base and operating costs are growing more rapidly than the growth in revenue, and are expected to continue to do so as the Company replaces aging infrastructure, enhances reliability of the distribution system, and provides for growth in the number of customers. Regulatory lag can impair the ability of a utility to provide safe and reliable service at a reasonable cost.

V. Mitigation of Regulatory Lag

In accordance with the provisions of §34-1101 of the Code of The District of Columbia, Pepco is required to charge rates that are "reasonable, just and non-discriminatory." While regulation does not guarantee an electric utility will achieve its projected revenues, it must provide a reasonable opportunity to earn a rate of return sufficient to maintain the utility's financial integrity, to attract necessary capital at reasonable cost and to compensate investors fairly for the risk they have assumed, while protecting relevant public interests.[3] The District of Columbia Court of Appeals has long recognized that realistic ratemaking must take into account the lengthening delays occasioned by the regulatory processes, while recognizing the need for preserving an appropriate balance between investor and consumer interests.[4] However, the Company has not had an *opportunity* to earn its authorized return in the current economic and

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[3] *Potomac Electric Power Company v. Public Service Commission*, 380 A.2d 126 at 132 (1977) (Holding that rate order was unjust and unreasonable since it deprived utility of opportunity to earn a fair rate of return).

[4] *Id.* at 137.

regulatory environment due to regulatory lag. To address the problem of regulatory lag, Pepco is proposing a reliability investment recovery mechanism ("RIM"). The Company is also seeking a prospective Commission rule change that will allow the use of fully forecasted test periods in future rate cases.

The RIM is a capital expenditure ("CAPEX") recovery mechanism that targets incremental capital costs resulting from Pepco's reliability improvement plan. The investments subject to cost recovery through the RIM would replace aging distribution facilities and/or improve reliability in the District. The CAPEX addressed by the RIM would occur after the test year and is not included in the rate base the Company is proposing in another part of this proceeding. Costs of new connections are excluded and none of the investments generate new revenue. Filings would be made annually that predict, with month to month itemization, the accumulating annual cost of RIM investments in the upcoming year and make certain adjustments for the operation of the RIM in prior years. The cost would be recovered via a rate rider featuring a non-bypassable charge that is specifically designed for each rate schedule.

The RIM proposed by Pepco addresses the issue of regulatory lag without guaranteeing Pepco a specified rate of return. Pepco would continue to be at risk for managing its operating and maintenance costs, its costs of debt and equity, and its investment in areas other than those which can be clearly demonstrated to benefit customers generally but which do not increase revenues. However, adoption of these proposals might serve to reduce the Company's need to file at shortened intervals future rate base proceedings, and so lessen the burden on the Commission, Pepco and other parties. In addition, customers would see lower costs from less frequent base rate cases, without a reduction in the Commission's ability to exercise its regulatory oversight. Indeed, under the RIM, Pepco would file its proposed reliability investments with the Commission on an annual basis, and the Commission would have the opportunity to review and approve Pepco's updated investment plan for the upcoming year.

The District of Columbia Court of Appeals has noted that "the readily recognized problem of regulatory lag has been considered by the Commission in earlier cases as a factor to be dealt with in calculating the rate of return, and as one to be allocated equitably to consumers as well as investors."[5] It is imperative that these factors be considered in this case if the Company is to be given a fair opportunity to earn its authorized return.

VI. Maintaining Pepco's Financial Strength

As will be discussed by Company Witnesses Kamerick, Cannell, Hevert and McGowan, maintaining investment grade credit ratings is vital to the financial health of Pepco and critical to its ability to access capital markets for financing essential capital projects on reasonable terms. Consequently, Pepco's customers and its investors benefit from a financially strong utility. If Pepco is unable to earn its authorized rate of return, the Company will not cover its costs and may be subject to negative credit rating actions. Over the long run, a company that is viewed as more risky will (1) pay more for capital, increasing its cost of capital, and (2) during constrained financial markets, have greater challenges accessing needed funds. In such a situation, Pepco would face increased debt and equity costs and customers would have to pay higher rates to fund those costs. The rate increase and the rate mechanisms Pepco seeks in this case are important to enable the Company to maintain, and even strengthen, its investment grade ratings on its securities and to compete for capital under all capital market conditions. While financial strength has always been important to utilities, it is even more so now, as was demonstrated

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[5] *Id.*

during the recent economic crisis in credit markets. Financial strength ultimately benefits customers by enabling the Company to attract capital on reasonable terms.

VII. Compliance with Commission Rules and Directives

Section 104.1(g) of the Commission's Rules of Practice and Procedure requires that the Applicant indicate whether the proceeding should be considered a "rate case" or an "other investigation" for purposes of Section 34-912 of the District of Columbia Official Code. This proceeding should be considered a "rate case" for purposes of that Code Section.

Statements setting forth the requirements of Rules 200.1 – 200.3, 200.5 and 200.8 - 200.11 are contained in Appendix A. Pursuant to Rule 200.10, unless otherwise ordered by the Commission, Pepco will submit the information required by Rules 201-207 and 211 within 21 days after the filing of this Application.

Pursuant to Section 34-912(a)(9)(A) of the District of Columbia Official Code, Appendix B provides a statement of costs anticipated to be incurred in this proceeding.

This Application and supporting testimony and exhibits are in full compliance with each of the Commission's filing requirements and precedential directives. However, in the event the Commission determines that Pepco has failed to conform in any respect to the filing requirements of its Rules or Orders, Pepco respectfully requests, pursuant to Rules 146.1 and 200.11, a waiver of such filing requirements. Alternatively, Pepco respectfully requests a reasonable opportunity to supplement this Application with the required, responsive information.

VIII. Procedural Schedule

Pepco respectfully requests that a decision on the merits of the Company's rate increase and other proposals be rendered within 270 days, or nine months, from the submission of this Application. The length of time that passes before a final decision on the adequacy of current rates is an important issue for the Company and other stakeholders. The requested nine-month time frame is consistent with past Commission rulings and its announced policy. *See* Formal Case No. 929, Order No. 10295 (1993) ("It is the general policy of this Commission to make every reasonable effort to decide all base rate proceedings within nine months of the filing of the application commencing the case"); Formal Case No. 905, Order No. 9742, 12 D.C.P.S.C. 353 (1991)(same). Appendix C sets forth a proposed schedule that is consistent with this policy.

IX. Conclusion

WHEREFORE, Pepco urges that the Commission approve the increase in retail distribution rates and charges requested in this Application, find the appended revised rate schedules for retail distribution service to be just and reasonable, and permit the rate schedules to become effective at the earliest possible time.

Respectfully submitted,

POTOMAC ELECTRIC POWER COMPANY

By: ______________________
Kirk J. Emge
Senior Vice President &
General Counsel

Kirk J. Emge, D.C. Bar No. 420581
Deborah M. Royster, D.C. Bar No. 359087
701 Ninth Street, N.W.
10th Floor
Washington, D.C. 20068
(202) 872-2890

Counsel for Potomac Electric Power Company

Washington, D.C.
July 8, 2011

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Application of Potomac Electric Power Company has been served by hand this 8th day of July, 2011, on:

Sandra Mattavous-Frye
Acting People's Counsel
Office of the People's Counsel
1133 15th Street, N.W.
Suite 500
Washington, D.C. 20005

Kirk J. Emge

APPENDIX A

APPENDIX A

FILING REQUIREMENTS FOR RATE CHANGES
(15 D.C.M.R. § 200)

200.1 All rate change applications, other than tariff filings not affecting existing rates, shall include the following information:

(a) A statement of a historical test year and the basis for choosing this test year;
See Prefiled Direct Testimony of Company Witness Hook, PEPCO (F), pp.2-3

(b) A statement of a proposed test year and the basis for choosing this test year;
See PEPCO (F), pp.2-3

(c) A description of the nature and basis of the changes proposed;
See Prefiled Direct Testimony of Company Witness Janocha, PEPCO (L)

(d) A listing of the tariff pages affected by the changes proposed;
See PEPCO (L)-2

(e) A listing of the existing rates and proposed rates for each service for which changes are being proposed;
See PEPCO (L)-2

(f) A full statement and description of any new or revised tariff rules and regulations;
See PEPCO (L)

(g) A statement listing the jurisdictional operating revenues of the utility for the historical test year and the proposed test year;
See PEPCO (F)-3, p. 1 of 48 and PEPCO (F)-1, p. 1 of 48, respectively.

(h) A listing of the total number of jurisdictional customers or accounts served for the historical test year and the proposed test year;

Historical test year (at 3/31/11) – 254,664
Prop. test year(budget at 9/30/11)– 260,450

(i) A calculation of the number of jurisdictional customers or accounts in each customer classification whose bills will be affected or a calculation of the average effect of the proposed change on jurisdictional customers in each customer classification based upon data for the historical test year and the proposed test year; and
See PEPCO (L)-1

(j) A calculation of the total proposed revenue change in dollars, by customer classification, projected on an annual basis.
See PEPCO (L)-1

200.2 Whenever, in a rate change application, a party proposes to change the ratemaking principles adopted in its most recent rate case, the party shall also file with its § 200.1 filing a statement describing each proposed change in the ratemaking principles adopted by the Commission in the applicant's last general rate proceeding, showing the effect of each such change upon the applicant's request if no such changes were made.
See prefiled Direct Testimony of Company Witnesses Kamerick, PEPCO (A), Lowry, PEPCO (B), and Janocha, PEPCO (L)

200.3 Any rate change application that proposes to increase a utility's jurisdictional operating revenues by more than one percent (1%) when projected on an annual basis shall include, in addition to the statements required by §§ 200.1 and 200.2 and §§ 201 through 213, the following information:

(a) A statement showing the utility's calculation of the jurisdictional rate of return earned or to be earned in the historical test year and the proposed test year;
See PEPCO (F)-3, p.1 of 48 and PEPCO (F)-1, p. 1 of 48, respectively.

(b) The anticipated jurisdictional rate of return to be earned when proposed rate changes become effective;
See PEPCO (F)-1, p.1 of 48

(c) The jurisdictional rate base(s) used in the rate of return calculation supported, if available, by summaries of original cost or other factors used in its determination;
See PEPCO (F)-1, p.1 of 48

(d) A summary, on a functional basis, of the book value (actual or projected) of the utility's jurisdictional property at the close of the historical test year and the proposed test year;
See PEPCO (K)-1, p.5

(e) A statement showing the amount of depreciation reserve, at the close of the historical test year and the proposed test year, applicable to the property summarized in paragraph (d);
See PEPCO (K)-1, p.8

(f) A statement of jurisdictional operating income, setting forth the operating revenues and expenses by accounts, for the historical test year and the proposed test year;
See PEPCO (K)-1, p.23

(g) A brief description of and basis for any major change affecting the utility's operating or financial condition during the proposed test year, known as of the date of transmittal of the application, and any major change during the rate effective period as follows:

(1) Known and measurable as of the date of transmittal of the application; or
(2) Known and which can be approximated with reasonable accuracy as of the date of transmittal of the application.

For purposes of this section, "a major change" means one which materially alters the utility's operating or financial condition from that reflected in paragraphs (a) through (f); and
Not applicable

(h) The most recent historic balance sheet available as of the date of filing.
See PEPCO (F)-5

200.5 When a utility submits forecasted data as part of its proposed test year data, the utility's filing shall include, in addition to the information and data required by §§ 200.1 through 200.3 and §§ 201 through 213, as applicable, the following information:

(a) The basis for including forecasted data in the test year;
See Prefiled Direct Testimony of Company Witness Hook, PEPCO (F), p.3

(b) Key assumptions which underlie the projected jurisdictional ratemaking data for the proposed test year, including but not limited to, the following:

(1) Operating Revenues;
(2) Construction Program;
(3) Operating Expenses:
(A) Fuel and interchange costs, if appropriate; and

(B) Operating and maintenance expenses (excluding those expenses under § 200.5(a);
See Prefiled Direct Testimony of Company Witness Hook, PEPCO (F), pp.4-5

(c) Description of the procedures employed in the preparation of the projected data for the proposed test year; and
See Prefiled Direct Testimony of Company Witness Hook, PEPCO (F), p.5

(d) Analyses of changes in jurisdictional rate base, jurisdictional expenses and jurisdictional operating income between the historical test year and the proposed test year.
See PEPCO (F)-4

200.8 When a utility's historical test year and proposed test year are the same, the utility shall submit a single set of data.
Not applicable

200.9 If pro forma changes are included in a utility's proposed test year filing, data in that filing shall be provided for the proposed test year on an actual as well as a pro forma basis.
See PEPC0 (F)-1, (F)-3

200.10 In cases governed by §200.3, the information specified in §§201 through 213 shall be supplied within twenty-one (21) days after the filing of the application, unless otherwise ordered by the Commission, but shall not be regarded as part of the evidentiary record unless admitted into evidence.
(To be Provided)

200.11 Any request for waiver of the filing requirement in this section shall be submitted at the time of the filing of the application for a rate change. If the request for waiver is denied, the utility shall have twenty-one (21) days after the issuance of the denial by the Commission within which to supply the information.
(Application, Section VII)

APPENDIX B

Appendix B

Statement of Estimated Costs to be Incurred

Court Reporter and other Miscellaneous Expenses		$10,000.00
Outside Consultants		$358,000.00
Dr. Mark N. Lowry	$100,000.00	
Ms. Julie Cannell	$ 65,000.00	
Mr. Robert B. Hevert	$ 93,000.00	
Leftwich & Ludaway	$100,000.00	
Total Pepco Expenses		$368,000.00
Public Service Commission Assessment		$800,000.00
Office of People's Counsel Assessment		$1,200,000.00
Total Projected Costs		$2,368,000.00

APPENDIX C

Appendix C

Proposed Procedural Schedule

July 8, 2011	Pepco Application and Direct Testimony Filed
July 15, 2011	Commission issues Public Notice and Notice of Pre-hearing Conference
July 29, 2011	Pepco 21-day Compliance Filing Due
August 5, 2011	Petitions to Intervene and Proposed Designated Issues Due
August 12, 2011	Pre-hearing Conference
August 26, 2011	Commission Order and Report on Pre-hearing Conference
September 9, 2011	Pepco Supplemental Direct Testimony Due
September 9, 2011	All Information Requests to Pepco Regarding its Application and Pre-filed Direct Testimony Due
September 16, 2011	Workpapers Supporting Supplemental Direct Testimony of Pepco (if any) Due
September 30, 2011	Responses by Pepco to Information Requests on its Application and Pre-filed Testimony Due
October 14, 2011	Testimony in Response to Pepco by Intervenor Witnesses Due
October 21, 2011	Workpapers Supporting Direct Testimony of Intervenor Witnesses Due
October 28, 2011	All information Requests Regarding Testimony Filed October 14, 2011 Due
November 18, 2011	Responses by Pepco to Information Requests Filed October 28, 2011
November 29, 2011	Settlement and Stipulation Conference
December 5, 2011	Report on Settlement and Stipulation Conference Due
December 9, 2011	Rebuttal Testimony, Exhibits and Workpapers by All Parties Due
December 19, 2011	All Information Requests Relating to Rebuttal Testimony Filed on December 9, 2011 Due
January 9, 2012	Responses to Information Requests Relating to Rebuttal Testimony Filed on December 9, 2011 Due
Week of Jan 23rd	Formal Hearings Held
Week of Jan 30th	Community Hearing Held
February 24, 2012	Post Hearing Briefs Due
March 9, 2012	Reply Briefs Due
April 6, 2012	Commission Decision Expected

A. J. KAMERICK
Direct Testimony
DC P.S.C. - July, 2011

Introduced as:
PEPCO ______ (A)

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF ANTHONY J. KAMERICK
FORMAL CASE NO.______

Q. PLEASE STATE YOUR NAME AND POSITION.

A. My name is Anthony J. Kamerick. I am Senior Vice President and Chief Financial Officer of Pepco Holdings, Inc. (PHI). I am testifying on behalf of Potomac Electric Power Company (Pepco or the Company).

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR ROLE AS SENIOR VICE PRESIDENT AND CHIEF FINANCIAL OFFICER?

A. I am responsible for all financial matters related to PHI and its three regulated utility subsidiaries, including Pepco. My responsibilities include: accounting and financial reporting; treasury operations; pension administration; and investor relations. I am also the senior officer responsible for regulatory matters that come before the state commissions and the Federal Energy Regulatory Commission (FERC). Prior to my election as Chief Financial Officer, I was PHI's Senior Vice President and Chief Regulatory Officer, and prior to that, PHI's Vice President and Treasurer. In the latter capacity, I was responsible for managing PHI's relationship with the financial community and served as the primary contact with credit rating agencies.

Q. **WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND AND EXPERIENCE?**

A. I hold a Bachelor of Science degree in Accounting from the University of Maryland and a Master of Business Administration with a concentration in Finance and Investment from George Washington University. I have also successfully completed the University of Michigan's Public Utility Executive Program.

I joined Pepco in 1970 and have served in various positions of increasing responsibility, including Manager, Revenue Requirements and Director, Budgets and Financial Planning. In 1982, I was elected Assistant Treasurer of the Company and in 1983, I was elected Assistant Comptroller. From 1985 through February 1988, I served as Treasurer of Pepco's then-principal subsidiary, Potomac Capital Investment Corporation (PCI). I was elected Vice President and Treasurer of PCI in September 1986. I was reassigned to Pepco and elected Assistant Comptroller in March 1988, and elected Comptroller in April 1992. In May of 1994, I was elected Vice President and Treasurer of Pepco. Following Pepco's merger with Conectiv, and the formation of PHI as the parent of Pepco and Conectiv in August 2002, I was elected to the additional position of Vice President and Treasurer of PHI. In March 2009, I was promoted to Senior Vice President and Chief Regulatory Officer. In June 2009 I was elected PHI's Senior Vice President and Chief Financial Officer.

I am a member of the District of Columbia Chapter of Financial Executives International and a past President of the Chapter and Board member. In addition, I am a member of the National Association of Rate of Return Analysts and a former member of the Edison Electric Institute Accounting Research Committee and the Budget and Financial Forecasting Committee. I also serve on the Board of Directors of Montgomery Alliance for Community Giving and the Board of Directors of the Community Services for Autistic Adults and Children Foundation.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to (A) provide an overview of the Company's Application for an Increase in Base Distribution Rates; (B) briefly summarize the testimony of the Company's Witnesses; (C) discuss the shortfall in earnings and the Company's proposed mechanisms to mitigate regulatory lag; (D) discuss the importance of Pepco remaining a financially sound utility with investment grade credit ratings; (E) give an overview of the sale of the wholesale power generation business of Conectiv Energy and the resulting organizational review project; (F) discuss the measures the Company has taken to mitigate the necessary rate increase; and, (G) address the important role that Pepco plays in the District of Columbia community and why it is in the best interest of customers for the Company to maintain the financial ability to serve this role.

The testimony and accompanying Exhibits were prepared by me or under my direct supervision. The source documents for my testimony are Company records, public documents, and my personal knowledge and expertise.

Q. **PLEASE DESCRIBE THE COMPANY'S APPLICATION.**

A. This filing consists of the Application for an Increase in Base Distribution Rates, together with my testimony and Exhibits, and that of 11 other Witnesses. As described more fully below, those Witnesses and the topics they address are as follows:

- Dr. Mark N. Lowry, President, Pacific Economics Group Research and Senior Advisor to Pacific Economics Group will provide testimony on the issue of regulatory lag and its impact on the

Company's ability to earn its authorized return. He also discusses several regulatory lag mitigation approaches being used effectively in other jurisdictions and recommends the adoption of two proposals - the Reliability Investment Recovery Mechanism (RIM) and a prospective Commission rule change that will allow the use of fully forecasted test periods in future rate cases.

- Ms. Julie M. Cannell, President, J.M. Cannell, Inc., will present testimony from the view of prospective investors. Specifically, she will provide the investors' views on investment risks, regulatory outcomes and regulatory lag.
- Mr. Robert B. Hevert, President, Concentric Energy Advisors, Inc., provides testimony and Exhibits in support of the Company's proposed cost of equity.
- Mr. Kevin M. McGowan, Vice President and Treasurer, provides testimony and Exhibits addressing the appropriate capital structure and embedded cost of debt for Pepco, which along with Company Witness Hevert's cost of equity, are used to arrive at the appropriate overall rate of

return for Pepco. Company Witness McGowan also discusses how he developed the Company's 2012 estimated cost of service.

- Ms. Linda J. Hook, Manager, Revenue Requirements, will provide testimony and Exhibits in support of the Company's revenue requirement, the test year selection and the proposed ratemaking adjustments. She will also provide evidence that the Company is currently and will continue to experience exceptional levels of regulatory lag during the rate effective period.
- Ms. Kathleen A. White, Assistant Controller, provides testimony on the Company's Accounting Books and Records; PHI's costing and accounting procedures; and accounting policy changes affecting the Company.
- Ms. Dorothy S. Winston, Director, Tax, provides testimony on the impact on the Company's post-employment benefit deferred tax balance resulting from the change in deductibility of Medicare Part D benefits.
- Mr. William M. Gausman, Senior Vice President, Strategic Initiatives, provides testimony on the Company's Advanced Metering Infrastructure (AMI)

program. He also provides testimony on the Company's construction program, as well as support for certain ratemaking adjustments and a tariff modification.

- Mr. Charles R. Dickerson, Vice President, Customer Care, provides testimony on the programs that have been initiated to improve the Company's customer service through the addition of staff and technology solutions.
- Mr. Elliott P. Tanos, Manager, Cost Allocation, provides testimony and Exhibits in support of the Company's cost of service studies.
- Mr. Joseph F. Janocha, Manager, Rate Economics, provides testimony and Exhibits in support of the proposed rate design and Pepco's proposed tariffs.

Q. WHAT ARE SOME OF THE KEY ELEMENTS OF THE COMPANY'S REQUEST?

A. In addition to providing a detailed cost of service study for Pepco's electric distribution business in the District of Columbia, the Company provides testimony that addresses the impact of regulatory lag and discusses several mechanisms that are used in jurisdictions around the country to help mitigate the effects of regulatory lag. Through Company Witness Lowry, the Company provides an in-depth discussion on a RIM; the use of a fully- or partially-forecasted test period; the implementation of performance-based regulation; the use of a terminal or end-of-period rate base; the use of regulatory assets; and other cost recovery rider mechanisms. All of these measures are designed to mitigate regulatory lag without diminishing the Commission's oversight authority and, in most instances, have precedent among state utility commissions around the country.

Q. PLEASE SUMMARIZE THE REASONS FOR PEPCO'S RATE INCREASE REQUEST.

A. Pepco is requesting a $42,101,000 increase in its District of Columbia distribution rates (a 5.27% increase in a typical residential customer's bill), because the Company is not currently earning the rate of return authorized by the Commission in Formal Case No. 1076 on either an unadjusted or an adjusted basis, as is shown in the testimony and Exhibits of Company Witness Hook. Without an increase in rates, Pepco will not have the opportunity to earn its authorized rate of return. Therefore, the Company is seeking to increase its distribution rates in order to provide it an opportunity to earn the authorized return during the rate effective period. The Company is also seeking to recover its investments in AMI and reliability enhancements to the distribution system. The requested increase is required in order for the Company to have the ability to provide safe and reliable service. Without an opportunity to earn its authorized rate of return, Pepco will be at a disadvantage in competing for capital on reasonable terms with other firms in the capital markets, which will work to the disadvantage of District of Columbia customers in the long run because of the resulting increased capital costs.

The Company is requesting an increase in the authorized ROE from 9.625% to 10.75%. This return on equity is fully justified based on the cost of capital study conducted by Company Witness Hevert.

Q. WHY IS IT NECESSARY FOR PEPCO TO APPLY FOR A RATE INCREASE FIFTEEN MONTHS FROM THE COMMISSION'S MOST RECENT RATE ORDER (ORDER NO. 15710)?

A. The Company is seeking an increase in distribution rates because its revenue growth has not kept pace with the growth in rate base and operating costs and this situation will only get worse. As the Commission is aware, the rate setting process is forward-looking. Adequate rates for the future cannot be based solely upon an historical test period, particularly an historical test period that uses an average rate base. This is especially true in today's environment, when utility rate base-related operating and capital costs are growing at a more rapid rate than is revenue. Under such circumstances, rates set using historical test periods fail to give the Company an opportunity to earn the authorized rate of return.

The most recent case (Formal Case No. 1076) was largely based on costs incurred during a test period ended December 31, 2008, more than two and a half years ago. As I noted above, Pepco is not currently earning the ROE authorized in that case.

Q. **WHY IS THE GROWTH IN DISTRIBUTION RATE BASE OUTPACING THE GROWTH IN DISTRIBUTION OPERATING INCOME?**

A. The growth in rate base is being driven by the need to replace aging infrastructure, to enhance the reliability of the distribution system and to provide for future growth in the number of customers. Company Witness Gausman discusses the details of the Company's construction budget in his Direct Testimony in this proceeding, including reliability-related investments. As shown in Table 3 and Table 4 of Company Witness Gausman's testimony, Pepco's budgeted reliability capital expenditures for 2011 exceed the 2010 level by $53.6 million or nearly 140%.

The growth in Pepco's revenue is driven by the growth in its number of customers, which has averaged 0.3% over the last five years (2005-2010) and is projected to average 1.2% over the next five years (2010-2015). The increased revenues resulting from a 1.2% growth in customers is not sufficient to provide the Company an opportunity to earn its authorized ROE, given the pace of its rate base and operating expense growth. Clearly, the Company's revenues must grow at a faster pace in order to allow it to pay operating expenses and have an opportunity to recover the costs associated with the faster growing rate base. While the Company will need higher distribution rates to keep pace with growing rate base and operating expenses, we would expect the modest 5.27% increase in overall bills we are seeking in this case to be typical of what will be needed in the future, thereby keeping customers' bills reasonable. With bill savings attainable through conservation and energy efficiency, the necessary rate increase impacts can be further mitigated.

Q. WHY IS THE COMPANY REQUESTING A 10.75% RATE OF RETURN ON EQUITY?

A. The Company is requesting a ROE of 10.75% based on the cost of capital study conducted by Company Witness Hevert, who has demonstrated that to authorize a lower return would not adequately compensate the Company's equity investors for the risk they are undertaking, and therefore would place the Company and PHI at a disadvantage relative to comparable companies competing for capital.

Q. PLEASE DESCRIBE THE REGULATORY LAG MITIGATION MECHANISMS THAT PEPCO SEEKS IN THIS PROCEEDING.

A. The Company is proposing that the Commission adopt two specific regulatory lag mitigation mechanisms in this proceeding: (1) a RIM and (2) a prospective rule change to allow the Company to file rate cases using forecasted future test periods.

Given the Company's current and upcoming high level of rate base investment, we propose that the Commission allow use of these two mechanisms so that the Company's revenue will more closely match the costs associated with providing service during the rate effective period. As discussed by Company Witness Lowry, the RIM and the use of future test periods will help reduce the effects of regulatory lag while still producing results that can be closely monitored by the Commission.

Pepco has made and will continue to make significant investments in the repair and replacement of the Company's aging reliability-related infrastructure. While necessary and beneficial for existing customers, the investments do not relate to the connection of new customers, and consequently do not produce sufficient revenue to recover costs associated with the investment. The creation of a RIM will allow the Company to efficiently recover costs that are mandated by Pepco's obligation to provide safe, reliable and adequate service to its customers without the need to file frequent rate cases.

Q. IS THE COMPANY'S FAILURE TO EARN ITS RATE OF RETURN A RECENT TREND?

A. No. As shown in Exhibit PEPCO (F)-8 attached to Company Witness Hook's testimony, the Company has not earned its authorized rate of return in the District of Columbia for several years. The shortfall in earnings necessary to earn the authorized rate of return due to the timing difference between the test period and the rate effective period is commonly referred to as "regulatory lag."

Q. WHY IS REGULATORY LAG MITIGATION IMPORTANT?

A. Without adequate recognition of the regulatory lag problem, and the adoption by the Commission of mechanisms to offset it, Pepco will continue to under-earn its authorized rate of return for the foreseeable future. This continual problem of under-earning is the reason for the Company's two regulatory lag mitigation proposals as discussed by Company Witness Lowry.

Moreover, without adequate mechanisms to combat the effects of regulatory lag, the Company will need to file rate increase applications almost annually over the next several years. Filing such frequent rate cases, with all the attendant testimony, discovery, hearings and costs, is a far less efficient and a much more time consuming and expensive process than to institute effective mechanisms to deal directly with regulatory lag. It is clear that the current rate case practice and process is not achieving the goals for which it was designed to address. It is inadequate, expensive, inefficient, time consuming and produces unreasonable results prospectively.

Q. WHAT IS CAUSING THE COMPANY'S INABILITY TO EARN THE AUTHORIZED RATE OF RETURN?

A. As I previously testified, the Company's revenues are not growing as fast as the growth in its rate base-related costs and operating costs, despite aggressive efforts to control costs. Moreover, the use of an historical average rate base, with only a few forward-looking adjustments, does not adequately measure the level of costs likely to be incurred by the Company during the rate effective period.

Q. IS THE COMPANY PRESENTING DATA TO DEMONSTRATE THE EFFECT OF REGULATORY LAG DURING THE RATE EFFECTIVE PERIOD?

A. Yes. Company Witness Hook presents testimony and an Exhibit demonstrating that even if the Company is granted 100% of its rate increase request, it will be unable to earn its authorized rate of return during the rate effective period.

Q. PLEASE DISCUSS OPTIONS TO MITIGATE REGULATORY LAG.

A. As Company Witness Lowry testifies, there are commission precedents to support the mitigation of regulatory lag through the use of various ratemaking mechanisms.

At the federal level, FERC has authorized a formula rate process whereby a company's transmission rates are updated annually without the necessity of having a time-consuming and costly rate case process to reflect current expenses and rate base investments based on a pre-set ROE. This process provides utilities the opportunity to earn their authorized ROE without costly and time-consuming rate case filings, and without sacrificing adequate oversight. Customers can be spared the high costs that result from frequent and protracted rate case filings. Additionally, formula rates protect customers and the utility from over and under recovery of the allowed ROE through a true-up mechanism and protect customers from rate shock by making gradual changes to transmission rates. These same principles can be applied to distribution rates.

The use of any one or more of the options discussed by Company Witness Lowry will not affect the Commission's ability to determine the prudence of any of the Company's costs.

Q. **HOW IMPORTANT IS THE NEED TO ADDRESS REGULATORY LAG?**

A. With the sale of its wholesale generation business and the wind down of its retail gas and electric supply business, PHI is now a transmission and distribution (T&D) company. Pepco's aging infrastructure will require repair and replacement in order to continue to supply safe and reliable service, as is the case with infrastructure across the country (e.g., other electric and gas distribution facilities, water systems, and federal, state and local roads and bridges).

Moreover, technology is now available that will enable us to provide more reliable service in a cost-effective manner. However, in order to replace aging infrastructure and implement cost-effective distribution technologies, the Company will be required to make substantial investments in its rate base.

It is more important than ever that the Company mitigate the impacts of regulatory lag. If these negative impacts are not alleviated with the adoption of effective regulatory lag mitigation mechanisms, the Company will never have a reasonable opportunity to earn its authorized rate of return. It will not be able to attract on reasonable terms the capital it needs to serve its customers, and will need to file for rate increases on a more or less annual basis over the next several years. Pepco's ability to maintain its financial health is essential to its being able to provide safe, reliable and efficient service to customers.

Q. IS THE INVESTMENT COMMUNITY CONCERNED ABOUT REGULATORY LAG?

A. Yes. Not only are they concerned, but regulatory lag is the single issue that investors bring up the most during investor meetings with the Company in discussing the challenges faced by Pepco and the other PHI utilities. In fact, since the beginning of 2011, the senior management of PHI, including myself, has participated in six investor conferences and held 36 additional meetings with investors across the Country. In virtually every meeting, investors consistently asked what the Company is doing and will be doing to address regulatory lag.

The practical problem that regulatory lag causes is that investors view an investment in the Company as more risky, because an inability to earn the authorized rate of return means that the Company is not covering its costs and is also more prone to negative credit rating actions. Over the long run, a company that is viewed as more risky will pay more for capital, increasing its cost of capital. During constrained markets, such as we have seen over the past few years, the Company could experience limited access to needed funds. Both of these problems will increase costs to the Company and cause a need for rates to be higher in the future than they otherwise need to be. Moreover, it is important that Pepco and PHI be able to compete for capital under all capital market conditions to be able to provide safe and reliable service to customers.

Q. **IS THE INVESTMENT COMMUNITY CONCERNED ABOUT UTILITY CREDIT RATINGS?**

A. Yes. Maintaining investment grade credit ratings is critical to the financial health of a utility and critical to its ability to access capital markets for financing essential capital projects on reasonable terms.

For example, in 2007, Ameren Corporation's credit rating was downgraded by all three credit rating agencies (Moody's Investors Service (Moody's), Standard & Poor's (S&P) and Fitch Ratings (Fitch)). Moody's stated with respect to the rating reduction, "The downgrade of parent company Ameren considers the challenging political and regulatory environment facing the company in both of its jurisdictions."[1]

Moody's noted in reference to the downgrade of Ameren and its Illinois subsidiaries, ". . .the increasing support for a rate freeze and the continued

[1] "Rating Action: Moody's downgrades Ameren & utility subs, ratings remain on review." Moody's Investors Service. 12 MAR 2007.

political intervention in the utility regulatory process in Illinois has increased credit risk for investors and is no longer supportive of investment grade senior unsecured ratings." In reference to its Missouri subsidiary, Moody's emphasized the downgrade was "prompted by higher costs at that utility, lower financial metrics and a continued challenging regulatory environment in Missouri. . ."[1]

Ameren, in its 2007 10-K filed with the U.S. Securities and Exchange Commission (SEC), discussed the downgrade's effect on its cost of borrowing, "Interest expense increased $73 million in 2007 compared with 2006, primarily because of increased short-term borrowings, higher interest rates due to reduced credit ratings, and other items . . ."[2] (Page 44)

Ameren's cash flow was also negatively affected by the downgrade; "Other factors also reduced cash flow: increased interest payments as a result of lower credit ratings and increased debt."[2] (Page 47)

In addition, the downgrade forced Ameren and its subsidiaries to make prepayments and post collateral on certain obligations; "Collateral postings and prepayments made as of the end of 2007 were $56 million, $5 million,

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[2] Ameren Corp., December 31, 2007 Form 10-K (filed February 29, 2008).

$8 million, $14 million, $14 million, and $21 million at Ameren, UE, CIPS, CILCORP, CILCO and IP, respectively, resulting from our reduced issuer and senior unsecured debt ratings." (Page 60)

Ameren went on to discuss the downgrade's effect on its ability to access the capital markets; "Ameren and UE are currently limited in their access to the commercial paper market as a result of downgrades in their short-term credit ratings." (Page 121)

Q. ARE THERE EXAMPLES WHERE A UTILITY'S CREDIT RATING WAS ADVERSELY AFFECTED BY REGULATORY LAG?

A. Yes. Hawaiian Electric Industries, Inc. (HEI) faced a downgrade by S&P on November 15, 2010 due in part to concerns about regulatory lag. In its research update, S&P downgraded the company and its electric utility subsidiaries of Hawaiian Electric Co. Inc. (HECO), Maui Electric Co. Ltd., and Hawaiian Electric Light Co. Inc. to 'BBB-'from 'BBB'. S&P went on to explain, "Meanwhile, the company's capital and O&M expenses continue to climb. Regulatory lag and disallowance of some costs has contributed to return on equity (ROE) that has been below

6% in the last three years for the three utilities, and we do not expect any material improvement."[3]

In its Form 10-K that was filed with the SEC after S&P's rating downgrade, HEI explained the risks it faced from such rating downgrades: "If S&P or Moody's were to downgrade HEI's or HECO's long-term debt ratings because of past adverse effects, or if future events were to adversely affect the availability of capital to the Company, HEI's and HECO's ability to borrow and raise capital could be constrained and their future borrowing costs would likely increase with resulting reductions in HEI's consolidated net income in future periods. Further, if HEI's or HECO's commercial paper ratings were to be further downgraded, HEI and HECO might not be able to sell commercial paper and might be required to draw on more expensive bank lines of credit or to defer capital or other expenditures."[4] (Pages 28 & 29)

Q. **HAVE THERE BEEN REGULATORY OUTCOMES THAT HAVE HAD A POSITIVE EFFECT ON CREDIT RATINGS?**

A. Yes. In 2008, S&P upgraded the Ameren Illinois utilities' credit ratings two notches from BB to BBB-

[3] "Rating Action: Hawaiian Electric Industries Inc. and Utility Subsidiaries Downgraded to 'BBB-' On Regulatory Lag, Weak Economy." Standard & Poor's Ratings Service. 15 NOV 2010.

[4] Hawaiian Electric Industries, Inc., December 31, 2010 Form 10-K (filed February 18, 2011).

based on its "assessment that the regulatory and political environment in Illinois will be reasonably supportive of investment grade credit quality with regard to their pending rate cases."[5] Likewise, in the second quarter of 2010, S&P upgraded Westar Energy's credit rating one notch to BBB from BBB- when "the Company implemented multiple constructive rate orders that supported base rates and reduced regulatory lag. . . "[6] (Page 4)

As discussed in the examples above, regulatory outcomes have a major impact on utility credit ratings and can adversely, or favorably, impact the financial health of the utility and the cost of providing service to its customers.

Q. HOW DO PEPCO'S RESIDENTIAL DISTRIBUTION RATE CHANGES COMPARE WITH THE RATE OF INFLATION?

A. The last distribution rate increase for Pepco prior to deregulation was in 1994. Since then, overall prices in the economy have increased by 53.2%, as measured by the U.S. Department of Labor, Bureau of Labor Statistics' Consumer Price Index (CPI). However, Pepco's residential distribution rates have only increased by a cumulative

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[5] "Research Update: Ameren Corp's Illinois Subsidiaries Upgraded to Investment Grade." Standard & Poor's. 11 SEP 2008.

[6] "EEI Q2 2010 Financial Update." Edison Electric Institute.

43.2% for a typical customer using 750 kWh per month, including the proposed rate increase in this case, over the same period of 17 years. Thus, Pepco's residential distribution rates have decreased in real terms since 1994.

Q. **HOW DO THE COMPANY'S ADMINISTRATIVE AND GENERAL (A&G) COSTS COMPARE WITH SIMILAR UTILITIES?**

A. To demonstrate the reasonableness of Pepco's A&G costs, I offer Exhibit PEPCO (A)-1. Exhibit PEPCO (A)-1 compares a peer group of utilities' A&G costs (from FERC Form 1 data) to Pepco's A&G costs, which include all of the A&G costs allocated from the PHI Service Company. The comparison looks at total A&G expenses as a percentage of retail sales and net electric plant in service.

As shown at line 22, page 1 of PEPCO (A)-1, Pepco's A&G costs, as a percentage of retail revenues, were 5.6%. In comparison, the average A&G cost for the peer group was 9.5% of retail revenues (line 19). As shown at page 2, line 22, Pepco's A&G cost, as a percentage of net plant, was 3.5% as compared to the peer group average of 4.6% (line 19).

Thus, Pepco's A&G cost ratios are consistently lower than the average for both metrics - revenue and net plant - when compared to the peer group.

Q. PLEASE EXPLAIN HOW THE PEER COMPANIES IN YOUR STUDY WERE SELECTED.

A. The companies reflected on PEPCO (A)-1 were chosen because they have a business mix similar to that of Pepco - that is, they are primarily focused on transmission and distribution functions.

Q. HAVE THERE BEEN ANY ADDITIONAL STUDIES PERFORMED REGARDING PHI'S SERVICE COMPANY COSTS?

A. Yes. In Formal Case No. 1076, the Company presented a benchmarking study conducted by the Hackett Group of service company administrative and general costs. The study demonstrated the reasonableness of PHI's service company costs in comparison to its peer companies, specifically stating that:

(1) PHI's operating costs, in proportion to total revenue for all benchmarked functions[7], were lower than those of its peer group;

(2) PHI's staffing levels were lower than its peer group on a normalized basis;

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[7] Functions include Human Resources, Procurement, Information Technology, Finance, and Executive & Corporate Services.

(3) PHI's staffing mixes revealed a higher level of professional and managerial staff than its peer group, likely due to PHI's extensive use of outsourcing and its greater reliance on technology; and

(4) PHI's inflation-adjusted, fully-loaded labor costs were in line with its peers.

PHI's A&G cost still remains reasonable after the sale of Conectiv Energy and the phasing out of the retail energy supply business of Pepco Energy Services (PES).

Q. PLEASE DISCUSS THE SALE OF CONECTIV ENERGY AND THE CHANGE IN PHI'S CORPORATE STRATEGY THAT RESULTED IN THE ORGANIZATIONAL REVIEW PROJECT.

A. The sale of Conectiv Energy and the wind down of PES' retail energy business were strategic decisions made by PHI's Board of Directors and executive management with the goal of repositioning PHI as primarily a T&D business. This change in strategic direction required us to closely analyze our corporate structure, and to reduce costs and the overhead that was previously borne by these discontinued businesses.

Concurrent with the closing of the Conectiv Energy transaction, the Company embarked upon a comprehensive review of the corporate services organization. Our ultimate goals were to ensure that the utility companies under PHI were not negatively affected by the decision to exit the competitive energy business, and that customers of regulated utility services would not experience an increase in cost as a result of the Company's actions.

Q. **PLEASE SUMMARIZE THE COMPANY'S ORGANIZATIONAL REVIEW PROJECT.**

A. The organizational review project was initiated by PHI to address the A&G costs incurred by the PHI Service Company that were previously allocated to competitive businesses that were being sold (Conectiv Energy) and phased out (PES' retail energy supply business).

As a result of the sale of Conectiv Energy, PHI recognized that approximately $20 million of corporate costs that were previously allocated to Conectiv Energy would remain after the sale and would be allocated, based on the approved Cost Allocation Manual, to utility operations, unless actions were taken to lower corporate costs.

PHI undertook a reorganization project to address this issue, with the goal of reducing operation and maintenance expenses by at least $20 million from Corporate Services. The initiative took several months and the efforts of several cross-departmental working groups, as well as the assistance of outside consultants experienced in corporate "right sizing." The result was nearly $28 million of operation and maintenance savings which included the reduction of a significant number of full-time employees, contractors, and the decision to not fill a significant number of open positions. The end result is that Pepco's cost of service will not be affected at all by the sale or wind down of PHI's unregulated businesses.

Q. HAS PEPCO IMPLEMENTED OTHER MEASURES TO MITIGATE THE RATE INCREASE IT WOULD OTHERWISE REQUIRE?

A. Pepco has completed a Cost Containment Study contained as Exhibit PEPCO (A)-2. This study identified the various areas of operations in which the Company has sought to mitigate rising costs.

Q. WHAT ARE SOME OF THESE MEASURES?

A. Pepco has undertaken a number of initiatives which will yield annual cost savings. The Company has improved and enhanced equipment inspection procedures, begun working with a mobile dispatch system for reconnection work, and added a paperless billing system to the eBill system website. These initiatives are just a small sample of the cost mitigation efforts in the Company's Cost Containment Study.

Q. HOW DOES THE COMPANY CONTRIBUTE TO THE COMMUNITY AT LARGE?

A. Pepco is a financial supporter of many non-profit organizations whose focus is improving the quality of life of our neighbors. Whether targeting improvements in education, emergency services, health and human services, programs for children and youth or tackling the issues of hunger and homelessness, Pepco's giving is meant to help non-profit organizations address and positively impact community life. All of these costs are recorded below the line and are therefore borne by PHI shareholders.

Community and neighborhood groups in Pepco's service territory often call with questions about electric service, rates, construction or maintenance on our system, and other issues. Pepco's Speakers Bureau helps to bring the answers directly to our customers in their own communities. The Company's Speakers Bureau is comprised of Pepco employees who are knowledgeable in a particular subject area that is of interest to the community. They are available to speak both during the day and in the evening to accommodate all customers' needs.

Q. HAS PHI BEEN RECOGNIZED FOR HAVING A DIVERSE SUPPLIER BASE AND WORKFORCE?

A. Yes. Pepco has a long-standing record of recruiting, hiring, developing, and retaining a workforce that is diverse, as well as having a diverse supplier base. Pepco has been recognized for these efforts by the following organizations:

- Diversity/Careers in Engineering & Information Technology: "Best Diversity Company 2010;"
- Women's Business Enterprise Council: "Shining Star;"
- Howard University Institute for Entrepreneurship, Leadership and Innovation: "Corporate Leadership" Award;
- Hispanic Business Magazine: "Top 25 Supplier Diversity Programs;"
- Black Enterprise Magazine: "40 Best Companies for Diversity" for the sixth year in a row for the supplier diversity initiatives and diversity of employee and senior management base; and
- Minority Corporate Counsel Association: "Employer of Choice."

Q. HOW DOES THE COMPANY HELP ACHIEVE THE DISTRICT OF COLUMBIA'S ENERGY GOALS?

A. The Company's Blueprint for the Future filings, and the Commission's review and acceptance of a suite of energy efficiency and conservation programs, has helped District residents to reduce their energy and demand while creating a smooth transition to the Sustainable Energy Utility. The Company has stressed partnership and collaboration with area small businesses to work on many of its programs. The Company is also committed to its role as a facilitator for bringing customers and third-party energy suppliers together.

Q. PLEASE SUMMARIZE THE KEY POINTS OF YOUR TESTIMONY.

A. Pepco continues to be a regulated transmission and distribution Company. Its core function is to deliver power to Pepco customers in a safe and reliable manner.

In order to accomplish this objective in light of PHI's strategic direction, it is imperative that the issue of regulatory lag be addressed and resolved favorably in order for Pepco and PHI to have access to the capital necessary for investments in transmission and distribution infrastructure and new technologies. In order for Pepco and PHI to have access to the capital markets on reasonable terms, they must maintain their financial integrity and strong investment grade credit ratings. The investments that Pepco makes in its distribution infrastructure directly affect citizens of the District of Columbia - our customers and our shareholders.

To mitigate the effects of regulatory lag, Pepco has offered the Commission a range of options to reduce the gap that occurs between the authorized rate of return and the return the Company actually earns.

Pepco has a solid and long-standing commitment to the communities that we serve.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

A. J. KAMERICK
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO ______ (A)-1

Analysis of A&G Expense as a Percentage of Ultimate Sales to Customers
Year 2010
Based on FERC Form 1 Data

(1) Line No.	(2) Company	(3) Total A & G ($) pg 323, col B, line 197	(4) Total Sales ($) to Ultimate customers pg 300, col B, line 10	(5) Ratio A&G to Sales Rev Col 4/Col 3
1	**Consolidated Edison**			
2	Consolidated Edison of New York	1,029,664,793	7,758,430,052	13.2716%
3	Orange & Rockland Utilities, Inc.	78,977,783	460,111,994	17.1649%
4	**Northeast Utilities**			
5	Connecticut Light & Power	220,132,768	2,596,172,369	8.4791%
6	Public Service of New Hampshire	112,765,246	987,277,699	11.4218%
7	Western Massachusetts Electric Company	37,161,314	367,453,850	10.1132%
8	**NSTAR**	149,338,323	2,249,567,243	6.6385%
9	**Alliant Energy**			
10	Wisconsin Power & Light Company	69,906,928	1,008,351,644	6.9328%
11	Interstate Power & Light	89,985,501	1,396,475,301	6.4438%
12	**Ameren Corp.**			
13	Union Electric Company	240,384,328	2,610,547,084	9.2082%
14	Illinois Power Company	53,632,185	806,013,615	6.6540%
15	Ameren Illinois Company	126,171,338	1,982,461,848	6.3644%
16	**Westar Energy**			
17	Westar Energy	93,046,273	812,333,787	11.4542%
18				
19	**Peer Group Average**			**9.5122%**
20				
21				
22	**PEPCO**	119,993,642	2,131,968,357	5.6283%
23	**Delmarva Power - Electric**	69,612,155	1,066,887,402	6.5248%
24	**Atlantic City Electric**	52,692,713	1,161,759,319	4.5356%

Analysis of A&G Expense as a Percentage of Net Utility Plant
Year 2010
Based on FERC Form 1 Data

(1) Line No.	(2) Company	(3) Total A & G ($) pg 323, col B, line 197	(4) Net Utility Plant ($) pg 200, col C, line 15	(5) Ratio A&G to Plant Col 3/Col 4
1	**Consolidated Edison**			
2	Consolidated Edison of New York	1,029,664,793	15,727,884,380	6.5467%
3	Orange & Rockland Utilities, Inc.	78,977,783	658,016,837	12.0024%
4	**Northeast Utilities**			
5	Connecticut Light & Power	220,132,768	5,499,173,722	4.0030%
6	Public Service of New Hampshire	112,765,246	1,992,618,139	5.6591%
7	Western Massachusetts Electric Company	37,161,314	805,228,666	4.6150%
8	**NSTAR**	149,338,323	3,964,677,406	3.7667%
9	**Alliant Energy**			
10	Wisconsin Power & Light Company	69,906,928	2,359,111,653	2.9633%
11	Interstate Power & Light	89,985,501	2,911,575,754	3.0906%
12	**Ameren Corp.**			
13	Union Electric Company	240,384,328	8,502,328,552	2.8273%
14	Illinois Power Company	53,632,185	1,922,140,099	2.7902%
15	Ameren Illinois Company	126,171,338	3,208,858,972	3.9320%
16	**Westar Energy**			
17	Westar Energy	93,046,273	3,242,249,985	2.8698%
18				
19	**Peer Group Average**			**4.5888%**
20				
21				
22	**PEPCO**	119,993,642	3,436,534,111	3.4917%
23	**Delmarva Power - Electric**	69,612,155	1,608,327,700	4.3282%
24	**Atlantic City Electric**	52,692,713	1,702,915,712	3.0943%

A. J. KAMERICK
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO ______ (A)-2

Potomac Electric Power Company
Cost Containment Study Summary

Savings ($ in Thousands)

Description of Activity	Entity	2003	2004	2005	2006	2007	2008	2009	2010
Information Technology									
Merger Synergies (FTE Related)	PHI	$ 3,600	$ 3,700	$ 300					
Realignment Synergies (FTE Related)						$ 1,100			
Negotiated Savings on Support Contracts	PHI		$ 500		400				
Negotiated Savings on Software Contracts	PHI				200	100			
Total IT		**$ 3,600**	**$ 4,200**	**$ 300**	**$ 600**	**$ 1,200**	**$ -**	**$ -**	**$ -**
Customer Care									
Deployed Natural Language speech recognition system	Pepco		$ 1,512	$ 2,016	$ 13,237	$ 10,299	$ 9,583	$ 8,037	$ 14,891
Enhanced CIS to adjust consumption and/or revenue transactions prior to billing	Pepco	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75
Added paperless option to eBill system and web site	Pepco	$ 17	$ 71	$ 86	$ 100	$ 200	$ 310	$ 341	$ 388
Implemented "Auto Attendant" system to corporate switchboard	Pepco	$ 30	$ 60	$ 60	$ 75	$ 75	$ 75	$ 75	$ 75
Enabled limited access to CIS by social agencies via the Web to assist low-income customers	Pepco			$ 75	$ 75	$ 75	$ 75	$ 75	$ 75
Started unified sample and periodic meter test programs	Pepco		$ 706	$ 706	$ 706	$ 706	$ 706	$ 706	$ 706
Initiated sample acceptance testing for new meters	Pepco			$ 106	$ 106	$ 106	$ 106	$ 106	$ 106
Installed Meter Information Data System	Pepco	$ 798	$ 798	$ 798	$ 798	$ 798	$ 798	$ 798	$ 798
Installed Meter Maintenance Work Management System	Pepco	$ 400	$ 400	$ 400	$ 400	$ 400	$ 400	$ 400	$ 400
Began using Mobile Dispatch system for Reconnection work	Pepco	$ 456	$ 510	$ 714	$ 797	$ -	$ -	$ -	$ -
Modified work shift schedules	Pepco		$ 150	$ 150	$ 150	$ -	$ -	$ -	$ -
Installed approximately 750 LCAMS metering systems	Pepco	$ 186	$ 186	$ 186	$ 195	$ 210	$ 205	$ 200	$ 195
Outsourced meter reading to Accu-Read	Pepco	$ 4,000	$ 6,800	$ 6,800	$ 6,800	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Implemented a workflow management and record imaging system	Pepco	$ 38	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75
Replaced special billing system with SAP R/3 system	Pepco	$ 21	$ 52	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102
Outsourced reconnects to Scope Services	Pepco				$ -	$ 1,343	$ 1,343	$ 1,343	$ 1,343
Implemented Maximo task management system	Pepco				$ -	$ 515	$ 515	$ 343	$ -
Significantly expanded Revenue Protection activities	Pepco				$ -	$ 1,569	$ 8,760	$ 4,360	$ 5,123
Move Meter personnel from 1620 2nd St to Benning	Pepco				$ -	$ 404	$ 404	$ 404	$ 404
G99 Meter removal project outsourced to Scope	Pepco				$ 200	$ -	$ -	$ -	$ -
Accu-Read performing special reads	Pepco					$ -	$ 326	$ 435	$ 304
Total Customer Care		**$ 6,021**	**$ 11,395**	**$ 12,349**	**$ 23,891**	**$ 26,952**	**$ 33,857**	**$ 27,875**	**$ 35,061**
Operations									
Productivity and technological improvements resulting from 2003 Contract Negotiations Benefits	Pepco	$ 2,230	$ 2,260	$ 3,010	$ 3,050	$ 3,050	$ 3,050	$ 3,050	$ 3,050
Improved Equipment Inspection Procedures					$ 170	$ 170	$ 170	$ 170	$ 170
Rebid T&M Aerial Line Contracts with Unit Price Work					$ 200	$ 400	$ 200	$ 200	$ 200
Rebid T&M Underground Contract with Unit Price Work					$ 100	$ 150	$ 100	$ 100	$ 100
General Improvement in Productivity FTE reductions					$ 600	$ 650	$ 600	$ 600	$ 600
Total Operations		**$ 2,230**	**$ 2,260**	**$ 3,010**	**$ 4,120**	**$ 4,420**	**$ 4,120**	**$ 4,120**	**$ 4,120**
Corporate Services									
Merger Synergy Savings	PHI	$ 20,789	$ 26,013	$ 23,934	-	-	-	-	-
Supply Chain Procurement Savings	PHI	$ 32,133	$ 29,026	$ 26,712	$ 17,100	$ 34,400	$ 23,543	$ 18,880	$ 20,333
Total Corporate Services		**$ 52,922**	**$ 55,039**	**$ 50,646**	**$ 17,100**	**$ 34,400**	**$ 23,543**	**$ 18,880**	**$ 20,333**
Grand Total		$ 64,773	$ 72,894	$ 66,305	$ 45,711	$ 66,972	$ 61,520	$ 50,875	$ 59,514
Cumulative Grand Total		$ 64,773	$ 137,667	$ 203,972	$ 249,683	$ 316,655	$ 378,175	$ 429,050	$ 488,564

Potomac Electric Power Company
Cost Containment Study Summary

		Savings ($ in Thousands)						
Description of Activity	**Entity**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Deployed Natural Language speech recognition system	Pepco				$ 1,512	$ 2,016	$ 13,237	$ 10,299
Enhanced CIS to adjust consumption and/or revenue transactions prior to billing	Pepco	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75
Added paperless option to eBill system and web site	Pepco			$ 17	$ 71	$ 86	$ 100	$ 200
Implemented "Auto Attendant" system to corporate switchboard	Pepco	$ 30	$ 30	$ 30	$ 60	$ 60	$ 75	$ 75
Enabled limited access to CIS by social agencies via the Web to assist low-income customers	Pepco					$ 75	$ 75	$ 75
Started unified sample and periodic meter test programs	Pepco				$ 706	$ 706	$ 706	$ 706
Initiated sample acceptance testing for new meters	Pepco					$ 106	$ 106	$ 106
Installed Meter Information Data System	Pepco		$ 798	$ 798	$ 798	$ 798	$ 798	$ 798
Installed Meter Maintenance Work Management System	Pepco	$ 400	$ 400	$ 400	$ 400	$ 400	$ 400	$ 400
Began using Mobile Dispatch system for Reconnection work	Pepco	$ 375	$ 405	$ 456	$ 510	$ 714	$ 797	$ -
Modified work shift schedules	Pepco				$ 150	$ 150	$ 150	$ -
Installed approximately 750 LCAMS metering systems	Pepco	$ 186	$ 186	$ 186	$ 186	$ 186	$ 195	$ 210
Outsourced meter reading to Accu-Read	Pepco	$ 1,200	$ 3,200	$ 4,000	$ 6,800	$ 6,800	$ 6,800	$ 10,000
Implemented a workflow management and record imaging system	Pepco			$ 38	$ 75	$ 75	$ 75	$ 75
Replaced special billing system with SAP R/3 system	Pepco			$ 21	$ 52	$ 102	$ 102	$ 102
Outsourced reconnects to Scope Services	Pepco						$ -	$ 1,343
Implemented Maximo task management system	Pepco						$ -	$ 515
Significantly expanded Revenue Protection activities	Pepco						$ -	$ 1,569
Move Meter personnel from 1620 2nd St to Benning	Pepco						$ -	$ 404
G99 Meter removal project outsourced to Scope	Pepco						$ 200	$ -
Accu-Read performing special reads								$ -
New Improvement Activity								
New Improvement Activity								
New Improvement Activity								
Total Customer Care		$ 2,266	$ 5,094	$ 6,021	$ 11,395	$ 12,349	$ 23,891	$ 26,952

Potomac Electric Power Company
Cost Containment Study Summary

		Savings ($ in Thousands)									
Description of Activity	**Entity**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Finance											
Outsourcing of shareholder services	PHI			$ 161	$ 483	$ 483	483	604	628	628	628
Debt and Preferred Stock Refinancing	Pepco		$ 1,527	$ 4,753	$ 22,430	$ 26,007	25,120	24,251	22,258	23,478	23,442
Total Finance			$ 1,527	$ 4,914	$ 22,913	$ 26,490	$ 25,603	$ 24,855	$ 22,886	$ 24,106	$ 24,070
Benefits											
Total Benefits							$ 7,100	$ 19,400	$ 26,800	$ 27,100	$ 37,220
Legal Services											
In-sourcing and consolidation	PHI			$ 3,600	$ 7,160	$ 4,050	4,145	4,255	7,909	5,840	9,120
Operations											
Productivity and technological improvements	Pepco			$ 2,230	$ 2,260	$ 3,010					
Corporate Services											
Merger Synergy Savings	PHI		$ 9,500	$ 20,789	$ 26,013	$ 23,934					
Supply Chain Procurement Savings	PHI		$ 2,100	$ 32,133	$ 29,026	$ 26,712					
Total Corporate Services			$ 11,600	$ 52,922	$ 55,039	$ 50,646	$ -	$ -	$ -	$ -	$ -
Total		$ -	$ 13,127	$ 63,666	$ 87,372	$ 84,196	$ 36,848	$ 48,510	$ 57,595	$ 57,046	$ 70,410
Cumulative		$ 4,166	$ 17,293	$ 80,959	$ 168,331	$ 252,527	$ 289,375	$ 337,884	$ 395,479	$ 452,524	$ 522,934

Savings Totals by Year

Line of Business		*Year Reduction*	*OM Avoidance*	*OM Reduction*	*Capital Cost*	*Capital Savings*	*Auction Savings*	*Total*
ACE								
	2006	$0	$0	$1,192,171	$216,107	$0	$1,408,278	$2,816,556
	2007	$0	$109,306	$1,281,834	$2,231,807	$0	$3,622,947	$7,245,894
	2008	$43,807	$0	$128,756	$397,987	$0	$570,550	$1,141,100
	2009	$744,829	$17,504	$43,400	$189,624	$0	$995,357	$1,990,714
	2010	$848,524	$0	$140,819	$67,264	$0	$1,056,607	$2,113,214
Total ACE		$1,637,160	$126,810	$2,786,980	$3,102,789	$0	$7,653,739	$15,307,478
CE								
	2006	$337,177	$0	$4,825,557	$0	$0	$5,162,734	$10,325,468
	2007	$497,265	$29,310	$9,288,411	$0	$0	$9,814,986	$19,629,972
	2008	$857,129	$0	$7,766,424	$0	$0	$8,623,553	$17,247,106
	2009	$0	$0	$4,457,870	$0	$0	$4,457,870	$8,915,740
Total CE		$1,691,571	$29,310	$26,338,262	$0	$0	$28,059,143	$56,118,286
CPD								
	2006	$3,668	$36,360	$109,792	$52,335	$0	$202,155	$404,310
	2007	$113,003	$3,069	$55,207	$72,311	$0	$243,590	$487,180
	2008	$0	$0	$0	$0	$0	$0	$0
	2009	$0	$2,852	$0	$91,791	$0	$94,643	$189,286
	2010	$434,169	$0	$0	$0	$0	$434,169	$868,338
Total CPD		$550,840	$42,281	$164,999	$216,437	$0	$974,557	$1,949,114
DPL								
	2006	$0	$187,160	$94,160	$727,841	$0	$1,009,161	$2,018,322
	2007	$126,963	$1,137	$80,547	$531,431	$0	$740,078	$1,480,156
	2008	$209,203	$190	$568,670	$473,479	$0	$1,251,542	$2,503,084
	2009	$409,308	$83,373	$438,196	$1,218,814	$0	$2,149,691	$4,299,382
	2010	$693,848	$156,350	$587,211	$434,599	$0	$1,872,008	$3,744,016
Total DPL		$1,439,322	$428,210	$1,768,784	$3,386,164	$0	$7,022,480	$14,044,960
PHI								
	2006	$1,612,582	$2,400,113	$422	$0	$0	$4,013,117	$8,026,234

Line of Business		*Year Reduction*	*OM Avoidance*	*OM Reduction*	*Capital Cost*	*Capital Savings*	*Auction Savings*	
	2007	$1,260,499	$2,666,422	$3,082,081	$303,359	$0	$7,312,361	$14,624,722
	2008	$947,260	$1,545,149	$834,043	$1,760,346	$0	$5,086,798	$10,173,596
	2009	$1,186,335	$2,205,381	$4,310,942	$287,265	$0	$7,989,923	$15,979,846
	2010	$3,008,658	$1,372,342	$6,237,592	$0	$0	$10,618,592	$21,237,184
Total PHI		$6,402,752	$7,789,294	$14,464,658	$2,350,970	$0	$31,007,674	$62,015,348
PPD								
	2006	$3,241,418	$562,376	$367,381	$1,299,534	$10,000	$5,470,709	$10,951,418
	2007	$2,696,520	$636,350	$1,167,889	$9,971,053	$0	$14,471,812	$28,943,624
	2008	$2,889,054	$34,577	$838,146	$4,248,950	$0	$8,010,727	$16,021,454
	2009	$788,481	$55,930	$1,080,870	$1,266,803	$0	$3,192,084	$6,384,168
	2010	$2,173,110	$38,283	$3,116,418	$1,024,028	$0	$6,351,839	$12,703,678
Total PPD		$11,788,583	$1,327,516	$6,570,704	$17,810,368	$10,000	$37,497,171	$75,004,342

Year Total(s)

		Year Reduction	*OM Avoidance*	*OM Reduction*	*Capital Cost*	*Capital Savings*	*Auction Savings*	*Total*
	2006	$5,194,845	$3,186,009	$6,589,483	$2,295,817	$10,000	$17,266,154	$34,542,308
	2007	$4,694,250	$3,445,594	$14,955,969	$13,109,961	$0	$36,205,774	$72,411,548
	2008	$4,946,453	$1,579,916	$10,136,039	$6,880,762	$0	$23,543,170	$47,086,340
	2009	$3,128,953	$2,365,040	$10,331,278	$3,054,297	$0	$18,879,568	$37,759,136
	2010	$7,158,309	$1,566,975	$10,082,040	$1,525,891	$0	$20,333,215	$40,666,430
Grand Total		$25,122,810	$12,143,534	$52,094,809	$26,866,728	$10,000	$116,227,881	$232,465,762

M. N. LOWRY
Direct Testimony
DC P.S.C. - July, 2011

Introduced as:
PEPCO ______ (B)

POTOMAC ELECTRIC POWER COMPANY

**BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF MARK NEWTON LOWRY
FORMAL CASE NO.______**

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

A. My name is Mark Newton Lowry. I am the President of Pacific Economics Group (PEG) Research LLC. My business address is 22 E. Mifflin Street, Suite 302, Madison, WI 53703. I am testifying in this proceeding on behalf of Potomac Electric Power Company (Pepco or the Company).

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR ROLE AS COMPANY PRESIDENT?

A. PEG Research is a company in the Pacific Economics Group consortium which is active in the fields of utility regulation and statistical cost research. Alternatives to the traditional North American approach to regulation, including incentive regulation, are a company specialty. We maintain a large library of documents on the structure and performance of Alternative Regulation (Altreg) plans.

Our practice, which includes four PhD regulatory economists, is international in scope and has, to date, included projects in eleven countries. We work for a mix of utilities, regulators, and public agencies and this has given us a reputation for objectivity and dedication to regulatory science.

My duties as company President include the management of the company, consultation on Altreg plans, supervision of statistical cost and demand research, and expert witness testimony. I have for many years served as an advisor to the Edison Electric Institute (EEI) here in Washington on Altreg issues, teaching the Altreg segment at their Advanced Rates School, and have written several EEI white papers on Altreg issues. I have testified numerous times on Altreg and utility performance. Venues for my testimony have included California, Colorado, Georgia, Hawaii, Illinois, Kentucky, Maine, Massachusetts, Missouri, Oklahoma, New York, Rhode Island, Vermont, Alberta, British Columbia, Ontario, and Quebec.

Q. PLEASE TELL US MORE ABOUT YOUR PROFESSIONAL BACKGROUND, INCLUDING YOUR EDUCATIONAL EXPERIENCE.

Before assuming my present position I was a partner of Pacific Economics Group for ten years and managed its Madison office. Prior to that I worked for nine years at Christensen Associates, first as a senior economist and later as a Vice President. My career has also included work as an academic economist. I was for several years an Assistant Professor of Mineral Economics at the Pennsylvania State University and have also been a visiting professor at the Ecole des Hautes Etudes Commerciales in Montreal.

In total, I have twenty-seven years of experience as a practicing economist, spending the last twenty-one years doing research on gas and electric utilities. I hold a B.A. in Ibero-American studies and a Ph.D. in applied economics from the University of Wisconsin. I have an extensive record of professional publications and have served as a referee for several scholarly journals. I have chaired numerous conferences on Altreg and utility performance measurement. My resume is attached as PEPCO (B)-1.

Q. ARE YOU FAMILIAR WITH THE SITUATION OF THE PEPCO HOLDINGS UTILITIES?

A. Yes. I have previously been engaged to perform Altreg and benchmarking projects in Delaware, New Jersey, and Maryland, including work for Pepco's sister utility Delmarva Power & Light Company. PEG Research actively monitors regulatory proceedings in these three states as well as the District of Columbia and Virginia. Additionally, I have used data for the three Pepco Holdings utilities and similarly situated Northeast utilities in my statistical research on the cost and output trends of power distributors for more than a decade.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses the challenge of regulatory lag that faces Pepco and many other regulated energy distributors today. I will explain these challenges, describe their consequences, and discuss regulatory measures that mitigate regulatory lag. My testimony concludes by discussing the immediate remedy that Pepco is proposing in this proceeding: the Reliability Investment Recovery Mechanism (RIM).

Q. ARE YOU FAMILIAR WITH THE PROBLEM OF REGULATORY LAG?

A. Yes. Alternative regulation has developed in response to deficiencies in the traditional North American approach to ratemaking. A driving force for the adoption of Altreg in recent years has been the problem of regulatory lag. Approaches to regulation that help to mitigate regulatory lag include multi-year rate plans, revenue decoupling, targeted cost-recovery mechanisms, formula rates, and forward test years. I have advised clients on all of these remedies for regulatory lag, helped them to design specific measures, and testified in support of measures on numerous occasions. For example, I have provided relevant testimony in proceedings leading to the approval of sixteen revenue decoupling plans.

EEI has recently published two white papers that I wrote on regulatory lag issues. These are *Forward Test Years for U.S. Electric Utilities* (2010) and *Innovative Regulation: A Survey of Remedies for Regulatory Lag* (2011). Copies of these papers are attached as Exhibits PEPCO (B)-2 and PEPCO (B)-3.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Regulatory lag is a serious obstacle to Pepco's ability to earn its authorized return on equity (ROE). The Company needs a sustained increase in its capital expenditures (capex) over the next few years in order to further improve its reliability. The regulatory system under which the Company currently operates cannot provide it with the timely rate increases it needs to undertake this initiative without chronic underearning. It is important that this initiative, which will benefit customers and is driven in part by rising reliability standards, not deny the Company a chance to earn its authorized ROE.

Regulatory lag is a common problem today for gas and electric power distributors that, like Pepco, are engaged in accelerated programs of system modernization. Various regulatory measures are in use around the country which help to mitigate regulatory lag, while preserving regulatory oversight and incentives for efficient management. I recommend that the Commission draw from the menu of options thus developed to strengthen the regulatory lag mitigation measures that it uses to regulate Pepco. The best steps that the Commission can take in this proceeding are to approve a RIM and initiate a generic hearing to consider the establishment of a fully forecasted test year option for utilities in the District of Columbia.

Q. PLEASE EXPLAIN THE CONCEPT OF REGULATORY LAG AND WHY IT SHOULD MATTER TO REGULATORS.

A. Regulatory lag is the delay between the time when a utility's rate of return on equity deviates from the target set by regulators and the time when an offsetting rate decrease or rate increase is put into effect. When the ROE is chronically below the target, regulatory lag results in chronic underearning.

Regulators have the job of ensuring that the terms of utility service are just and reasonable. This is usually understood to mean rates that give efficient utilities the expectation of earning their target ROE. This just and reasonable standard is violated when a combination of regulatory lag and external business conditions creates an environment where a utility making sound economic choices experiences chronic underearning. This is unfortunately the situation facing Pepco and many other energy distributors today.

Q. **PLEASE EXPLAIN WHY REGULATORY LAG MIGHT PRODUCE CHRONIC UNDEREARNING FOR GAS AND ELECTRIC POWER DISTRIBUTORS.**

A. Chronic underearning occurs when cost grows more rapidly than revenue over a prolonged period. This can happen for reasons that are substantially beyond a utility's control. To understand how this might occur, it is constructive to consider the external business conditions that drive utility cost and revenue growth. The cost of a utility or any other business is driven chiefly by three factors: input prices, productivity, and operating scale. My statistical research over many years has revealed that the number of customers is the principal dimension of operating scale that drives the cost of energy distributors in the short and medium term. These considerations lead to the following Distributor Cost Growth Formula, which has been acknowledged by several regulatory commissions: *growth Cost = growth Input Prices - growth Productivity + growth Customers.*

Q. WHAT DOES THIS FORMULA TELL US?

A. The Distributor Cost Growth Formula shows that two of the biggest drivers of an energy distributor's cost --- inflation and customer growth --- are substantially beyond its control. Productivity can be influenced by distributor behavior, since a distributor can by its own initiative reduce its inefficiency. But productivity growth is also influenced by external business conditions, such as technical change and change in service requirements such as power line undergrounding.

A commission can trigger a slowdown in productivity growth by mandating a substantial improvement in reliability. Large improvements in reliability often require accelerated modernization of distribution infrastructure. The new facilities raise cost but do not, like new customer connections, automatically trigger new revenue growth.

Q. WHAT EXTERNAL BUSINESS CONDITIONS DRIVE REVENUE GROWTH?

A. The revenue growth of utilities depends on growth in their rates and billing determinants. Under traditional rate designs, most fixed costs of energy distributors are recovered by the volumetric charges of residential and commercial (R&C) customers. Revenue growth is thus quite sensitive to the trend in R&C delivery volumes. The trend in these volumes depends mostly on changes in external business conditions such as income levels, appliance efficiency standards, building codes, and demand-side management (DSM) policy.

Q. WHAT ARE THE IMPLICATIONS OF THIS ANALYSIS?

A. From the perspective of an energy distributor, two factors will trigger the need for an adjustment in rates. One is the tendency of input price inflation to exceed productivity growth. The other is the tendency of growth in R&C delivery volumes to outpace customer growth. The difference between the growth of R&C delivery volumes and customers is sometimes called the growth in "average use". Thus, the following Distributor Rate Relief Formula explains how external business conditions drive the growth in rates that is needed to avoid underearning:

$$\begin{aligned} &\textit{growth Rates} \\ &\quad = (\textit{growth Input Prices} - \textit{growth Productivity}) \\ &\qquad\qquad - \textit{growth Average Use}. \end{aligned}$$

Q. WHAT IS KNOWN ABOUT THE INPUT PRICE AND PRODUCTIVITY TRENDS OF ENERGY DISTRIBUTORS?

A. The growth in the productivity of most firms in the economy --- conventionally measured by multifactor productivity indexes --- is typically a good bit slower than the inflation in the prices they pay for inputs. That is why prices of goods and services tend to rise over time. Energy distributors are no exception. PEPCO (B)-4 contains a table and figure that details new estimates that I have prepared for Pepco of the input price and productivity trends of energy distributors in the Northeast. This comparison demonstrates that, for the Northeast as a whole, the input price inflation facing power distributors exceeded growth in their total factor productivity by an average of about 255 basis points annually on average from 1999 to 2010. The corresponding inflation-productivity gap was 296 basis points for sampled distributors in the urban Northeast. The gap for Pepco was around 235 basis points.

Under typical conditions, it follows that the trend in the average use of energy by R&C customers that an energy distributor experiences is crucial to its need for rate relief. If average use is growing *briskly* (*e.g.*, 2% annually), the usual gap between input price and productivity growth can be largely offset and rate cases can be avoided for several years at a time. If average use is *static*, there are no additional margins to offset the inflation-productivity gap and rate cases will be needed fairly frequently. If average use is *declining*, rate cases will be needed frequently, and possibly annually. The need for attrition relief will be even greater when a utility is engaged in an accelerated program of system modernization because this exacerbates the inflation-productivity gap.

Q. HAS THE ABILITY OF AVERAGE USE TO HELP UTILITIES AVOID UNDEREARNING CHANGED OVER TIME?

A. Yes. U.S government data on trends in the average use of electricity by residential and commercial customers are found in PEPCO (B)-5. This Exhibit shows that, for more than two decades after World War II, average use of power by R&C customers grew quite briskly. In Maryland and the District of Columbia, for instance, growth in average use by residential customers typically exceeded 5% annually as recently as the 1960s. Inflation was typically slow. These favorable circumstances sharply lowered the pace of rate escalation needed by utilities to avoid financial attrition. Rate cases were rare, and it usually made sense to set rates using the cost and output in a recent historical test year.

Average use fell in ensuing decades but was still appreciably positive in the 1990s and the first years of the new century. The need for rapid growth in average use was diminished somewhat by slow inflation.

Additionally, most vertically integrated utilities were not building new base load power plants, and this slowed the growth in their rate bases.

Q. **DOES THE SITUATION OF ENERGY DISTRIBUTORS TODAY DIFFER FROM THIS?**

A. Yes. Energy distributors generally do not experience declining rate bases because they make their plant additions more gradually across time as the urban areas they serve expand. The productivity growth of energy utilities has in recent years been somewhat below that of the U.S. private business sector as a whole. Meanwhile, growth in the average use of power by residential and commercial customers has vanished for the typical utility in recent years. Where customers are affected by large DSM programs, average use is materially declining. Natural gas distributors have, meanwhile, suffered from material declines in residential and commercial average use for more than a decade.

Q. **WHAT IS THE UPSHOT OF YOUR ANALYSIS?**

A. The persistent gap between inflation and productivity, along with stagnant or declining average use, stem from factors that are largely beyond the control of U.S. energy distributors. These conditions result in an environment where distributors need steady rate escalation to avoid underearning. The need for rate relief is exacerbated in service territories where distributors are engaged in large capital spending programs that do not generate revenue, such as an accelerated program of system modernization.

Q. **WHAT IS THE TRADITIONAL REMEDY FOR BUSINESS CHALLENGES LIKE THESE?**

A. The traditional remedy is to file frequent rate cases. This approach does make rates more reflective of trends in business conditions, and gives the Commission, its staff, and interveners an opportunity to monitor the Company's activities. Frequent rate cases nonetheless have several drawbacks. First, a rate case is a long process that is expensive to all parties in the proceeding, and ultimately to customers. Infrequent rate cases give senior managers more time to devote to the basic business of providing quality service cost effectively. Frequent rate cases also weaken utility performance incentives. A dollar saved today will reduce rates in just a year or two, and there is less time to recover the upfront costs of initiatives, such as labor force downsizings, that reduce long-term expenses.

It is also important to consider that the outcome of a rate case is not known to the utility from the outset, while capital planning decisions require that the utility make decisions based on expectations of earnings significantly into the future. The prospect of frequent rate cases increases the uncertainty of what return the utility can expect on its investment. A recent downgrade by Moody's Investors Service (Moody's) in the credit ratings for Central Hudson Gas & Electric was attributed in part to the company's increased dependence on rate filings to address regulatory lag in a period of large planned capital expenditures.

To make matters worse, frequent rate cases do not typically provide sufficient relief when they are based on historical or hybrid test years, since these test year approaches do not produce rates that fully reflect business conditions in the rate effective year.

Q. PLEASE APPLY YOUR ANALYSIS TO THE SITUATION OF PEPCO IN THE DISTRICT OF COLUMBIA.

A. Pepco is a large electric utility that serves the District of Columbia and the surrounding Maryland suburbs. Like most electric utilities in the Northeast, it no longer operates a large generation fleet and is instead a utility delivery company specializing in the provision of transmission and distribution services. The Company can no longer count on an acceleration of productivity growth between major generation plant additions. Rate base is growing. Pepco's distribution productivity growth trend is similar to that of other Northeast urban power distributors and well below input price inflation.

Pepco obtains virtually all of its distribution base rate revenues from residential and commercial customers. Since customer charges are still fairly low, earnings are sensitive to growth in average use by R&C customers. Growth in Pepco's average use has been sluggish for many years and has in recent years been negative.

The Public Service Commission of the District of Columbia recently directed Pepco to submit a continuous reliability improvement plan,

> …including resourcing, specific performance targets and milestone dates to achieve the reliability and outage restoration performance of the best (quartile) performing (comparably) utilities in the Benchmarking Studies.

The Commission has recently proposed new reliability standards that would rise substantially between 2013 and 2020.

Q. **HOW HAS PEPCO RESPONDED TO THESE REGULATORY REQUIREMENTS?**

A. In September 2010, Pepco responded to this initiative by filing a Comprehensive Reliability Plan for

District of Columbia. The plan details a six point strategy for reliability improvement which includes feeder improvements, selective undergrounding, and some distribution automation. Implementation of the strategy would involve an acceleration of system modernization and higher capital expenditures that do not automatically trigger additional and compensating revenues. A multi-year capital expenditure budget for the District of Columbia is discussed in this proceeding in the testimony of Company Witness Gausman.

The District of Columbia's current regulatory system involves rate cases with partially forecasted test years. After the expiration of an extended rate freeze, rate cases were filed in 2007, 2009, and now in 2011. A decoupling true-up plan was instituted in 2009 which is called the Bill Stabilization Adjustment (BSA). While this system involves some adjustments to traditional regulation which make rate increases more timely, it is insufficient to avoid serious regulatory lag during a period of accelerated system modernization. Similarly situated utilities are operating today under more robust sets of lag mitigation measures.

Q. WHY DOES THE CURRENT REGULATORY PRACTICE, WHICH USES A PARTIALLY PROJECTED TEST PERIOD TO SET RATES, NOT WORK IN THE CURRENT ENVIRONMENT?

A. Currently in the District of Columbia, Pepco can use a hybrid test year that can include up to six months of projected data. The partially projected results may be adjusted for reasonably known and measurable changes that will occur in the twelve months immediately following the end of the test year. Assuming that it takes three months to assemble and file a rate case, and that an Order is received within the nine month target for processing the case, known and measurable changes that will occur in the second half of the rate effective period are precluded from consideration. For example, assuming that an Order in this proceeding is received within the nine-month time frame, rates will go into effect in early April, 2012. Known and measurable changes that will occur up through September 2012 will have been reflected, but any post-September changes will not have. For this reason alone, rates set in this proceeding will essentially be out of date just seven months after they go into effect. Moreover, current practice ignores all of the cost impact of changes in many important business conditions that occur after the close of the test year because these impacts do not meet the known and measurable standard. These business conditions include inflation and plant additions with uncertain completion dates. In a time of aggressive capital expansion such as Pepco is currently undertaking, nearly annual filings are virtually guaranteed by the limitation of projected data to six months.

Q. SHOULD UTILITY INVESTORS BE GUARANTEED THE ABILITY TO EARN THE ROE AUTHORIZED BY THE COMMISSION?

A. No. A guarantee is undesirable, because of its incentive ramifications, but investors should have a reasonable chance to realize the ROE target. In a period of high capital investment, investors will not have a reasonable opportunity to realize the ROE deemed to be appropriate by the Commission. It is therefore reasonable for Pepco to ask the Commission to consider and adopt one or more regulatory remedies that give the Company a better chance of realizing its target ROE.

Q. WHAT ARE THE CONSEQUENCES OF NOT BEING ABLE TO EARN THE COMMISSION-AUTHORIZED ROE?

A. As Company Witness Kamerick discusses in his testimony, large capex programs require access to capital markets, and the cost of such programs is reduced when capital can be raised on reasonable terms. Lower earned returns make it more difficult to raise equity, and can also increase the cost of debt. On the equity side, dilution can occur. On the debt side, the financial metrics considered by rating agencies can deteriorate. The investment community pays close attention to Pepco's ability to earn its allowed ROE. The negative consequences of regulatory lag and earnings attrition are discussed further in the testimony of Company Witnesses Cannell and Hevert.

Q. HOW DOES ADDRESSING THE ISSUE OF REGULATORY LAG BENEFIT THE COMPANY'S CUSTOMERS?

A. More timely recovery of capital costs through a reduction in regulatory lag will continue to allow the Company to attract, at a reasonable cost, the capital that it needs for investments. This is particularly important during a program of accelerated system modernization, since it is a period of high borrowing activity. Utilities that earn their authorized ROE are also more comfortable making the large new investments needed for a modern, high performance system. Reducing regulatory lag therefore brings into line the desire of the Commission and consumers for improved service reliability with incentives for Pepco to make needed capital expenditures.

Regulatory lag mitigation measures can also expedite the regulatory process. The costs to customers of filing frequent traditional rate cases are reduced. Executives will have stronger incentives and more time available to oversee the reliability improvement program and make sure that it improves the quality of service cost-effectively.

Consider also that some remedies for regulatory lag smooth out rate changes and the impact of large additions to rate base. These investments can be introduced into rates gradually rather than building up and coming into rates in large increments.

Q. WHAT ARE SOME MECHANISMS THAT THE COMMISSION SHOULD CONSIDER TO MITIGATE THE EFFECTS OF REGULATORY LAG?

A. There are numerous well established measures that, separately or in combination, could give Pepco a better chance to earn the Commission-authorized ROE. In this testimony I focus on the four remedies for regulatory lag that are most widely used today:

- Revenue decoupling
- Multi-year revenue caps
- Targeted cost-recovery mechanisms
- Fully forecasted test years.

Pepco currently uses only one of these measures, a form of revenue decoupling. I will describe each of these lag

-mitigation options, the precedents for them, and advantages and disadvantages of each.

Q. PLEASE DISCUSS FIRST THE REVENUE DECOUPLING REMEDIES FOR THE PROBLEM OF REGULATORY LAG.

A. The term revenue decoupling refers to a group of regulatory provisions designed to weaken the link between a utility's revenue and the volume of its services. This reduces the utility's disincentive to promote DSM and can alleviate the financial stress caused by declining average use. Three approaches to decoupling are well established: decoupling true-up plans, lost revenue adjustment mechanisms (LRAMs), and fixed variable pricing.

Decoupling true-up plans should be well known to the Commission, since Pepco uses such mechanisms. These plans help a utility's actual revenue track the revenue allowed by regulators. Most decoupling true-up plans have two basic components: a revenue decoupling mechanism (RDM) and a revenue adjustment mechanism (RAM). A typical RDM tracks variances between actual and allowed revenue and makes periodic true-ups. Utilities are compensated for any *decline* in average use but are denied the benefit from any *growth* in average use.

The RAM component of a decoupling true-up plan reduces the need for additional rate cases by escalating allowed revenue for external factors that impact the utility's costs. Pepco's BSA expedites recovery of revenue per customer (RPC) but has no provision for *escalating* RPC. This is tantamount to an RPC freeze and allows revenue to grow only at the gradual pace of customer growth. Recall from the Distributor Cost Growth Formula that customer growth is only one of the recognized drivers of distributor cost. Other RAMs are "broad-based" in the sense that they provide enough revenue growth to compensate the utility for several kinds of cost pressures. For example, allowed revenue may be escalated for input price inflation as well as for customer growth.

Q. **WHAT ARE THE PRECEDENTS FOR DECOUPLING TRUE-UP PLANS?**

A. States that have tried gas and electric decoupling true-up plans are indicated on the maps below in Figures 1a and 1b, respectively. The maps indicate that there are more plans for gas utilities than for electric utilities. This reflects the more pervasive character of the declining average use problem that gas distributors face. In the electric utility industry, decoupling true-up plans are most likely to be adopted in service territories where there is decline in average use. This is usually due to the local administration of a large DSM program by the utility or an independent agency.

Q. HOW COMMON ARE BROAD-BASED RAMS IN DECOUPLING TRUE-UP PLANS?

A. Broad-based RAMs are featured about as often as RPC freezes in the decoupling true-up plans of U.S. electric utilities. The RPC freeze approach predominates in the decoupling true-up plans of gas distributors. However, several of the largest gas distributors in North America, including Consolidated Edison, Pacific Gas & Electric, Southern California Gas, and Enbridge Gas Distribution, operate today under broad-based RAMs. I believe that RPC freezes are more common in gas distribution because gas distributors are willing to settle for a less compensatory RAM in exchange for relief from a more serious problem of declining average use.

Figure 1a Electric Decoupling True-Up Plans by State

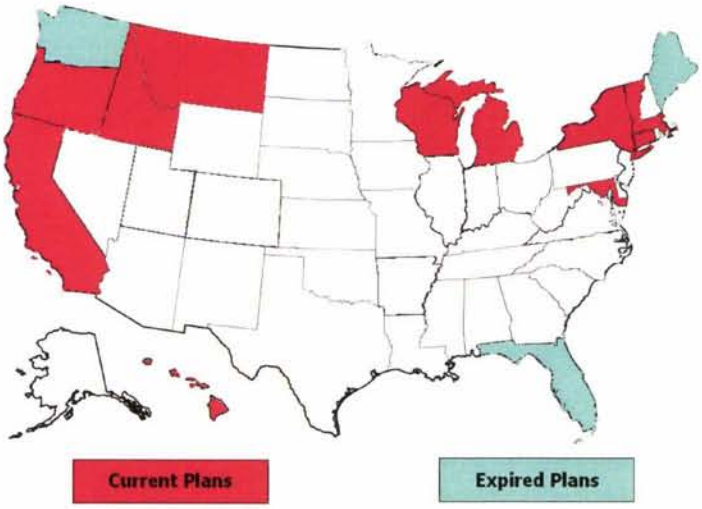
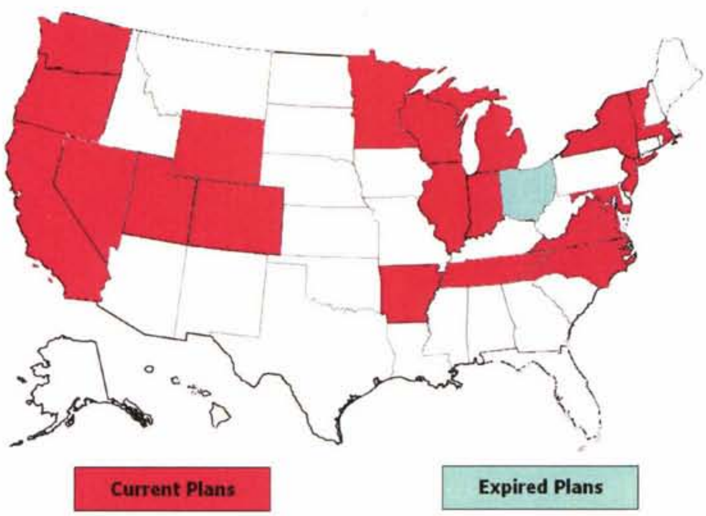


Figure 1b: Gas Decoupling True-Up Plans by State



Q. PEPCO ALREADY OPERATES UNDER A DECOUPLING TRUE-UP PLAN. WHY IS THIS NOT SUFFICIENT TO SOLVE ITS REGULATORY LAG PROBLEM?

A. The BSA has partially addressed Pepco's regulatory lag but cannot be expected by itself to solve the problem, for two reasons. First, a decoupling true-up plan only compensates a utility for *declines* in average use. It does not compensate the Company for the disappearance of *growth* in average use. Pepco does not profit from any growth in average use that might result from new market developments such as electric vehicles (EVs). Recall from my earlier remarks that lack of growth in average use is a key source of the regulatory lag problem that many energy distributors face.

The second reason why the current decoupling true-up plan is not by itself sufficient to eliminate regulatory lag is that it features an RPC freeze approach to RAM design. This is not a broad-based RAM. The Distributor Cost Growth Formula can be rearranged to produce the following result.

growth Cost/Customer = growth Input Prices − growth Productivity

Growth in cost per customer is the difference between input price and productivity growth. This difference is, as I showed earlier, usually substantial and is especially large during a campaign of accelerated system modernization such as Pepco has underway. For this reason, utilities agreeing to operate under RPC freezes usually retain the right to file rate cases and frequently do file.

Q. **WHAT ADDITIONAL STATISTICAL EVIDENCE CAN YOU PROVIDE THAT AN RPC FREEZE IS INADEQUATE FOR DISTRIBUTORS IN GENERAL RATHER THAN A PROBLEM FOR PEPCO SPECIFICALLY?**

A. PEPCO (B)-6 presents evidence on the recent trends in the base rate cost per customer of major investor-owned utility power distribution companies in the Northeast. The sample period is 2004-2010. This survey excluded costs of customer service and information expenses, which for several Northeast utilities rose at an especially rapid rate during the sample period due to the growth of utility DSM programs. Inspecting the results, it can be seen that even with these rapidly rising costs removed distributor cost per customer averaged 2.16% annually for the full Northeast sample, 3.87% for the urban Northeast sample, and 1.41% for Pepco. Thus, per-customer costs have risen persistently while revenue per customer is essentially frozen under the BSA - a condition that, if unaddressed, will lead to underearning.

Q. HAVE REGULATORS IN OTHER JURISDICTIONS NOTED THE INADEQUATE ATTRITION RELIEF PROVIDED BY AN RPC FREEZE?

A. Yes. The Hawaii Public Utilities Commission commented, in a recent Order approving broad-based RAMs for the three Hawaiian Electric utilities, that

> The RPC mechanism, which was not intended to address issues such as regulatory lag, will not perform as well as the [broad-based] RAM in meeting the objective to maintain the HECO Companies' financial integrity. In addition, the commission finds that the RPC method may not provide adequate rate relief where increases in costs may be far greater than increases in customers… Although various "pack-ages", including RPC plus rate cases, were discussed at the hearing, it does not appear from the record that any of these options would reduce regulatory lag, maintain the HECO company's financial integrity, or support the achievement of Hawaii's objectives as well as the RAM.[1]

Q. ARE THERE WAYS TO MAKE PEPCO'S DECOUPLING TRUE-UP PLAN A MORE EFFECTIVE REMEDY FOR REGULATORY LAG?

A. Yes there are, although the Company is not proposing changes to the BSA in this proceeding. One way would be to exempt from decoupling Pepco's deliveries of power that are used to recharge EVs on the grounds that these

[1] Hawaii PUC, *Final Decision and Order*, Docket No. 2008-0274, August 31, 2010.

deliveries improve air quality, reduce noise, and can help Pepco deal with its regulatory lag problem. This idea dovetails nicely with the build out of AMI that is underway in the District since the new meters can be used to offer customers lower night-time volumetric charges that encourage night-time recharging.

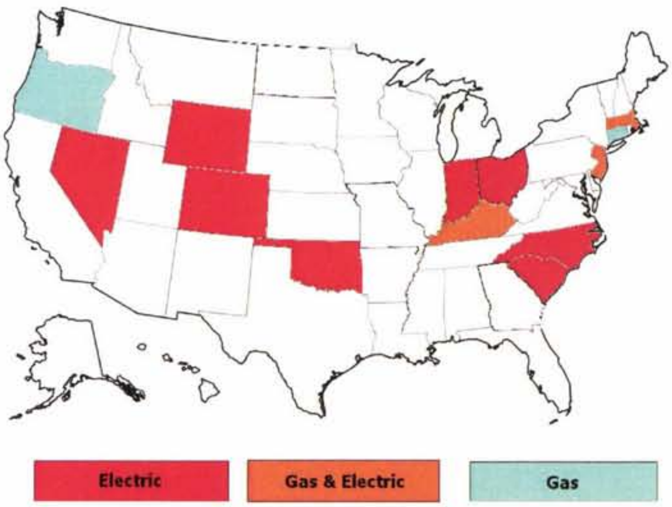
Another way that the decoupling true-up plan can be made more effective in reducing regulatory lag is to replace the RPC freeze with a broad-based RAM. We discuss this option further below.

Q. PLEASE DISCUSS THE LRAM APPROACH TO DECOUPLING.

A. An LRAM explicitly compensates a utility for base rate revenues that are estimated to be lost due to DSM programs. Compensation for lost margins is usually effected through a rate rider. Estimates of energy (and sometimes also peak load) savings are needed for LRAM calculations. Compensation is not confined to *declines* in average use, as it is under decoupling true-up plans, and the utility can use any growth in average use that occurs notwithstanding DSM to alleviate underearning.

Precedents for LRAMs are detailed in Figure 2 below. It can be seen that LRAMs are less widely used than decoupling true-up plans today. One reason is that they are less useful for gas distributors, which experience declines in average use for reasons other than DSM programs. LRAMs have nonetheless experienced a rebound recently due in part to their use in Duke Energy's "Save a Watt" approach to DSM regulation in several states.

Figure 2: Current LRAMs by State:



Q. WHAT ARE THE PROS AND CONS OF THE LRAM APPROACH?

A. This approach provides a utility with full compensation for the economic loss caused by DSM programs. The utility retains an incentive to promote environmentally benign uses of energy such as EVs. Critics of LRAMs argue that they disincent the utility from pursuing every means at its disposal to promote DSM. LRAMs also involve complex calculations of DSM savings, but these calculations should arguably be undertaken even in the absence of the LRAM in order to assess the effectiveness of the DSM program.

Q. PLEASE DESCRIBE MULTI-YEAR RATE PLANS AND EXPLAIN HOW THEY CAN ALLEVIATE REGULATORY LAG.

A. Multi-year rate plans are a form of incentive regulation that involves multi-year moratoriums on general rate cases. The length of such plans is typically three to five years, but plans as long as ten years have been approved. Many multi-year rate plans feature predetermined rate adjustment mechanisms that provide automatic rate adjustments for changing business conditions between rate cases. These mechanisms can be designed to eliminate regulatory lag and provide funds needed for plant additions, including reliability improvement programs. The rate adjustments provided by predetermined rate adjustment mechanisms are largely "external" in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* cost growth. This can strengthen incentives to contain cost growth. Benefits of the performance improvements that are stimulated by the plan can be shared with customers. The ability of multi-year rate plans to provide needed rate increases without high regulatory cost or a weakening of performance incentives constitutes a remarkable advance in the "technology" of regulation.

Multi-year rate and revenue caps commonly allow supplemental rate adjustments for changes in external business conditions that were especially difficult to anticipate at the time that the plan was fashioned. These include changes in tax rates and other government policies (*e.g.* conductor undergrounding requirements) that affect costs. Some multi-year plans also feature earnings sharing mechanisms that share earnings surpluses and/or deficits that result when the ROE deviates from its regulated target. Plans also sometimes feature award and/or penalty mechanisms that are linked to service quality metrics.

Predetermined rate adjustment mechanisms may cap the growth in allowed rates or revenue. Rate caps limit the escalation in rates (*e.g.* customer charges and cents per unit of power delivered). They are favored where utilities are encouraged to bolster system use, since rate caps strengthen incentives to promote system use and can facilitate marketing flexibility by reducing concerns about cross subsidization. Revenue caps limit the escalation in allowed revenues. They are often favored over rate caps where DSM is encouraged and/or declining average use is a problem.

Revenue caps are usually, though not always, combined with decoupling true-ups. The predetermined rate adjustment mechanism is in this case the same as the RAM component of a decoupling true-up plan. A RAM usually has to be broad-based if it is to provide the basis for a rate case moratorium.

Q. HOW ARE BROAD-BASED RAMS DESIGNED?

A. Several kinds of broad-based RAMs have been established. The most common approaches are indexing, stairsteps, and hybrids. The indexing approach to RAM design is based on the Distributor Cost Growth Formula that I discussed earlier. An example might be

Growth Revenue = Inflation - X + growth Customers.

Here X, the "X factor," reflects a productivity growth target that is usually the total factor productivity (TFP) trend of the industry. The indexing approach is more likely to be used where no capital spending surge is anticipated, which would complicate calculation of a productivity target.

The stairstep approach to RAM design provides pre-determined fixed increases in allowed revenue, which are often based on forecasts of cost growth. For example, revenue might be scheduled to grow 6% in the first year, 7% in the second, and 4% in the third year of a three year plan. One advantage of this approach is that it can easily accommodate major plant additions such as those that might result from an accelerated program of system modernization. Stakeholders are compelled to consider a multi-year capex budget, and are given the usual opportunity that a rate case provides to weigh in on its details. Customers may value knowing in advance the schedule for future rate increases. However, the stairstep approach is less able than the indexing approach to adjust allowed revenue automatically for unforeseen inflationary conditions such as might be triggered, for example, by an oil price shock.

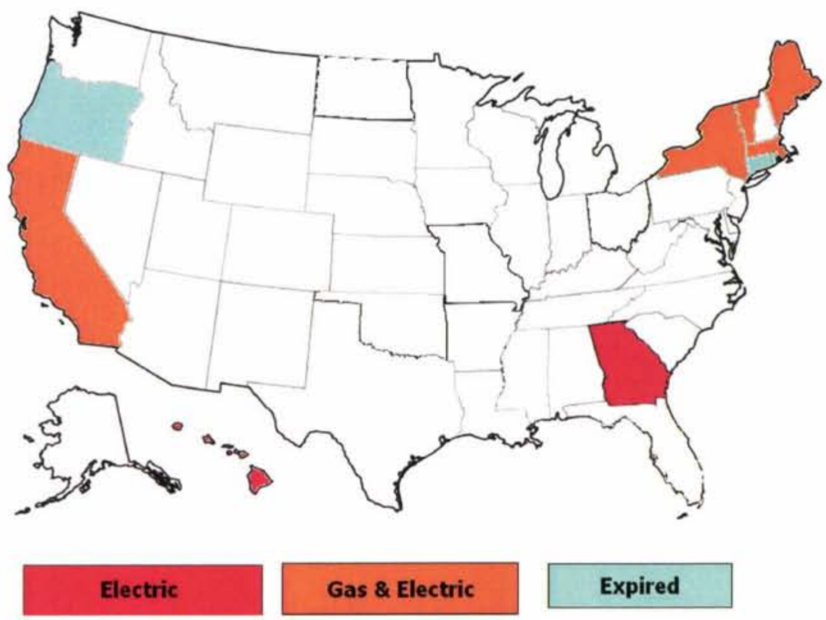
Q. PLEASE EXPLAIN THE HYBRID APPROACH TO RAM DESIGN.

A. A hybrid RAM involves a mix of indexing and forecasts. In North America, hybrid RAMs typically involve indexes for O&M expenses and stairsteps for capital costs. A company called Global Insight has maintained input price indexes for utility O&M expenses for many years which can be used in the O&M escalator. The X factor reflects the trend in O&M productivity. The stairsteps for capital cost are sometimes fixed in real terms and then adjusted for construction cost inflation as measured by an energy utility construction cost index. Hybrid RAMs exploit the flexibility of stairsteps in accommodating major plant additions and the streamlining and hyperinflation protection that indexing provides for O&M expenses.

Q. **WHAT ARE THE PRECEDENTS FOR MULTI-YEAR RATE PLANS?**

A. Recent precedents for multi-year rate plans of U.S. energy utilities are summarized in Figure 3. It can be seen that this kind of Altreg has to date been most common in California and the Northeast. It is used primarily to regulate gas and electric power distribution. Multi-year rate plans are also popular for energy utilities in Canada. They are used to regulate all gas and electric distributors in Ontario and are also used in Alberta, Quebec, and British Columbia. The Alberta Utilities Commission recently directed all gas and electric power distributors to file multi-year rate plans. Overseas, multi-year rate plans are more the rule than the exception for energy distributors. The "RPI (retail price index) - X" plans in Britain are especially well known.

Figure 3: US Precedents for Multi-year Rate Plans



Q. WHY ARE MULTI-YEAR RATE PLANS MORE POPULAR AMONGST ENERGY DISTRIBUTORS THAN AMONGST VERTICALLY INTEGRATED ELECTRIC UTILITIES?

A. This is due in part to the tendency of distribution cost to grow at a comparatively steady and predictable pace. This makes it easier for parties to agree on a predetermined rate adjustment mechanism. The popularity of rate and revenue caps for power distributors also reflects the fact that they rarely experience the combination of *declining* rate base and *growth* in average use that might permit them to operate for several years under a rate freeze. Rate freezes are still occasionally an option for vertically integrated electric utilities.

Q. WHICH OF THE BROAD-BASED APPROACHES TO RAM DESIGN ARE MOST POPULAR?

A. Indexing is used in Ontario and Vermont, whereas stairsteps are used in New York and have recently been favored in California as well. The hybrid approach was developed in California in the early 1980s and has been used there by my count more than a dozen times. These plans commonly escalated O&M expenses for input price inflation using the custom Global Insight indexes that I mentioned earlier. Hybrid RAMs are currently used by the three Hawaiian Electric utilities.

Q. PLEASE DISCUSS THE PROS AND CONS OF MULTI-YEAR RATE PLANS AS A REMEDY FOR THE REGULATORY LAG THAT PEPCO FACES.

A. Multi-year rate plans are in my opinion the best approach to the mitigation of regulatory lag. Chronic regulatory lag from changing external business conditions can be eliminated without frequent rate cases. Regulatory cost is lower, and better utility cost management is encouraged. If accelerated system modernization is planned, the Commission, its staff, and stakeholders are compelled to consider the appropriate multi-year budget, as they should in any event. The utility is likely to lose money if it exceeds its capex budget. The revenue cap variant of a multi-year rate plan is a form of revenue decoupling and effectively removes utility disincentives to promote DSM.

The main challenge with a multi-year rate plan is the difficulty of designing the predetermined rate adjustment mechanism. This is a particular challenge for a jurisdiction with little experience, but the parties to regulation will gain expertise with experience. In California, for example, the parties to regulation have been negotiating these plans for almost thirty years. In jurisdictions where there is significant concern regarding extreme earnings outcomes, an earnings sharing mechanism can be added to the plan. However, such mechanisms reduce the incentive benefits of the plan.

In an application to energy distributors it is generally not too difficult to agree on a predetermined rate adjustment mechanism. In my opinion, the net benefits of multi-year rate plans will eventually become widely recognized, and such plans will become the most common approach to the regulation of power distribution utilities in the United States, as they are in other countries.

Q. PLEASE DISCUSS THE OPTION OF FULLY FORECASTED TEST YEARS.

A. A fully forecasted test year, sometimes called a future or forward test year (FTY), is a twelve-month period that begins after the rate case is filed. Most commonly, an FTY *begins* about the time that the rate case is expected to *end* and thus comes very close to matching the rate effective year. This typically involves forecasting cost about two years into the future. A more conservative approach, called a current FTY, is to begin the test period around the date of the rate case. This typically involves forecasting out about one year.

The forecasts used to make FTY cost projections are sometimes company budgets. Other utilities make a more detailed traditional cost filing for a historical reference year and then escalate many costs by external mechanisms such as the Distributor Cost Growth Formula. Global Insight forecasts of growth in power distributor O&M input price and construction cost indexes are useful for this.

The use of a forward test year would permit Pepco's rates to reflect expected input price inflation in the rate effective year. It would also allow for earlier inclusion of capital projects in base rates because under a forward test year the costs of all projects can be included in rates which are likely but not certain to be finished during the rate effective year.

Q. WHAT WOULD BE THE MOST CONSERVATIVE WAY FOR THIS COMMISSION TO APPROACH A FULLY FORECASTED TEST YEAR?

A. To increase confidence in cost projections, the Commission could require detailed, traditional cost evidence for a historical reference year and ask that escalation of cost to the forward test year be limited where possible to external index-based adjustments. Utilities may, additionally, be asked to report periodically on the accuracy of their cost forecasts. Another cautious step in the direction of forward test years would be to permit a *current* FTY with an *interim* rate that takes effect early in the proceeding subject to refund. This would effectively address the problem of regulatory lag without a two-year cost forecast.

Q. PLEASE EXPLAIN THE USE OF INTERIM RATES.

A. Interim rates are a means of getting at least a portion of a requested rate increase implemented before a final Order is used. Many states allow a utility to put a requested rate increase into effect, subject to refund, if the Commission is unable to render a final decision within the prescribed time frame. This Commission has the statutory authority to grant these temporary rates.

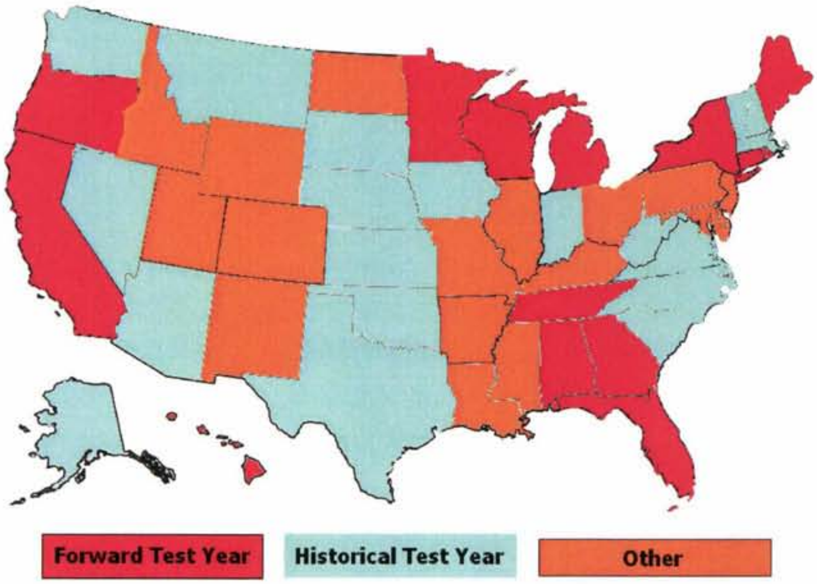
Some states allow part of the requested increase to become effective, also subject to refund, shortly after a rate case is filed. In Delaware, for example, utilities can implement an increase equal to the lesser of 15% of the utility's intrastate revenues or $2.5 million, subject to refund, 60 days after filing a rate case. This can provide appreciable relief from regulatory lag.

Q. WHAT ARE THE PRECEDENTS FOR FORWARD TEST YEARS?

A. We have already noted that historical test years made sense in the early decades of the postwar period when cost growth was more similar to growth in sales volumes. Forward and hybrid test years were adopted in many jurisdictions during the 1970s and 1980s when rapid input price inflation and major plant additions coincided with slower growth in average use. Commissions in several additional states have recently moved in the direction of FTYs. Many of these states are in the West, where comparatively rapid economic growth has required more rapid buildout of utility infrastructure. However, the Illinois Commerce Commission recently accepted a return to forward test years in a rate case for Peoples Gas Light and Coke in Chicago.

Current state policies concerning test years are summarized below in Figure 4. The ranks of U.S. jurisdictions that use alternatives to historical test years have swollen and now encompass over half of the total. The "other" category in Figure 4 includes states that use FTYs for some utilities and historical test years for others (*e.g.*, Illinois), states that are transitioning towards forward test years (*e.g.*, New Mexico and Utah), jurisdictions like the District of Columbia that use hybrid test years with some but not all months forecasted, and jurisdictions that have used FTYs in the past but don't currently use them (*e.g.*, Delaware).

Figure 4: Test Year Policies by State



Q. PLEASE SUMMARIZE THE PROS AND CONS OF A FORWARD TEST YEAR.

A. A forward test year can provide effective relief from the problem of regulatory lag. Capital can be obtained on more reasonable terms and rate "shock" can be avoided. Forward test years can also in some circumstances produce a reduction in the frequency of rate cases. In an application to a distributor engaged in a multi-year program of accelerated capex, however, frequent and possibly annual rate cases are still quite likely absent additional measures such as a capex recovery mechanism. Forward test years are, additionally, somewhat more complex to implement than hybrid test years.

Q. ARE THERE WAYS TO IMPROVE THE EFFECTIVENESS OF HYBRID TEST YEARS IN RELIEVING REGULATORY LAG?

A. Yes. The Commission can expand on the concept of known and measurable changes to encompass more of the investments that are likely to be in service during the year that new rates take effect. The Commission could also employ a terminal rate base rather than the average value of the rate base over the test period. During a time of high capex such as Pepco is planning, a terminal rate base is more reflective of the investment that is expected during the rate effective period. It is, additionally, known and measurable prior to the time that the Commission issues its rate case decision. This approach has been used before in the District of Columbia.

Q. PLEASE DISCUSS HOW TARGETED COST-RECOVERY MECHANISMS CAN BE USED TO MITIGATE REGULATORY LAG.

A. A targeted cost-recovery mechanism expedites recovery of particular utility costs outside of general rate cases. Balancing accounts are used to track unrecovered costs. Cost recovery is then typically implemented using tariff amendments called riders.

Targeted cost-recovery mechanisms are used in various situations where it is less practical to rely on general rate cases to adjust rates for changes in particular utility costs. For example, the energy costs of utilities are usually recovered via such mechanisms because their volatility and substantial size would otherwise lead to frequent general rate cases and/or elevated earnings risk. Other volatile costs that are recovered using targeted cost recovery mechanisms include those for pensions and uncollectible bills.

Under today's business conditions, where cost growth tends to outpace revenue growth, such mechanisms are also used to expedite recovery of costs that drive overall cost growth, irrespective of their volatility. This can reduce the frequency of rate cases because the residual cost that is recovered through conventional rates grows more slowly. Examples of utility costs that are tracked because of their rapid growth include those for health care, DSM, and capex. In the balance of this testimony I will refer to targeted cost-recovery mechanisms for capex as capex recovery mechanisms. The District of Columbia has in the past approved cost-recovery mechanisms for DSM expenses but not for capex.

Q. UNDER WHAT CIRCUMSTANCES DO REGULATORS TYPICALLY APPROVE CAPEX RECOVERY MECHANISMS?

A. Capex recovery mechanisms have the general advantage of recovering those capital costs that result from growth in the rate base. The part of the rate base that is subject to recovery via conventional rates will usually grow more slowly when there is a capex recovery mechanism. The greater is the percentage of capex recovered separately, the slower is the growth in the residual rate base.

If *all* capital costs resulting from capex are recovered via the capex recovery mechanism, the residual rate base will actually decline. This can materially reduce the need for general rate cases. In Ohio, for example, the three FirstEnergy electric utilities currently operate under a mechanism that recovers the cost of almost all new distribution investment. This has permitted FirstEnergy to agree to multi-year freezes on the conventional rates that recover residual cost. Notwithstanding such precedents, capex recovery mechanisms are usually used only to recover costs of major capex programs.

Q. PLEASE DEFINE A MAJOR CAPEX PROGRAM AND EXPLAIN WHY CAPEX RECOVERY MECHANISMS ARE PARTICULARLY USEFUL FOR UTILITIES ENGAGED IN SUCH PROGRAMS.

A. Major capex programs can occur for several reasons. Base load generation is a common type of major plant addition for vertically integrated electric utilities. Utilities engaged in transmission sometimes make large investments in new facilities to promote regional power trade or access remote renewable resources. Both kinds of investments can take more than a year to construct. An allowance in rates for funds used during construction is traditionally not permitted until assets are used and useful. This involves extra interest expenses and produces rate shock when the value of the plant is finally added to the rate base. The delay in receiving a return on investment increases utility risk, and this further increases the cost of construction that customers ultimately pay. Many commissions address these problems by including costs of construction work in progress (CWIP) in the rate base so that a return on investment can start sooner. Capex recovery mechanisms are often used in lieu of rate cases to recover the return on CWIP.

For energy distributors, major capex programs are usually occasioned by an accelerated program of system modernization. The annual plant additions may not be as large as that for new or repowered baseload generation, and facilities become used and useful over a series of years instead of in one year. However, the annual expenditures can still be sizable and, unlike expenditures for new generation or transmission facilities or customer connections, don't naturally trigger new revenue when facilities become used and useful. Under today's operating conditions, timely recovery of the cost of an accelerated program of system modernization will under traditional regulation therefore require frequent rate cases. A recovery mechanism for the accumulating annual cost of the new investment can help a company modernize its system and improve service quality without frequent rate cases or the rate shock that can occur if rate cases are held less frequently.

Q. ISN'T THIS A FORM OF SINGLE ISSUE RATEMAKING?

A. Yes. But many commissions today find single issue ratemaking preferable to salient comprehensive remedies for regulatory lag such as multi-year rate plans. There is less concern about overearning in an environment where cost growth is clearly outpacing revenue growth, as I have shown to be the case for companies like Pepco. Decoupling is also a form of single issue ratemaking, and is clearly very popular. Earnings can be monitored if overearning is a particular concern.

Q. **WHAT CAPITAL COSTS ARE TYPICALLY RECOVERED BY CAPEX RECOVERY MECHANISMS?**

A. Most capex recovery mechanisms recover the accumulating annual capital costs that result from the targeted capex until a general rate case permits these costs to be recovered through conventional rates. The annual cost of capex includes a return on the value of the assets, depreciation on plant in service, and associated net taxes. The operation of a capex recovery mechanism thus requires a specification of the rate of return on plant and the depreciation rate. An adjustment is sometimes made for the retirement of plant that is occasioned by the capex.

Q. **IN A CONVENTIONAL RATE CASE A TEST YEAR MUST BE CHOSEN. HOW IS THIS ISSUE HANDLED IN THE DESIGN OF A CAPEX RECOVERY MECHANISM?**

A. Most capex recovery mechanisms recover a forecast of the capital cost in the upcoming year. However, some capex recovery mechanisms have more of a hybrid test year flavor. A capex recovery mechanism for New Jersey

Natural Gas, for instance, recovers only the annual cost of the plant in service and CWIP in rate base at a date a few months prior to the implementation of the new capex recovery surcharges. This approach, which is analogous to a hybrid test year with a year-end rate base, involves more regulatory lag than the fully forecasted approach.

Q. WHAT PROTECTIONS WOULD CONSUMERS HAVE AGAINST AN INNACURATE COST FORECAST?

A. Capex recovery mechanisms that feature cost forecasts usually involve a periodic (*e.g.*, annual) reconciliation of the revenue gathered by the mechanism in previous years to an updated estimate of the cost that was incurred. The annual filing is for this reason often called a reconciliation filing. Reconciliation facilitates recovery of the cost of service and therefore involves revenue decoupling.

Q. WHAT ATTENTION IS PAID IN CAPEX RECOVERY MECHANISMS TO THE PRUDENCE OF INVESTMENTS?

A. Most capex recovery mechanisms for energy distributors are the outcome of a proceeding in which a detailed multi-year investment plan is considered that includes the specific projects to be undertaken and an estimate of their cost. The proceedings usually result in settlements that contain a multi-year capex budget and a list of specific projects. The utilities usually have some flexibility regarding the timing of the investments and particular projects.

The subsequent reconciliation proceedings may also consider the reasonableness of the costs and the projects. These proceedings are commonly assigned a window of between two and four months to be resolved. The proceedings usually allow for data requests, and some permit opposition testimony before the Commission makes its decision.

Costs and projects are, additionally, sometimes subject to a final prudence review when the plant additions are added to the rate base. When the capex recovery mechanism involves cost forecasts, these reviews usually occur in the next general rate case. When the capex recovery mechanism is entirely retrospective, however, the final prudence review may occur in the reconciliation proceeding. In final prudence reviews, costs that fall within the established budget are sometimes granted *ex ante* prudence.

Q. HOW ARE DEVIATIONS FROM CAPEX BUDGETS TREATED?

A. In most plans, underspends are passed entirely to customers and capex in excess of budgeted amounts is subject to prudence review. However, the capex budgets in some plans are hard caps. In California where, as we have seen, experience with incentive regulation is quite extensive, sharing mechanisms are sometimes used in which positive and negative deviations from budgets in a prescribed range are shared mechanistically (*e.g.*, 90%/10%) between customers and shareholders. When plans involve hard caps or sharing mechanisms, the initial capex budgets naturally require more careful consideration.

Q. WHAT PROTECTIONS ARE PROVIDED AGAINST RAPID RATE GROWTH?

A. In addition to the protections provided by prudence reviews and incentivized mechanisms for handling overspends, a few capex recovery mechanisms have featured "soft" caps that limit the revenue growth that can be triggered by the mechanism. Any shortfalls in the recovery of approved capital costs due to the cap can be recovered later with interest.

Q. CAN REVIEWS OF THE INVESTMENT PROGRAM INCLUDE CONSIDERATION OF HOW MUCH "BANG" CONSUMERS GOT FOR THEIR "BUCK"?

A. Yes, impacts of the capex on O&M expenses and service quality are sometimes compared to forecasts of same that were used to justify the capex. Moreover, capex recovery mechanisms for AMI and other forms of system modernization may involve supplemental award/penalty mechanisms that encourage effective use of the new facilities.

Q. HOW IS THE INTEGRITY OF RECONCILIATION FILINGS ENSURED?

A. The prudence of the filings can be addressed in either or both of the filings themselves and the next general rate case. Additionally, some utilities have committed to periodic internal or external audits of these filings.

Q. WHAT ARE THE PRECEDENTS FOR CAPEX RECOVERY MECHANISMS?

A. Recent capex recovery mechanism precedents for electric, gas, and water utilities are summarized in Figures 5 and 6. It can be seen that there are numerous precedents. Those for energy distributors most commonly recover the cost of AMI or more general system modernization programs. Recent electric utility precedents for CWIP in rate base are listed in Figure 7. Most of these involve investments in generating plant.

Figure 5: Recent Capex Recovery Mechanism Precedents for US Energy Utilities

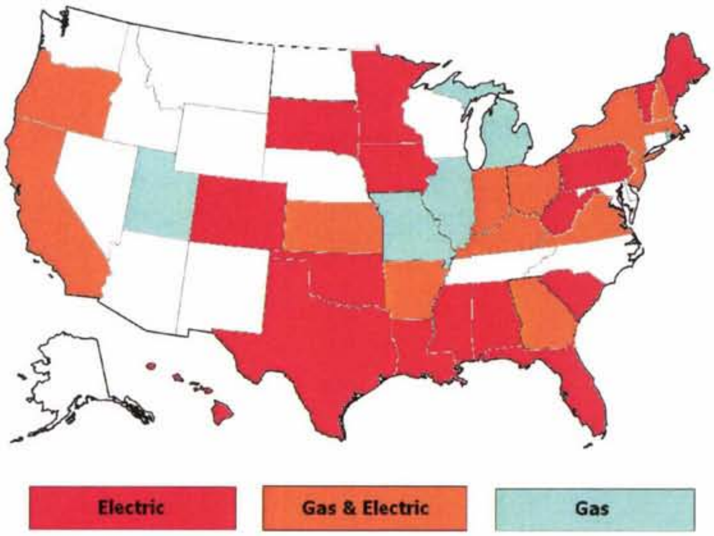


Figure 6: Recent Capex Recovery Mechanism Precedents for US Water Utilities

Figure 7: Recent Electric Precedents for CWIP in Rate Base

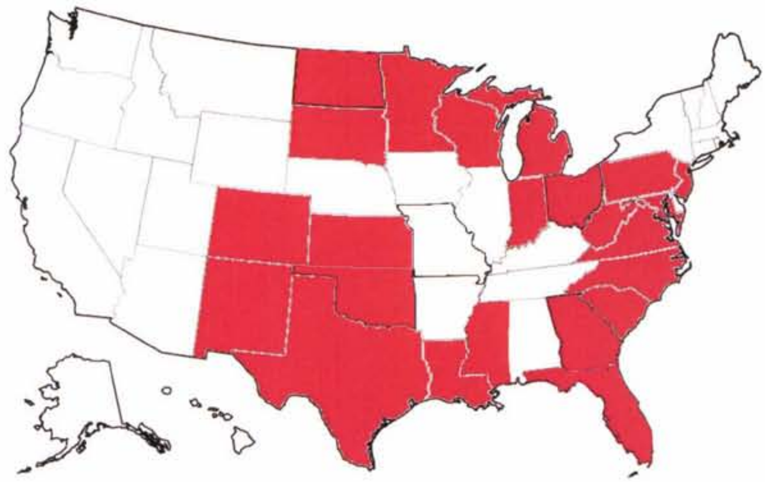


Figure 5 shows that many gas distributors have capex recovery mechanisms. This reflects the fact that gas distribution systems in Eastern and some Midwestern states tend to be older than their electric counterparts. The older facilities were often built with cast iron and/or bare steel, materials which today involve high maintenance costs. Capex recovery mechanisms have helped gas distributors accelerate the replacement of these old facilities. I believe that these precedents are quite relevant to the consideration of Pepco's RIM proposal. Capex surcharges are also common in the water utility industry.

Q. ARE CAPEX RECOVERY MECHANISMS USED IN THE MID-ATLANTIC STATES?

A. Yes. Capex recovery mechanisms are operative for most gas and electric distributors in New Jersey, including Pepco's sister utility Atlantic City Electric Company. The period of operation of some of these mechanisms has recently been extended. In Virginia, capex recovery mechanisms for gas utilities were in 2010 expressly sanctioned by a new law, the SAVE Act, and a mechanism has since been approved there for Washington Gas Light. Appalachian Power has recently operated under capex recovery mechanisms in Virginia and West Virginia.

Q. DO SOME UTILITIES OPERATE UNDER A COMBINATION OF REVENUE DECOUPLING AND CAPEX RECOVERY MECHANISMS?

A. Most definitely. More than thirty energy utilities currently operate under a combination of capex recovery mechanisms and some form of revenue decoupling. Many of these are utilities that, like Pepco, operate under RPC freezes or an alternative approach to decoupling that is not designed to finance capex investment surges. Utilities that operate under such combinations include Duke Energy (OH), Pacific Gas & Electric (CA), Peoples Gas Light and Coke (IL), San Diego Gas & Electric (CA), and Southern California Edison (CA). These are energy distributors that, like Pepco, are engaged in programs of accelerated system modernization.

Q. PLEASE DISCUSS THE PROS AND CONS OF CAPEX RECOVERY MECHANISMS.

A. Capex recovery mechanisms are a sensible remedy for the regulatory lag of an energy distributor engaged in an accelerated system modernization program. Regulatory lag can be mitigated considerably, and annual rate cases are likely to be avoided if the distributor is, additionally, protected from material declines in average use. Regulation is thereby streamlined, and utility performance can be improved. In contrast to multi-year rate plans and forward test years, forecasts are required only for the targeted capex, and these forecasts are subject to annual reconciliations. Rate shock is mitigated. In summary, capex recovery mechanisms make particular sense for commissions that want to encourage system modernization and recognize the potential for regulatory lag but prefer not to mitigate the lag using salient alternatives such as multi-year rate plans.

One factor to address in the development of a capex recovery mechanism is the need to ensure that the capital spending that is thereby encouraged is prudent. Prudence involves making sure that the capex is really needed and undertaken efficiently and that benefits of the capex, such as better reliability, are realized.

These concerns can be mitigated by a well designed plan. Multi-year capex plans should reflect extensive evidence on the specific projects to be undertaken, their net benefits, and their efficiency compared with alternative means of improving reliability. Plans should create a material risk that costs in excess of budgets will not be recovered, and perhaps also provide the utility with an opportunity to share in the benefit of underspends.

Q. HAS THE ABILITY OF CAPEX RECOVERY MECHANISMS TO REDUCE RATE CASE FREQUENCY BEEN ACKNOWLEDGED BY REGULATORS?

A. Yes. The Illinois Commerce Commission (ICC) recently approved a capex recovery mechanism for Peoples Gas Light and Coke. That company is engaged in an accelerated program to replace cast iron and bare steel facilities. The ICC in its decision approving the mechanism acknowledged its superiority over alternative remedies such as frequent rate cases and regulatory assets. Concerning the former, it stated that

> From our perspective, rate cases consume vast amounts of time, money, and resources, and are not only burdensome for utilities and other parties. They also strain the limited resources of the Commission and its Staff and divert attention from other pressing matters. Ultimately too, rate case costs are consumer costs. We cannot and will not speculate on when the Company will need to come in for a rate case in the future, but it is reasonable to believe that Rider ICR may extend that period and to that extent, it is reasonable. Notably too, we do not see Staff or any other party to say that they prefer annual rate cases.[2]

[2] Illinois Commerce Commission, *Order*, 09-0166 and 09-0167 Consolidated, January 21, 2010 pp. 173-174.

Q. WHAT EMPIRICAL EVIDENCE EXISTS THAT CAPEX RECOVERY MECHANISMS REDUCE CAPITAL COSTS?

A. PEPCO (B)-7 presents selected credit quality metrics for large samples of gas and electric utilities that did and did not have capex recovery mechanisms over the 2007-2009 period. The sources are *Credit Stats: Gas Utilities - U.S.* and *Credit Stats: Electric Utilities - U.S.* Both reports were prepared by Standard and Poor's and appear in the Global Credit Portal of its RatingsDirect service. I present results for four credit metrics: Standard & Poor's corporate credit rating, the (rate of) return on capital, and two cash flow ratios (EBITDA/interest coverage and FFO/Debt).

Cash flow ratios are used by credit analysts to assess a utility's ability to service debt. The cash flow measures are normally calculated as adjustments to net income that add back cash flows that could be used to service debt. FFO (funds from operations), for instance, adds back depreciation and amortization expenses. EBITDA (earnings before interest, taxes, depreciation, and amortization) adds back interest and taxes as well as depreciation and amortization.

PEPCO (B)-7 reports averages for each of the metrics for sampled utilities over the 2007-2009 period. There is an indeterminate category for utilities that are not easily categorized as having operated under capex recovery mechanisms throughout this period. I include in the capex recovery mechanisms category the retail formula rates used by a few Southern utilities, since this effectively provides expedited treatment of capex costs.

Caution must be taken in making comparisons inasmuch as these metrics may differ between the sampled utilities due to differences in several other business conditions as well as to any differences in the use of capex recovery mechanisms. The other relevant business conditions include the ability to rate base construction work in progress, the local severity of the recent recession, and whether or not utilities operated under revenue decoupling. Despite these complications, the samples may be large and diverse enough to shed some light on the effect that capex recovery mechanisms have on credit metrics.

Q. PLEASE DISCUSS THE RESULTS OF THIS RESEARCH

A. Comparing the results for gas distributors, it can be seen that the values of all four credit metrics were typically more favorable for distributors that had capex recovery mechanisms than for those that did not.

- The capex recovery mechanism distributors had a typical credit rating between A- and A whereas the other distributors had a typical credit rating between BBB+ and A-.
- The capex recovery mechanism distributors had an average rate of return on capital of 9.7% whereas the other distributors had an average return of 8.3%.
- The capex recovery mechanism distributors had an average EBITDA/interest coverage of 5.4 whereas the other distributors had an average coverage of 4.8.
- The capex recovery mechanisms distributors had an average FFO/debt ratio of 24.8 whereas the other distributors had an average ratio of 21.0.

Similar results were obtained for sampled electric utilities.

Q. **REGULATORY LAG IS SOMETIMES CONSIDERED AN INCENTIVE FOR A UTILITY COMPANY TO MANAGE ITS COSTS AND BE EFFICIENT. DOES ADOPTION OF A LAG MITIGATION MEASURE REDUCE THE INCENTIVE FOR THE UTILITY TO BE EFFICIENT AND MANAGE COSTS?**

A. Based on my many years of experience in the field of incentive regulation, I believe that the regulatory lag produced by traditional regulation under today's operating conditions does not strengthen performance incentives on balance. While the prospect of underearning provides some inducement to cut costs, utilities will likely also respond to the prospect by filing frequent rate cases. As I discussed earlier, this weakens performance incentives, since any cost savings will be quickly passed through to customers and there is no time to recover the upfront costs of major downsizing initiatives.

This is not to say that regulatory lag cannot encourage better cost performance if combined with periodic rate adjustments for changes in the external business conditions that drive cost. In that event, utilities have a chance to earn a superior return but performance incentives aren't weakened because utilities aren't compensated specifically for their *own* cost growth. In a competitive industry like banking, companies are incentivized to contain their costs despite the fact that the lending rates they charge tend to rise and fall with the borrowing rates that they pay. That is why multi-year rate plans with indexing for inflation are considered a form of incentive regulation.

Q. HAVE YOU DONE ANY STATISTICAL WORK TO TEST THE HYPOTHESIS THAT REMEDIES FOR REGULATORY LAG WEAKEN PERFORMANCE INCENTIVES?

A. Yes. I measured the trends in the power distributor O&M expenses of a large group of utilities over the 1999-2010 sample period. For this exercise, I focused on power distribution, customer account, and sales expenses as reported on the FERC Form 1. Differences in the O&M cost growth of power distributors are due chiefly to differences in their customer growth. We therefore divided O&M expenses by the number of customers served. We compared the trends in unit costs of utilities that operated under forward and historical test years during the sample period. If forward test years weaken operating efficiency, we would expect the growth in the cost metrics to be higher on average for the forward test year utilities.

Results of this exercise are reported in PEPCO (B)-8. It can be seen that the unit cost growth of the forward test year utilities was similar to and a little slower than that of the historical test year utilities during the sample period. These results are consistent with the notion that there is no significant difference in the cost containment incentives generated by future and historical test years despite the greater likelihood that historical test years will produce regulatory lag problems.

Q. **WHAT DO YOU RECOMMEND THAT THE COMMISSION DO ABOUT REGULATORY LAG AT THIS TIME?**

A. I recommend that the Commission take two concrete steps in this proceeding to further reduce Pepco's regulatory lag problem. One is to approve the Reliability Investment Recovery Mechanism that I helped the Company to develop. Approval of the RIM should take place in the context of this proceeding with implementation shortly after its conclusion, consistent with the Company's proposed tariff. The first compliance filing implementing the RIM would take place within 60 days of the Commission's Order in this proceeding approving the RIM concept.

I also recommend that the Commission initiate in this proceeding a new generic proceeding to consider giving utilities a forward test year option. This proceeding would be analogous to Formal Case 712, which previously contemplated forward test years in the District. In addition, I support the Commission in its continued use of revenue decoupling and regulatory assets for AMI costs. Prospectively, I recommend that the

Commission seriously consider a multi-year revenue cap for Pepco.

Q. **PLEASE DESCRIBE THE RIM THAT YOU HELPED THE COMPANY TO DESIGN.**

A. The RIM is a capex recovery mechanism that targets incremental capital costs resulting from Pepco's system modernization program. The investments subject to cost recovery through the RIM would replace aging distribution facilities and/or improve reliability in the District. The capex addressed by the RIM would occur after the test year and is not included in the rate base the Company is proposing in another part of this proceeding. Costs of new connections are excluded and none of the investments would generate new revenue automatically.

Filings would be made annually which predict, with month to month itemization, the accumulating annual cost of RIM investments in the upcoming year and make certain adjustments for the operation of the RIM in prior years. The cost would be recovered via a rate rider, as discussed in the testimony of Company Witness Janocha.

Q. **HOW WOULD RIM-RELATED COSTS BE TREATED IN FUTURE RATE CASES?**

A. In the Company's next general rate case following implementation of the RIM, the undepreciated balance of the capex would be considered for inclusion in the rate base. RIM charges related to costs that are included in the rate base at that time would be terminated.

Q. PLEASE DESCRIBE IN MORE DETAIL THE CALCULATION OF THE RIM REVENUE REQUIREMENT.

A. One component of the revenue requirement would be a return on investment. The eligible investment would include appropriate capitalized expenses and the CWIP on facilities that are not yet used and useful. The revenue requirement would also include depreciation on plant that is used and useful and an adjustment for changes in taxes that result from the capex. The calculations would use the depreciation rates and weighted average cost of capital that the Commission establishes in this proceeding.

An illustrative calculation of the revenue requirement and RIM charge is provided in PEPCO (B)-9. This Exhibit details the calculation of monthly revenue requirements and an annual charge for the RIM over a 12-month period. The calculation uses the projected capex of $89,388,952 that is supported in Company Witness Gausman's testimony.

Q. WHAT ADJUSTMENTS WOULD BE MADE IN THE ANNUAL FILING?

A. The annual RIM filing would, additionally, adjust the revenue requirement for variances between last year's actual costs and RIM revenues. Any differences would be recorded as a deferred balance. In calculating the monthly interest on net over- and under-recoveries, the interest rate would be based upon the Company's interest rate obtained on its commercial paper and/or bank credit lines. If both commercial paper and bank credit lines were used, the weighted average of both sources of debt would be used.

Q. WHAT PRECAUTIONS WOULD BE TAKEN AGAINST A RIM MISCALCULATION?

A. The search for errors in RIM calculations would be a focus of each annual reconciliation hearing. The Company would conduct an internal audit of the RIM each year and report its outcome in these hearings. This audit would include a determination of whether the costs recovered through the RIM were recovered, redundantly, through other approved tariffs; whether the surcharges were properly billed to customers in the correct time periods; and whether the costs and revenues were properly identified and recorded. Any errors discovered would be factored into the new RIM tariff with interest. The

Sarbanes-Oxley Act provides further protections against RIM miscalculations.

Q. WHAT PROTECTIONS EXIST AGAINST OVEREARNING UNDER THE PROPOSED RIM?

A. Chronic overearning is in my view unlikely under the plan. Pepco underearned in 2009 and 2010 despite the operation of the BSA, and capex will be higher prospectively. The Company will, in any event, continue to file quarterly earnings statements.

Q. WOULD APPROVAL OF THE RIM COMPLETELY ELIMINATE THE NEED FOR BASE RATE CASES IN THE NEXT FEW YEARS?

A. No. The RIM would address an emerging source of regulatory lag, but would not fully address the sources of the Company's underearning. There would still be the need for occasional base rate cases.

Q. WOULD THE RIM HAVE AN EXPIRATION DATE?

A. A fixed expiration date is not proposed. However, a special proceeding to review the RIM would begin three years from the effective start date of the mechanism. The extension, modification, or termination of the RIM can be considered in this proceeding.

Q. PLEASE EXPLAIN HOW THE RIM MAINTAINS STRONG INCENTIVES FOR CAPEX CONTAINMENT.

A. Pepco will file in this proceeding extensive information on its proposed RIM expenditures over a multi-year period. The filing will include data on specific projects and their estimated costs and completion dates. The expected nine month duration of this proceeding should provide sufficient time for the Commission to consider and approve a multi-year budget for the program. Approval of the RIM is thus preconditioned on a Commission finding that substantial capital expenditures are needed to refurbish, rebuild, and modernize the distribution system of the District of Columbia. Parties to the proceeding can potentially agree on a multi-year capex budget and other details of the investment plan in a settlement.

The annual RIM filings would last two months and give the Commission a chance to review and approve Pepco's updated investment plan for the upcoming year. Staff and Intervenors would have an opportunity for discovery and filed comments prior to the issuance of a Commission Order establishing the Company's new RIM adjustment.

A full and thorough final review of whether RIM costs are reasonable and prudent would occur in the rate case. This review would include consideration of whether the investments are used and useful and have achieved any forecasted benefits.

It should also be remembered that, in a period of substantial capex, it will remain a challenge for Pepco to manage its business in a way that allows it to earn close to its authorized ROE. Consider, finally, that the Company will likely hope for the RIM to continue. This gives Pepco an incentive to keep the operation of the RIM non-controversial. The Company will wish to avoid any appearance of overspending.

Q. DO CAPEX RECOVERY MECHANISMS MAKE SENSE FOR PEPCO'S DISTRIBUTION-SYSTEM MODERNIZATION AND RELIABILITY ENHANCEMENT PLAN?

A. Yes. A capex recovery mechanism would surgically address the principal source of regulatory lag that Pepco is facing in the next several years. The Commission has already recognized the need for reliability improvements. Salient alternative options, such as multi-year rate plans, involve noteworthy complications. The Commission would determine the categories of reliability investments for which recovery would be authorized, and establish the details of the mechanism (*e.g.* true-ups, review periods, audits, caps, etc.) to be used. A capex recovery mechanism would permit Pepco and other parties to regulation in the District to focus on the challenge of improving system reliability.

Q. **YOU HAVE ALSO PROPOSED THAT THE COMMISSION INITIATE A GENERIC PROCEEDING TO GIVE UTILITIES IN THE DISTRICT OF COLUMBIA A FORWARD TEST YEAR OPTION. IS THERE MERIT IN COMBINING THIS WITH A CAPEX TRACKER AND REVENUE DECOUPLING?**

A. Yes. I have already noted that the addition of a forward test year to Pepco's current regulatory system will likely solve the Company's regulatory lag problem only with frequent rate cases. With a RIM in place, however, a forward test year can materially help reduce the frequency of rate cases during the period of accelerated system modernization and beyond. The resultant benefits would more than make up for the somewhat greater complexity of individual rate cases. In summary, capex recovery mechanisms and forward test years are complementary measures for capturing the benefits of regulatory lag mitigation.

Q. **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes, it does.

M. N. LOWRY
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO ______ (B)-1

RESUME OF MARK NEWTON LOWRY

June 2011

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Date of Birth: August 7, 1952

Education:
High School: Hawken School, Gates Mills, Ohio, 1970
BA: Ibero-American Studies, University of Wisconsin-Madison, May 1977
Ph.D.: Agricultural and Resource Economics, University of Wisconsin -Madison, May 1984

Relevant Work Experience, Primary Positions:

Present Position — **President, Pacific Economics Group Research LLC, Madison WI**

Chief executive of the research unit of the Pacific Economics Group consortium. Leads internationally recognized practice in alternative regulation ("Altreg") and utility statistical research. Other research specialties include: codes of competitive conduct, markets for oil and gas, and commodity storage. Duties include senior management, supervision of research, and expert witness testimony.

October 1998-February 2009 — **Partner, Pacific Economics Group LLC, Madison, WI**

Managed PEG's Madison office. Specific duties include project management and research, written reports, public presentations, expert witness testimony, personnel management, and marketing.

January 1993-October 1998 — **Vice President**
January 1989-December 1992 — **Senior Economist, Christensen Associates, Madison, WI**

Directed the company's Regulatory Strategy group. Participated in all Christensen Associates testimony on energy utility PBR and statistical benchmarking during these years.

Aug. 1984-Dec. 1988 — **Assistant Professor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Responsibilities included research and graduate and undergraduate teaching and advising. Courses taught: Min Ec 387 (Introduction to Mineral Economics); 390 (Mineral Market Modeling); 484 (Political Economy of Energy and the Environment) and 506 (Applied Econometrics). Teaching and research specialty: analysis of markets for energy products and metals.

August 1983-July 1984 — **Instructor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Taught courses in Mineral Economics (noted above) while completing Ph.D. thesis.

April 1982-August 1983 **Research Assistant, Department of Agricultural and Resource Economics, University of Wisconsin-Madison**

Dissertation research under Dr. Peter Helmberger on the role of speculative storage in markets for field crops. Work included the development of an econometric rational expectations model of the U.S. soybean market.

March 1981-March 1982 **Natural Gas Industry Analyst, Madison Consulting Group, Madison, Wisconsin**

Research under Dr. Charles Cicchetti in two areas:

- Impact of the Natural Gas Policy Act on the production and average wellhead price of natural gas in the United States.
- Research supporting litigation testimony in an antitrust suit involving natural gas producers and pipelines in the San Juan Basin of New Mexico.

Relevant Work Experience, Visiting Positions:

May-August 1985 **Professeur Visiteur, Centre for International Business Studies, Ecole des Hautes Etudes Commerciales, Montreal, Quebec.**

Research on the behavior of inventories in non-competitive metal markets.

Major Consulting Projects:

1. Research on Gas Market Competition for a Western Electric Utility. 1981.
2. Research on the Natural Gas Policy Act for a Northeast Trade Association. 1981
3. Interruptible Service Research for an Industry Research Institute. 1989.
4. Research on Load Relief from Interruptible Services for a Northeast Electric Utility. 1989.
5. Design of Time-of-Use Rates for a Midwest Electric Utility. 1989.
6. PBR Consultation for a Southeast Gas Transmission Company. 1989.
7. Gas Transmission Productivity Research for a U.S. Trade Association. 1990.
8. Productivity Research for a Northeast Gas and Electric Utility. 1990-91.
9. Comprehensive Performance Indexes for a Northeast Gas and Electric Utility. 1990-1991.
10. PBR Consultation for a Southeast Electric Utility. 1991.
11. Research on Electric Revenue Adjustment Mechanisms for a Northeast Electric Utility. 1991.
12. Productivity Research for a Western Gas Distributor. 1991.
13. Cost Performance Indexes for a Northeast U.S. Gas and Electric Utility. 1991.
14. Gas Transmission Rate Design for a Western U.S. Electric Utility. 1991.
15. Gas Supply Cost Indexing for a Western U.S. Gas Distributor. 1992.
16. Gas Transmission Strategy for a Western Electric Utility. 1992.
17. Design and Negotiation of Comprehensive Benchmark Incentive Plans for a Northeast Gas and Electric Utility. 1992.

18. Gas Supply Cost Benchmarking and Testimony for a Northeast U.S. Gas Distributor, 1992.
19. Bundled Power Service Productivity Research for a Western Electric Utility. 1993-96.
20. Development of PBR Options for a Western Electric Utility. 1993.
21. Review of the Regional Gas Transmission Market for a Western Electric Utility. 1993.
22. Productivity and PBR Research and Testimony for a Northeast Electric Utility. 1993.
23. Productivity and PBR Research and Testimony for a Northeast Electric Utility. 1994.
24. Productivity Research for a Western Gas Distributor. 1994.
25. White Paper on Price Cap Regulation for a U.S. Trade Association. 1994.
26. Bundled Power Service Benchmarking for a Western Electric Utility. 1994.
27. White Paper on PBR for a U.S. Trade Association. 1995.
28. Productivity Research and PBR Plan Design for a Northeast Gas and Electric Company. 1995.
29. Regulatory Strategy for a Restructuring Canadian Electric Utility. 1995.
30. PBR Consultation for a Japanese Electric Utility. 1995.
31. Regulatory Strategy for a Restructuring Northeast Electric Utility. 1995.
32. Productivity Research and Plan Design Testimony for a Western Gas Distributor. 1995.
33. Productivity Testimony for a Northeast Gas Distributor. 1995.
34. Speech on PBR for a Western Electric Utility. 1995.
35. Development of a PBR Plan for a Midwest Gas Distributor. 1996.
36. Stranded Cost Recovery and Power Distribution PBR for a Northeast Electric Utility. 1996.
37. Benchmarking and Productivity Research and Testimony for a Northeast Gas Distributor. 1996.
38. Consultation on Gas Production, Transmission, and Distribution PBR for a Latin American Regulator. 1996.
39. Power Distribution Benchmarking for a Northeast Electric Utility. 1996.
40. Testimony on PBR for a Northeast Power Distributor. 1996.
41. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1996.
42. Design of Gas Distributor Service Territories for a Latin American Regulator. 1996.
43. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1996.
44. Service Quality PBR for a Canadian Gas Distributor. 1996.
45. Productivity and PBR Research and Testimony for a Canadian Gas Distributor. 1997.
46. Bundled Power Service Benchmarking for a Northeast Electric Utility. 1997.
47. Design of a Price Cap Plan for a South American Regulator. 1997.
48. White Paper on Utility Brand Name Policy for a U.S. Trade Association. 1997.
49. Bundled Power Service Benchmarking and Testimony for a Western Electric Utility. 1997.
50. Review of a Power Purchase Contract Dispute for a Midwest City. 1997.
51. Research on Benchmarking and Stranded Cost Recovery for a U.S. Trade Association. 1997.
52. Research and Testimony on Productivity Trends for a Northeast Gas Distributor. 1997.
53. PBR Plan Design, Benchmarking, and Testimony for a Southeast Gas Distributor. 1997.
54. White Paper on Power Distribution PBR for a U.S. Trade Association. 1997-99.
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Agribusiness
American Journal of Agricultural Economics
Energy Journal
Journal of Economic Dynamics and Control
Materials and Society

M. N. LOWRY
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO ______ (B)-2

FORWARD TEST YEARS FOR US ELECTRIC UTILITIES

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August 2010

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EXECUTIVE SUMMARY

U.S. investor-owned electric utilities (electric "IOUs") in jurisdictions with historical test year rate cases are grappling today with financial stresses that threaten their ability to serve the public well. Unit costs are rising because growth in sales volumes and other billing determinants is not keeping pace with growth in cost. Cost growth is stimulated by the need to rebuild and expand legacy infrastructure and to meet environmental and other public policy goals. In this situation historical test years, still used in almost 20 U.S. jurisdictions, can erode credit quality and condemn IOUs to chronic underearning.

This report provides an in depth discussion of the test year issue. It includes the results of empirical research which explores why the unit costs of electric IOUs are rising and shows that utilities operating under forward test years realize higher returns on capital and have credit ratings that are materially better than those of utilities operating under historical test years. The research suggests that shifting to a future test year is a prime strategy for rebuilding utility credit ratings as insurance against an uncertain future.

CHAPTER 1 (FORWARD TEST YEARS) provides an introduction to test year issues. Problems with historical test years are discussed. We explain that the "matching principle" used to rationalize historical test years assumes that cost and revenue remain balanced. This assumption doesn't hold when unit cost is rising. In a rising unit cost environment, rates based on historical test years are uncompensatory even in the year they are implemented. As a result, operating risk increases, raising the cost of obtaining funds in capital markets. Service quality may be compromised. Customers receive out of date price signals that encourage excessive consumption. The problems are aggravated when rate hearings are protracted. Utilities commonly respond with more frequent rate case filings but these raise regulatory cost, weaken performance incentives, and distract managers from their basic business while still not giving utilities sufficient attrition relief. It is unfair to expect utilities to offset revenue shortfalls produced by regulatory lag with higher productivity and unrealistic to think that they can do so. Forward test years can yield better results for utilities and their customers.

The unit cost trends of utilities are driven by conditions that are substantially beyond their control. These conditions include trends in input prices, productivity, and the average use of utility services by customers. For the matching principle to work, some combination of growth in utility productivity and average use must offset input price inflation.

Utility efforts to promote customer energy conservation slow growth in average use, thereby raising unit cost and making historical test year rates less compensatory. Forward test years can anticipate the slower growth in average use that results from utility conservation programs. They therefore help to remove utility disincentives to promote conservation aggressively.

The forecasts of costs and billing determinants that are made in a forward test year proceeding are uncertain but involve conditions that are at most two years into the future. A large part of utility cost is no more difficult to budget under forward test years than under historical test years. More volatile components of cost are often subject to true-up mechanisms. Conservative, well-reasoned methods for making forecasts are available. In a rising unit cost environment, the uncertainty of forecasts is less of a concern than the bias of historical test year rates.

Utilities seeking forward test years must be mindful of their high evidentiary burden. The following rate case measures bolster confidence.

- Provide concrete evidence as to why future test years and not historical test years are needed under current circumstances. Evidence concerning trends in the unit cost of utilities and in key unit cost drivers is especially pertinent.
- Provide cost and billing determinant data for one or more historical reference years and carefully explain methodologies for predicting cost and billing determinant changes between those years and the forward test year.
- Use forecasting methods that are transparent and based on reason but not needlessly complex.
- Routine variance reports comparing costs and billing determinants to utility forecasts can increase comfort that forecasts are unbiased.

CHAPTER 2 (TEST YEAR HISTORY) presents a brief history of test years in the United States. Historical test years became the norm in the U.S. because periods of stable or declining unit cost, made possible by slow price inflation and brisk growth in utility productivity and average use, were the rule rather than the exception in the electric utility industry prior to the late 1960s. Growth in productivity and average use have slowed enough in subsequent decades that unit cost has frequently risen. Under favorable business conditions, unit cost can still be flat for several years, making historical test years more reasonable. However, conditions like these can give way to conditions in which unit cost rises for years at a time.

Forward test years were adopted in many jurisdictions during the 1970s and 1980s as unit cost grew briskly, spurred by input price inflation and slower growth in average use and utility productivity. Unit cost growth was flat during most of the 1990s because business conditions driving unit cost growth were more favorable. Input price inflation slowed. Investment needs were more limited, as many utilities grew into capacity added during the construction cycle of the 1970's and early 1980's. Average use grew less rapidly than in the past but nonetheless increased appreciably in most years. Under these conditions, utilities were sometimes able to commit to multiyear base rate freezes.

Unit cost growth has since rebounded due to higher inflation, increased plant additions, and slowing growth in average use. Commissions in several states with historical test year traditions have recently moved in the direction of forward test years. Many of these states are in the West, where comparatively rapid economic growth has stimulated plant additions. The ranks of U.S. jurisdictions that use alternatives to historical test years have swollen and now encompass well over half of the total.

In summary, historical test years became the norm in U.S. rate cases during decades when unit cost was flat or declining due to remarkably brisk utility productivity and average use. Under contemporary conditions, in which average use grows slowly, if at all, and the productivity growth of utilities is more like that of the economy, unit cost may rise for extended periods undermining the matching principle.

CHAPTER 3 (EMPIRICAL SUPPORT FOR FORWARD TEST YEARS) presents results of some empirical research on test year issues. In original work for this paper, we calculated the unit cost trends of a sample of vertically integrated electric utilities from 1996 to 2008. Trends in business conditions that drive unit cost growth were measured. We also considered how test year policies affect credit metrics and utility operating performance.

Here are some salient results.

- The unit cost of sampled utilities was fairly stable from 1996 to 2002 but has since rebounded, averaging 2.3% annual growth from 2003 to 2008. The underlying causes of rising unit cost included higher input price inflation and capital spending and slower growth in the average system use of residential and commercial customers.
- In the three year period from 2006 to 2008 average use actually declined for the typical utility, pulled down by sluggish economic growth and government policies that encourage conservation. The decline was especially marked in states with large conservation programs.
- These results suggest that many IOUs may not be able in the future to count on brisk growth in average use by residential and commercial customers to buffer the impact on unit cost growth of input price inflation and increased plant additions. The problem will be considerably more acute in service territories where there are aggressive conservation programs.
- Utilities operating under forward test years were more profitable and had better credit ratings on average than those of utilities operating under historical test years. For example, from 2006 to 2008 utilities operating under forward test years realized an average return on capital of 9.2% and maintained a typical credit rating between A- and BBB+ whereas the utilities operating under historical test years realized an average return of 7.9% and maintained a typical credit rating between BBB and BBB-.
- Examination of recent trends in operation and maintenance ("O&M") expenses of utilities provides no evidence that historical test years encourage better cost management.

CHAPTER 4 (CONCLUDING REMARKS) provides some suggestions as to how interested regulators can get started down the road to forward test years.

1. Allow a forward test year on a trial basis for one interested utility.

2. Allow forward test years on an as needed basis when a utility makes a convincing case that rising unit costs make historical test years unjust and unreasonable.
3. Borrow one or two of the methods used in FTY rate cases to make additional adjustments to *historical* test year costs and billing determinants. For example, historical test year O&M expenses can be adjusted for forecasts of price inflation prepared by respected independent agencies. Special adjustments can be made for large plant additions that are expected to be finished in the near future.
4. Try a current test year (essentially the year of the rate case), which involves forecasts only one year into the future. Current test years can be combined with interim rate increases which are subject to true up when the rate case is finalized. A combination of a current test year and interim rates eliminates regulatory lag without the necessity of a two year forecast.

In states where regulators aren't ready to abandon historical test years but are sympathetic to the attrition problems caused by rising unit costs, alternative measures are available to relieve the financial attrition. Options include the following:

1. Make sure that historical test year calculations incorporate the full array of normalization, annualization, and known and measurable change adjustments that are used in other jurisdictions.
2. Grant utilities interim rate increases at the outset of a rate case. Even when later adjusted for the final rate case outcome, interim rates effectively reduce regulatory lag by a year.
3. Capital spending trackers can ensure timely recovery of the costs of plant additions, without rate cases, as assets become used and useful.
4. Several methods have been established to compensate utilities for acceleration in unit cost growth that results from flat or declining average system use. These include decoupling true up plans, lost revenue adjustment mechanisms, and higher customer charges.
5. Multiyear rate plans can give utilities rate escalation between rate cases for inflation and other business conditions that drive cost growth.

1. FORWARD TEST YEARS

This chapter provides an in depth discussion of test year issues. Basic test year concepts are introduced in Section 1.1. The rationale for forward test years is discussed in Section 1.2. The kinds of evidence used in forward test year proceedings are explored in Section 1.3.

1.1 Basic Concepts

1.1.1 Rate Cases

In the United States, rates for the services of energy utilities are periodically reset by regulators in litigated proceedings called rate cases. These cases typically take about nine or ten months to resolve and sometimes end in a settlement between contending parties which is approved by the regulator. The first year following approval of new rates is called the "rate year".

In a rate case, rates are reset to reflect the cost and service levels of the utility in a test year. The first step in this process is to establish a revenue "requirement" that is commensurate with a cost for service deemed reasonable for test year operating conditions. Rates are then established which recover the revenue requirement given the levels of service provided in the test year. The service levels (*e.g.* the number of customers served and the power delivery volume) are sometimes called "billing determinants".

Bills of energy utilities often contain charges to recover the cost of energy commodities (*e.g.* fuel and purchased power) procured on a customer's behalf which are separate from the charges to recover the cost of capital, labor, and other inputs used to operate their systems. The rates that recover the costs of non-energy inputs are commonly called "base" rates. Base rate revenues are sometimes called "margins".

Rates for the cost of energy procurement are commonly subject to true ups to recover the actual cost of energy procured. Base rates, on the other hand, have traditionally been reset only in rate cases. The earnings of utilities thus depend primarily on the difference between their base rate revenues and the cost of their base rate inputs.

1.1.2 Historical Test Years

Various kinds of test years are used in rate cases today. An historical test year ("HTY") is a twelve month period that ends before the rate case filing. It typically ends a few months before the filing because it is desirable for the test year to be as current as possible but it takes several months to properly account for a year of costs and take the other steps needed to prepare a rate case. The year between an historical test year and the rate year is sometimes called the "bridge year".

The passage of time between a test year and the rate year is sometimes called "regulatory lag".[1] The lag between an historical test year and the rate year is typically two years. A utility filing for new rates in calendar 2011, for example, would typically file in March or April of 2010 using a calendar 2009 test year. Thus, historical test year rates applicable in 2011 would typically reflect business conditions in 2009.

Regulatory lag in this case has several causes. One is the necessity of using a year of historical data in the rate case filing. Another is the time required to prepare a rate case filing. Still another is the time required to execute the rate case and reach a final decision on new rates.

Historical test year data are usually adjusted in some fashion to make rates more relevant to rate year business conditions. Costs and billing determinants are often normalized for the effects of volatile business conditions on the grounds that there is no reason to expect these conditions to be abnormal during the rate year. For example, if residential and commercial delivery volumes during an historical test year were elevated by unusually high summer temperatures, they may be statistically normalized to reflect average summer weather conditions. Other examples of abnormal events that can prompt normalization adjustments include ice storms, recessions, and extended generation plant outages.

Cost and output conditions in the historical test year may also be "annualized". Effects may be removed, for a full year, of conditions that occurred during part of the HTY but are not expected to continue. One example would be costs reported for the HTY that pertained to years before the test year. Another would be the volume and peak demand of a large industrial customer who has closed its local operations.

Impacts of conditions that occurred only during certain months of the test year and are expected to prevail in the near future may also be annualized. For example, the value of the rate base at the end of an historical test year is sometimes assumed to be applicable for

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[1] This is one of several definitions of "regulatory lag" which are sometimes used in discussions of regulation. Another is the length of time between rate cases.

the entire year for purposes of calculating depreciation and the return on rate base. If union wage rates are raised in the last month of the HTY pursuant to the terms of a labor contract, labor expenses may be adjusted so that the higher cost per employee is effective for the entire year.

Cost and output data may, additionally, be adjusted for "known and measurable" (sometimes called "imminent certain") changes that have already occurred since the historical test year or are likely to occur in the near future. For example, if a labor contract provides for an escalation in union wages in the bridge year, HTY cost may be adjusted to reflect the wage rates provided in the contract.

The adjustments made to HTY cost and billing determinants vary across jurisdictions. While all such adjustments tend to make rates more relevant to rate year conditions, the HTY adjustment process often ignores important changes in business conditions that occur between an historical test year and a rate year. Here are some typical omissions.

- Cost is usually not adjusted to reflect future inflation in the prices of materials, services, and new equipment because the extent of such inflation isn't known with certainty.
- Costs of plant additions in the bridge year and the rate year are often omitted if their completion date and/or final cost aren't known with certainty.
- Billing determinants are usually not adjusted to reflect trends that are likely to occur after the test year because these are not known with certainty.
- Adjustments for known and measurable changes are sometimes limited arbitrarily to the bridge year.

1.1.3 Forward and Hybrid Test Years

A forward or future test year ("FTY") is a twelve month period that begins after the rate case is filed. Test year cost and billing determinants must in this case be forecasted, and forward test years are for this reason sometimes called forecasted test years. Utilities in some jurisdictions file rate cases with *multiple* forward test years. In the Canadian province of Alberta, for instance, it has recently been common for utilities to file for two forward test years in a rate case.

Most commonly, a forward test year begins about the time that the rate case is expected to end. The test year is then the same as the rate year. A utility filing on April 1

2010, for instance, might use calendar 2011 as its test year on the assumption that the rate case will take nine months to complete.

Some utilities use FTYs that begin about the time of the rate case filing. This kind of test year may be called a "current" FTY. The initial filing is in this case based entirely on forecasts but some months of actual data for the test year become available in the course of the proceeding.

Utilities in some states make rate case filings using test years that encompass some months *before* the filing and some months *afterwards*. Data for all months of the test year are then likely to become available during the course of the filing. This kind of test year has been called a "hybrid" or "partial" test year.

1.2 Rationale for Forward Test Years

1.2.1 The Financial Challenge

The Key Role of Unit Cost

We have noted that the rates that result from a rate case are designed to recover a revenue requirement that equals cost in a test year. In the case of an historical test year the new rates embody business conditions that are typically about two years older than those of the rate year. Business conditions are likely to change between an historical test year and the rate year, causing both cost and revenue to differ from the HTY level. For rates to be exactly compensatory, base rate cost and revenue must differ from their HTY levels in the same proportion.

The assumption that cost and revenue remain in balance underlies the matching principle that regulators still use to rationalize historical test years. Kamershen and Paul note in a thoughtful 1978 article on regulatory lag that "Philosophically, the strict [historical] test year assumes the past relationship among revenues, costs, and net investment will continue into the future."[2] A 2003 NARUC *Rate Case and Audit Manual* states in this regard that

> When looking at an historical test year, one of the first questions asked is whether the test year is too stale to make it a reasonable basis upon which to establish rates for a future period... In looking at the months beyond the end of the test year, have the growth rates for rate base, expenses, and revenues all remained fairly close and constant, maintaining the test year relationship

[2] David R. Kamershen and Chris W. Paul II, "Erosion and Attrition: A Public Utility's Dilemma", *Public Utilities Fortnightly*, December 1978, p. 23.

> among these three elements, or has one element changed dramatically, making the test year out of kilter with current operations? If so, can this situation be resolved through adjustments to the test year?[3]

Cost in the rate year is likely to be substantially higher than cost in an historical test year. To understand why, consider that cost growth in any business can be decomposed into inflation in the prices it pays for inputs plus the growth in its output less the growth in its productivity:

$$\textit{growth Cost} = \textit{growth Input Prices} + \textit{growth Output} - \textit{growth Productivity}. \quad [1]$$

The productivity growth of a business is typically not rapid enough to offset the combined effects of input price inflation and output growth. A recent study reported in testimony by Pacific Economics Group ("PEG") found, for example, that a national sample of U.S. power distributors averaged 1.03% annual growth in multifactor productivity ("MFP") from 1996 to 2006 whereas input price growth averaged 2.72% and customer growth averaged 1.00%.[4] The productivity trend of sampled distributors was similar to that of the U.S. private business sector but far from sufficient to offset the combined effects on cost of input price inflation and customer growth.

As for base rate revenue during the rate year, it can exceed the HTY revenue requirement only due to growth in billing determinants because rates are fixed at levels that reflect HTY conditions. Whether or not historical test year rates are compensatory thus depends critically on whether *unit* cost is stable in the sense that growth in billing determinants has kept pace with cost growth. If cost growth exceeds growth in billing determinants, unit cost will rise and HTY rates will be uncompensatory.

An element of complexity is added when it is considered that a utility offers many services and gathers revenue for each service from multiple charges, each with its own billing determinant. A bill for residential service, for instance, typically involves a flat monthly charge called a "customer" or "basic" charge and a "volumetric" (per kWh) charge. In this world of multiple billing determinants, historical test years will yield uncompensatory rates to the extent that cost growth between the test year and the rate year exceeds a *weighted average* of the growth in billing determinants, where the weight for each determinant is its

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3 NARUC Staff Subcommittee on Accounting and Finance, *Rate Case and Audit Manual*, Summer 2003.
4 Mark Newton Lowry, *et al.*, *Revenue Adjustment Mechanisms for Central Vermont Public Service Corporation*, Exhibit CVPS-Rebuttal-MNL-2 in Docket No. 7336, June 2008.

share of the total base rate revenue. In other words, rates are uncompensatory when cost growth exceeds the growth in a billing determinant *index*. This is the definition of growth in a *unit cost index*.

The utility uses most of its base rate revenue to pay its workforce, vendors of materials and services (including construction services), bondholders, and tax authorities. The residual margin, called net income or earnings, is available to provide the company's shareholders with a return on their investments. The return on equity is the component of cost that is most at risk for non-recovery when base rate revenue falls short of cost. When historical test year rates are non-compensatory they can reduce a utility's rate of return on equity ("ROE") materially.

Unit Cost Drivers

If the unit cost growth of a utility has made new historical test year rates non-compensatory, it may fairly be asked whether utility actions could have stopped the growth and avoided the problem. Research over many years has shown that the unit cost of a utility is driven chiefly by changes in business conditions that are beyond its control. Growth in the unit cost of a utility's base rate inputs depends on inflation in the prices it pays for those inputs, growth in the productivity with which it uses the inputs, and an average use effect:

$$\text{growth Unit Cost} = \text{growth Input Prices} - (\text{growth Productivity} + \text{Average Use}). \qquad [2]$$

We discuss each of these unit cost "drivers" in turn.

Input Price Inflation Inflation routinely occurs in the prices utilities pay for labor, materials, services, and equipment. Since utilities have capital-intensive technologies, inflation in the price of capital is an especially important driver of their input price growth. The trend in the price of capital depends chiefly on trends in construction costs, tax rates, and the going rates of return on debt and equity in capital markets.[5]

Productivity The productivity growth of a utility depends on various conditions that include technological change, the realization of scale economies, and the pace of plant additions as

[5] The impact of construction cost on price inflation is complex. In setting rates, utility plant is valued in historical dollars. The cost of service thus depends on prices paid for construction in past decades. Construction costs in more recent years matter more because the corresponding assets are less depreciated. The rate base will tend, on average, to reflect construction costs more than a decade into the past. For most utilities, new investments therefore embody more than a decade of construction cost inflation compared to investments of average vintage. This is one of the reasons why unusually large plant additions can increase the rate base so substantially.

well as utility efforts to root out inefficiencies. Plant additions may boost efficiency gains in the long run but can slow them in the short run, especially if they involve major investments such as new base load generating units, advanced metering infrastructure, or an accelerated program to replace aging infrastructure. Scale economies depend on the pace of output growth and on whether the utility is so large that it has reached a minimum efficient scale at which incremental scale economies from output growth aren't available.

The ability of utilities to achieve productivity surges is limited in the short run. Since technology is capital intensive, the depreciation and return on rate base associated with older investments --- which cannot be changed in the short run --- account for a large share of the total cost of base rate inputs. A utility can increase productivity only by slowing growth in O&M expenses and plant additions. Opportunities to achieve *sustained* productivity gains often involve sizable upfront costs and net gains may not occur for more than a year. A downsizing of the labor force, for instance, may involve severance payments. The chief means for a utility to trim its cost in the very short run is to defer maintenance expenses and plant additions. Such deferrals must be followed by higher expenses in short order if service quality is to be maintained. A utility can't rely on a deferral strategy year after year when it is filing frequent rate cases.

Average Use A utility's unit cost growth also depends on the difference in the impact that its output growth has on its revenue and its cost. When output growth boosts revenue more than cost, unit cost growth slows. When output growth causes cost to rise more rapidly than revenue, unit cost growth accelerates.

A utility's output growth has different impacts on revenue and cost when two conditions are present. One is that the design of base rates doesn't reflect the drivers of base rate input cost. The other is that billing determinants tend to grow at a different rate than cost drivers.

Consider, first, whether the design of utility base rates is cost causative. The cost of a utility's base rate inputs is largely fixed in the short run with respect to system use. Cost is much more sensitive to growth in the number of customers served.[6] As for billing determinants, we have seen that utility tariffs for most services involve multiple charges. These include one or more "variable" charges that are so called because they vary with

[6] Cost growth may also depend, in the long run, on the growth in peak demand and/or the delivery volume.

system use. Volumetric charges vary with the volume of power delivered. "Demand" charges vary with the peak level of demand (*i.e.* the highest hourly volume registered during the month). There are, additionally, "fixed" charges that are so called because they do not vary with a customer's use of the system during the billing period. Chief amongst the fixed charges of electric utilities are customer charges. Residential and small business customers account for the bulk of a utility's base rate revenue because these customers account for the bulk of a utility's cost. In these customer classes, base rate revenue is drawn chiefly from volumetric charges.

Under these circumstances, the difference between the way that output growth affects revenue and cost is chiefly a matter of the difference between the trends in the volume of sales to residential and small business customers and the trends in the number of customers served. This is equivalent to the trends in the delivery *volume per customer* of these service classes, which are sometimes referred to as the trends in their average (system) use. Unit cost growth slows when average use rises and accelerates when growth in average use slows.

In the electric utility industry, as in most sectors of the economy, the productivity growth of utilities has for decades been a good bit slower than the inflation in the prices they pay for inputs.[7] The recent PEG study noted earlier, for example, found that power distributor productivity growth fell short of input price growth by about 169 basis points annually on average from 1996 to 2006.[8] Under conditions like these, the average use trends of residential and small-volume business customers play an important role in determining whether a utility's unit cost rises. If growth in average use is *brisk* (*e.g.* 1.5 to 2% annually), the difference between input price and cost efficiency growth can be offset.[9] If average use is *static*, unit cost will rise substantially even under normal inflationary conditions. If average use is *declining*, the rise in unit cost can be quite rapid.

Recent changes in state and federal policy are encouraging more electricity demand-side management ("DSM") and development of customer-sited solar resources. These policies include net metering, tighter appliance efficiency standards and building codes, and

[7] The difference is greater in periods of brisk input price inflation and smaller in periods of slow inflation, since productivity does not characteristically rise and fall with inflation.
[8] Lowry *et al.* (2008) *op. cit.*
[9] Irston Barnes wrote, for example, in a classic treatise on rate regulation, that "as an offset to such factors making for rising rates, the increased volume of business that usually accompanies an upward movement of prices may so reduce the overhead charges per unit as to make any increase in rates unnecessary". See Irston R. Barnes, *The Economics of Public Utility Regulation* (New York: F.S. Crofts, 1942).

subsidies for energy efficiency investments. Our discussion suggests that such programs can accelerate unit cost growth by slowing growth in average use. Whether or not the utility provides DSM programs, average use can become static or decline, removing a key means by which utilities have traditionally coped with input price inflation and avoided unit cost growth. The problem can be remedied by redesigning rates in ways that raise customer charges. But rate designs are regulated and regulators in the United States generally do not sanction high customer charges.[10]

Implications Our analysis suggests that the unit cost of an electric utility is likely to rise, making historical test year rates non-compensatory, to the extent that the following external business conditions prevail.

- Input price inflation is brisk.
- Utilities need to make large plant additions that temporarily slow productivity growth.
- Average use of the utility system is static or declining.

Situations in which unit cost is stable, encouraging use of historical test years, include those in which inflation is slow, utilities aren't making large plant additions, and average use is growing briskly.

A program to accelerate the replacement of aging distribution facilities provides a classic example of the non-compensatory nature of historical test year rates. Suppose that a power distributor replaces 10% of its distribution infrastructure during a year when new rates are implemented. The new plant has capacity similar to the plant replaced but reflects more than forty years of construction cost inflation. The company's rate base will rise substantially, temporarily slowing productivity growth and accelerating unit cost growth. Even with normal growth in input prices and average use a utility with rates based on historical test years may earn little return on this sizable investment for as much as two years after it becomes used and useful.

Conclusions

These results permit us to draw several conclusions concerning the reasonableness of historical test years in ratemaking.

[10] High customer charges are more common for U.S. gas utilities and for gas and electric IOUs in Canada.

1) Historical test years are rationalized by a matching principle that assumes a balance of cost and revenue. Our analysis shows that this relationship is not balanced in a rising unit cost environment.
2) An individual utility reporting that rates produced by historical test years are uncompensatory may be suspected by stakeholders of poor cost management. However, research shows that a utility's unit cost trend is determined primarily by business conditions over which it has little control. These include the trends in input price inflation, average use, and the need for plant additions.
3) In a rising unit cost environment, the ability of a utility to "take a hair cut" between the historical test year and the rate year is limited. Long term performance gains involve upfront costs. Deferment of expenses lowers cost today at the expense of higher costs in the future.
4) Absent favorable operating conditions, the rise in a utility's unit cost due to changing business conditions may be so great that it is unable to earn its allowed rate of return under historical test year rates even with normal productivity gains. As Kamerschen and Paul comment, "while a utility is never guaranteed that it will earn its authorized fair rate of return, if no allowance is made for attrition or the other explosive elements, the utility is denied a realistic opportunity of earning the permitted rate of return."[11] In this situation, rates produced by historical test years are inherently unjust and unreasonable. This can prompt the investment community to downgrade its credit valuations, not just for the subject utility but for other utilities in the same jurisdiction.
5) Firms in competitive markets have ways of coping with rising unit costs that aren't available to utilities. The prices a competitive firm receives for its products will tend to rise at the same pace as the unit cost of its industry. Firms experiencing unit cost growth in excess of growth in sales prices can always scale back their offerings. A utility, in contrast, charges prices set by regulators which may not be reflective of unit cost trends. The utility is obligated to provide service even if prices are non-compensatory due to flawed ratemaking practices.

[11] Kamerschen and Paul *op. cit.* p. 23.

6) Unit cost pressures are not constant over time. Several years of flat unit cost can give way to a sustained period of rising unit cost. Thus, historical test years can produce reasonable results for many years and then become uncompensatory for many years due to rising unit cost. A utility's success at earning its allowed ROE during a string of recent years does not necessarily mean that a forward test year isn't warranted prospectively.
7) Forward test years have major advantages over historical test years in a rising unit cost environment. Rates are more likely to reflect unit cost conditions in the rate year and are, to this extent, more just and reasonable. Customers receive better price signals. Lower operating risk reduces the utility's cost of securing funds in capital markets. This benefit is especially important in periods of large plant additions, when high borrowing costs can have an especially large impact on the embedded cost of debt.
8) Whether or not unit cost is rising, historical test years do not adjust rates for slowdowns in volume growth, between the test year and the rate year, which are due to utility conservation initiatives. They therefore dampen utility incentives to encourage conservation.

1.2.2 Uncertainty

Opponents of forward test years often stress the uncertainty of cost and billing determinant forecasts. Future costs cannot be verified. The changes in business conditions that drive unit cost growth (*e.g.* inflation and the in service dates on looming plant additions) can be hard to predict accurately. The impact that changing business conditions have on unit cost is not always well understood. Opponents also argue that utilities are incented to exaggerate future cost growth and to understate future growth in billing determinants. Cost and billing determinants in a historical test year are, meanwhile, known with certainty.

On the other hand, the projections at issue in a forward test year concern business conditions that are at most two years into the future. A large chunk of future cost, the depreciation and the return on older plant, is known with considerable certainty at the time that the forecast is made. There are many aids in the preparation of credible forecasts, as we discuss further in Section 1.3. Consider also that volatile components of a utility's unit cost (*e.g.* expenses for pensions and uncollectible bills) are often subject to trackers that reduce or eliminate the risk of bad forecasts.

Current test years involve less forecasting uncertainty because the test year is only a year into the future at the time that the rate case is filed. Actual data for some or all months of the test year become available in the course of the proceeding. The accuracy of the methods used to forecast cost and billing determinants can thus be tested against their ability to predict the actuals in some months of the test year.

FTY projections are, in any event, quickly followed by actual data, and a utility that makes forecasts that are consistently biased in its favor will find that its forecasts are discounted in ratemaking. Biased forecasts can even jeopardize a regulator's willingness to use forward test years. The other stakeholders to the rate case process have incentives to bias cost and sales forecasts in the other direction. These circumstances reduce or eliminate the bias of the forecasts on which FTY rates are ultimately based. If the forecast of future cost and output is accurate, the utility will receive revenue that is exactly equal to its cost. FTY rates will be fair to the utility and ratepayer alike, whereas historical test year rates are likely to be biased in a rising (or falling) unit cost environment.

On balance then forward test year rates, while involving some uncertainty, are likely to be more reflective of future business conditions than are historical test year rates in a rising unit cost environment. The uncertainty involved in basing rates on FTYs is no greater than that involved in rate freezes and other kinds of multiyear rate plans that are often approved by regulators. The Michigan Public Service Commission ("PSC") commented, in a recent decision on an FTY rate filing for Consumers Energy, that

> The basis for using a forward test year is to address the problem of regulatory lag between past and future costs. While the advantage of historical data is its objective and verifiable nature, it lacks the necessary forward perspective required in a changing economic environment. An historical test year is by definition not timely and may fail to adequately consider future demands....What is gained by dealing with data that is "known and measurable" can be lost in forcing a utility to operate with outdated numbers.[12]

[12] Michigan PSC *Opinion and Order*, Case U-175645, November 2009.

1.2.3 Regulatory Cost

A third consideration in weighing the advantages of historical and forward test years is regulatory cost. The net impact of forward test years on regulatory cost is difficult to assess. Forward test year rate cases typically do involve higher cost than rate cases based on historical test years because of the need for forecasts.

On the other hand, a number of the major issues in a rate case, including the depreciation rates and the rate of return on common equity, are not markedly more complicated in a forward test year proceeding. Depreciation on existing plant is easy to predict once a depreciation rate is established. Some of the more uncertain components of cost and revenue may be subject to trackers that mitigate rate case controversy. The cost of FTY rate cases falls as jurisdictions gain experience with forecasted evidence. Consider also that in a rising unit cost environment rates based on forward test years can, by reducing earnings attrition, sometimes reduce the frequency of rate cases.

1.2.4 Operating Efficiency

The effect of alternative test year approaches on utility operating efficiency is also frequently discussed in debates on test year approaches. Opponents of forward test years sometimes argue that they weaken utility incentives to operate efficiently. In a rising unit cost environment, an expectation that rates are going to be non-compensatory might encourage utilities to tighten their belts. FTY opponents also argue that a utility wishing to inflate its cost in an historical test year, in an effort to create higher rates in the rate year, would incur a real cost to do so.

On the other hand, the notion that rate cases generally weaken utility performance incentives is a central result of regulatory economics and is not confined to future test years. When a utility is operating under a series of annual rate cases with historical test years, cost savings this year lead quickly to lower rates. The fact that a forward test year involves forecasts does not in and of itself weaken performance incentives. Forward test year forecasts are often linked to actual costs in one or more historical reference years, so the utility must once again incur a real cost if it wishes to bolster its argument for higher costs in the test year.

Consider also that when unit cost is rising, the non-compensatory rates yielded by forward test years may cause utilities to file rate cases more frequently. This weakens performance incentives, and senior managers devote less time to the utility's basic business of providing quality service at a reasonable cost. Analysis by PEG Research has revealed that reducing the frequency of rate cases from one to three years increases a utility's productivity performance by about 50 basis points annually in the long run.[13] We therefore do not expect utility operating incentives to differ significantly between historical and forward test years on balance.

It is, in any event, unreasonable for stakeholders and regulators to acquiesce in non-compensatory HTY rates on the grounds that they encourage utilities to trim "fat" if the existence of fat has not been demonstrated in the rate case. J. Michael Harrison, an administrative law judge with the New York PSC, commented in this regard in a 1979 article on forward test years that

> It is reasonable to set rates conservatively when company's management or operations are significantly and demonstrably poor... Evidence of general management inadequacy, however, is rarely seen in rate cases and ... management normally will be striving to improve efficiency in periods of continuously rising costs. Regulatory commissions certainly have an obligation to monitor operations and management effectiveness, but it does not appear justifiable to indulge in a presumption, absent specific evidence to the contrary, that deficient earnings can be attributed to management shortcomings rather than to unfavorable operating conditions.[14]

1.2.5 Other Considerations

Here are some additional considerations that merit note in a discussion of forward test year pros and cons.

- Forward test years encourage the utility, other stakeholders, and the Commission to focus more attention on the utility's plans for the future. Undesirable trends, such as rising costs that reflect inadequate attention to productivity growth, can be recognized and discouraged in advance of their occurrence. Budgeting is apt to play a more central role in cost management.

[13] See, for example, "Incentive Plan Design for Ontario's Gas Utilities", a presentation made by the senior author in work for the Ontario Energy Board in November 2006.
[14] J. Michael Harrison, "Forecasting Revenue Requirements", *Public Utilities Fortnightly*, March 1979, p. 13.

- Forward test year rate cases sharpen the ability of the regulatory community to undertake and review statistical analyses of unit cost trends. These same skills are useful in the design of multiyear rate plans in which rates are adjusted automatically between rate cases to reflect changing business conditions. Multiyear rate plans can reduce regulatory cost and strengthen utility performance incentives, creating benefits that can be shared with customers.

1.3 Evidentiary Basis for FTY Forecasts

Good evidence on future costs and billing determinants is critical to the effectiveness of forward test year rate cases. The New York PSC stated, in an order rejecting a forward test year for New York State Electric and Gas in 1972, that

> To justify the commission in deviating from its long-standing policy of using an actual test year adjusted for known changes, there must be a full showing that such a change is a practical necessity. This showing must encompass the twin requirements of substantial accuracy and an impending, uncontrollable diminution in profitability.

We have already discussed at some length the kinds of conditions that can cause unit cost to rise between an historical test year and the rate year. We consider here kinds of evidence used in FTY rate cases that increase the confidence of regulators that forecasts are accurate.

Linkage to Historical Data

Utilities in forward test year rate cases usually file detailed and extensive evidence concerning cost and billing determinants in one or more historical reference years.[15] Data for these years are usually subject to normalization and annualization adjustments like those used in historical test year filings. The utility will then present evidence on expected changes in cost and billing determinants between the historical reference year and the test year.[16] Cost projections are often made for the same detailed Uniform System of Account categories that are used in historical test year rate cases. J. Michael Harrison commented in this regard in his 1979 article that "the New York commission's requirement that a verifiable nexus be established between a forecast and an historical base of actual experience is a sine qua non

[15] An historical reference year is sometimes called a "base period".
[16] This sometimes includes a forecast of cost during the rate case year (if different), which is sometimes called the "bridge year".

for forecasting revenue requirements. The burden of proving the reasonableness of its filing remains with the utility company."[17]

Indexation

Indexation is used by several utilities in FTY rate cases to escalate cost items for changing business conditions. Recall from Section 1.2.1 that the growth in the cost of a utility equals the inflation in the prices it pays for inputs plus the growth in its output less the trend in its productivity. The trend in the productivity of utilities tends to be similar to the growth in their output. Testimony just prepared by PEG Research for San Diego Gas & Electric reports that, for a national sample of power distributors, MFP averaged 0.88% annual growth from 1999 to 2008 while the number of customers served averaged 1.37% average annual growth.[18] An assumption that productivity growth equals output growth makes it possible to escalate cost from historical reference year(s) values by the forecasted growth in prices. This is the most common use of indexing in FTY forecasts.

The United States is fortunate to have available some of the best data in the world on utility input price trends. One company, Whitman, Requardt and Associates, has for decades published "Handy Whitman Indexes" of trends in the construction costs of both gas and electric utilities.[19] These are available for six geographic regions of the United States for detailed asset classes. Another company, Global Insight, has a *Power Planner* service that has forecasts, updated quarterly, of construction cost indexes. Global Insight also forecasts inflation in the prices of labor, materials, and services used by gas and electric utilities.[20] The materials and service ("M&S") price indexes are available for the detailed O&M expense categories that are itemized in the FERC's Uniform System of Accounts. Global Insight input price indexes have been used for many years to adjust revenue requirements in the multiyear rate plans of California gas and electric utilities.

Some utilities instead escalate O&M expenses in rate cases using familiar macroeconomic price indexes. The gross domestic product price index ("GDPPI") is often preferred for this purpose to the better known consumer price index because the GDPPI assigns less weight to price volatile commodities, such as food and energy, which do not

[17] J. Michael Harrison, *op. cit.*, p. 13.
[18] Mark Newton Lowry *et al.*, *Productivity Research for San Diego Gas & Electric,* August 2010.
[19] Whitman, Requardt & Associates LLP, "The Handy-Whitman Index of Public Utility Construction Costs".
[20] A discussion of an early use of detailed inflation forecasts in ratemaking is found in Michael J. Riley and H. Kendall Hobbs, Jr. "The Connecticut Solution to Attrition", *Public Utilities Fortnightly*, November 1982.

loom large in base rate input costs. Our research over the years has found that the GDPPI and CPI both tend to understate escalation in the prices of utility O&M inputs. One reason is that they are measures of inflation in the economy's prices of final goods and services and therefore reflect the productivity growth of the U.S. economy, which has been substantial in recent years. In a recent report for Hawaiian Electric, for instance, PEG found that from 1996 to 2007 the GDPPI averaged 2.21% average annual growth whereas an index of the O&M input prices paid by HECO averaged 3.05% average growth.[21] The GDPPI should therefore inspire confidence as an O&M escalator that often yields reasonable results for customers.

Simple Trend Analyses

Simple approaches to forecasting based on historical trends can, if well designed, strike a reasonable balance between the desire of regulators for accuracy and simplicity. For example, a given cost item can equal its adjusted value in the historical reference year, plus a one or two-year escalation for the average annual growth of this cost for a group of peer utilities in recent years. This approach is more sensible to the extent that the recent inflation, productivity, and output trends of the peers are similar to those that the subject utility will experience in the near future. A refinement on this general approach would be to assume a trend in cost *per customer* equal to the recent historical trend of peer utilities and then to reach cost by adding a forecast of the utility's own customer growth. Simple methods like these have counterparts for the forecasting of billing determinants. For example, the volume of residential sales in a future test year can be forecasted as the expected number of customers multiplied by the expected volume per customer, where the latter is allowed to differ from the normalized value(s) in the historical reference year(s) by its normalized trend in the last three years.

Budgeting

Some utilities use the same figures in forward test year filings that they use in their own budgeting process.

[21] Mark Newton Lowry *et al.*, *Revenue Decoupling for Hawaiian Electric Companies*, Pacific Economics Group, January 2009. pp. 65-66.

Econometric Modeling

Econometric modeling is used by several utilities in FTY cost and billing determinant projections. In an econometric model, the variable to be forecasted is posited to be a function of one or more external business conditions. Model parameters are estimated using historical data on the variable to be forecasted and the business conditions. A rich theoretical and empirical literature is available to guide model development. Given forecasts of the business conditions, the model can forecast how cost will grow between one or more historical reference years and the forward test year.

Benchmarking

Utilities can bolster the confidence of regulators in their FTY cost forecasts by benchmarking them using data from other utilities. A variety of benchmarking methods are available, ranging from econometric modeling to peer group comparisons that use simple unit cost metrics. Public Service of Colorado, for instance, recently filed a study in an FTY rate case filing that benchmarked their non-fuel O&M expense forecast.[22] The study used an econometric benchmarking model as well as unit cost metrics for a Western Interconnect peer group. The authors found that the forecasted expenses reflected a high level of operating efficiency.

[22] See Public Service Company of Colorado's Exhibit MNL-1 in docket 09AL-299E before the Public Utilities Commission of Colorado, filed October 13, 2009.

2. TEST YEAR HISTORY AND PRECEDENTS

2.1 A Brief History

Few states have laws on the books that mandate a particular test year approach. Statutes instead commonly feature more general provisions on regulation such as guidelines that rates be just and reasonable, that terms of service be non-discriminatory, and that service be of good quality. Flexibility with respect to test years is also encouraged by the Supreme Court's influential *Hope* decision, which held that

> The Commission was not bound to the use of any single formula or combination of formulae in determining rates. Under the statutory [Natural Gas Act] standard of "just and reasonable" it is the result reached and not the method which is controlling...If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end.[23]

Historical test years were nonetheless the norm in the early history of electric utility rate cases, and this reflects the prevalence over many years of business conditions that were conducive to slow unit cost growth. Slow price inflation was a contributing factor. Table 1 shows the history of GDPPI inflation in the United States from 1930 to 2009. It can be seen that inflation was negative in most years of the 1930s but was brisk during World War II, the immediate post war years, and in 1951. After the Korean War, the table shows that GDPPI inflation averaged only 1.74% annually in the 1952-1965 period.

Table 1 also shows the trend in the MFP index for the electric, gas, and sanitary sector of the U.S. economy. This index was computed by the U.S. Bureau of Labor Statistics ("BLS") for many years and was sensitive to the productivity trend in the electric utility industry due to the industry's disproportionately large size. It can be seen that the productivity growth of the electric, gas, and sanitary sector was extraordinarily rapid during the 1952-65 period, averaging 4.13% per annum. This was more than double the MFP index trend for the U.S. non-farm private business sector as a whole.

Under these favorable operating conditions, the unit cost of the electric utilities was typically stable or declining.[24] Rate cases were rare and historical test years were the norm in the rate cases that did occur. Regulators gained confidence that the matching principle could

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[23] 320 U.S. 591.

[24] See Paul Joskow, "Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation", *Journal of Law and Economics*, 1974 for an insightful discussion of some of this history.

Table 1

U.S. Inflation and Productivity Trends

	GDP Price Index		Multifactor Productivity: Private Non-Farm Business		Multifactor Productivity: Electric, Gas & Sanitary Sector	
Year	Index	Growth	Index	Growth	Index	Growth
1929	10.6		NA	NA	NA	NA
1930	10.2	-3.94%	NA	NA	NA	NA
1931	9.2	-10.45%	NA	NA	NA	NA
1932	8.1	-12.08%	NA	NA	NA	NA
1933	7.9	-2.66%	NA	NA	NA	NA
1934	8.3	4.78%	NA	NA	NA	NA
1935	8.5	1.97%	NA	NA	NA	NA
1936	8.6	1.09%	NA	NA	NA	NA
1937	8.9	3.61%	NA	NA	NA	NA
1938	8.7	-1.90%	NA	NA	NA	NA
1939	8.6	-1.27%	NA	NA	NA	NA
1940	8.7	0.87%	NA	NA	NA	NA
1941	9.2	6.32%	NA	NA	NA	NA
1942	10.0	7.91%	NA	NA	NA	NA
1943	10.6	5.47%	NA	NA	NA	NA
1944	10.8	2.37%	NA	NA	NA	NA
1945	11.1	2.52%	NA	NA	NA	NA
1946	12.4	10.90%	NA	NA	NA	NA
1947	13.7	10.54%	NA	NA	NA	NA
1948	14.5	5.52%	53.0	NA	37.1	NA
1949	14.5	-0.06%	53.8	1.41%	37.7	1.66%
1950	14.6	0.78%	57.2	6.08%	40.5	7.20%
1951	15.6	6.66%	58.6	2.47%	44.4	9.16%
1952	16.0	2.15%	59.0	0.67%	46.3	4.19%
1953	16.2	1.26%	59.9	1.59%	48.1	3.80%
1954	16.3	1.01%	59.9	-0.12%	50.0	4.01%
1955	16.6	1.42%	62.4	4.15%	53.9	7.41%
1956	17.1	3.39%	61.6	-1.33%	56.6	4.99%
1957	17.7	3.44%	62.3	1.11%	58.7	3.59%
1958	18.1	2.28%	62.4	0.29%	60.3	2.71%
1959	18.3	1.13%	65.2	4.35%	64.1	6.10%
1960	18.6	1.39%	65.5	0.51%	66.0	2.95%
1961	18.8	1.12%	66.6	1.54%	67.7	2.41%
1962	19.1	1.36%	68.9	3.46%	70.9	4.68%
1963	19.3	1.05%	70.8	2.68%	72.3	2.02%
1964	19.6	1.54%	73.5	3.72%	76.1	5.02%
1965	19.9	1.80%	75.6	2.82%	79.2	4.00%
1966	20.5	2.80%	77.7	2.82%	82.4	4.07%
1967	21.1	3.03%	77.8	0.06%	85.0	3.01%
1968	22.0	4.16%	79.8	2.56%	88.8	4.42%
1969	23.1	4.82%	79.2	-0.76%	91.2	2.69%
1970	24.3	5.14%	78.8	-0.50%	92.7	1.56%
1971	25.5	4.88%	81.3	3.11%	93.8	1.21%
1972	26.6	4.22%	83.7	2.87%	95.4	1.70%
1973	28.1	5.39%	86.1	2.87%	97.2	1.88%
1974	30.7	8.66%	83.2	-3.35%	94.0	-3.31%
1975	33.6	9.06%	83.6	0.43%	94.2	0.18%
1976	35.5	5.58%	86.8	3.77%	95.4	1.28%
1977	37.8	6.17%	88.1	1.46%	95.2	-0.25%
1978	40.4	6.78%	89.4	1.47%	95.1	-0.04%
1979	43.8	7.99%	88.8	-0.67%	94.0	-1.21%
1980	47.8	8.75%	86.9	-2.20%	93.5	-0.53%
1981	52.3	9.01%	86.5	-0.42%	93.5	0.04%
1982	55.5	5.92%	83.5	-3.59%	92.6	-1.04%
1983	57.7	3.87%	86.6	3.68%	91.4	-1.23%
1984	59.8	3.69%	88.7	2.35%	94.5	3.34%
1985	61.6	2.98%	89.2	0.65%	94.4	-0.16%
1986	63.0	2.20%	90.6	1.47%	94.7	0.35%
1987	64.8	2.76%	90.7	0.16%	94.8	0.04%
1988	67.0	3.38%	91.7	1.04%	98.5	3.84%
1989	69.5	3.71%	91.7	0.00%	98.9	0.44%
1990	72.2	3.80%	92.0	0.40%	100.4	1.49%
1991	74.8	3.47%	91.3	-0.80%	100.2	-0.18%
1992	76.5	2.35%	93.5	2.39%	100.0	-0.21%
1993	78.2	2.18%	93.7	0.18%	102.6	2.52%
1994	79.9	2.08%	94.4	0.78%	103.2	0.67%
1995	81.5	2.06%	94.5	0.09%	105.6	2.22%
1996	83.1	1.88%	95.8	1.42%	106.9	1.24%
1997	84.6	1.76%	96.5	0.66%	106.9	-0.02%
1998	85.5	1.12%	97.7	1.28%	107.0	0.11%
1999	86.8	1.46%	99.0	1.27%	NA	NA
2000	88.6	2.15%	100.0	1.05%	NA	NA
2001	90.7	2.24%	100.4	0.39%	NA	NA
2002	92.1	1.60%	102.5	2.08%	NA	NA
2003	94.1	2.13%	105.2	2.60%	NA	NA
2004	96.8	2.80%	108.0	2.60%	NA	NA
2005	100.0	3.28%	109.3	1.26%	NA	NA
2006	103.3	3.21%	109.9	0.51%	NA	NA
2007	106.2	2.82%	110.1	0.21%	NA	NA
2008	108.5	2.11%	111.4	1.13%	NA	NA
2009	109.7	1.16%	NA	NA	NA	NA
Averages 1952-1965		**1.74%**		**1.82%**		**4.13%**
1973-1981		**7.49%**		**0.37%**		**-0.22%**
1982-1991		**3.58%**		**0.54%**		**0.69%**
1992-2003		**1.92%**		**1.18%**		**NA**
2004-2008		**2.84%**		**1.14%**		**NA**

yield just and reasonable rates.

The unit cost growth of electric utilities accelerated in the late 1960s and remained high for about two decades thereafter for several reasons.

- Price inflation accelerated, spurred initially by the Vietnam War and subsequently by the oil price shocks of 1974-75 and 1979-80. During the 1973-81 period, GDPPI inflation averaged 7.49% annually. Inflation thereafter slowed but still averaged 3.58% annually during the 1982-91 period.
- Rising utility rates and slowing economic growth slowed growth in use per customer.
- Utility productivity growth, far from keeping pace with inflation, slowed substantially falling by 0.22% annually on average in the 1973-1981 period and averaging only 0.69% annual growth in the 1982-91 period. Factors contributing to the slowdown included the exhaustion of scale economies by some of the nation's larger electric utilities and the propensity of some utilities to continue making major plant additions despite slower demand growth.

Under these changed conditions, utilities in the two decades after 1967 sought financial relief by filing frequent rate cases. However, many utilities found that they could not earn their allowed ROE under newly established rates. One author commented in 1974, a particularly bad year, that "it would be difficult, if not impossible, to find a utility which has been able in the first year in which a rate increase was in effect to earn the return on which the rate increase was predicted".[25] A study found that the earned ROE on equity in the electric utility industry was more than 200 basis points below the allowed rate of return on average in 1974, 1979, and 1980.[26] Interest coverage fell markedly for many utilities, limiting their ability to issue new debt. Financing of new investments required greater reliance on issuance of new common stock, and the value of stock fell below the book value of assets in many cases. Articles about attrition and regulatory lag appeared with regularity in the trade press.[27]

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[25] W. Truslow Hyde, "It Could Not Happen Here – But it Did", *Public Utilities Fortnightly*, June 1974.
[26] Walter G. French, "On the Attrition of Utility Earnings", *Public Utilities Fortnightly*, February 1981.
[27] See, as another example, Theodore F. Brophy, "The Utility Problem of Regulatory Lag", *Public Utilities Fortnightly*, January 1975.

Regulators responded to this situation with an array of measures, some of which had been used at one time or another in the past. The measures included interim rate increases; the inclusion of construction work in progress ("CWIP") in rate base; more widespread use of fuel adjustment clauses; the addition of an "attrition allowance" to the target ROE, and more widespread use of forward and hybrid test years. Adopters of FTYs in these years of brisk unit cost growth included the Federal Energy Regulatory Commission ("FERC") and state commissions in California, Connecticut, Florida, Georgia, Hawaii, and New York.

Some of these states initially experimented with hybrid test years which, as we have noted, make it possible to update rate filings as actual data for the later months of the test year become available. J. Michael Harrison explained in his 1979 article some grounds for dissatisfaction with hybrid test year experiments:

> Parties charged with testing or contesting a utility's rate case presentation were faced with figures and issues that changed and shifted through all phases of the case. Even after their direct evidentiary presentations were made, these parties were faced with a required reevaluation of their positions and the possibility that a host of new issues would be created by emerging actual data. The commission staff, which in New York bore the brunt of this burden, faced an almost impossible task of analyzing new data, even as its case went to the administrative law judge or commission for decision. It became clear that the value of the already completed hearings was being seriously undermined.[28]

The New York Commission decided in 1977 to move to fully forecasted test years consisting of the first twelve months expected under the new rates.[29]

The need for forward test years subsided with the slowdown of unit cost growth that occurred in the electric utility industry in the 1990s. This slowdown was driven primarily by a partial reversal of the business conditions that had previously caused brisk unit cost growth. During the 1992-2003 period GDPPI growth averaged only 1.92% per year. Yields on newly issued long term bonds fell substantially as the market lowered its expectation of future inflation. The productivity growth of the electric, gas, and sanitary sectors increased modestly, averaging 0.94% annually during the 1992-98 period, a trend similar to that of the private business sector. One reason for the productivity rebound was a slowdown in plant additions as the industry increased utilization of the generation and transmission capacity

[28] J. Michael Harrison, *op. cit.*, p. 12.
[29] New York Public Service Commission, "Statement of Policy on Test Periods in Major Rate Proceedings", November 1977.

built in the previous twenty years. Several electric utilities operated under base rate freezes during these years. Their willingness to agree to freezes reflected in part the generally favorable unit cost conditions but sometimes also reflected an expected spurt of productivity growth due to participation in mergers or acquisitions.

Interest in forward test years has renewed for electric utilities in recent years due to a renewed growth in unit cost, which is discussed in more detail in Section 3.1 below. We note here that general inflation accelerated after 2003, with GDPPI growth averaging 2.84% annually during the 2004-2008 period. Inflation slowed in 2009 but will likely rebound as the world economy recovers from the recession. Utility investment needs increased during the period to replace aging facilities, reverse declining generation capacity margins, implement "smart grid" technologies, and meet the rising demand for transmission services to reach remote sources of renewable energy and promote bulk power market competition. Growth in average use has slowed with slowing economic growth and new initiatives to promote energy conservation.

Interest in forward test years has been especially keen in the American west. Brisk economic growth in most western states has increased the need for plant additions. Here is a brief summary of changing test year policies in selected states.

Colorado

In Colorado, the commission rejected an FTY request by Public Service of Colorado in 1993 but acknowledged that "the purpose of a test year is to provide, as closely as possible, an interrelated picture of revenue, expense, and investment reasonably representative of the interrelationships that will be in place at the time the new rates proposed in a rate case will be in effect".[30] The commission did not forbid FTY evidence and encouraged the company to consider a *current* test year, an option that it said "might provide a promising mixture of comfort and flexibility acceptable to the parties and the commission.[31]

Public Service filed FTY evidence in a 2008 rate case but the approved settlement in the case was based on historical test year evidence.[32] In May 2009, Public Service again filed FTY evidence as it sought to include in its cost of service some major plant additions,

[30] PUC Colorado Decision No. C93-1346 in Docket No. 93S-001EG, October 1993, pp. 21-22.
[31] *Ibid*, p. 40.
[32] Docket No. 08S-520E.

including a new coal-fired generating unit and a smart grid build out, which would come online in late 2009 or 2010.[33] A settlement agreement, approved with modifications, based the revenue requirement on a historical 2008 test year with extraordinary adjustments to include the cost of the impending major plant additions. The company agreed not to file a rate case for two years.

This settlement also indicated an expectation that the company would file FTY evidence in its next rate case. It commits the company to provide companion historical test year evidence, including a detailed analysis of deviations between HTY and FTY results. The Company agreed to work with interested parties on reporting requirements with respect to such deviation analyses in order to facilitate the review of future cases.

Idaho

In Idaho the largest electric utility, Idaho Power, successfully used a hybrid test year in a rate case filing in 2003. In a 2009 filing it successfully used a test year beginning in January 2009.[34] This was essentially a current FTY.

Illinois

The move to forward test years is not confined to western states. Illinois utilities have long retained the right to file FTY rate cases and Integrys recently did so successfully for its North Shore Gas and Peoples Gas Light and Coke units.[35] Peoples has a major need to increase replacement investments in its aging system, which serves Chicago.

Michigan

In Michigan, utilities have used varied test year approaches. Recent legislation (2008 PA 286) explicitly sanctions forward test year filings. The law also permits utilities to "self-implement" interim rates if rate cases aren't resolved in 180 days. Consumers Energy and Detroit Edison have recently filed FTY rate cases successfully.

New Mexico

In New Mexico a bill was passed in 2009 that allows the state commission to use forward test years in electric and gas rate proceedings. The bill states that

[33] Docket No. 09AL-299E.
[34] Docket No. IPC-E-09-10.
[35] Dockets No. 09-0166 and 09-0167.

> The commission shall set rates based on a test period that the commission determines best reflects the conditions to be experienced during the period when the rates determined by the commission take effect. If a future test period is proposed, the commission shall give due consideration that the future test period may best reflect those conditions.[36]

The Bill was supported by majority voice vote of the New Mexico Public Regulation Commission. Public Service of New Mexico recently filed an FTY rate case.

Utah

Utah statutes were amended in 2003 to allow hybrid and forward test years for gas and electric utilities. The amended statutes state that

> If in the commission's determination of just and reasonable rates the commission uses a test period, the commission shall select a test period that, on the basis of the evidence, the commission finds best reflects the conditions that a public utility will encounter during the period when the rates determined by the commission will be in effect.[37]

The choice of a test year has since become an issue in the early stages of rate cases. In 2004, for example, PacifiCorp [d/b/a Rocky Mountain Power ("RMP")] filed a rate case based on a forward test year. It defended the FTY on the grounds that its costs were increasing due to rapid system growth and a plan to improve system reliability. An unopposed Test Year Stipulation acknowledged that the FTY was the most sensible test year for this case and provided for a task force to address test period procedural issues. The terms of the stipulation were not binding for future proceedings. The Commission commented in its order approving the stipulation that

> Each case needs to be considered on its own merits and the test period selected should be the most appropriate for that case. The test period selected for a utility in a particular case may not be appropriate for another utility or even the same utility in a different case. Some of the factors that need to be considered in selecting a test period include the general level of inflation, changes in the utility's investment, revenues, or expenses, changes in utility services, availability and accuracy of data to the parties, ability to synchronize the utility's investment, revenues, and expenses, whether the utility is in a cost

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[36] New Mexico Senate Bill 477, 2009.
[37] Utah Code Annotated Section 54-4-4 (3).

> increasing or cost declining status, incentives to efficient management and operation, and the length of time the new rates are expected to be in effect.[38]

In December 2007, RMP filed a rate case based on a forward test year beginning in July 2008.[39] The Commission instead chose a current FTY beginning in January 2008. The Company was compelled to update its testimony to reflect the sanctioned test year. In its final decision in the case, the Commission instructed the Company to file a semi-annual "variance report" comparing its actual operating results to its rate case forecasts.

In April 2009, RMP filed a notice of intent to file a rate case in June 2009 based on a forward test year beginning in January 2010. A high level of capital investment was emphasized in advocating the need for an FTY. The Commission approved a Test Period Stipulation providing for a current FTY beginning in June 2009. The decision notes that the Division of Public Utilities argued in support of the stipulation that

> the stipulated test period, combined with the opportunity for the Company to request alternative cost recovery treatment for major plant additions, will balance the interest of the Company in reducing regulatory lag and the interests of customers by reducing the risks associated with the timing and cost of major capital additions projected to be completed 18 months into the future.[40]

Wyoming

In Wyoming, a stipulation approved in 2006 provided that RMP (d/b/a PacifiCorp) could, on a one time trial basis, file a rate case based on a forward test year. RMP filed a rate case in June 2007 using an FTY ending in August 2008. The Wyoming Public Service Commission approved a rate settlement based on the forecasts for this test year. They indicated a willingness to hear forward test year evidence in the general rate case but required the company to submit conventional historical test year evidence as well. The Commission also directed the company to prepare a report comparing its actual cost and billing determinants for the current test year to those which the company forecasted in the proceeding. In the event, the variance report stated that the company had overestimated its

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[38] Public Service Commission of Utah, "Order Approving Test Period Stipulation", Docket 04-035-42, October 2004.
[39] Public Service Commission of Utah, "Order on Test Period", Docket No. 07-035-93, February 2008.
[40] Public Service Commission of Utah, "Report and Order on Test Period Stipulation", Docket No. 09-035-23, June 2009.

cost by a small amount but overestimated its revenue and on balance did not earn its allowed rate of return for the year.

In July 2008, RMP filed a new rate case with a current FTY ending in June 2009 using calendar 2007 as a historical reference year. The company emphasized in its case the inability of historical test year rates to compensate the utility for sizable new investments in its system. The Commission approved a settlement that included a provision that RMP file historical test year evidence as well as any FTY evidence in its next rate proceeding.[41] RMP will continue to file operating results that will permit the Commission to review the accuracy of its FTY forecasts.

2.2 Current Status

Table 2 and Figure 1 detail the test year approaches that are currently in use across the United States. It can be seen that historical test years are now used by most large IOUs in less than twenty U.S. jurisdictions. Nearly as many jurisdictions (AL, CA, CT, FL, GA, HI, ME, MI, MN, MS, NY, OR, RI, TN, WI, and the FERC) use forward test years routinely, at least for larger utilities. Forward test years are also used in several Canadian jurisdictions. Four jurisdictions (AR, OH, NJ, & PA) use hybrid test years. An additional 13 jurisdictions are not neatly categorized. Here are some examples.

- Large utilities in Illinois, Kentucky, Maryland, and North Dakota utilities use various test years.
- As previously noted, test years used by utilities in Utah and Wyoming depend on conditions at the time of filing and New Mexico is heading in that direction.

2.3 Conclusions

In Section 1.2 we noted that the matching principle used in historical test year rate cases is based on the assumption that growth in billing determinants matches cost growth so that unit cost is stable. This is true when growth in utility productivity and average use somehow combine to offset the cost impact of input price growth. We report in this chapter that conditions like these have not been normal for electric utilities since the 1960s. Periods of unit cost stability can still occur, but are apt to be followed by periods of rising unit cost.

[41] Wyoming PSC Docket Number 20000-333-ER-08 (Record No. 11824), May 2009.

Table 2

Test Year Approaches of U.S. Jurisdictions

Forward (16)

State	Notes
Alabama	Alabama Power's Rate Stabilization and Equalization Factor is forward looking.
California	
Connecticut	Cost is based on a historical test year that is escalated to a future rate year.
FERC	Rate cases use forward test years while formula rate plans tend to use HTYs.
Florida	
Georgia	
Hawaii	
Maine	Cost is based on a historical test year that is escalated to a future rate year.
Michigan	
Minnesota	
Mississippi	
New York	
Oregon	
Rhode Island	Cost is based on a historical test year that is escalated to a future rate year.
Tennessee	
Wisconsin	

Hybrid (4)

State	Notes
Arkansas	
Ohio	
New Jersey	
Pennsylvania	

Transitional/Varying (13)

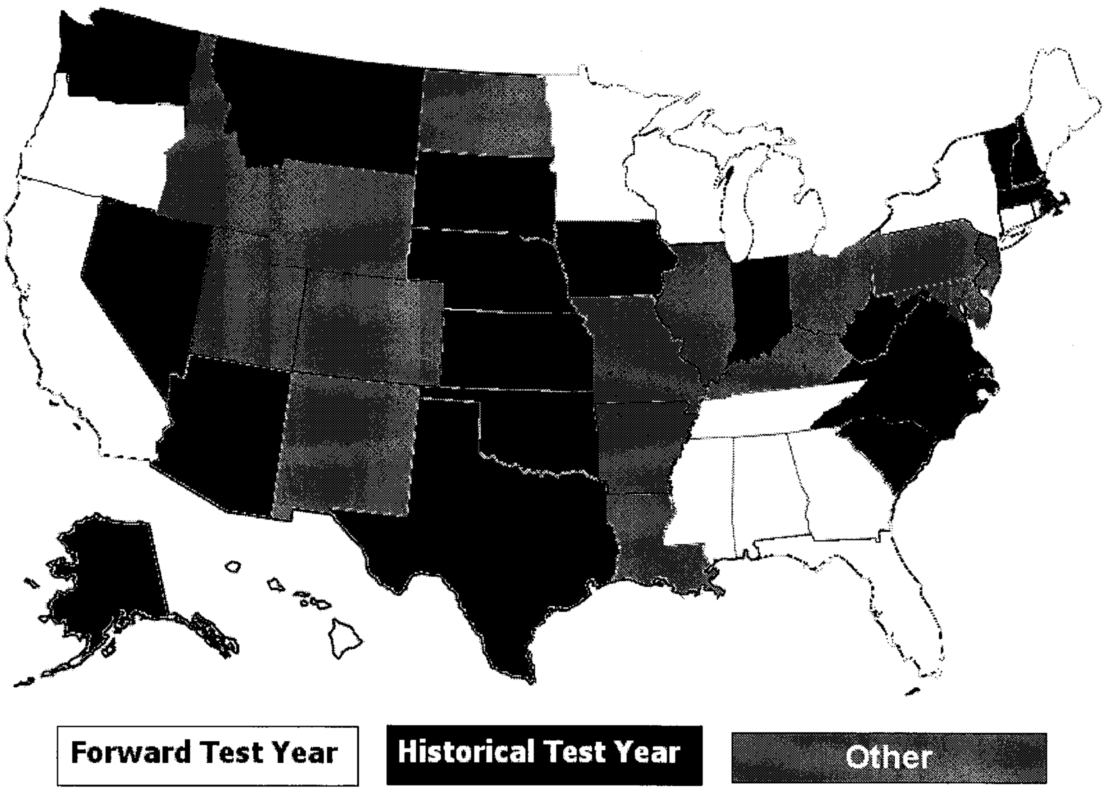
Utility Name	Notes
Colorado	Public Service of Colorado can file FTY evidence. No FTY rates have yet been approved but the most recent case made extraordinary HTY adjustments.
District of Columbia	PEPCO has filed rate cases using both hybrid and historical test years recently.
Delaware	Before restructuring FTY filings were common, but companies have used HTY in recent filings.
Idaho	
Illinois	Historic test years are the norm in IL. However, utilities have the right to make FTY filings and an FTY was accepted in a recent rate case of the Integrys gas utilities.
Kentucky	FTYs are legally authorized, but only Duke Energy has utilized them to date.
Louisiana	Cleco Power frequently uses hybrid test years. Entergy New Orleans recently had a hybrid test year approved via settlement.
Maryland	Baltimore Gas & Electric tends to file hybrid test years while other utilities tend to file historical test years.
Missouri	Utilities have the option to file hybrid year forecasts that are trued up during the course of the proceeding.
New Mexico	Recently passed law allows for use of FTY, but no rate case with an FTY has yet been approved.
North Dakota	Utilities use various test years including FTYs.
Utah	Test year selection is part of the rate case and can be contested. Several recent rate cases have used FTYs.
Wyoming	Rocky Mountain Power has recently had FTYs approved.

Historical (19)

Utility Name	Notes
Alaska	
Arizona	
Indiana	
Iowa	
Kansas	
Massachusetts	
Montana	
Nebraska	Nebraska has no electric IOUs in its jurisdiction. Gas companies are legally authorized to use FTYs, but no gas company has had FTY rates approved.
Nevada	
New Hampshire	
North Carolina	
Oklahoma	
South Carolina	
South Dakota	
Texas	
Vermont	
Virginia	
Washington	
West Virginia	

Figure 1

Map of Jurisdictions by Approved Test Year



Numerous regulators have moved away from historical test years in periods when unit cost is rising. Historical test year jurisdictions are now in the minority.

3. EMPIRICAL SUPPORT FOR FORWARD TEST YEARS

3.1 UNIT COST TRENDS OF U.S. ELECTRIC UTILITIES

In Section 1.2 we detailed the key role that the trend in the unit cost of utilities has in determining the reasonableness of historical test years and the need for forward test years. In original research for this paper, we have calculated the unit cost trends of a sample of vertically integrated electric utilities ("VIEUs"). In this section, we explain our research methods in some detail before discussing the results.

3.1.1 Data

The primary source of utility cost date used in the study was the FERC Form 1. Major investor-owned electric utilities in the United States are required by law to file this form annually. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Details of these accounts can be found in Title 18 of the Code of Federal Regulations.

Unit cost calculations also require data on billing determinants. Data on the number of customers served were drawn from FERC Form 1. Data on delivery volumes were drawn from Form EIA 861. The FERC Form 1 and Form EIA 861 data used in this study were gathered by SNL Financial, a respected commercial vendor.

Data were considered for inclusion in the sample from all major investor-owned VIEUs that did not offer gas distribution service or sell or spin off the bulk of their transmission assets in recent years. To be included in the study the data were required, additionally, to be plausible and not unduly burdensome to process. Data from the thirty four companies listed in Table 3 were used in the unit cost research. The sample period was 1996-2008. The year 2008 is the latest for which the requisite data were available when the study was prepared.

Supplemental data sources were used to measure input price trends. Handy Whitman indexes were used to measure electric utility construction cost trends. Global Insight indexes were used to measure trends in the prices of electric utility materials and services. Employment cost indexes prepared by the BLS were used to measure trends in labor prices. Regulatory Research Associates data was used to measure trends in target ROEs approved by regulators.

Table 3

Utilities Included in the Unit Cost Research

Company
Alabama Power
Appalachian Power
Arizona Public Service
Black Hills Power
Carolina Power & Light
Cleco Power
Columbus Southern Power
Dayton Power and Light
Duke Energy Carolinas
Empire District Electric
Entergy Arkansas
Florida Power & Light
Florida Power
Georgia Power
Gulf Power
Idaho Power
Indianapolis Power & Light
Kansas City Power & Light
Kentucky Power
Kentucky Utilities
Minnesota Power
Mississippi Power
Nevada Power
Ohio Power
Oklahoma Gas and Electric
Otter Tail Power
PacifiCorp
Portland General Electric
Public Service Company of Oklahoma
Southwestern Electric Power
Southwestern Public Service
Tampa Electric
Tucson Electric Power
Virginia Electric and Power

Number of utilities in sample: 34

3.1.2 Definition of Unit Cost

In Section 1.2.1 we discussed a measure of unit cost growth that is relevant in the appraisal of test years. It is constructed by taking the difference between growth in the net cost of base rate inputs and the growth in an index of utility billing determinants. For each sampled utility, we calculated the total cost of base rate inputs net of taxes as the sum of non-energy O&M expenses, depreciation, amortization, and return on rate base. Non-energy O&M expenses were calculated as total O&M expenses less customer service and information expenses and energy expenses that included those for steam power generation fuel, nuclear power generation fuel, other power generation fuel, and purchased power.[42] [43]

Return on rate base was calculated as the value of the rate base times a weighted average cost of capital ("WACC"). In constructing the WACC we assumed 50/50 weights for debt and common equity. The rate of return on debt was calculated as the ratio of the interest payments of electric utilities to the value of their debt as reported on the FERC Form 1. The ROE was calculated as the average applicable allowed ROEs of electric utilities as reported by Regulatory Research Associates.[44] The rate base for each utility was calculated as its net plant value less net accumulated deferred income taxes plus the value of its fuel, material, and supply inventories.

We reduced the base rate cost thus calculated by two kinds of "non-core" revenues, as is common in the calculation of retail base rate revenue requirements. One item deducted was Other Operating Revenue. This is the revenue from miscellaneous goods and services that include bulk power wheeling. The other component of non-core revenues was an estimate of the margin from power sales for resale.[45]

The growth in the billing determinant index used in our study is a weighted average of the growth in important billing determinants of electric utilities. The determinants used in index construction were the numbers of residential, commercial, and other retail customers

[42] Customer service and information expenses were excluded because they tended to rise over the sample period due to expanding demand-side management programs. The cost of DSM programs is typically recovered using tracker-rider mechanisms.
[43] We also excluded the Other Expenses category of Other Power Supply Expenses. We believe that large and volatile commodity-related costs are sometimes reported in this category.
[44] In this calculation, we assumed that the target ROE approved for a utility in its most recent rate case was applicable until a new target ROE was approved.
[45] These margins were computed as the difference between sales for resale revenue and an estimate of the energy commodity costs used in power supply.

and the corresponding delivery volumes.[46] We weather normalized the volumes using econometric demand research. In constructing the index, the trends in the billing determinants thus assembled were weighted by our estimates of the typical shares of individual billing determinants in the base rate revenue requirements of VIEUs.[47] The estimates were drawn from a perusal of recent VIEU rate case filings.

3.1.3 Unit Cost Results

Unit Cost Trends

The average annual trends of the sampled utilities in their cost, billing determinants, and unit cost can be found in Table 4 and Figure 2. It can be seen that unit cost declined by a modest 0.78% annually on average in the 1996-2002 period as average growth in billing determinants exceeded average growth in cost. The average growth in unit cost was positive in only one year of this period. These results suggest that, under typical operating conditions, historical test years would have yielded compensatory outcomes in rate cases during this period.

In the 2003-2008 period, on the other hand, it can be seen that unit cost grew briskly, averaging about 2.31% annually. Utilities experienced unit cost growth on average in every year of the period. Cost averaged 1.98% annual growth from 1996 to 2002 and 4.36% annual growth thereafter. The normalized growth of billing determinants averaged 2.75% per annum through 2002 but only 2.05% per annum thereafter. Thus, growth in billing determinants slowed despite marked acceleration of cost growth.

Earnings Impact

To consider the earnings attrition resulting from 2.3% annual unit cost growth, consider that if the typical company in the sample earned its target ROE it would constitute about 13% of the total cost of its base rate inputs. Assuming two years of 2.3% unit cost growth, revenue based on prices reflecting only the normalized business conditions of the historical test year would be expected to result in a 4.45% base rate revenue shortfall. If there was no tax adjustment, this would reduce the return on equity by about 35%. Assuming

[46] The retail peak demands of commercial and industrial customers are also important billing determinants but data on these were unavailable.
[47] We assigned the base rate revenue shares corresponding to demand charges to the "other retail" delivery volume, expecting that these volumes have trends that are similar to those of demand charge billing determinants.

Table 4

Trends in the Unit Cost of US Vertically Integrated Utilities

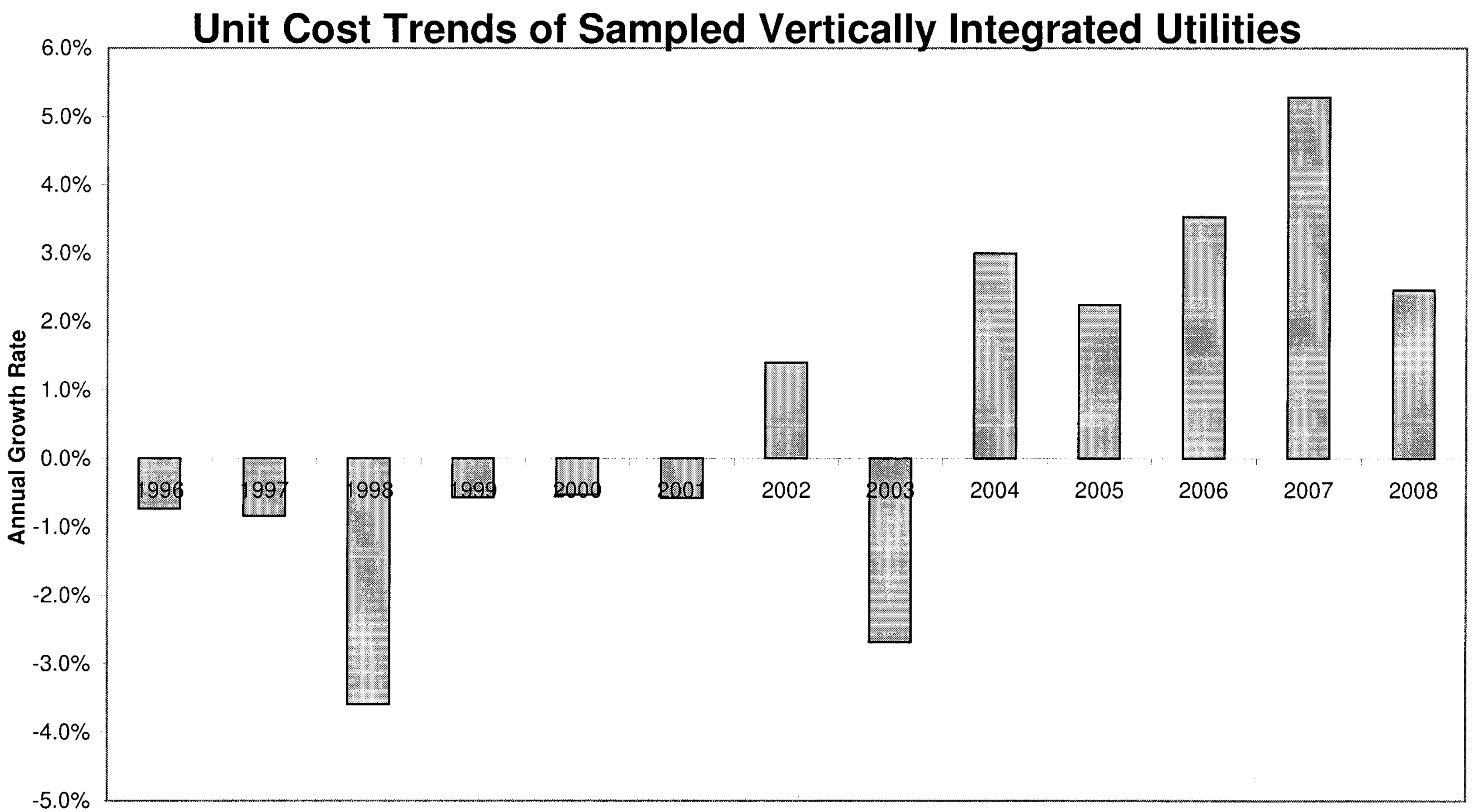
Sample Average Annual Growth Rates, Unweighted

Year	**Cost**[1]	**Billing Determinants**[2]	**Unit Cost**
1996	2.8%	3.5%	-0.7%
1997	1.4%	2.2%	-0.8%
1998	-0.7%	2.9%	-3.6%
1999	2.5%	3.0%	-0.6%
2000	3.4%	4.0%	-0.5%
2001	0.9%	1.4%	-0.6%
2002	3.6%	2.2%	1.4%
2003	1.6%	4.3%	-2.7%
2004	4.6%	1.6%	3.0%
2005	4.0%	1.8%	2.2%
2006	5.0%	1.5%	3.5%
2007	7.9%	2.6%	5.3%
2008	3.0%	0.5%	2.5%
Average Annual Growth Rates			
1996-2008	**3.08%**	**2.43%**	**0.65%**
1996-2002	**1.98%**	**2.75%**	**-0.78%**
2003-2008	**4.36%**	**2.05%**	**2.31%**

[1] The net cost formula is (Total O&M Expenses - Energy O&M Expenses - Customer Service and Information Expenses) + (Depreciation + Amortization + WACC x Rate Base) - (Other Operating Revenues + Estimated Resale Margin). The source of the cost data is FERC Form 1.

[2] The annual growth in billing determinants is a weighted average of the growth in residential, commercial, and other retail delivery volumes and customers served. The weights are shares in the base rate revenue requirement that are typical of vertically integrated electric utilities. Volumes were weather normalized by PEG Research using econometric demand modelling. The source of the raw volume data is Form EIA 861. The source of the customer data is FERC Form 1.

Figure 2


Unit Cost Trends of Sampled Vertically Integrated Utilities
Annual Growth Rate
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
-1.0%
-2.0%
-3.0%
-4.0%
-5.0%
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008

an allowed ROE of 11%, this would mean a drop in ROE of around 375 basis points before tax adjustments. While lower income taxes would mitigate the earnings impact, we may conclude from this analysis that historical test years would have been inherently non-compensatory for a utility operating under the *typical* business conditions facing VIEUs in recent years. Results would be much worse for utilities facing more pronounced unit cost pressures due, for example, to an accelerated program of replacement capex or a large scale DSM program.

Unit Cost Drivers

Input Prices Our discussion in Section 1.2.1 contained the result that input price inflation, productivity growth, and the trend in average use were key drivers of unit cost growth. We calculated for this report indexes of the inflation in the prices of base rate inputs faced by the sampled VIEUs. The growth rates of the summary input price indexes are weighted averages of the growth rates in indexes of prices for electric utility plant and O&M labor and materials and services. The index for each utility uses as weights the share of each input group in the total cost of the company's base rate inputs.[48] The index for the price of plant was calculated from the trends in bond yields, allowed returns on equity, and the Handy Whitman Construction Cost Index for vertically integrated electric utilities in the applicable region.

Results of our input price research are presented in Table 5 and Figure 3. It can be seen that the prices of base rate inputs averaged 2.76% annual inflation in the 1996-2002 period and 3.65% inflation in the 2003-2008 period --- an increase of 89 basis points. The price acceleration was primarily in materials and services and capital. M&S price inflation averaged 2.08% annually in the 1996-2002 period and 4.31% annually in the 2003-2008 period.

[48] An input price index with cost share weights effectively estimates the impact of price inflation on cost.

Table 5

Trends in Prices of Electric Utility Base Rate Inputs, 1996-2008

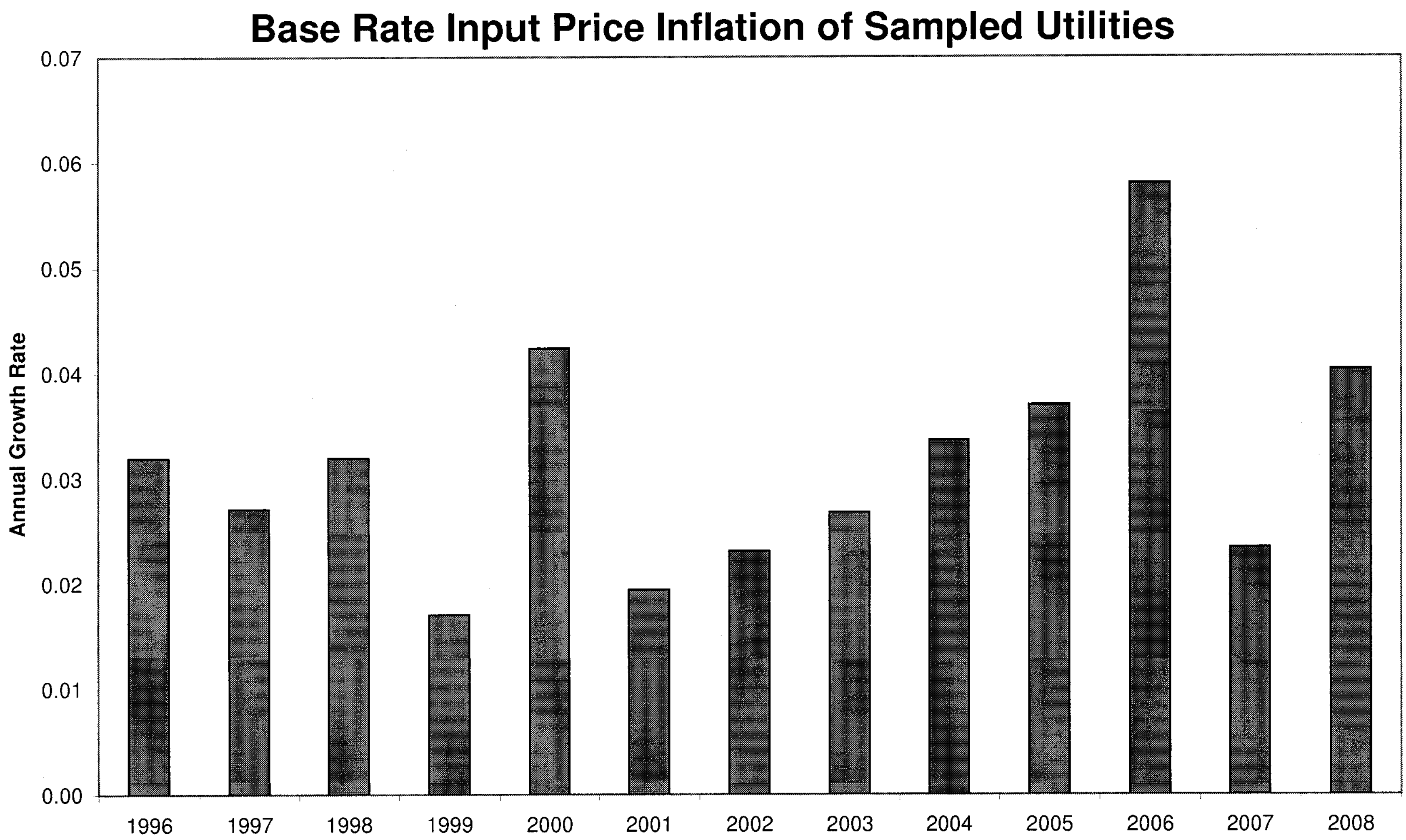
	Summary Input Price Index		**Labor**		**Materials & Services**		**Capital**	
Year	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate
1995	1.000		1.000		1.000		1.000	
1996	1.032	3.2%	1.033	3.2%	1.020	2.0%	1.034	3.3%
1997	1.061	2.7%	1.065	3.1%	1.042	2.1%	1.061	2.7%
1998	1.095	3.2%	1.108	4.0%	1.058	1.6%	1.098	3.4%
1999	1.114	1.7%	1.139	2.7%	1.076	1.6%	1.112	1.2%
2000	1.162	4.2%	1.193	4.6%	1.109	3.0%	1.158	4.1%
2001	1.185	1.9%	1.242	4.0%	1.135	2.4%	1.168	0.8%
2002	1.213	2.3%	1.301	4.6%	1.157	1.9%	1.186	1.5%
2003	1.246	2.7%	1.356	4.2%	1.189	2.7%	1.206	1.7%
2004	1.289	3.4%	1.428	5.1%	1.241	4.3%	1.227	1.7%
2005	1.337	3.7%	1.501	5.0%	1.303	4.9%	1.251	1.9%
2006	1.417	5.8%	1.652	9.6%	1.364	4.6%	1.303	4.1%
2007	1.451	2.3%	1.578	-4.6%	1.421	4.1%	1.352	3.6%
2008	1.510	4.0%	1.629	3.2%	1.498	5.3%	1.396	3.2%
Average Annual Growth Rate								
1996-2008		**3.17%**		**3.76%**		**3.11%**		**2.57%**
1996-2002		**2.76%**		**3.76%**		**2.08%**		**2.43%**
2003-2008		**3.65%**		**3.75%**		**4.31%**		**2.72%**

Sources

Labor	Calculated by PEG Research from BLS Employment Cost Indexes that include pensions and benefits
Materials & Services	Calculated by PEG Research using functional cost shares for sampled utilities obtained from FERC Form 1 and detailed electric utility M&S price indexes obtained from Global Insight's *Power Planner.*
Capital	Calculated by PEG Reseach from Handy Whitman electric utility construction cost indexes Average yields on utility bonds calculated from FERC Form 1 data gathered by SNL Interactive Applicable allowed ROEs as reported by Regulatory Research Associates
Summary	Calculated by PEG Research from the labor, M&S, and capital price indexes using vertically integrated electric utility base rate input cost shares drawn from FERC Form 1

FERC Form 1 data gathered by SNL

Figure 3


Base Rate Input Price Inflation of Sampled Utilities
Annual Growth Rate
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0.00
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008

Plant Additions Large plant additions were noted in Section 1.2.1 to be an important driver of utility productivity growth. Table 6 and Figure 4 describe the trend in real (*i.e.* inflation adjusted) plant additions per customer of the sampled utilities. It can be seen that from 2003 through 2008, real plant additions were 25% higher on average than in the 1995-2002 period.

Average Use In Table 7 and Figure 5 we present information on the trends in weather normalized average use by the residential and commercial customers of a large sample of U.S. electric utilities from 1996 to 2008. The sample included specialized transmission and distribution utilizes as well as VIEUs. It can be seen that the growth rates in average use have tended to fall for both residential and commercial customers since 2002. The trend was more pronounced for residential customers. Growth in normalized average use of power by residential customers averaged 1.09% per year in the 1996-2002 period and 0.43% per year in the 2003-2008 period. Growth in weather-normalized average use by commercial customers averaged 1.04% per year in the 1996-2002 period and 0.74% per year in the 2003-2008 period.

The average use slowdown was especially pronounced in the 2006-2008 period. The normalized average use of residential customers averaged a slight 0.19% annual decline and average use by commercial customers was essentially flat. For this more recent period, we separately calculated trends for utilities in service territories with large DSM programs and the trends for utilities in other territories. The normalized average use by residential customers of utilities operating in territories with large DSM programs declined by a remarkable 0.68% on average.

These results suggest that the typical IOUs may not be able in the future to count on brisk growth in average use by residential and commercial customers to buffer the impact on unit cost growth of input price inflation and increased plant additions. The problem will be considerably more acute in service territories where there are aggressive conservation programs. Forward test years will be particularly uncompensatory where utilities must cope with the consequences for load of aggressive DSM programs.

Table 6

Real Plant Additions Per Customer of Sampled Utilities

	Real Additions to Plant in Service (1995=100)	Number of Customers (1995=100)	Real Additions per Customer (1995=100)
1995	100.00	100.00	100.00
1996	93.26	101.89	91.53
1997	85.99	103.99	82.70
1998	70.50	106.33	66.30
1999	89.82	108.20	83.01
2000	102.31	110.66	92.46
2001	111.46	112.80	98.81
2002	108.46	114.70	94.56
2003	148.32	116.57	127.23
2004	110.42	118.78	92.96
2005	115.52	120.98	95.49
2006	125.04	123.89	100.93
2007	149.51	125.82	118.83
2008	165.19	126.85	130.22
Averages			
1996-2002			87.05
2003-2008			110.94

Sources: Cost and cutomer data from FERC Form 1. Plant additions deflated using applicable regional Handy Whitman electric utility construction cost indexes.

Figure 4

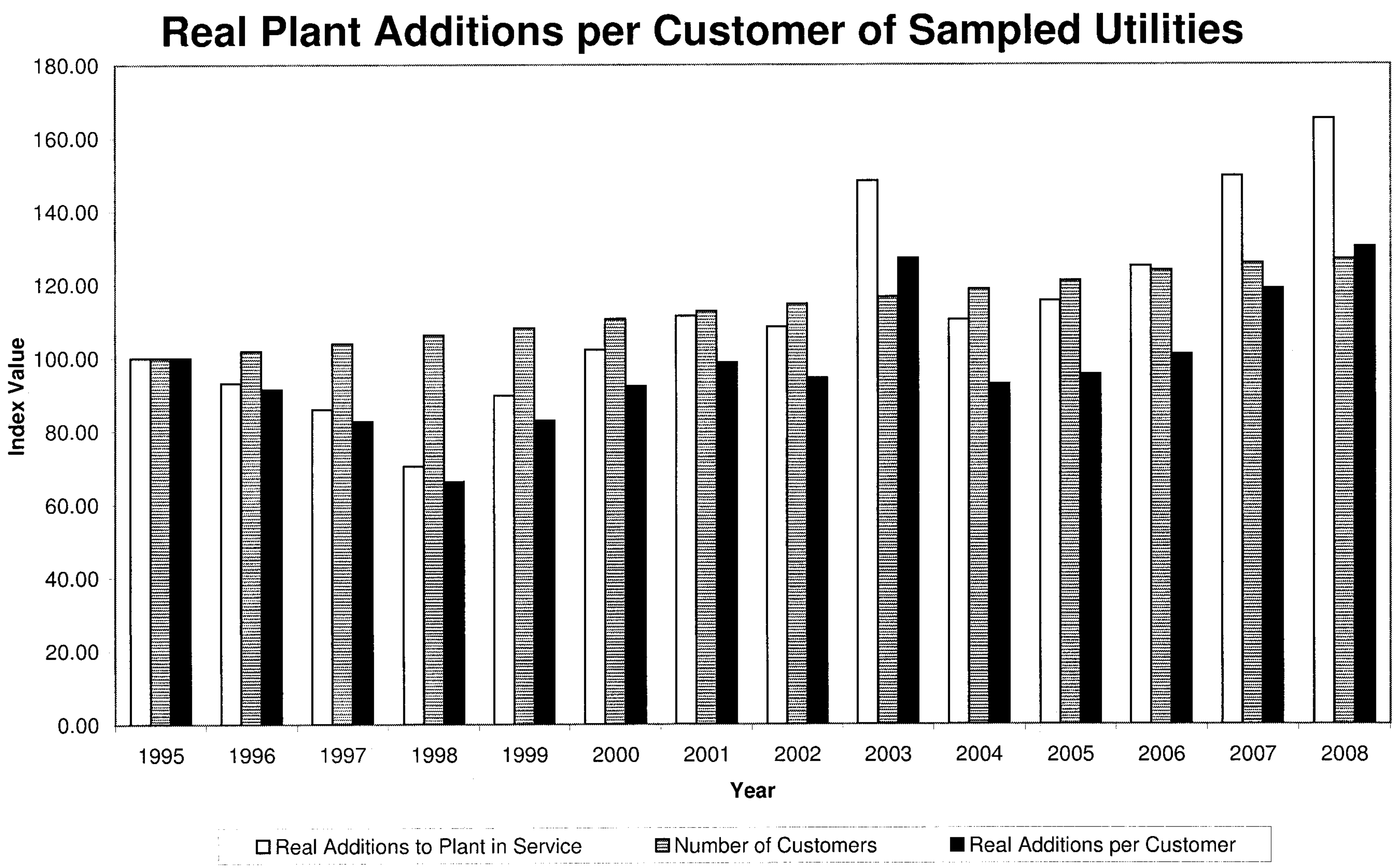

Real Plant Additions per Customer of Sampled Utilities
Index Value
180.00
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
Year
Real Additions to Plant in Service
Number of Customers
Real Additions per Customer

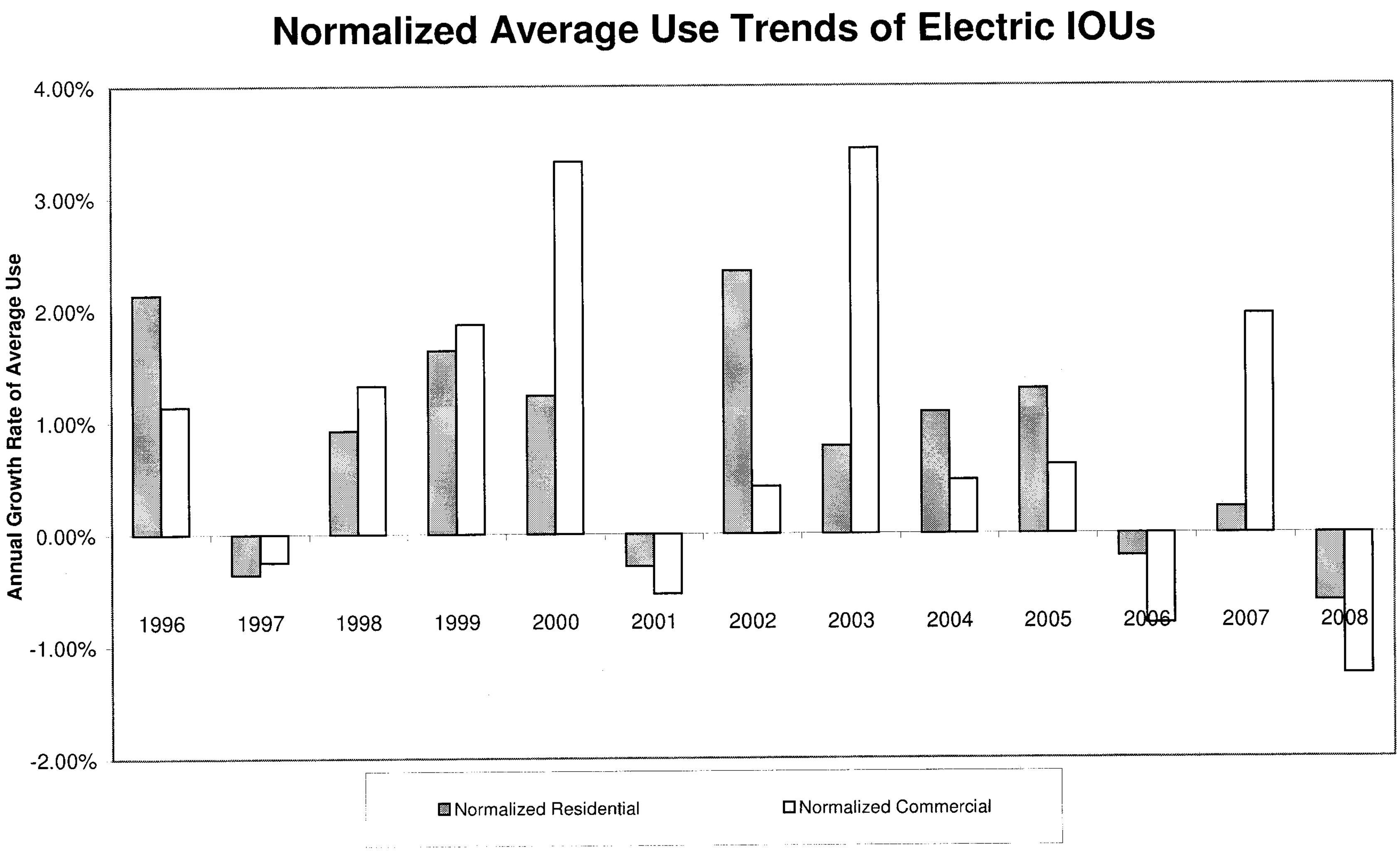
Table 7

Trends in Average Use by Residential & Commercial Customers of Investor-Owned Electric Utilities

Year	Residential		Commercial	
	Raw	Normalized	Raw	Normalized
1996	1.10%	2.14%	0.68%	1.14%
1997	-2.35%	-0.36%	-0.43%	-0.25%
1998	1.39%	0.93%	1.91%	1.33%
1999	1.66%	1.64%	1.63%	1.87%
2000	2.02%	1.24%	3.20%	3.33%
2001	-0.65%	-0.29%	-0.35%	-0.53%
2002	4.18%	2.35%	0.71%	0.42%
2003	-0.71%	0.78%	2.88%	3.44%
2004	0.03%	1.08%	0.35%	0.48%
2005	4.02%	1.29%	1.24%	0.61%
2006	-2.86%	-0.21%	-1.06%	-0.80%
2007	2.68%	0.23%	2.26%	1.95%
2008	-1.95%	-0.61%	-1.83%	-1.26%
Average Annual Growth Rate				
1996-2008	**0.66%**	**0.79%**	**0.86%**	**0.90%**
1996-2002	**1.05%**	**1.09%**	**1.05%**	**1.04%**
2003-2008	**0.20%**	**0.43%**	**0.64%**	**0.74%**
2006-2008	**-0.71%**	**-0.19%**	**-0.21%**	**-0.04%**
High DSM utilities	**-1.07%**	**-0.68%**	**-0.19%**	**-0.08%**
Other utilities	**-0.54%**	**0.05%**	**-0.22%**	**-0.02%**

Sources: Customer data from FERC Form 1. Volume data from Form EIA 861. Volumes were weather normalized by PEG Research using econometric demand modelling.

Figure 5


Normalized Average Use Trends of Electric IOUs
4.00%
3.00%
2.00%
1.00%
0.00%
-1.00%
-2.00%
Annual Growth Rate of Average Use
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
Normalized Residential
Normalized Commercial

3.2 How Test Years Affect Credit Quality Metrics

Table 8 presents results for selected credit quality metrics for a large sample of electric utilities. The reported metrics are averages for the 2006-2009 period. The source is *Credit Stats: Electric Utilities—U.S.*, a report appearing in the Global Credit Portal of Standard & Poor's RatingsDirect. We present results for four credit metrics: Standard & Poor's corporate credit rating, the (rate of) return on capital, and two cash flow ratios (EBITDA interest coverage and FFO/Debt).

Cash flow ratios are used by credit analysts to assess a utility's ability to service debt. The cash flow measures are normally calculated as adjustments to net income that add back cash flows that could be used to service debt. FFO (funds from operations), for instance, adds back depreciation and amortization expenses. EBITDA (earnings before interest, taxes, depreciation, and amortization) adds back interest and tax payments as well as depreciation and amortization.

Table 8 reports averages for each of the numerical metrics for utilities that operated under historical, hybrid, and forward test years throughout the 2006-2008 period. There is also an indeterminate category for utilities that are not easily categorized as having operated under one kind of test year during this period.

Caution must be taken in making comparisons inasmuch as these metrics may differ between the sampled utilities due to differences in several other business conditions as well as to any differences in test years. The other relevant business conditions include the ability to rate base construction work in progress, the local severity of the 2008 recession, and whether or not utilities operated under formula rates and/or revenue decoupling. Despite these complications, the samples are large and diverse enough to shed some light on the effect that test years have on credit metrics.

Comparing the results, it can be seen that the values of all four credit metrics were typically much more favorable for the *forward* test year utilities than for the *historical* test year utilities.

- The forward test year utilities had a typical credit rating between BBB+ and A- whereas the historical test year utilities had a typical credit rating between BBB- and BBB.

Table 8

How Credit Metrics of Electric Utilities Differ by Test Year, 2006-2008

Company Name	S&P Corporate Credit Rating	Return on Capital (%)	EBITDA/Interest Coverage	FFO/debt (%)
Historical Test Years		**7.9**	**4.2**	**18.2**
AEP Texas Central	BBB	6.9	2.8	8.7
AEP Texas North	BBB	8.1	4.9	21.0
Appalachian Power	BBB	6.0	2.9	9.5
Arizona Public Service	BBB-	7.3	4.6	19.3
Black Hills Power	BBB-	9.6	4.8	25.3
Carolina Power & Light	BBB+	11.3	5.9	25.0
CenterPoint Energy Houston Electric	BBB	9.8	6.2	24.4
Central Illinois Light	BBB-	9.5	8.2	29.5
Central Illinois Public Service	BBB-	4.9	3.6	15.7
Central Vermont Public Service	BB+	7.0	2.7	12.8
Commonwealth Edison	BBB-	6.4	3.1	12.1
Duke Energy Carolinas	A-	7.0	6.1	28.5
Duke Energy Indiana	A-	8.0	5.1	21.3
El Paso Electric	BBB	9.4	4.2	18.8
Entergy Gulf States	BBB	7.2	2.8	25.1
Entergy Louisiana	BBB	6.6	3.2	36.3
Entergy Texas	BBB	5.6	2.5	14.0
Interstate Power & Light	BBB+	10.5	5.5	24.4
IPALCO Enterprises (Indianapolis Power & Light)	BB+	13.2	3.4	12.9
Kentucky Power	BBB	6.5	3.5	13.8
MidAmerican Energy	A-	10.7	5.5	22.7
Nevada Power	BB	8.4	2.6	11.1
NSTAR Electric	A+	10.2	7.7	21.6
Oklahoma Gas & Electric	BBB+	10.0	6.4	25.2
Oncor Electric Delivery	BBB+	9.6	4.4	17.9
Public Service Company of Colorado	BBB+	8.1	4.3	19.6
Public Service Company of New Hampshire	BBB	8.4	4.8	13.7
Public Service Company of New Mexico	BB-	3.9	2.3	8.6
Public Service Company of Oklahoma	BBB	4.9	2.7	18.3
Puget Sound Energy	BBB	7.5	3.8	13.7
Sierra Pacific Power	BB	7.4	2.9	12.7
South Carolina Electric & Gas	BBB+	8.3	4.7	21.1
Southern Indiana Gas & Electric	A-	9.5	5.4	22.8
Southwestern Electric Power	BBB	7.4	3.5	15.4
Southwestern Public Service	BBB+	5.3	3.5	12.1
Texas-New Mexico Power	BB-	5.3	3.3	9.5
Tuscon Electric Power	BB+	8.4	3.2	17.9
Westar Energy	BBB-	6.7	3.9	14.8
Western Massachusetts Electric	BBB	5.8	3.7	11.8
Hybrid Test Years		**9.5**	**5.9**	**19.9**
Atlantic City Electric	BBB	9.6	4.4	34.2
Baltimore Gas & Electric	BBB	6.8	4.3	11.1
Cleveland Electric Illuminating	BBB	13.3	4.3	9.2
Cleco Power	BBB	8.3	3.7	10.9
Columbus Southern Power	BBB	13.5	6.5	23.3
Dayton Power & Light	A-	16.3	16.1	42.9
Duke Energy Ohio	A-	5.2	6.3	25.5
Entergy Arkansas	BBB	6.7	5.6	27.7
Idaho Power	BBB	6.6	3.8	10.7
Jersey Central Power & Light	BBB	8.3	8.5	22.9
Metropolitan Edison	BBB	9.3	6.7	12.7
Ohio Edison	BBB	9.4	4.6	14.5
Ohio Power	BBB	8.2	4.3	15.0
PECO Energy	BBB	10.5	7.0	19.5
Pennsylvania Electric	BBB	8.9	5.5	15.8
PPL Electric Utilities	A-	9.5	4.6	18.6
Public Service Electric & Gas	BBB	8.7	4.9	14.9
Toledo Edison	BBB	11.9	5.2	28.0

Table 8, continued

How Credit Metrics of Electric Utilities Differ by Test Year, 2006-2008

Company Name	S&P Corporate Credit Rating	Return on Capital (%)	EBITDA/Interest Coverage	FFO/debt (%)
Forward Test Years		**9.2**	**5.1**	**21.0**
ALLETE (Minnesota Power)	BBB+	10.8	5.1	19.5
Central Hudson Gas & Electric	A	9.6	4.9	14.9
Central Maine Power	BBB+	8.2	5.3	17.8
Connecticut Light & Power	BBB	6.7	4.3	12.2
Detroit Edison	BBB	8.2	4.9	16.8
Entergy Mississippi	BBB	7.2	4.3	27.1
Florida Power & Light	A	9.9	7.0	30.7
Florida Power Corp.	BBB+	9.9	4.5	19.0
Georgia Power	A	10.1	5.9	22.6
Gulf Power	A	9.7	5.6	19.2
Hawaiian Electric	BBB	7.1	4.4	15.3
Mississippi Power	A	11.6	8.9	35.5
Northern States Power - MN	BBB+	9.4	4.9	22.9
Northern States Power - WI	A-	8.8	5.9	26.6
Pacific Gas & Electric	BBB+	10.7	4.0	23.3
PacifiCorp	A-	7.9	4.0	17.3
Portland General Electric	BBB+	7.9	4.1	19.2
Rochester Gas & Electric	BBB	9.4	3.8	19.4
Southern California Edison	BBB+	11.4	4.0	19.3
Tampa Electric	BBB	9.6	4.5	21.0
Wisconsin Electric Power	A-	6.9	5.4	14.6
Wisconsin Power & Light	A-	10.1	5.0	24.7
Wisconsin Public Service	A-	9.8	5.6	23.8
Indeterminate		**7.8**	**4.3**	**18.1**
Alabama Power	A	9.5	5.7	21.5
Empire District Electric	BBB-	7.3	3.5	15.7
Indiana Michigan Power	BBB	6.7	3.5	15.4
Kansas City Power & Light	BBB	7.9	4.8	19.4
Potomac Electric	BBB	7.4	4.4	20.6
Southwestern Electric Power	BBB	7.4	3.5	15.4
Union Electric	BBB-	8.2	4.4	18.4
All Companies		**8.6**	**4.8**	**19.3**

Source: Standard & Poor's Ratings Direct, *Credit Stats: Electric Utilities - U.S.* August 24, 2009. Financial metrics are averages of the years 2006-2008.

- The forward test year utilities had an average return on capital of 9.2% whereas the historical test year utilities had an average return of 7.9%.
- The forward test year utilities had an average EBITDA/interest coverage of 5.1 whereas the historical test year utilities had an average coverage of 4.2
- The forward test year utilities had an average FFO/debt ratio of 21.0% whereas the historical test year utilities had an average ratio of 18.2%.

Additional insights concerning the effect of forward test years on credit quality can be found in another recent Standard & Poor's report.[49] The study sought to rank state regulatory regimes with respect to their effect on credit quality. Of the fourteen states covered by the study which had well-established forward test year traditions at the time of the study, the author found five to be "more credit supportive", six to be "credit supportive", only two to be "less credit supportive", and none to be "least credit supportive". In contrast, of the seventeen states covered by the study that had well-established historical test year conditions, only three were categorized as "more credit supportive", seven were categorized as "credit supportive", six were categorized as "less credit supportive" and one was categorized as "least credit supportive".

3.3 Incentive Impact of Forward Test Years

In Section 1.2.4 we noted that the incentive impact of forward test years has been an issue in some proceedings. We argued, based on our experience in the field of incentive regulation, that the incentive impact of forward and historical test years should be similar on balance. To test the hypothesis that the choice of a test year has no impact on operating efficiency, PEG Research measured the trends in the O&M expenses of a large group of VIEUs over the 1996-2008 sample period. O&M expenses are a better focus than the total cost of base rate inputs in such a study because some utilities had greater needs than others for major plant additions and these needs had little to do with the kind of test year in a jurisdiction. Differences in cost growth are due in part to differences in output growth, so we divided O&M expenses by three alternative output metrics: generation volumes, generation capacity, and the number of customers served. We calculated how the trends in the three cost metrics differed for utilities operating under three kinds of test years: historical, hybrid, and

[49] Todd Shipman, *Assessing U.S. Utility Regulatory Environments*, Standard & Poor's Ratings Direct, November 2008.

forward. If forward test years weaken operating efficiency, we would expect the growth in the cost metrics to be higher on average for the forward test year utilities.

Results of this exercise are reported in Table 9. It can be seen that, using all three cost metrics, the cost trends of the forward test year utilities were similar to --- and a little slower than --- those of the historical test year utilities and of the full utility sample. These results are consistent with the notion that there is no significant difference in the incentives to contain cost that are generated by future and historical test years.

Table 9

Trends in Unit Non-Fuel O&M Expenses by Test Year, 1996-2008

	Test Year Type			
	Historic	Partial	Forward	All
Cost/Customer	2.1%	2.0%	1.9%	2.2%
Cost/Generation Volume	2.2%	3.0%	1.4%	2.3%
Cost/Generation Capacity	1.9%	3.2%	1.3%	1.9%

Source: Federal Energy Regulatory Commission (FERC) Form 1 and Form EIA-876 data gathered by SNL Financial.

4. CONCLUDING REMARKS

Having established in some detail in the chapters above the financial stresses imposed on U.S. electric utilities by historical test years today, we provide in this chapter some concluding remarks on action plans for regulators who wish to move forward with sensible remedies.

4.1 Sensible First Steps

In states where regulators are interested in experimenting with forward test years but not yet prepared to "make the plunge" to large scale adoption, our discussion has identified a number of cautious first steps down the road that limit the risk of bad outcomes but permit the regulatory community to learn more about FTY pros and cons.

- Allow a forward test year on a trial basis for one interested utility.
- Allow forward test years on an occasional basis when a utility makes a convincing case that rising unit costs make historical test years unjust and unreasonable. A ruling on the test year issue can precede the preparation of a rate case, as in Utah.
- Borrow a few of the methods used in FTY rate cases to make additional adjustments to *historical* test year costs and billing determinants. For example, HTY O&M expenses and/or plant addition costs can be adjusted for forecasts of price inflation prepared by respected independent agencies. Residential and commercial delivery volumes can be adjusted for recent average use trends. Special adjustments can be made for looming major plant additions.
- Try current FTYs, which involve forecasts only one year into the future. Current test years can be combined with interim rate increases at the outset a rate case which are subject to true up when new rates are ultimately approved. The combination of current test years and interim rates is a salient option because it eliminates regulatory lag without a two year forecast.

4.2 Alternative Remedies for Test Year Attrition

In states where regulators aren't ready to abandon historical test years but are sympathetic to the attrition problems that they sometimes cause, a variety of alternative measures are available to relieve the financial attrition that can result from using historical test years in a rising unit cost environment.

1. HTY calculations can incorporate the full array of normalization, annualization, and known and measurable change adjustments that are used in other jurisdictions.
2. Utilities can be permitted to implement interim rate increases. Interim rates can effectively reduce regulatory lag by a year. States that permit interim rates include HI, IA, MI, MO, NH, OK, TX, VA, and WI.
3. Capital spending trackers can ensure timely commencement of the recovery of costs of plant additions, without rate cases, when assets become used and useful. Trackers can be designed to maintain incentives for good capital cost management and timely project completion. Monitoring by PEG Research reveals that capital spending trackers have been approved for use by energy utilities in AR, CA, FL, GA, IA, ID, IL, IN, KS, KY, MD, ME, MN, MO, NJ, NY, OH, OK, OR, PA, TX, VA, and WI.
4. The inclusion of CWIP in rate base improves cash flow and reduces future rate shocks. This practice also reduces the losses that a utility experiences making large plant additions under historical test year rates. Monitoring by the Edison Electric Institute has found that states that have recently allowed inclusion of CWIP in rate base include CO, FL, GA, IN, KS, KY, LA, MI, MO, NC, NM, NV, SD, TN, VA, and WV.
5. Cost trackers can also adjust rates automatically to ensure timely recovery of O&M expenses that are unusually volatile and/or expected to rise rapidly. Expenses that are often recovered using trackers include those for pensions and benefits, uncollectible bills, and DSM.
6. Several methods have been established to compensate utilities for slowing growth in average use.
    - Lost revenue adjustment mechanisms (a/k/a lost margin trackers) restore margins that are estimated to have been lost because of utility conservation programs. These are currently used by electric utilities in CT, IN, KY, OH, NC, and SC.

- Decoupling true-up plans help base rate revenue track revenue requirements more closely and can thereby restore lost margins that result from slow growth in average use resulting from a wider variety of sources, including conservation programs administered by independent agencies. Such plans are currently used by electric utilities in CA, CT, DC, HI, ID, MA, MD, MI, NY, OR, VT, and WI. They are used by gas utilities in several additional states (*e.g.* AR, CO, IN, MN, NJ, NC, UT, VA, WA, and WY).
- Higher customer charges are also effective in reducing attrition from declining average use. Straight fixed variable pricing, which recovers *all* fixed costs using fixed charges, is used by gas utilities in GA, MO, OH, OK, and ND.

7. The duration of rate cases can be limited. A reasonable cap is the average length of cases in the United States, which is currently between nine and ten months.[50]
8. Multiyear rate plans can give utilities rate escalation between rate cases for inflation and other business conditions that drive cost growth. Such plans typically have a duration of three to five years, and terms of seven to ten years have been approved. Even if an historical test year makes the initial rates under such plans non-compensatory, it would only happen once in a multiyear period. Utilities would have several years to recoup their losses through superior productivity growth --- and an incentive to do so. North American jurisdictions where multiyear rate plans are common include CA, ME, MA, NY, OH, and VT in the United States and Alberta, British Columbia, and Ontario in Canada. This approach to ratemaking is more the rule than the exception overseas.

[50] See *EEI 2007 Financial Review*, p. 36.

APPENDIX: UNIT COST LOGIC

To better understand the conditions that can cause historical test year rates to produce earnings attrition, suppose that year t is a rate year (a year when new rates take effect) and that the utility is underearning with its newly implemented HTY rates. The cost of base rate inputs then exceeds base rate revenue and the ratio of cost to revenue is positive.

$$Cost_t / Revenue_t > 0.$$

To simplify the story, suppose next that the utility has only one service and the base rate for that service is gathered exclusively from a volumetric charge. In the historical test year, the revenue requirement is then the product of a price (P_{t-2}) and a volume (V_{t-2}) and this is set equal to the allowed cost of service

$$P_{t-2} \times V_{t-2} = Cost_{t-2}$$

so that

$$P_{t-2} = Cost_{t-2} / V_{t-2} = \text{Unit } Cost_{t-2}.$$

The rate equals the cost per kWh of sales, which we may call the *unit* cost of service in the historical test year.

Revenue in the rate year is the product of this same price, which reflects *historical* business conditions, and the *contemporary* sales volume. The ratio of cost to revenue may then be restated as

$$\begin{aligned} Cost_t / Revenue_t &= Cost_t / (P_{t-2} \times V_t) \\ &= Cost_t / [(Cost_{t-2} / V_{t-2}) \times V_t] \\ &= (Cost_t / V_t) / (Cost_{t-2} / V_{t-2}) \\ &= \text{Unit } Cost_t / \text{Unit } Cost_{t-2}. \qquad \text{[A1]} \end{aligned}$$

An historical test year rate is thus non-compensatory if the utility's unit cost is higher in the rate year than it was two years ago in the test year. Growth in the unit cost of the utility is thus the fundamental reason for earnings attrition. Note also that

$$\text{Unit } Cost_t / \text{Unit } Cost_{t-2} = (Cost_t / Cost_{t-2}) / (V_t/V_{t-2}). \qquad \text{[A2]}$$

Unit cost thus grows between the test year and the rate year if cost grows more rapidly than the sales volume. Growth in the sales volume therefore matters as well as cost growth in determining a utility's unit cost trend. Moreover, the ability of historical test year rates to avoid under or, for that matter, over earning depends on the stability of the relationship between cost and billing determinants.

The key result that historical test years are non-compensatory when unit cost is rising extends to the real world situation in which a utility provides multiple services, each with several charges. In this situation the ratio of the total delivery volume in [A2] is replaced by a weighted average of the ratios for all billing determinants.[51]

[51] The weight for each individual billing determinant is its share of the total base rate revenue.

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M. N. LOWRY
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
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Edison Electric Institute

Power by Association

Innovative Regulation:

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Prepared by: Pacific Economics Group Research LLC

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April 2011

Edison Electric Institute

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April 2011

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Published by:
Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Phone: 202-508-5000
Web site: www.eei.org

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I. Introduction

Many utilities are experiencing the problem of regulatory lag today. They are struggling with a tendency of costs to grow more rapidly than the delivery volumes and other billing determinants that cause revenue growth. Some utilities need major generation or transmission plant additions. Others are engaged in accelerated programs to modernize distribution plant or install advanced metering infrastructure ("AMI"). Growth in the volume of utility services used by a typical customer ("average use") once helped to finance plant additions because it bolstered revenue more than cost. However, growth in average use has slowed with a weak economy and increased energy efficiency. Traditional approaches to regulation can fail to provide timely rate relief under these conditions. The result can be chronic financial attrition that increases risk and can discourage needed investments.

Alternatives to traditional regulation have been developed which reduce regulatory lag. These include cost trackers, the inclusion of construction work in progress ("CWIP") in rate base, multiyear rate and revenue caps, revenue decoupling, formula rates, and forward test years. This review briefly explains these options and provides a summary of precedents for electric and natural gas utilities. A summary of states that currently use these approaches is featured in Table 1. Natural gas precedents are included because of their relevance to "wires only" electric power distributors.

Table 1

Innovations to Reduce Regulatory Lag: An Overview of Current Precedents

State	Capex Cost Tracker	CWIP in Rate Base[1]	Multiyear Rate Cap[2]	Multiyear Revenue Cap[3]	Revenue Decoupling: Decoupling True Up Plans	Revenue Decoupling: Lost Revenue Adjustment Mechanisms	Revenue Decoupling: Fixed Variable Retail Pricing	Retail Formula Rate Plans	Forward Test Years
Alabama								Yes	Yes
Arizona									
Arkansas	Yes				Yes (gas only)				
California	Yes		Yes (electric only)	Yes	Yes				Yes
Colorado	Yes (electric only)	Yes			Yes (gas only)	Yes (electric only)			Pending
Connecticut					Yes (electric only)	Yes (gas only)	Yes (electric only)		Yes
Delaware							Pending		
District of Columbia					Yes (electric only)				
Florida	Yes (electric only)	Yes					Yes (gas only)		Yes
Georgia	Yes	Yes	Yes (electric only)				Yes (gas only)		Yes
Hawaii	Yes (electric only)			Yes (electric only)	Yes (electric only)				Yes
Idaho					Yes (electric only)				
Illinois	Yes (gas only)				Yes (gas only)		Yes (gas only)		Yes
Indiana	Yes	Yes			Yes (gas only)	Yes (electric only)			
Iowa	Yes (electric only)								
Kansas	Yes	Pending							
Kentucky	Yes					Yes			Yes
Louisiana	Yes (electric only)	Yes						Yes	
Maine	Yes (electric only)		Yes						Yes
Maryland		Yes			Yes				
Massachusetts	Yes		Yes		Yes	Yes			
Michigan		Pending			Yes				Yes

State	Capex Cost Tracker	CWIP in Rate Base[1]	Multiyear Rate Cap[2]	Multiyear Revenue Cap[3]	Revenue Decoupling			Retail Formula Rate Plans	Forward Test Years
					Decoupling True Up Plans	Lost Revenue Adjustment Mechanisms	Fixed Variable Retail Pricing		
Minnesota	Yes (electric only)	Yes			Yes (gas only)				Yes
Mississippi	Yes (electric only)	Yes					Yes (electric only)	Yes	Yes
Missouri	Yes (gas only)						Yes (gas only)		
Montana					Yes (electric only)				
Nebraska									
Nevada					Yes (gas only)	Yes (electric only)			
New Hampshire									
New Jersey	Yes				Yes (gas only)				
New Mexico		Pending							Pending
New York	Yes			Yes	Yes				Yes
North Carolina		Yes			Yes (gas only)	Yes (electric only)			
North Dakota		Pending					Yes (gas only)		Yes
Ohio	Yes		Yes (electric only)			Yes (electric only)	Yes (gas only)		
Oklahoma	Yes (electric only)	Pending				Yes (electric only)	Yes (gas only)	Yes (gas only)	
Oregon	Yes				Yes	Yes (gas only)			Yes
Pennsylvania	Yes (electric only)								
Rhode Island					Pending				Yes
South Carolina		Yes				Yes (electric only)		Yes (gas only)	
South Dakota		Pending							
Tennessee					Yes (gas only)				Yes
Texas	Yes (electric only)	Yes						Yes (gas only)	
Utah	Yes (gas only)				Yes (gas only)				Yes
Vermont	Yes (electric only)			Yes	Yes				
Virginia	Yes (electric only)	Yes			Yes (gas only)				
Washington					Yes (gas only)				
West Virginia		Yes							
Wisconsin		Yes			Yes				Yes
Wyoming					Yes (gas only)	Yes (electric only)			Yes (electric only)

[1] This column pertains only to electric utilities.

[2] This column excludes plans involving rate freezes.

[3] Revenue caps are also denoted as decoupling true up plans. However, many decoupling true up plans do not involve multiyear revenue caps because they do not have broad-based revenue adjustment mechanisms.

II. Cost Trackers and CWIP in Rate Base

Trackers are used in various situations where it is less practical to rely on general rate cases to adjust rates for particular changes in business conditions. For example, the energy costs of utilities are usually recovered via cost trackers because their volatility and substantial size would otherwise lead to frequent general rate cases and/or elevated earnings risk. Other volatile costs that are sometimes recovered using trackers include those for pensions and uncollectible bills.

Trackers are also used for recovering costs that are rapidly rising irrespective of their volatility. This can facilitate investment, and reduce risk and the frequency of rate cases. Slow growth in average use reduces concern about overearning because the growth in billing determinants is less likely to exceed the growth in cost that is not recovered by trackers. Examples of utility costs that are tracked because of their rapid growth include those for health care, demand side management ("DSM"), and surges in plant additions.

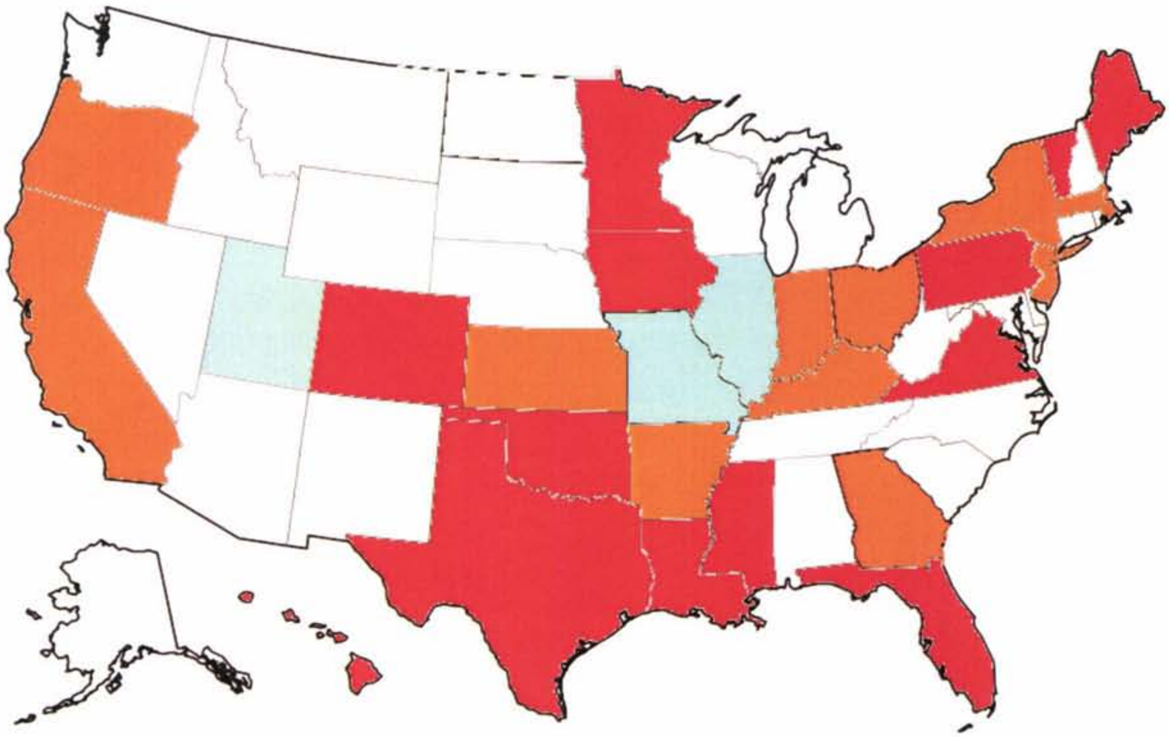
Trackers for the annual cost of plant additions are sometimes called capital expenditure ("capex") trackers. Plant additions can surge for several reasons. Utilities engaged in transmission and distribution occasionally have major plant additions that increase the rate base substantially. Base load generation is a common source of major plant additions for vertically integrated electric utilities. Base load power plants can take years to construct. An allowance in rates for funds used during construction is traditionally not permitted until assets are used and useful. This involves extra interest expenses and produces rate "shock" when the value of the plant is finally added to the rate base. The delay in receiving a return on investment increases utility risk, and this further increases the cost of construction that customers ultimately pay. Many commissions address these problems by including costs of construction work in progress ("CWIP") in the rate base so that a return on investment can start sooner. Capex trackers are often used in lieu of rate cases to recover the annual return on CWIP.

The cost of replacing aging distribution and metering facilities is sometimes recovered using capex trackers for a somewhat different set of reasons. The annual expenditure may not be as large as that for new or repowered baseload generation, and replacements in a particular neighborhood don't usually take several years. However, the annual expenditure can still be sizable and, unlike new generation or customer connections, doesn't naturally trigger new revenue when facilities become used and useful. A tracker for the accumulating annual cost of the new investment can help a company modernize its grid and improve its services without frequent rate cases.

Capex trackers have varied treatments of cost. Plant addition budgets are often set in advance. Some trackers permit conventional prudence review of cost overruns. In other cases, no adjustments are subsequently made if cost exceeds the budget. In between these extremes are mechanisms in which deviations, of prescribed magnitude, from budgeted amounts are shared formulaically (*e.g.* 50-50) between the utility and its customers. Trackers for AMI capex may involve supplemental award/penalty mechanisms that encourage effective use of the new metering systems.

Recent capex tracker precedents are shown in Figure 1 and Table 2. It can be seen that there are numerous precedents. Trackers for gas utilities often focus on the cost of replacing old cast iron and bare steel mains. Recent electric utility precedents for CWIP in rate base are shown in Table 3 and Figure 2. It can be seen that most involve investments in generating plant.

Figure 1: Recent Capex Tracker Precedents by State



Electric | Gas & Electric | Gas

Table 2: Recent Capex Tracker Precedents

Jurisdiction	Company Name	Tracker Name	Eligible Investments	Case Reference
AR	SWEPCO	Generation Recovery Rider	Financing costs and construction expenditures for Turk and Stall generation plants	Docket No. 09-008-U (November 2009)
AR	CenterPoint Energy Arkla	Main Replacement Rider	Accelerated replacement of cast iron and bare steel mains and services	Docket 06-161-U (October 2007)
CA	All utilities	Backstop Cost Recovery Mechanism	Construction of Tx facilities that facilitate RPS goals & not approved for recovery in Tx rates by the FERC	Decision No. 06-06-034 (June 2006)
CA	Pacific Gas & Electric	Balancing Accounts	AMI including associated computer systems and software	Decision 06-07-027 (July 2006)
CA	Pacific Gas & Electric	Cornerstone Improvement Project Balancing Account	Capital and O&M expenses to improve the reliability of the electric distribution system	Decision 10-06-048 (June 2010)
CA	San Diego Gas & Electric	Advanced Metering Infrastructure Balancing Account	AMI including information technology, business and organizational readiness, field deployment, systems integration and program management and organization	Decision 07-04-043 (April 2007)
CA	San Diego Gas & Electric	Steam Generator Replacement Project	Steam generator replacement for San Onofre Nuclear Generating Stations	Decision 06-11-026 (November 2006)
CA	Southern California Edison	Steam Generator Replacement Project	Steam generator replacement for San Onofre Nuclear Generating Stations	Decision 05-12-040 (December 2005)
CA	Southern California Edison	Advanced Metering Infrastructure Balancing Account	Predeployment costs associated with the Advanced Metering Infrastructure Project	Decision No. 06-12-026 (December 2006)
CA	Southern California Edison	SmartConnect Balancing Account	Deployment costs associated with the Advanced Metering Infrastructure Project	Decision No. 08-09-039 (September 2008)
CA	Southern California Edison	Backstop Cost Recovery Mechanism	Construction of the Vincent-Tehachapi Tx facilities that facilitate RPS goals & not approved for recovery in Tx rates by the FERC	Decision No. 07-03-045 (March 2007)
CO	Public Service Company of Colorado	Transmission Cost Adjustment	Transmission investment costs not recovered through the company's base rates	Docket No. 08S-520E, Decision No. C09-595 (June 2009)
FL	Florida Power and Light	Environmental Cost Recovery Clause	Renewable power generation plant	Docket No. 080281-EI (August 2008)
FL	Florida Power and Light	Capacity Cost Recovery Clause	Nuclear power plant	Docket No. 090009-EI (November 2009)
FL	Florida Power and Light	Nuclear Cost Recovery Clause	Construction of new nuclear generation	Docket No. 080009-EI (September 2008)
FL	Progress Energy Florida	Capacity Cost Recovery Clause	Nuclear power plant	Docket No. 090009-EI (November 2009)
FL	Progress Energy Florida	Nuclear Cost Recovery Clause	Nuclear generation	Docket No. 080009-EI (September 2008)
FL	Progress Energy Florida	Environmental Cost Recovery Clause	Renewable power generation plant or purchases from such plants	Docket No. 050078-EI (September 2005)
GA	Atmos Energy	Pipe Replacement Surcharge	Replace cast iron and bare steel pipe	Docket No. 12509-U (December 2000)
GA	Atlanta Gas Light	Strategic Infrastructure Development and Enhancement Program	Infrastructure improvements that sustain reliability and operational flexibility	Docket No. 8516-U (October 2009)
GA	Georgia Power Company	Environmental Compliance Cost Recovery	Cost related to environmental compliance	Docket No. 25060-U (December 2007)
HI	Hawaiian Electric Company	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure projects designed to encourage third party renewable developers and maintain reliability	Docket No. 2007-0416 (December 2009)
IA	MidAmerican Energy	Cooper Tracking Mechanism	Nuclear plant additions	Docket APP-96-1 (June 1997), Docket No. TF-02-154 (APP-96-1, RPU-96-8) (May 2002)
IL	Peoples Gas Light & Coke	Rider Incremental Cost Recovery	Replacement of cast iron and bare steel pipe	Case No. 09-0167 (January 2010)
IN	Duke Energy Indiana	Qualified Pollution Control Property	Investment for its Nitrogen Oxide reduction compliance plan	Cause No. 41744 (February 2001)
IN	Duke Energy Indiana	Integrated Coal Gasification Combined Cycle Generating Facility Cost Recovery Adjustment	Integrated gasification combined cycle generating plant	Docket No. 43114 (November 2007)
IN	Duke Energy Indiana	Clean Coal Operating Cost Revenue Adjustment Rider	Qualified pollution control property	Cause No. 42061 ECR 7 (June 2006)
IN	Indiana Gas Company a.k.a. Vectren North	Distribution Reliability Adjustment	Accelerated replacement of cast iron and bare steel mains and services	Docket No. 43298 (Feburary 2008)
IN	Southern Indiana Gas and Electric a.k.a. Vectren South	Distribution Reliability Adjustment	Accelerated replacement of cast iron and bare steel mains and services	Docket No. 43112 (August 2007)
KS	Atmos Energy	Gas System Reliability Surcharge	Infrastructure system replacements	Docket No. 10-ATMG-133-TAR (December 2009)
KS	Black Hills Energy (Aquila)	Gas System Reliability Surcharge	Infrastructure system replacements	Docket No. 07-AQLG-431-RTS (May 2007)
KS	Kansas Gas Service	Gas System Reliability Surcharge	Infrastructure system replacements	Docket 10-KGSG-155-TAR (December 2009)
KS	Midwest Energy	Gas System Reliability Surcharge	Infrastructure system replacements	Docket 09-MDWE-722-TAR (May 2009)
KS	Westar Energy Inc.	Environmental Cost Recovery Rider	Equipment directly tied to enviromental improvement	Docket No. 05-WSEE-981-RTS (October 2005)
KY	Atmos Energy	Pipe Replacement Program Rider	Replacement of bare steel service lines, curb valves, meter loops, and mandated relocates	Docket No. 2009-00354 (May 2010)
KY	Columbia Gas	Advanced Main Replacement Rider	Accelerated replacement of cast iron and bare steel mains and services	Docket No. 2009-00141 (September 2009)
KY	Delta Natural Gas	Pipe Replacement Program Surcharge	Accelerated replacement of bare steel pipe, service lines, curb valves, meter loops, and mandated pipe relocations	Case No. 2010-00116 (October 2010)
KY	Kentucky Power	Environmental Cost Recovery Surcharge	Pollution control facilities	Docket No. 2002-00169 (March 2003)
KY	Union Light, Heat and Power (Duke Energy Kentucky)	Advanced Main Replacement Rider	Accelerated replacement of cast iron and bare steel mains and services	Docket No. 2001-00092 (January 2002)
LA	Cleco Power	Infrastructure and Incremental Costs Recovery	Power plants, Acadiana load pocket transmission, environmental control facilities, other projects to be determined	Docket U-30689 (October 2010)

Table 2 (continued)

Jurisdiction	Company Name	Tracker Name	Eligible Investments	Case Reference
MA	Bay State Gas	Targeted Infrastructure Recovery Factor	Incremental replacement above test year expenditures of unprotected steel mains and services	DPU 09-30
MA	National Grid (Boston-Essex Gas and Colonial Gas	Targeted Infrastructure Recovery Factor	Replacement of bare steel, cast iron, and wrought iron mains, services, meters, meter installations, and house regulators	DPU 10-55
MA	National Grid (Massachusetts Electric & Nantucket Electric)	Net CapEx Adjustment	Distribution capital investment including customer additions and reliability projects	DPU 09-39
MA	National Grid (Massachusetts Electric & Nantucket Electric)	Smart Grid Distribution Adjustment Factor	Smart grid pilot program	DPU 09-32
MA	NSTAR	NA	Smart grid pilot program	DPU-09-33
MN	Northern States Power (Xcel Energy)	Mercury Cost Recovery Rider	Investments made to comply with the Mercury Emissions Reduction Act of 2006	Docket No. M-09-847 (November 2009)
ME	Central Maine Power	NA	AMI	Docket No. 2007-215(II) (Feburary 2010)
MO	Atmos Energy	Infrastructure System Replacement Surcharge	Mains, valves, service lines, regulator stations, vaults, other pipeline components that have worn out, need upgrading due to safety requirements or were relocated due to public construction works	Docket No. GO-2009-0046 (October 2008)
MO	Laclede Gas	Infrastructure System Replacement Surcharge	Mains, valves, service lines, regulator stations, vaults, other pipeline components that have worn out, need upgrading due to safety requirements or were relocated due to public construction works	Docket No. GR-2007-0208 (July 2007)
MO	Missouri Gas Energy	Infrastructure System Replacement Surcharge	Natural gas line replacements and relocations	Docket No. GR-2009-0355 (Feburary 2010)
MS	Mississippi Power	Enviromental Compliance Overview Plan Rate	Environmental equipments and facilities at various generation plants	Docket No. 92-UA-0058 and 92-UN-0059 (July 1992)
NJ	Atlantic City Electric	Infrastructure Investment Surcharge	Investments to replace, reinforce and expand infrastructure	Docket No. EO09010049 and GO09010054 (April 2009)
NJ	Elizabethtown Gas	Cost Recovery Rider	Projects to enhance reliability and reinforce infrastructure	Docket No. GO09010053 (April 2009)
NJ	New Jersey Natural Gas	Accelerated Infrastructure Projects	Replace bare steel mains, reinforce distribution system & transmission mains	Docket No. GO09010052 and GR07110889 (April 2009)
NJ	Public Service Electric and Gas	Capital Infrastructure Investment Program	Electric reliability upgrades & feeder replacement, Gas: replacement of cast iron & bare steel mains and services	Docket No. GO09010050 (April 2009)
NJ	Public Service Electric and Gas	Solar Generation Investment Program	Solar generation construction including small distributed solar systems on power poles	Docket No., EO09020125 (August 2009)
NJ	South Jersey Gas	Capital Investment Recovery Tracker	Bare steel replacement, expand key distribution mains for reliability	Docket No. GO09010051 (April 2009)
NY	Consolidated Edison	Monthly Adjustment Clause	AMI, SCADA, undergrounding	Case 09-E-0310 (October 2010)
NY	Corning Natural Gas	Delivery Rate Adjustment	Capital additions & proprety taxes that are incremental to the amounts included in the Rate Year rates	Docket No. 08-G-1137 (March 2009)
NY	National Grid NY (formerly Brooklyn Union Gas and Long Island Lighting)	Capital Tracker	Keyspan Energy Delivery New York's and Long Island's differences between actual construction expenditures required by the City or State and the projected levels set forth in the Joint Proposal	Docket No. 06-M-0878 (September 2007)
OH	Cleveland Electric Illuminating	Delivery Service Improvement Rider	Distribution reliability enhancements	0021-EL-ATA, 09-0022-EL-AEM, and 09-0023-EL-AAM (March 2009)
OH	Cleveland Electric Illuminating	Rider AMI	Ohio Site Deployment Pilot (3 year AMI pilot)	Case No. 07-551-EL-AIR, 09-1820-EL-ATA, and 10-388-EL-SSO
OH	Cleveland Electric Illuminating	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case No. 10-388-EL-SSO (August 2010)
OH	Columbia Gas of Ohio	Infrastructure Replacement Program Rider	Replacement of cast iron and bare steel mains & services, replace faulty customer-owned services, install AMI over 5 years	Case No. 08-0072-GA-AIR, 08-0073-GA-ALT, 08-0074-GA-AAM, and 08-0075-GA-AAM (December 2008); Case No. 09-1036-GA-RDR (April 2010)
OH	Columbus Southern Power	GridSMART Rider (Phase I)	Install smart grid including AMI, Distribution Automation (DA) that allows the identification and isolation of faulted distribution lines & Home Area Network (HAN)	Case No. 08-917-EL-SSO and 08-918-EL-SSO (March 2009)
OH	Dayton Power and Light	Environmental Investment Rider	Environmental plant additions	Case No. 05-276-EL-AIR (December 2005)
OH	East Ohio Gas d/b/a Dominion East Ohio	Pipeline Infrastructure Replacement Rider	Pipelines & faulty risers replacements	Case No. 09-458-GA-RDR (December 2009)
OH	East Ohio Gas d/b/a Dominion East Ohio	Automated Meter Reading Charge	Installation of automated meter reading technology	Case No. 07-0829-GA-AIR, 07-0830-GA-ALT, 07-0831-GA-AAM, 08-0169-GA-ALT, and 06-1453-GA-UNC (October 2008); Case No. 09-38-GA-UNC (May 2009); Case No. 09-1875-GA-RDR (May 2010)
OH	Duke Energy Ohio	Accelerated Main Replacement Program Rider	Replacement of bare steel and cast iron mains and services, later extended to customer risers	Case No. 01-1228-GA-AIR, and 01-1478-GA-ALT, and 01-1539-GA-AAM (May 2002); 07-0589-GA-AIR 07-0590-GA-ALT 07-0591-GA-AAM (May 2008)
OH	Duke Energy Ohio	Advanced Utility Rider	AMI	Case No. 07-0589-GA-AIR 07-0590-GA-ALT 07-0591-GA-AAM (May 2008)

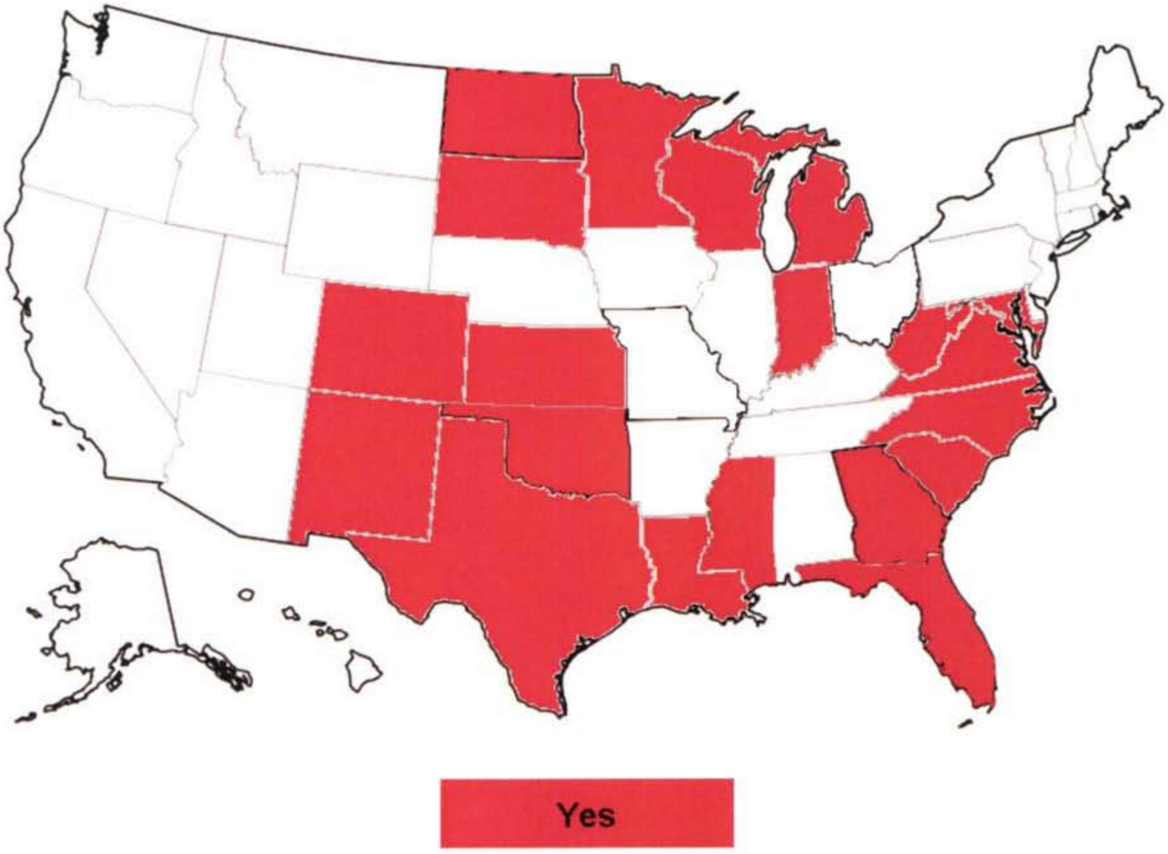
Table 2 (continued)

Jurisdiction	Company Name	Tracker Name	Eligible Investments	Case Reference
OH	Duke Energy Ohio	Infrastructure Modernization Distribution Rider	AMI	Case No. 08-920-EL-SSO and 08-921-EL-AAM and 08-922-EL-UNC and 08-923-EL-ATA (December 2008)
OH	Ohio Edison	Delivery Service Improvement Rider	Distribution reliability enhancement	Case No. 08-0935-EL-SSO, 09-0021-EL-ATA, 09-0022-EL-AEM, and 09-0023-EL-AAM (March 2009)
OH	Ohio Edison	Rider AMI	Ohio Site Deployment Pilot (3 year AMI pilot)	Case No. 07-551-EL-AIR, 09-1820-EL-ATA, and 10-388-EL-SSO
OH	Ohio Edison	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case No. 10-388-EL-SSO (August 2010)
OH	Ohio Power	GridSMART Rider (Phase I)	Install smart grid including AMI, Distribution Automation (DA) & Home Area Network (HAN)	Case No. 08-917-EL-SSO and 08-918-EL-SSO (March 2009)
OH	Toledo Edison	Delivery Service Improvement Rider	Distribution reliability enhancement	Case No. 08-0935-EL-SSO, 09-0021-EL-ATA, 09-0022-EL-AEM, and 09-0023-EL-AAM (March 2009)
OH	Toledo Edison	Rider AMI	Ohio Site Deployment Pilot (3 year AMI pilot)	Case No. 07-551-EL-AIR, 09-1820-EL-ATA, and 10-388-EL-SSO
OH	Toledo Edison	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case No. 10-388-EL-SSO (August 2010)
OH	Vectren Energy Delivery	Distribution Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket No. 07-1081-GA-ALT, 07-1080-GA-AIR and 08-0632-GA-AAM (January 2009)
OK	Oklahoma Gas & Electric	Smart Grid Rider	Systemwide smart grid implementation	Cause No. 201000029 (July 2010)
OK	Oklahoma Gas & Electric	System Hardening Recovery Rider	Undergrounding and other circuit hardening capex	Cause No. 20080387, Order No. 567670 (May 2009)
OK	Oklahoma Gas & Electric	OU Spirit Rider	Construction of the OU Spirit Wind Farm	Cause No. 200900167, Order No. 571788 (October 2009)
OR	Northwest Natural Gas	Bare steel replacement program	Replacement of bare steel	Docket No. UG 177 UM 1779, Order No. 07-480 (October 2007)
OR	Northwest Natural Gas	NA	Expansion of distribution system into Coos County	Docket No. UG 152, Order No. 03-236 (April 2003)
OR	Northwest Natural Gas	NA	Installation of AMI Phase II, previously subject to meter reading agreement with Portland General Electric	Docket UM 1413, Order 09-105 (March 2009)
OR	Portland General Electric	NA	Installation of AMI	Docket UE 189, Order No. 08-245 (May 2008)
PA	PPL Electric Utilities	Energy Development Rider	All interconnection equipment for renewable generation resources of 10 kW or less	Docket No. M-00031715 F0003 (August 2006); Previously R-00973954 (May 14, 1998)
PA	PPL Electric Utilities	Act 129 Compliance Rider	Predeployment and subsequent deployment costs associated with the Advanced Metering Infrastructure Project	Docket No. M-2009-2123945 (January 2010)
PA	PECO	Smart Meter Cost Recovery Rider	Predeployment and subsequent deployment costs associated with the Advanced Metering Infrastructure Project	Docket No. M-2009-2123944 (April 2010)
PA	Metropolitan Edison	Smart Meters Technologies Charge	Predeployment and subsequent deployment costs associated with the Advanced Metering Infrastructure Project	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania Electric	Smart Meters Technologies Charge	Predeployment and subsequent deployment costs associated with the Advanced Metering Infrastructure Project	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania Power	Smart Meters Technologies Charge	Predeployment and subsequent deployment costs associated with the Advanced Metering Infrastructure Project	Docket M-2009-2123950 (April 2010)
PA	Duquesne Light	Smart Meter Charge Rider	Predeployment and subsequent deployment costs associated with the Advanced Metering Infrastructure Project	Docket No. M-2009-2123948 (April 2010)
TX	AEP Texas Central	Advanced Metering System Surcharge	AMI and associated software	Docket No. 36928
TX	AEP Texas North	Advanced Metering System Surcharge	AMI and associated software	Docket No. 36928
TX	Centerpoint Energy Houston Electric	Advanced Metering System Surcharge	AMI and associated software	Docket No. 35620 (August 2008)
TX	Oncor Electric Delivery	Advanced Metering System Surcharge	AMI and associated software	Docket No. 35718 (August 2008)
UT	Questar Gas	Infrastructure Rate Adjustment Tracker	Replacement of aging high-pressure feeder lines	Docket 09-057-16 (June 2010)
VA	Appalachian Power	Environmental & Reliability Cost Recovery Surcharge	Environmental & reliability related incremental costs	Docket No. PUE-2007-00069 (December 2007)
VA	Virginia Electric Power	Rider R	Costs incurred in construction of Bear Garden Generating Station and related transmission line	Case No. PUE-2009-00017 (March 2010)
VA	Virginia Electric Power	Rider S	Costs incurred in construction of Virginia City Hybrid Energy Center	Case No. PUE-2007-00066 (March 2008)
VT	Central Vermont Public Service	New Initiatives Adder	Smart grid implementation including hardware, software, two-way communications systems	Dockets 7586 and 7612

Table 3: CWIP in Rate Base: Recent Retail Precedents

Jurisdiction	Company	Year Approved	Type of Project	Reference
Colorado	Public Service of Colorado	2006	Transmission, generation	Docket No. 06S-234EG
Colorado	Legislation	2007	Transmission	Senate Bill 07-100
Florida	Rulemaking	2007	Nuclear and IGCC generation	Docket 060508-EL
Florida	Florida Power & Light	2008	Nuclear generation	Docket 080650-EL
Florida	Progress Energy Florida	2008	Nuclear generation	Docket 080148-EI
Georgia	Georgia Power	2009	Nuclear generation	Docket 27800
Indiana	General Policy		Pollution Control Equipment	
Indiana	Duke Energy Indiana	2007	IGCC generation	Docket No. 43114
Kansas	Legislation	2008	Nuclear generation	Senate Bill 586
Louisiana	Rulemaking	2007	Nuclear generation	Docket R-29712
Louisiana	Cleco Power	2006	Generation	Docket U-28765
Maryland	General Policy		Environmental projects	
Michigan	Legislation	2008	Significant capital projects	House Bill 5524
Minnesota	Northern States Power- MN	2003	Pollution control	
Mississippi	Mississippi Power	2010	IGCC generation	Docket 2009-UA-14
New Mexico	Legislation	2009	All	Senate Bill 477
North Carolina	Duke Energy Carolinas	2009	Generation	Docket No. E-7, Sub 909
North Carolina	Legislation	2007	Generation	Senate Bill 3
North Dakota	Legislation	2007	Transmission, federally mandated environmental compliance projects	Senate Bill 2031 & House Bill 1221
Oklahoma	Legislation	2005	Environmental, transmission	House Bill 1910
South Carolina	South Carolina Electric & Gas	2003	Generation	Docket No. 2002-223-E
South Carolina	South Carolina Electric & Gas	2009	Nuclear generation	Docket 2009-211-E
South Dakota	Legislation	2006/2007	Transmission, environmental compliance projects	
Texas	Rulemaking	2005	All Transmission within ERCOT (conditional)	Project 28884
Virginia	Legislation	2007	Reliability-related, nuclear, renewables, new generation using Virginia coal,	Senate Bill 1416
Virginia	Virginia Electric Power	2008	New generation using Virginia coal	PUE-2007-00066
West Virginia	Appalachian Power	2006	Transmission, environmental compliance, IGCC generation	Case No. 05-1278-E-PC-PW-42T
West Virginia	Monongahela Power	2007	Environmental compliance	Case No. 05-0750-E-PC
Wisconsin	Wisconsin Public Service	2000	Nuclear generation, transmission	Docket 6690-UR-112
Wisconsin	Wisconsin Public Service	2005	Generation	Docket 6690-UR-117
Wisconsin	General Policy		Diverse operations	

Figure 2: Recent Electric Precedents for CWIP in Rate Base



III. Multiyear Rate and Revenue Caps

Multiyear rate and revenue caps are performance-based ratemaking ("PBR") mechanisms that limit the true up of revenue to a utility's *own* cost for several years. The length of such plans is typically three to five years, but plans as long as ten years have been approved. Most multiyear rate plans feature an attrition relief mechanism that provides automatic rate relief for changing business conditions between rate cases. These can be designed to provide funds needed for plant additions. The rate adjustments provided by attrition relief mechanisms are largely "external" in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* cost growth. This can strengthen incentives to contain cost growth. Benefits of the performance improvements that are stimulated by the plan can be shared with customers.

Attrition relief mechanisms may cap the growth in allowed rates or revenue. Rate caps limit the escalation in rates (*e.g.* customer charges and cents per unit of service). They are favored where utilities are encouraged to bolster system use because rate caps strengthen incentives for sales growth and facilitate marketing flexibility. Revenue caps limit the escalation in allowed revenues (the escalation in rates then depending, additionally, on the growth in billing determinants). They are often favored in service territories with large-scale DSM programs. Revenue caps are usually combined with decoupling true ups, as discussed further below.

Multiyear rate and revenue caps commonly allow supplemental rate adjustments for changes in external business conditions that were especially difficult to anticipate at the time that the plan was fashioned. These include changes in tax rates and other government policies (*e.g.* conductor undergrounding requirements) that affect costs. Some multiyear rate and revenue caps feature earnings sharing mechanisms that automatically share earnings surpluses and/or deficits that result when the rate of return on equity ("ROE") deviates from its regulated target. Plans also sometimes feature award and/or penalty mechanisms that are linked to service quality.

Current U.S. and Canadian precedents for multiyear *rate* caps that do not involve rate freezes are indicated in Table 4 and Figure 3. Precedents for multiyear *revenue* caps are discussed in the revenue decoupling section below. Multiyear rate and revenue caps are more common for energy distributors than for vertically integrated electric utilities. This is due in part to the tendency of distribution cost to grow at a comparatively steady and predictable pace. This makes it easier to identify a fair attrition relief mechanism if accelerated programs of replacement investment aren't planned. The popularity of rate and revenue caps for power distributors also reflects the fact that they rarely experience today the combination of declining rate base and growth in average use that might permit them to operate for several years without rate escalation. Canada is moving towards multiyear rate caps for all power distributors in the two provinces that have retail competition. Rate and revenue caps are the rule rather than the exception for power distributors overseas.

Table 4: Multiyear Price Cap Precedents

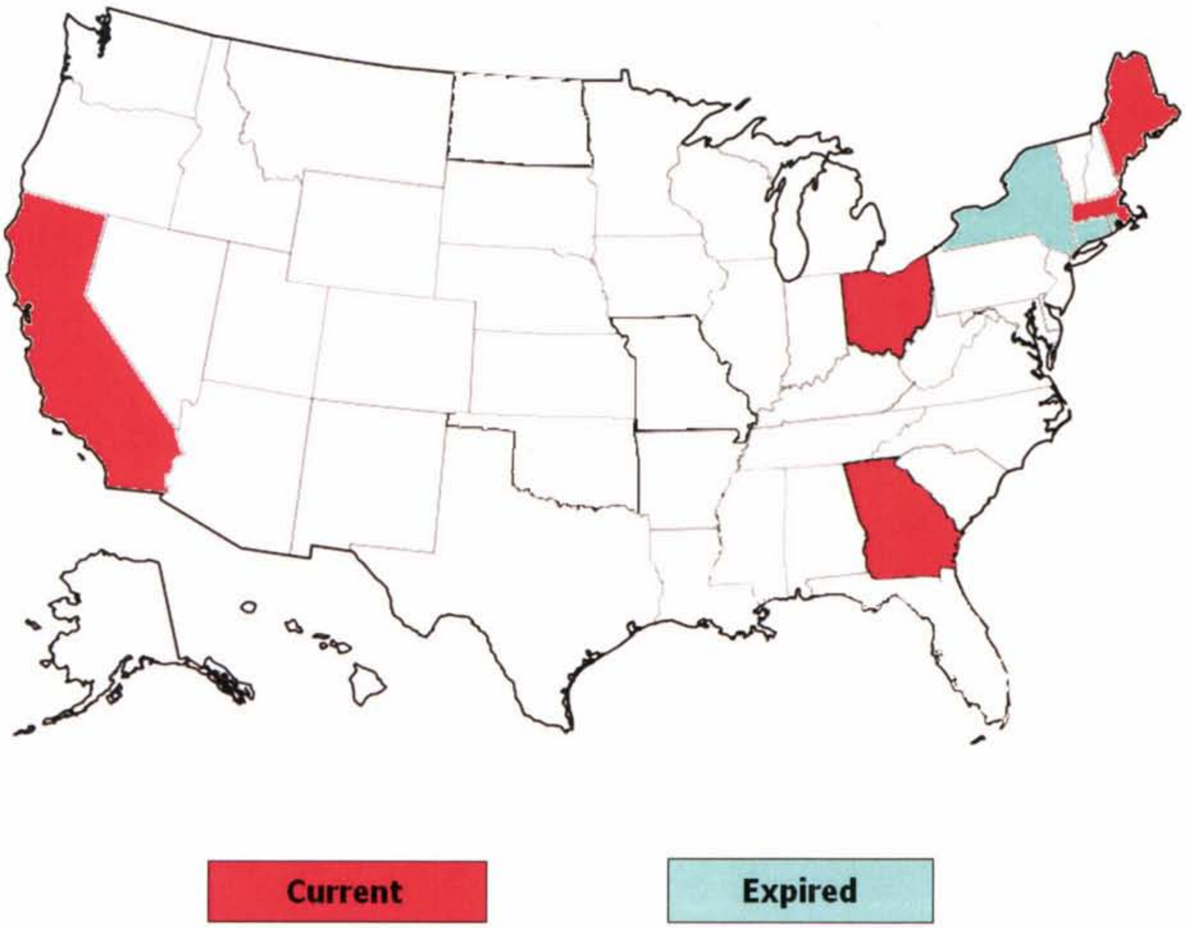
Jurisdiction	Company Name	Plan Term	Services Covered	Attrition Relief Mechanism	Case Reference
Current					
CA	PacifiCorp	2011-2013	Bundled power service	Indexing: Rates escalated by Global Insight forecast of CPI, less 0.5% productivity factor; major plant additions can be requested in annual filings.	Decision 10-09-010; September 2, 2010
CA	Sierra Pacific Power	2009-2011	Bundled power service	Indexing: Rates escalated by Global Insight forecast of CPI, less 0.5% productivity factor; major plant additions can be requested in annual filings.	Decision 09-10-041
GA	Georgia Power	2011-2014	Bundled power service	Stairstep: Rate increases permitted for DSM and the lesser of the actual plant expenditure for generating facilities or the approved capital expenditure by the Commission	Docket 31958
MA	Berkshire Gas	2002-2011	Gas distribution	No adjustment until September 2004, then Indexing: GDPPI - 1%	Docket D.T.E. 01-56
MA	Nstar	2006-2012	Power distribution	Indexing: GDPPI - X. X increases from 0.50% to 0.75% during plan.	Docket D.T.E. 05-85
ME	Bangor Gas	2000-2009, extended to 2012	Gas Distribution	Indexing: First 5 years: GDPPI Next 5 years: GDPPI-0.5%	Docket 970795 (June 26, 1998)
ME	Central Maine Power (III)	2009-2013	Power distribution	Indexing: GDPPI - 1%, separate AMI tracker	Docket 2007-215
OH	Cincinnati Gas & Electric	2009-2011	Power generation	Stairstep: Negotiated rate increases for base generation charges on January 2009 and January 2010 for all generation customers, in January 2011 rate increase only for nonresidential customers.	Case 08-920-EL-SSO
Alberta	Enmax	2007-2013	Power distribution	Index: Input Price Index -1.2%	Decision 2009-035
Ontario	All Ontario distributors	2010-2013	Power distribution	Indexing: GDP IPI for Final Domestic Demand - (0.92% to 1.32% depending on company's annual performance in benchmarking studies)	EB-2007-0673 (July 14, 2008, September 17, 2008, and January 28, 2009)
Historical					
CA	PacifiCorp	1994-1997, extended to 1999	Bundled power service	Indexing: Rates escalated by Input Price Index - X, where X=1.5% through 1997 and 1.4% through 1999, and input price index is cost-weighted index of DRI-forecasted capital, fuel, materials, and labor price indexes.	Decision 93-12-106; December 3, 1993
CA	PacifiCorp	2007-2009, extended to 2010	Bundled power service	Indexing: Rates escalated by Global Insight forecast of CPI, less 0.5% productivity factor; major capital additions (over $50 million) can be requested in annual filings.	Decisions 06-12-011 and 09-04-017
CA	San Diego Gas and Electric	1999-2002	Electric & Gas	Indexing: Gas & Electric separate. Attrition factor is Input Price Index - X. Input price index composed of DRI-forecasted labor, non-labor, and capital price subindexes. X factor increases during plan.	Decision 99-05-030; May 13, 1999
CA	Southern California Edison	1997-2002	Electric	Indexing: Growth in rates is CPI - X. X increases from 1.2% to 1.6% during plan	Decision 96-09-092; September 6, 1996
CT	United Illuminating	2006-2009	Power Distribution	Stairstep	Docket 05-06-04
MA	Bay State Gas	2006-2009	Gas distribution	Indexing: GDPPI - 0.51%	Docket DTE 05-27
MA	Boston Gas (I)	1997-2001	Gas distribution	Indexing: GDPPI - 0.5%	Docket D.P.U. 96-50-C (Phase I) May 16, 1997
MA	Boston Gas (II)	2004-2010	Gas distribution	Indexing: GDPPI - 0.41%	Docket DTE 03-40
MA	Blackstone Gas	November 1, 2004 - October 31, 2009	Gas distribution	Indexing	Docket D.T.E. 04-79
MA	National Grid	2000-2010	Power distribution	Rate Freeze between 2000 and 2005, Inflation: 2006-2010, inflation adjustment made based on index of regional power distribution charges.	Docket DTE 99-47 (November 29, 1999)
ME	Bangor Hydro Electric (I)	1998-2000	Power distribution	Indexing: GDPPI - 1.2%	Docket 97-116 (March 24, 1998)
ME	Central Maine Power (I)	1995-1999	Bundled power service	Indexing: 1995 GDPPI - 0.5% ; for 1996 GDPPI - 1.0%, for 1997-99: (1-non-inflation driven costs)*(GDPPI-1%)	Docket 92-345 Phase II (January 10, 1995)
ME	Central Maine Power (II)	2001-2007	Power distribution	Indexing: GDPPI-X. X increases from 2% to 2.9% during plan.	Docket 99-666 (November 16, 2000)

Table 4 (continued)

Historical

Jurisdiction	Company Name	Plan Term	Services Covered	Attrition Relief Mechanism	Case Reference
NY	Brooklyn Union Gas	October 1, 1991 - September 30, 1994	Gas distribution	Stairstep: Rate year 1 increase in rates of $35.7 million. Increases for rate years 2 and 3 to be based upon a forecast that parties agree to.	Case 90-G-0981, Opinion 91-21, October 9, 1991
NY	Brooklyn Union Gas	October 1, 1994 - September 30, 1997	Gas distribution	Stairstep: No rate increase in year 1. Rates for years 2 and 3 based on a formula and limited to the rate of inflation	Case 93-G-0941, Opinion 94-22, October 18, 1994
NY	Central Hudson Gas & Electric	July 1, 2006 - June 30, 2009	Electric & Gas	Stairstep: Electric rate increases of $41.5, $6.4, and $5.5 million for rate years 1, 2, and 3 respectively. Gas rate increases of $8.003 million for rate year 1, $6.057 million for rate year 2, and no gas rate increase for rate year 3 approved.	Case 05-E-0934 & Case 05-G-0935; July 24, 2006
NY	Consolidated Edison	October 1, 1994 - September 30, 1997	Gas Distribution	Hybrid: Rate year 1 increase of $7,735,000. Rate years 2 and 3 projected rate increases are $20.4 million and $21.7 million, subject to a cap defined as the lesser of the latest GDP deflator forecast + 1% + incentives or 4.8%. Any expenses unrecovered due to cap deferred for later recovery.	Case 93-G-0996, Opinion 94-21, October 12, 1994
NY	Consolidated Edison	April 1, 2005 - March 31, 2008	Power distribution	Stairstep	Case 04-E-0572, March 24, 2005
NY	Long Island Lighting Company	December 1, 1993- November 30, 1996	Gas distribution	Stairstep: Revenue increases of $25.6 million in rate year 1, $23 million in rate year 2, and $20 million in rate year 3	Case 93-G-0002, Opinion 93-23, December 23, 1993
NY	New York State Electric & Gas	December 1, 1993 - August 31, 1995	Gas	Stairstep: Gas revenues increase by $7.6 million in rate year 1, $7 million in rate year 2, and $7.2 million in rate year 3.	Case 92-G-1086, Opinion 93-22, November 9, 1993
NY	New York State Electric & Gas	August 1, 1995 - July 31, 1998, Years 2 and 3 not implemented due to restructuring	Electric	Stairstep: Rate increases of $45.1 million, $45.3 million, and $45.5 million approved for rate years 1, 2, and 3, respectively.	Case 94-M-0349, Opinion 95-27, September 27, 1995
NY	Niagara Mohawk	July 1, 1990 - December 31, 1992	Gas	Stairstep: Revenue increases of $27.2 million, $0, and $5.5 million for Rate Years 1, 2, and 3, respectively.	Case 29327, Opinion 89-37, June 28, 1991
NY	Orange & Rockland Utilities	November 1, 2003- October 31, 2006	Gas	Stairstep: First year rate increase of $9.25 million, Second rate year increase of $7.375 million, Third year rate increase of $5.00 million; rate increases for second and third rate year can be supplemented by a total of $1.9 million for verified system safety and reliability improvements incurred during the first and second rate years	Case 02-G-1553, October 23, 2003
NY	Orange & Rockland Utilities	November 1, 2006 - October 31, 2009	Gas	Stairstep: First year rate increase of $6.5 million, Second rate year increase of $6.5 million, Third year rate increase of $1.8 million	Case 05-G-1494, October 20, 2006
NY	Rochester Gas & Electric	July 1, 1993 - June 30, 1996	Gas	Stairstep: Rate increases of $2.6 million, $4.4 million, and $4.3 million, respectively for rate years 1, 2, and 3.	Case 92-G-0741, Opinion No. 93-19; August 24, 1993
OH	Columbus Southern Power, Ohio Power	2006-2008	Power Generation	Stairstep: 3% rate increase per year for Columbus Southern, 7% rate increase per year for Ohio Power	Case No. 04-169-EL-UNC (January 2005)
RI	Blackstone Valley Electric, Montaup Electric	1997-1998	Power Distribution	Indexing: CPI	Docket 2514
RI	Narragansett Electric	1997-1998	Power Distribution	Indexing: CPI	House Bill 8124, Substitute B3
Alberta	Northwestern Utilities	1999-2002	Bundled power service	Stairstep: fixed price increases of 0.5% (1999), 1% (2000, 2001), 2% (2002)	Decision U98060 (March 31, 1998)
Alberta	EPCOR	2002-2005, Terminated 12/31/2003	Power distribution	Indexing: Rate Increase of 85% of Input Price Index; Input Price Index constructed of 48% CPI, 52% 5-year rolling average Industrial Product Price Index	Distribution Tariff Bylaw 12367 (August 18, 2000)
Ontario	All Ontario distributors	2000-2003	Power distribution	Indexing: Input Price Index -1.5%	RP-1999-0034
Ontario	All Ontario Distributors	2006-2009	Power Distribution	Indexing: GDP IPI for final domestic demand - 1%	EB-2006-0089 (December 20, 2006)
Ontario	Union Gas	2001-2003	Gas distribution	Indexing: GDP IPI -2.5%	RP-1999-0017 (July 21, 2001)

Figure 3: Recent Electric Rate Cap Precedents by State



IV. Revenue Decoupling

The term revenue decoupling refers to a group of regulatory provisions designed to facilitate recovery of allowed base rate (fixed cost) revenue and so weaken the link between a utility's revenue and the volume of its services. This reduces the utility's disincentive to promote energy efficiency and can alleviate the financial stress caused by stagnant or declining average use. Energy efficiency programs can yield substantial cost savings for customers. Three approaches to decoupling are well established: decoupling true up plans, lost revenue adjustment mechanisms ("LRAMs"), and fixed variable pricing.

A. Decoupling True Up Plans

Decoupling true up plans are designed to help a utility's actual revenue track the revenue allowed by regulators. Most decoupling true up plans have two basic components: a revenue decoupling mechanism ("RDM") and a revenue adjustment mechanism ("RAM"). A typical RDM tracks variances between actual and allowed revenue and makes periodic true ups. Utilities are compensated for any net decline in average use and denied the benefit from any net growth in average use.

True ups may be made annually or more frequently. More frequent adjustments cause actual and allowed revenue to match up better in a given year so that rates fluctuate less from year to year. The size of the true up that is allowed in a given year is sometimes capped. A "soft" cap permits utilities to defer for later recovery any account balances that cannot be recovered immediately.

RDMs vary in the scope of utility services to which they apply. Quite commonly, only revenues from residential and smaller business customers are decoupled. These customers account for an especially high share of the base rate revenue of energy distributors and are usually the primary targets of DSM programs. RDMs also vary in terms of the service classes for which revenues are pooled for true up purposes. In some plans, all service classes are placed in the same "basket". In others, multiple baskets are created to insulate customers of services in each basket from trends in the demands for services in other baskets.

Some RDMs are "partial" in the sense that they exclude from decoupling the revenue impact of certain kinds of demand fluctuations. For example, true ups are sometimes allowed only for the difference between *weather normalized* revenue and allowed revenue. An RDM that instead accounts for *all* sources of demand variance is called a "full" decoupling mechanism.

The RAM component of a decoupling true up plan is an attrition relief mechanism that escalates allowed revenue between rate cases. Some RAMs are "broad-based" in the sense that they provide enough revenue growth to compensate the utility for several kinds of cost pressures and thereby make it possible to reduce rate case frequency. A broad-based RAM provides the basis for a multiyear revenue cap. When RAMs are not broad-based, utilities usually retain the right to file rate cases during the decoupling plan and frequently do file.

Several approaches to RAM design have been established. These approaches include stairsteps, indexing, hybrids, and revenue per customer freezes. Stairsteps provide predetermined increases in allowed revenue which often reflect forecasts of cost growth. Indexing escalates allowed revenue for inflation and frequently also for customer growth. In North America, hybrid RAMs typically involve indexes for O&M expenses and stairsteps for capital costs. Revenue per customer freezes escalate the revenue requirement only for customer growth. All but the last of these approaches is broad-based and provides the basis for a multiyear revenue cap.

States that have tried gas and electric decoupling true up plans are indicated on the maps in Figures 4a and 4b, respectively. Decoupling true up plan precedents in the United States, Australia, and Canada are detailed in Table 5. It can be seen that there are more plans for gas utilities than for electric utilities. This reflects the more pervasive character of the declining average use problem facing gas distributors. However, decoupling true up plans have become common for electric utilities that experience some decline in average use due to large DSM programs. Note also that most RAMs for electric utilities are broad-based, whereas most RAMs for gas utilities are revenue per customer freezes. Gas distributors are presumably more willing to settle for an undercompensatory RAM in return for relief from declining average use.

B. Lost Revenue Adjustment Mechanisms

An LRAM explicitly compensates a utility for base rate revenues that are estimated to be lost due to its DSM programs. Compensation for lost margins is usually effected through a rate rider. Estimates of energy (and sometimes also peak load) savings are needed for LRAM calculations. The utility remains at risk for fluctuations in volumes and peak load due to weather, local economic activity, power market prices, and other volatile demand drivers.

Compensation is not confined to *declines* in average use, as it is under decoupling true up plans. This is desirable because a DSM program that causes billing determinants to grow more slowly than cost increases the need for frequent rate cases even if average use does not decline. Overearning is still unlikely under typical operating conditions.

Precedents for LRAMs are detailed in Table 6 and Figure 5. It can be seen that LRAMs are less widely used than decoupling true up plans today. However, they have experienced a rebound recently due to their use in Duke Energy's "Save a Watt" approach to DSM regulation ongoing in several states.

Figure 4a: Electric Decoupling True Up Plans by State

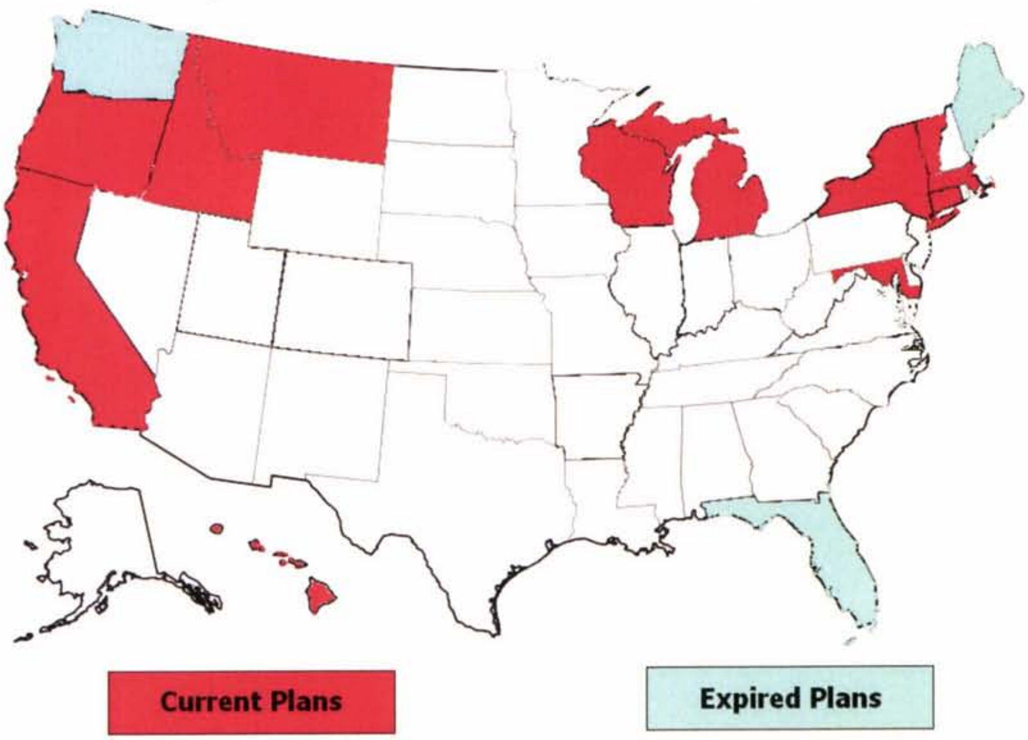


Figure 4b: Gas Decoupling True Up Plans by State

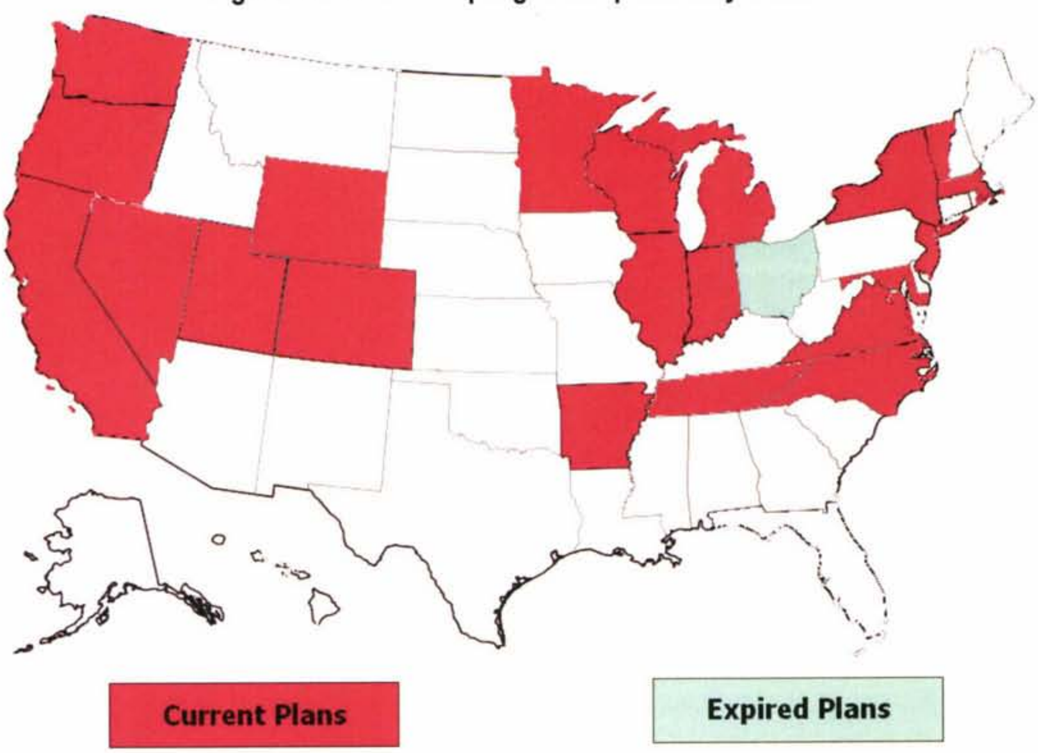


Table 5: Decoupling True Up Plan Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
			Current		
Canada					
BC	Terasen Gas	Gas	2010-2011	Hybrid	Order G-141-09
BC	Pacific Northern Gas	Gas	2003-open	RPC Freeze	N/A
ON	Enbridge Gas Distribution	Gas	2008-2012	Inflation Indexing	Docket EB-2007-0615
ON	Union Gas	Gas	2008-2012	Inflation Indexing	Docket EB-2007-0606
QU	Gaz Metro	Gas	2007-2012	Inflation Indexing	R-3599-2006
United States					
AR	CenterPoint Energy	Gas	2008-2010	RPC Freeze	Docket 06-161-U
AR	Arkansas Oklahoma Gas	Gas	2007-2011	RPC Freeze	Docket 07-026-U
AR	Arkansas Western	Gas	2007-2010	RPC Freeze	Docket 06-124-U
CA	Southwest Gas	Gas	2009-2013	Stairstep	Decision 08-11-048
CA	Southern California Edison	Electric	2009-2011	Stairstep	Decision 09-03-025
CA	Southern California Gas	Gas	2008-2011	Stairstep	Decision 08-07-046
CA	San Diego Gas & Electric	Electric & Gas	2008-2011	Stairstep	Decision 08-07-046
CO	Public Service Company of Colorado	Gas	2008-2011	RPC Freeze	Decision C07-0568
CT	United Illuminating	Electric	2009-2010	Stairstep	Docket No. 08-07-04
DC	Potomac Electric Power	Electric	2010-open	RPC Freeze	Order 15556
HI	Hawaiian Electric Company	Bundled Power	2010-2011	Hybrid	Docket No. 2008-0274
HI	Hawaiian Electric Light Company	Bundled Power	2010-2011	Hybrid	Docket No. 2008-0274
HI	Maui Electric Company	Bundled Power	2010-2011	Hybrid	Docket No. 2008-0274
ID	Idaho Power	Electric	2010-2012	RPC Freeze	Case No. IPC-E-09-28
IL	North Shore Gas	Gas	2008-2012	RPC Freeze	Case 07-0241
IL	Peoples Gas Light & Coke	Gas	2008-2012	RPC Freeze	Case 07-0242
IN	Vectren Energy	Gas	2007-open	RPC Freeze	Cause No. 43046
IN	Vectren Southern Indiana	Gas	2007-open	RPC Freeze	Cause No. 43046
IN	Citizens Gas	Gas	2007-2011	RPC Freeze	Cause No. 42767
MA	Western Massachusetts Electric	Electric	2011-open	No RAM	DPU 10-70
MA	Massachusetts Electric	Electric	2010-open	No RAM	DPU 09-39
MA	Bay State Gas	Gas	2009-open	No RAM	DPU 09-30
MA	Boston-Essex Gas	Gas	2010-open	No RAM	DPU 10-55
MA	Colonial Gas	Gas	2010-open	No RAM	DPU 10-55
MD	Baltimore Gas & Electric	Electric	2008-open	RPC Freeze	Letter Orders ML 108069, 108061
MD	Delmarva Power & Light	Electric	2007-open	RPC Freeze	Order No. 81518
MD	Potomac Electric Power	Electric	2007-open	RPC Freeze	Order No. 81517
MD	Chesapeake Utilities	Gas	2006-open	RPC Freeze	Order No. 81054
MD	Washington Gas Light	Gas	2005-open	RPC Freeze	Order No. 80130
MD	Baltimore Gas & Electric	Gas	1998-open	RPC Freeze	Case No. 8780
MI	Detroit Edison	Electric	2010-2011	RPC Freeze	Case No. U-15768
MI	Michigan Consolidated Gas	Gas	2010-2011	RPC Freeze	Case No. U-15985
MI	Consumers Energy	Gas	2010-2011	RPC Freeze	Case No. U-15986
MI	Consumers Energy	Electric	2009-2011	RPC Freeze	Case No. U-15645
MI	Michigan Gas Utilities	Gas	2010-2011	RPC Freeze	Case No. U-15990
MI	Upper Peninsula Power	Electric	2010-2011	RPC Freeze	Case No. U-15988
MN	CenterPoint Energy	Gas	2010-2013	RPC Freeze	GR-08-1075
MT	Northwestern Energy	Electric	2011-2015	RPC Freeze	Docket No. 2009.9.129
NC	Public Service Co of NC	Gas	2008-open	RPC Freeze	Docket No. G-5, Sub 495
NC	Piedmont Natural Gas	Gas	2008-open	RPC Freeze	Docket No. G-9, Sub 550
NJ	New Jersey Gas Natural	Gas	2010-2013	RPC Freeze	Docket GR05121020
NJ	South Jersey Gas	Gas	2010-2013	RPC Freeze	Docket GR05121019
NV	Southwest Gas	Gas	2009-open	RPC Freeze	D-09-04003
NY	Niagara Mohawk	Electric	2011-open	No RAM	Case 10-E-0050
NY	New York State Electric & Gas	Electric & Gas	2010-2013	Stairstep	Case 09-E-0715
NY	Rochester Gas & Electric	Electric & Gas	2010-2013	Stairstep	Case 09-E-0717

Table 5 (continued)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
NY	Consolidated Edison	Gas	2010-2013	Stairstep	Case 09-G-0795
NY	Consolidated Edison	Electric	2010-2013	Stairstep	Case 09-E-0428
NY	Central Hudson G&E	Electric & Gas	2010-2013	Stairstep	Case 09-E-0588
NY	Orange & Rockland Utilities	Gas	2009-2012	Stairstep	Case 08-G-1398
NY	Niagara Mohawk	Gas	2009-open	RPC Freeze	Case 08-G-0609
NY	Orange & Rockland Utilities	Electric	2008-2011	Stairstep	Case 07-E-0949
NY	National Fuel Gas	Gas	2008-open	RPC Freeze	Case 07-G-0141
OR	Northwest Natural Gas	Gas	2009-2012	RPC Freeze	Order No. 07-426
OR	Portland General Electric	Electric	2011-2013	RPC Freeze	Order No. 10-478
OR	Cascade Natural Gas	Gas	2006-2010	RPC Freeze	Order No. 06-191
TN	Chattanooga Gas	Gas	2010-2013	RPC Freeze	Docket 09-0183
UT	Questar Gas	Gas	2010-open	RPC Freeze	Docket No. 09-057-16
VA	Washington Gas Light	Gas	2010-2013	RPC Freeze	Case No. PUE-2009-00064
VA	Columbia Gas of Virginia	Gas	2010-2012	RPC Freeze	Case No. PUE-2009-00051
VA	Virginia Natural Gas	Gas	2009-2012	RPC Freeze	Case No. PUE-2008-00060
VT	Green Mountain Power	Electric	2010-2013	Inflation Indexing	Docket No. 7585
VT	Central Vermont Public Service	Electric	2009-2011	Inflation Indexing	Docket No. 7336
VT	Vermont Gas Systems	Gas	2007-2011	Hybrid	Docket No. 7109
WA	Avista	Gas	2009-open	RPC Freeze	Docket UG-060518
WA	Cascade Natural Gas	Gas	2005-2010	RPC Freeze	Docket UG-060256
WI	Wisconsin Public Service	Electric & Gas	2009-2012	RPC Freeze	D-6690-UR-119
WY	Questar Gas	Gas	2009-2012	RPC Freeze	Docket 30010-94-GR-08
WY	SourceGas Distribution	Gas	2011-open	RPC Freeze	Docket 30022-148-GR-10
Australia					
Federal	ElectraNet	Power Transmission	2008-2012	Hybrid	Final Decision (11 April 2008)
Federal	Powerlink	Power Transmission	2007-2011	Hybrid	Final Decision (14 June 2007)
			Historical		
Canada					
BC	Terasen Gas	Gas	2008-2009	Hybrid	Order G-33-07
BC	Terasen Gas	Gas	2004-2007	Hybrid	Order G-51-03
BC	BC Gas	Gas	2000-2001	Hybrid	Order G-48-00
BC	BC Gas	Gas	1998-2000	Hybrid	Order G-85-97
BC	BC Gas	Gas	1996-1997	Hybrid	N/A
BC	BC Gas	Gas	1994-1995	Hybrid	Order G-59-94
United States					
CA	Pacific Gas & Electric	Electric & Gas	2007-2010	Stairstep	Decision 07-03-044
CA	Southern California Edison	Electric	2006-2008	Hybrid	Decision 06-05-016
CA	San Diego Gas & Electric	Electric & Gas	2005-2007	Inflation Indexing	Decision 05-03-025
CA	Southern California Gas	Gas	2005-2007	Inflation Indexing	Decision 05-03-025
CA	Southern California Edison	Electric	2004-2006	Hybrid	Decision 04-07-022
CA	Pacific Gas & Electric	Gas & Elec Dx/Gen	2004-2006	Inflation Indexing	Decision 04-05-055
CA	Southern California Edison	Electric	2002-2003	Inflation Indexing	Decision 02-04-055
CA	Southern California Gas	Gas	1998-2002	Inflation Indexing	Decision 97-07-054
CA	San Diego Gas & Electric	Electric & Gas	1994-1999	Hybrid	Decision 94-08-023
CA	Pacific Gas & Electric	Electric	1993-1995	Hybrid	Decision 92-12-057
CA	Southern California Gas	Gas	1990-1993	Hybrid	Decision 90-01-016
CA	Pacific Gas & Electric	Electric	1990-1992	Hybrid	Decision 89-12-057
CA	San Diego Gas & Electric	Electric	1989-1993	Hybrid	Decision 89-11-068
CA	Southern California Edison	Electric	1986-1991	Hybrid	Decision 85-12-076
CA	Southern California Gas	Gas	1986-1989	Hybrid	Decision 85-12-076
CA	Pacific Gas & Electric	Electric	1986-1989	Hybrid	Decision 85-12-076
CA	San Diego Gas & Electric	Electric & Gas	1986-1988	Hybrid	Decision 85-12-108
CA	Pacific Gas & Electric	Electric	1984-1985	Hybrid	Decision 83-12-068
CA	PacifiCorp	Electric	1984-1985	Stairstep	Decision 89-09-034
CA	Southern California Edison	Electric	1983-1984	Hybrid	Decision 82-12-055
CA	San Diego Gas & Electric	Electric & Gas	1982-1983	Hybrid	Decision 93892
CA	Pacific Gas & Electric	Electric & Gas	1982-1983	Hybrid	Decision 93887
CA	Southern California Gas	Gas	1981-1982	Stairstep	Decision 92497
CA	Southern California Gas	Gas	1979-1980	Stairstep	Decision 89710
CA	Pacific Gas & Electric	Gas	1978-1981	No RAM	Decisions 89316,91107

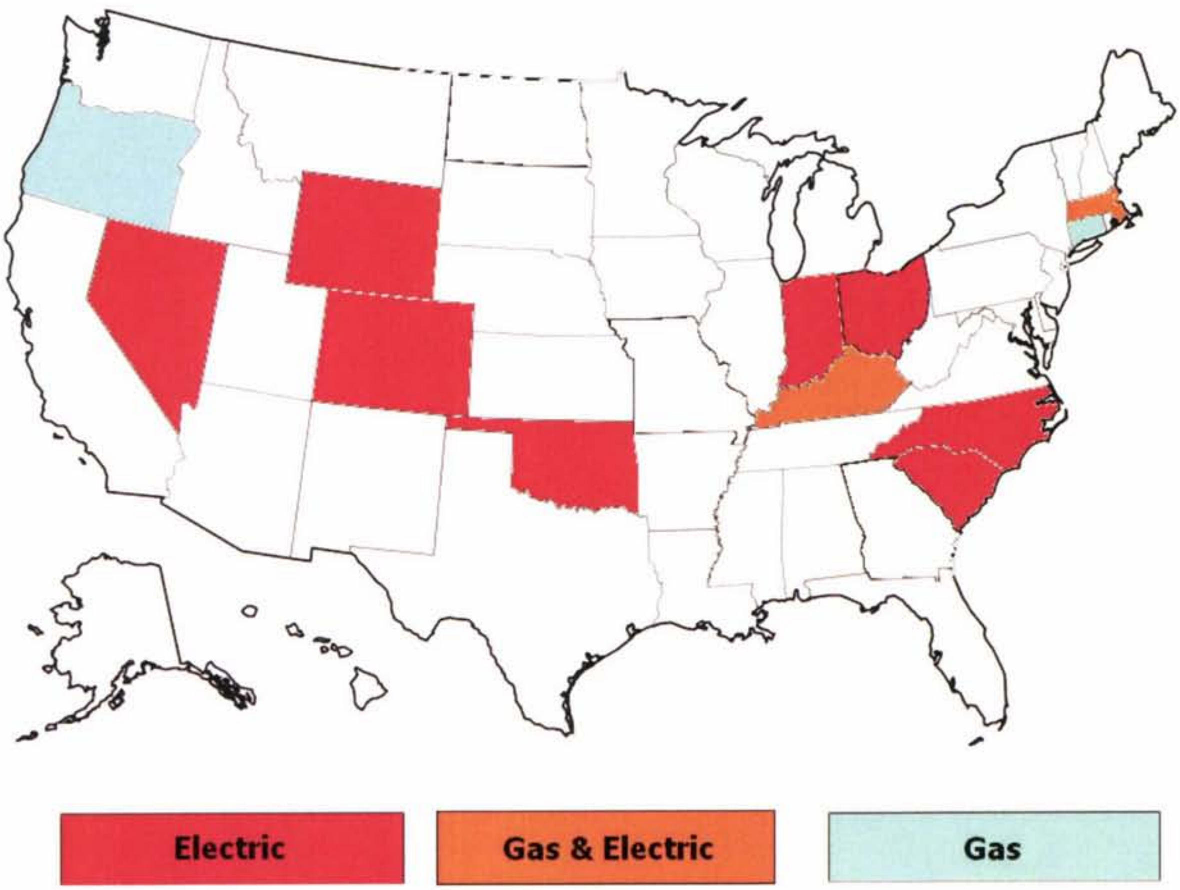
Table 5 (continued)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
FL	Florida Power Corporation	Electric	1995-1997	RPC Freeze	Docket 930444
ID	Idaho Power	Electric	2007-2009	RPC Freeze	Case No. IPC-E-04-15
ME	Central Maine Power	Electric	1991-1993	RPC Freeze	Docket No. 90-085
MT	Montana Power Company	Electric	1994-1998	RPC Freeze	Docket No. 93.6.24
NC	Piedmont Natural Gas	Gas	2005-2008	RPC Freeze	Docket G-44 Sub 15
NJ	New Jersey Gas Natural	Gas	2007-2010	RPC Freeze	Docket GR05121020
NJ	South Jersey Gas	Gas	2007-2010	RPC Freeze	Docket GR05121019
NY	Central Hudson G&E	Gas	2009-open	RPC Freeze	Case 08-E-0888
NY	Central Hudson G&E	Electric	2009-open	No RAM	Case 08-E-0887
NY	Consolidated Edison	Electric	2008-open	No RAM	Case 07-E-0523
NY	Consolidated Edison	Gas	2007-2010	Stairstep	Case 06-G-1332
NY	Rochester Gas & Electric	Electric	1993-1996	Stairstep	Opinion No. 93-19
NY	New York State Electric & Gas	Electric	1993-1995	Stairstep	Opinion No. 93-22
NY	Consolidated Edison	Electric	1992-1995	Stairstep	Opinion No. 92-8
NY	Long Island Lighting Company	Electric	1992-1994	Stairstep	Opinion No. 92-8
NY	Orange & Rockland Utilities	Electric	1991-1993	Stairstep	Case 89-E-175
NY	Niagara Mohawk	Electric	1990-1992	Stairstep	Case 94-E-0098
OH	Vectren Energy	Gas	2007-2009	RPC Freeze	Case 05-1444-GA-UNC
OR	Portland General Electric	Electric	2009-2010	RPC Freeze	Order No. 09-020
OR	Northwest Natural Gas	Gas	2005-2009	RPC Freeze	Order No. 05-934
OR	Northwest Natural Gas	Gas	2002-2005	RPC Freeze	Order No. 02-634
OR	PacifiCorp	Electric	1998-2001	Inflation Indexing	Order No. 98-191
OR	Portland General Electric	Electric	1995-1996	Stairstep	Order No. 95-0322
UT	Questar Gas	Gas	2006-2010	RPC Freeze	Docket No. 05-057-T01
VT	Green Mountain Power	Electric	2007-2010	Stairstep	Docket No. 7176
WA	Avista	Gas	2007-2009	RPC Freeze	Docket UG-060518
WA	Puget Sound & Power	Electric	1991-1995	RPC Freeze	Docket UE-901184-P
Australia					
Federal	EnergyAustralia	Power Transmission	2004-2009	Hybrid	File No: S2004/138
Federal	TransGrid	Power Transmission	2004-2009	Hybrid	File No: M2003/287
Federal	ElectraNet	Power Transmission	2003-2007	Hybrid	File No: C2001/1094
Federal	Powerlink	Power Transmission	2002-2006	Hybrid	File No: 2000/659
Federal	EnergyAustralia	Power Transmission	1999-2004	Hybrid	File No: CG98/118
Federal	TransGrid	Power Transmission	1999-2004	Hybrid	File No: CG98/118
Federal	Snowy Mountains	Power Transmission	1999-2004	Hybrid	File No: C1999/62
New South Wales	Energy Australia	Electric	1999-2003	Hybrid	NEC Determination 99-1
New South Wales	Integral Energy	Electric	1999-2003	Hybrid	NEC Determination 99-1
New South Wales	Advance Energy	Electric	1999-2003	Hybrid	NEC Determination 99-1
New South Wales	Great Southern Energy	Electric	1999-2003	Hybrid	NEC Determination 99-1
New South Wales	Northern Electric	Electric	1999-2003	Hybrid	NEC Determination 99-1
New South Wales	Australian Inland Energy	Electric	1999-2003	Hybrid	NEC Determination 99-1
Tasmania	Transcend Networks	Power Transmission	2004-2008	Hybrid	File No: C2001/1100
Victoria	SPI PowerNet	Power Transmission	2003-2008	Hybrid	File No: C2001/1093
Victoria	VENCorp	Power Transmission	2003-2007	Hybrid	File No: C2001/1093

Table 6: Recent LRAM Precedents

State	Company	Services	Currently Effective	Case Reference	Name of Mechanism
CO	Public Service of Colorado	Electric	Yes	Docket 07A-420 E Decision C08-560	
CT	Connecticut Natural Gas	Gas	Yes	Docket No. 93-02-04	Conservation Adjustment Mechanism (CAM)
CT	Southern Connecticut Gas	Gas	Yes	Docket No. 93-03-09	Conservation Adjustment Mechanism (CAM)
IN	Duke Energy Indiana (PSI)	Electric	Yes	Cause No. 43374	
IN	Indiana-Michigan Power	Electric	Yes	Cause 43827	
KY	Delta Natural Gas	Gas	Yes	Docket No. 2008-00062	Conservation/Efficiency Program Cost Recovery
KY	Louisville Gas & Electric	Electric & Gas	Yes	Order No. 199300150-05101993	Demand-Side Management Cost Recovery Mechanism
KY	Kentucky Utilities	Electric	Yes	Order No. 200000459-051101	
KY	Duke Energy Kentucky	Electric	Yes	Docket No. 95-321	
MA	Berkshire Gas/Energy East	Gas	Yes	D.P.U. 91-154	Local Distribution Adjustment Clause (LDAC)
MA	Fitchburg Gas and Electric Light/Uniti	Gas	Yes	D.P.U. 98-51	
MA	NSTAR Electric	Electric	Yes	D.P.U. 10-06	Energy Efficiency Charge
MA	NSTAR Gas	Gas	Yes	D.P.U. 91-93 D.P.U. 92-116	
MA	New England Gas Company	Gas	Yes	D.P.U. 02-36	Local Distribution Adjustment Clause (LDAC
MT	Northwestern Energy	Electric	No	Docket No. D2004.6.90; Interim Order No. 6574	
NC	Duke Energy Carolinas	Electric	Yes	Docket No. E-7, Sub 831	
NC	Progress Energy Carolinas (Carolina Power & Light)	Electric	Yes	Docket No. E-2, Sub 931	
NV	Nevada Energy	Electric	Yes	Docket 09-07016	
OH	Duke Energy Ohio (Cincinnati Gas & Electric)	Electric	Yes	Docket No. 06-0091-EL-UNC	Called Energy Efficiency Cost Recovery Rider
OK	Empire District Electric	Electric	Yes	Cause No. 200900146 Order 571326	Demand-Side Management Cost Recovery Mechanism
OK	Oklahoma Gas & Electric	Electric	Yes	Cause No. 200800059 Order 556179	Class Lost Revenue Factor included in the Demand Program Rider
OK	Public Service of Oklahoma	Electric	Yes	Cause No. 200800144 Order 564437	Demand-Side Management Cost Recovery Mechanism
ON	Union Gas	Gas	Yes	EB-2007-0606	Lost Revenue Adjustment Mechanism
ON	Enbridge Gas Distribution	Gas	Yes	EB-2007-0615	Lost Revenue Adjustment Mechanism
ON	Toronto Hydro-Electric	Electric	Yes	EB-2007-0096	Lost Revenue Adjustment Mechanism
OR	Avista Utilities	Gas	Yes	Order 93-1881	
SC	Progress Energy Carolinas	Electric	Yes	Docket No. 2008-251-E Order 2009-373	Demand-Side Management Cost Recovery Mechanism
SC	Duke Energy Carolinas	Electric	Yes	Docket No. 2009-226-E Order No. 2010-79	
WY	Montana-Dakota Utilities	Electric	Yes	Docket No. 20004-65-ET-06	

Figure 5: Current LRAMs by State



C. Fixed Variable Pricing

Fixed variable pricing is an approach to the design of base rates that increases the proportion of fixed costs (costs that do not vary in the short run with system use) which is recovered through fixed charges (charges that do not vary with the sales volume or peak demand). A *straight* fixed variable ("SFV") rate design recovers *all* fixed costs through fixed charges. A rate design that recovers a substantial but more limited share of fixed costs through fixed charges is sometimes called *modified* fixed variable ("MFV") pricing. Most approved fixed variable rate designs implemented to date have involved the same fixed charge for all customers in a service class. However, "sliding scale" rate designs have been developed which assign lower fixed charges to customers who have historically had low volumes.

SFV pricing has been used on a large scale by the Federal Energy Regulatory Commission ("FERC") since the early 1990s to regulate natural gas pipelines. Precedents for fixed variable pricing in retail ratemaking are shown in Figure 6 and Table 7. It can be seen that fixed variable retail pricing has to date been more common for gas utilities than for electric utilities. Ohio is noteworthy for having recently switched from the true up approach to decoupling to fixed variable pricing. In addition to the precedents listed here, several states have in recent years made sizable steps in the direction of fixed variable pricing by redesigning rates for small volume customers to raise customer charges and lower volumetric charges substantially. Fixed charges are generally much higher for investor-owned utilities in Canada than in the United States.

Most fixed variable rate designs feature uniform fixed charges within service classes, but utilities in at least three states (Florida, Georgia, and Oklahoma) have fixed charges that vary in some rough fashion with delivery volumes.

Figure 6: Fixed Variable Pricing Precedents by State

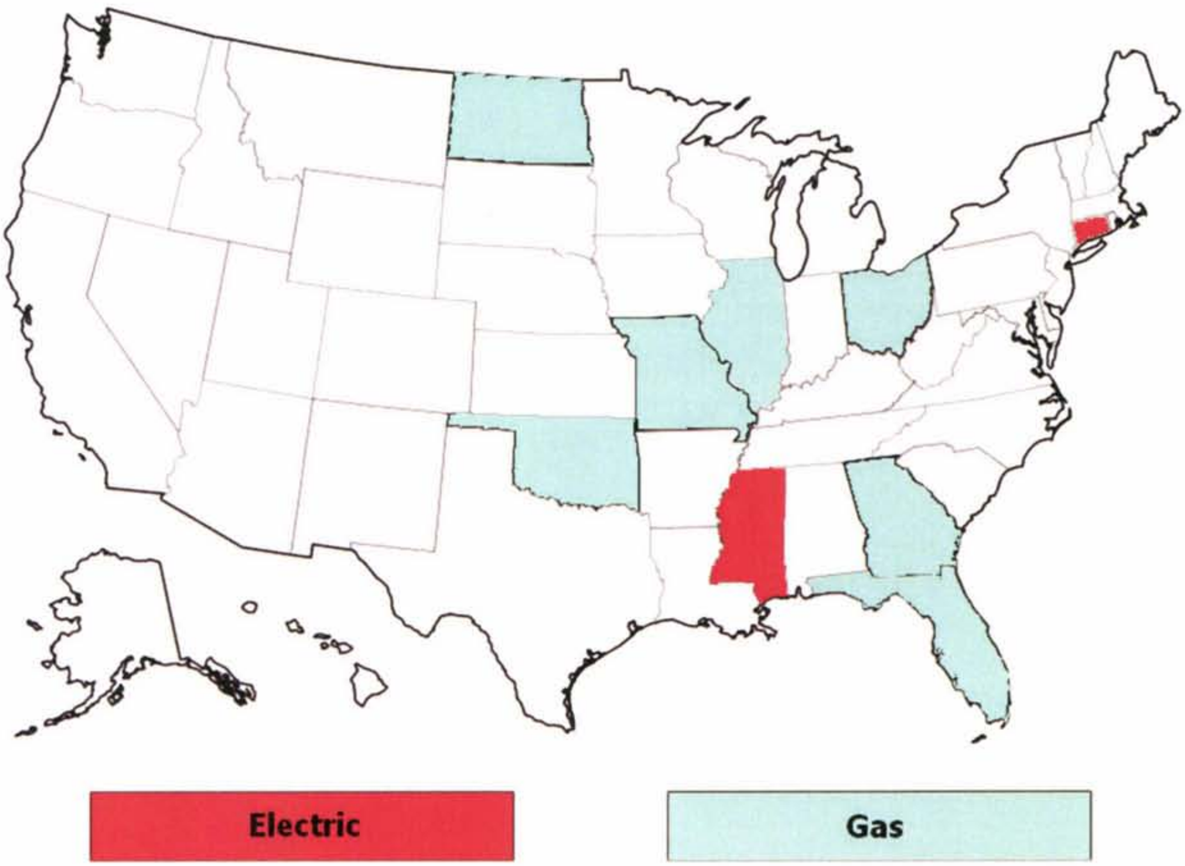


Table 7: Fixed Variable Retail Pricing Precedents

Jurisdiction	Company Name	Services	Years in Place	Case Reference
CT	Connecticut Light & Power	Electric	2007-open	Docket 07-07-01
FL	Peoples Gas	Gas	2009-open	Docket 080318-GU
GA	Altanta Gas Light	Gas	1998-open	Docket No. 8390-U
IL	Ameren CILCO	Gas	2008-2012	Case 07-0588
IL	Ameren CIPS	Gas	2008-2012	Case 07-0589
IL	Ameren IP	Gas	2008-2012	Case 07-0590
IL	Nicor Gas	Gas	2009-open	Docket No. 08-0363
MO	Atmos Energy	Gas	2007-2010	Case GR-2006-0387
MO	Atmos Energy	Gas	2010-open	Case No. GR-2010-0192
MO	Empire District Gas	Gas	2010-open	Case GR-2009-0434
MO	Missouri Gas Energy	Gas	2007-open	Case GR-2006-0422
MO	Laclede Gas	Gas	2002-open	Case GR-2002-356
MS	Mississippi Power	Electric	Occurred over period of years	No specific case
ND	Xcel Energy	Gas	2005-open	Case PU-04-578
OH	Duke Energy Ohio (CG&E)	Gas	2008-open	Case 07-590-GA-ALT
OH	Dominion East Ohio	Gas	2008-2010	Case 07-830-GA-ALT
OH	Columbia Gas	Gas	2008-open	Case 08-0072-GA-AIR
OH	Vectren Energy Delivery of Ohio	Gas	2009-open	Case 07-1080-GA-AIR
OK	Oklahoma Natural Gas	Gas	2004-open	Cause Nos. PUD 2004-00610, PUD 201000048, PUD 200900110

V. Formula Rates

A formula rate plan ("FRP") is essentially a wide-scope tracker mechanism that is designed to help a utility's revenue track its pro forma cost of service. When a company's revenue and cost are not in balance, its realized ROE deviates from the target set by regulators, and earnings surpluses or deficits occur. FRPs have earnings true up mechanisms that adjust rates so as to reduce or eliminate such earnings variances.

The earnings true up mechanism in an FRP calculates the revenue adjustment necessary to reduce or eliminate earnings variances. Some compare the earned ROE to the target (a/k/a benchmark) ROE, and then calculate the rate adjustment needed to reduce the ROE variance. Another approach is to adjust rates for the difference between revenue and a pro forma cost of service that is calculated using the ROE target. Both approaches typically add interest to the revenue adjustment. Earnings true up mechanisms in FRPs commonly move the ROE all, or almost all, of the way to its regulated target. This is an important distinction between an FRP earnings true up mechanism and the earnings *sharing* mechanisms found in some multiyear rate and revenue caps.

The earnings impacts of certain business conditions are typically handled outside of the FRP. The excluded business conditions are often addressed by separate trackers. Utilities operating under FRPs must occasionally make major plant additions. Budgets for major plant additions are generally determined outside the FRP mechanism through, for example, hearings on certificates of public convenience and necessity. Mechanisms are sometimes added to an FRP to encourage better operating performance in targeted areas. An example is an index-based limit on the escalation of O&M expenses.

The FERC accounts for the lion's share of FRP precedents today, as it has in the past. Formula rates have been used at the FERC and its predecessor, the Federal Power Commission, to regulate interstate services of gas and electric utilities since at least 1950. Use of FRPs by the FERC was encouraged in the 1970s and early 1980s by rapid input price inflation. Despite slower inflation in recent years, the FERC's use of formula rates has rebounded in the power transmission industry, encouraged by national policies that promote transmission investment.

Precedents for retail formula rates, which recover costs of generation and/or distribution, are shown in Table 8 and Figure 7. It can be seen that formula rate plans for *retail* utility services are operative today in the Southeast and Southern Plains states. Alabama was an early innovator, approving "Rate Stabilization and Equalization" plans for Alabama Power and Alabama Gas in the early 1980s. Formula rates are, additionally, now used to regulate electric utilities in Mississippi, some gas and electric utilities in Louisiana, and some gas utilities in Oklahoma, Texas, and South Carolina. Utilities in some additional states have formula rate plans to recover their transmission costs from retail customers.

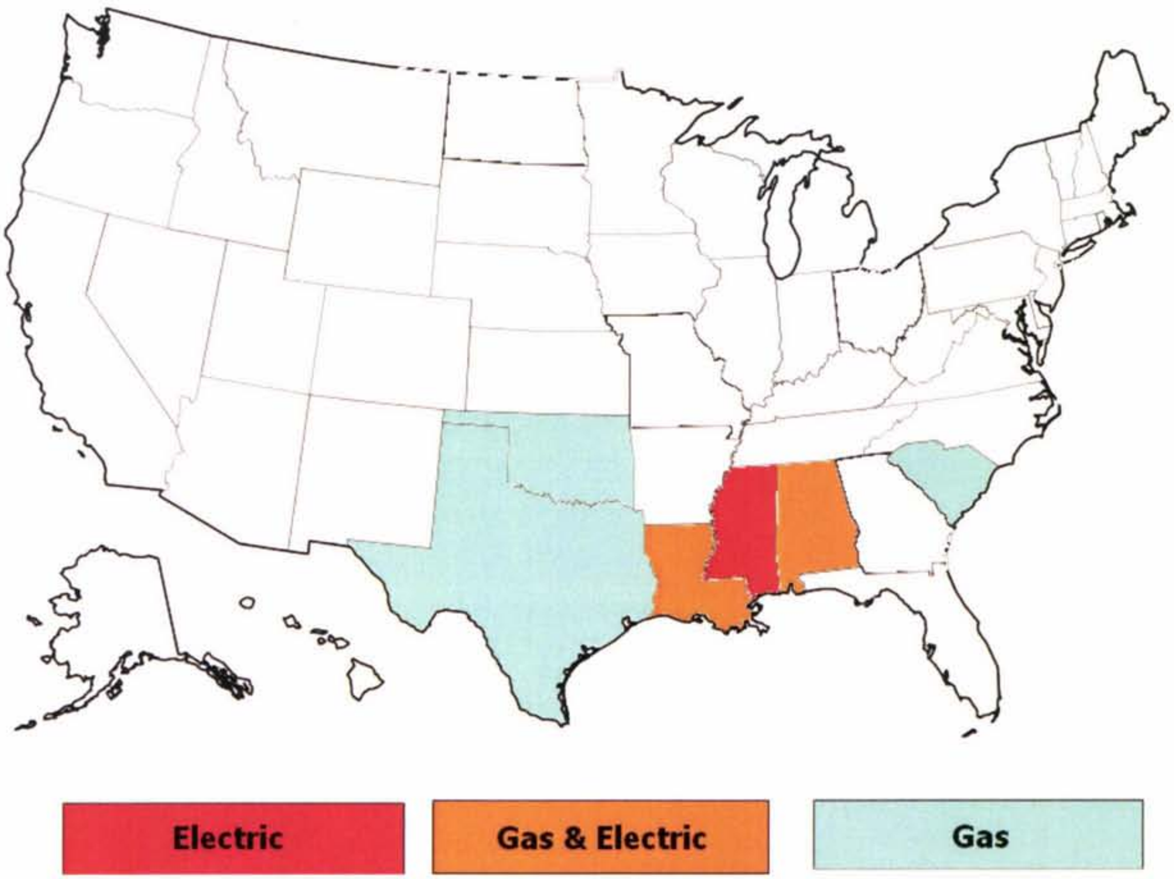
Table 8: Retail Formula Rate Plan Precedents

Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2006-open	Dockets No. 18117 and 18416 (October 2005)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2002-2006	Dockets No. 18117 and 18416 (March 2002)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1998-2002	Dockets No. 18117 and 18416 (March 1998)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1990-1998	Dockets No. 18117 and 18416 (March 1990)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1985-1990	Dockets No. 18117 and 18416 (June 1985)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1982-1985	Dockets No. 18117 and 18416 (November 1982)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2008-2014	Dockets No. 18406 and 18328 (December 2007)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2002-2007	Dockets No. 18046 and 18328 (June 2002)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1996-2001	Dockets No. 18046 and 18328 (October 1996)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1991-1994	Dockets No. 18046 and 18328 (December 1990)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1987-1990	Dockets No. 18046 and 18328 (September 1987)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1985-1987	Dockets No. 18046 and 18328 (May 1985)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1983-1985	Dockets No. 18046 and 18328 (January 1983)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2009-2013	Docket 28101 (December 2009)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2005-2009	Docket 28101 (June 2005)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2001-2005	Docket 28101 (June 2002)
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Plan	2006-open	Docket No. U-21484 (May 2006)
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Plan	2001-2003	Docket No. U-21484 (January 2001)
LA	Atmos Energy - Trans Louisiana Gas	Gas	Rate Stabilization Plan	2006-open	Docket No. U-28814 and U-28588 and U-28587(May 2006)
LA	Entergy New Orleans	Electric and Gas	Formula Rate Plan	2010-2012	Docket No. UD-08-03 (April 2009)
LA	Entergy New Orleans	Electric only	Formula Rate Plan	2004-2006	Docket No. UD-01-04 (May 2003)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 5 (FRP-5)	2010-open	Docket No. 2009-UN-388 (March 2010)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 5 (PEP-5)	2010-open	Docket No. 2003-UN-0898 (November 2009)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 4A (PEP- 4A)	2009	Docket No. 06-UN-0511 (January 2009)

Table 8 (continued)

Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 4 (PEP-4)	2004-2009	Docket No. 03-UN-0898 (May 2004)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 3 (PEP-3)	2002-2004	Docket No. 01-UN-0826 (October 2002)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 2A (PEP-2A)	2001-2002	Docket No. 01-UN-0548 (December 2001)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 2 (PEP-2)	1994-2001	Docket 93-UA-0302 (January 1994)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 1A (PEP-1A)	1992-1993	Docket 92-UN-0059 (July 1992)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 1 (PEP-1)	1991-1992	Docket No. 90-UN-0287 (December 1990)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan	1986-1990	Docket No. U-4761 (August 1986)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2010-open	Docket No. 201000030 (July 2010)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2008-2010	Docket No. 200800062 (July 2008)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2004-2008	Docket No. 200400187 (November 2004)
OK	Oklahoma Natural Gas	Gas	Performance Based Rate of Change Plan	2009-2013	Docket No. 200800348 (April 2009)
SC	Piedmont Gas	Gas		2005-present	Docket No. 2005-125-G (September 2005)
SC	South Carolina Electric and Gas	Gas		2005-present	Docket No. 2005-113-G (October 2005)
TX	Centerpoint Energy-Texas Coast Division	Gas	Cost of Service Adjustment Clause	2008-open	Gas Utility Docket 9791 (October 2008)
TX	Atmos Energy-Mid Texas Division	Gas	Rate Review Mechanism	2008 - conclusion of rate case to be filed on or before June 1, 2013	Various Resolutions/Ordinances across cities in service territory, including City of Fort Worth Ordinance 17989-02-2008
TX	Atmos Energy West Texas Division	Gas	Rate Review Mechanism	2009 - conclusion of rate case to be filed on or before June 1, 2013	Various Resolutions/Ordinances across cities in service territory
TX	Texas Gas Service - North Service Area	Gas	Cost of Service Adjustment Tariff	2009-open	Various Resolutions/Ordinances in service territory and Gas Utility Docket 9839 (April 2009)

Figure 7: Current Retail Formula Rate Precedents by State



VI. Forward Test Years

General rate cases involve test years in which revenue requirements and billing determinants are jointly considered in fashioning new rates. A historical test year ends before the rate case is filed. A forward (a/k/a forecasted) test year ("FTY") is a twelve month period that begins after the rate case is filed. The test year typically begins about the time that the rate case is expected to end.

Historical test years are chronically uncompensatory when cost has a tendency to grow more rapidly than billing determinants. Annual rate cases can alleviate but not eliminate underearning. Where historical test years are used in rate cases there are thus added advantages from implementing other innovations discussed in this paper, such as capex trackers, multiyear rate and revenue caps, and/or some form of revenue decoupling.

Forward test years were adopted in many jurisdictions during the 1970s and 1980s when rapid input price inflation and major plant additions coincided with slower growth in average use. Commissions in several additional states have recently moved in the direction of forward test years. Many of these states are in the West, where comparatively rapid economic growth has required more rapid buildout of utility infrastructure.

Current state policies concerning test years are summarized in Figure 8 and Table 9. The ranks of U.S. jurisdictions that use alternatives to historical test years have swollen and now encompass well over half of the total. The "other" category in Figure 8 includes states that use FTYs for some utilities and historical test years for others (*e.g.* Illinois), states that are transitioning towards forward test years (*e.g.* New Mexico and Utah), states that use hybrid test years with some but not all months forecasted (*e.g.* Pennsylvania and Idaho), and states that have used FTYs in the past but don't currently use them (*e.g.* Delaware).

Figure 8: Test Year Policy by State

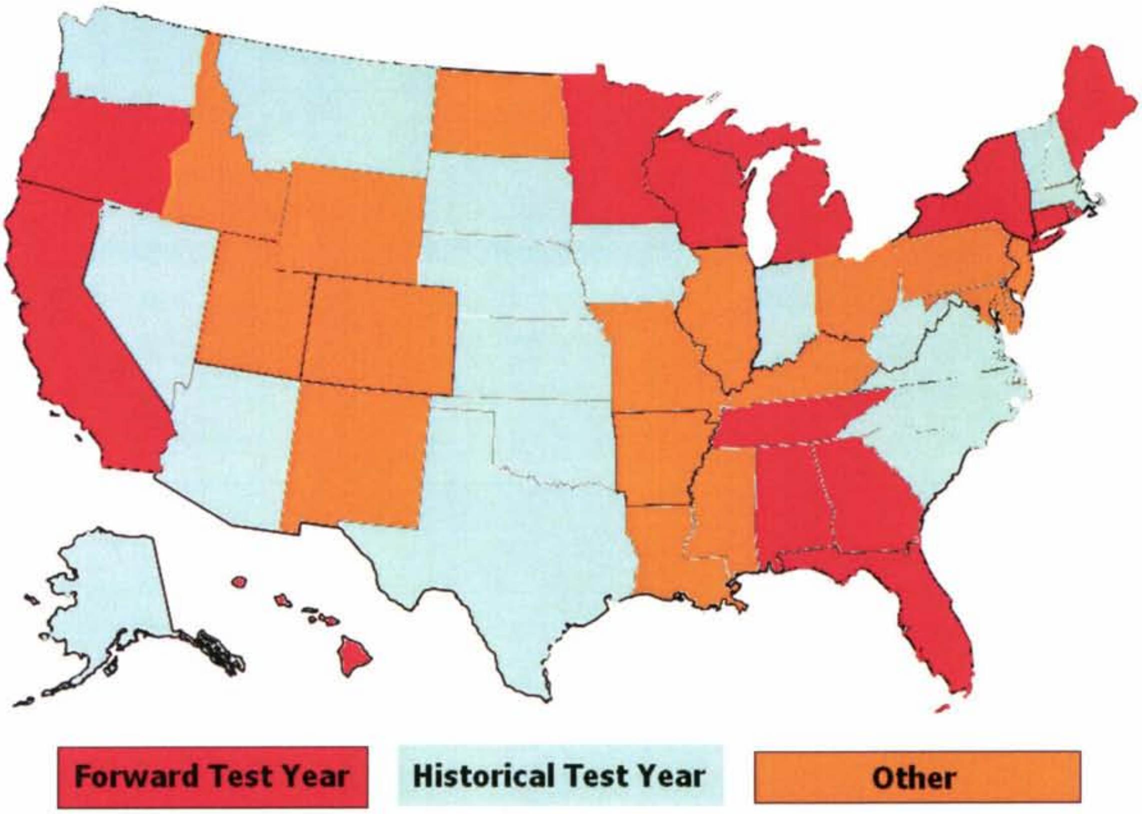


Table 9: Test Year Approaches of U.S. Jurisdictions

Forward (15)

State	Notes
Alabama	Utilities operate under forward-looking formula rate plans
California	
Connecticut	Cost is based on a historical test year that is escalated to a future rate year
FERC	Rate cases use forward test years while formula rate plans tend to use HTYs
Florida	
Georgia	
Hawaii	
Maine	Cost is based on a historical test year that is escalated to a future rate year
Michigan	
Minnesota	
New York	
Oregon	
Rhode Island	Cost is based on a historical test year that is escalated to a future rate year
Tennessee	
Wisconsin	

Hybrid (4)

State	Notes
Arkansas	
Ohio	
New Jersey	
Pennsylvania	

Transitional/Varying (14)

Utility Name	Notes
Colorado	Public Service of Colorado can file FTY evidence. No FTY rates have yet been approved but the most recent case made extraordinary HTY adjustments.
District of Columbia	PEPCO has filed rate cases using both hybrid and historical test years recently
Delaware	Before restructuring FTY filings were common, but companies have used HTY in recent filings
Idaho	
Illinois	Utilities use various test years including FTYs
Kentucky	Utilities use various test years including FTYs
Louisiana	Cleco Power frequently uses hybrid test years. Entergy New Orleans recently had a hybrid test year approved via settlement
Maryland	Baltimore Gas & Electric tends to file hybrid test years while other utilities tend to file historical test years
Mississippi	One electric utility operates under a forward-looking formula rate plan
Missouri	Utilities have the option to file hybrid year forecasts that are trued up during the course of the proceeding
New Mexico	A recently passed law allows for use of FTY, but no rate increase based on FTY evidence has yet been approved
North Dakota	Utilities use various test years including FTYs
Utah	Test year selection is part of the rate case and can be contested. Several recent rate cases have used FTYs.
Wyoming	Rocky Mountain Power has recently had FTYs approved

Historical (19)

Utility Name	Notes
Alaska	
Arizona	
Indiana	
Iowa	
Kansas	
Massachusetts	
Montana	
Nebraska	Nebraska has no electric IOUs in its jurisdiction. Gas companies are legally authorized to use FTYs but commonly use HTYs.
Nevada	
New Hampshire	
North Carolina	
Oklahoma	
South Carolina	
South Dakota	
Texas	
Vermont	
Virginia	
Washington	
West Virginia	

VII. Conclusions

Regulation of North American energy utilities is evolving to address the problem of regulatory lag. Innovations are occurring, and some older variants on traditional regulation are again finding favor. Approaches detailed in this report are sometimes used in combination. A capex tracker for AMI may, for example, be combined with a forward test year or a multiyear rate or revenue cap.

The variety of approaches that have been established reflects the varied circumstances of individual utilities. Some are vertically integrated, while others are more specialized power distributors. Investment needs and trends in average use vary greatly. No single approach is right for every situation. The availability of multiple remedies for the underlying problems increases the chance that an approach has already been tried that fits the situation of almost any electric utility. Numerous precedents for an approach should raise confidence that it makes good sense under fairly common circumstances.

Taken together, the many innovations described in this survey can encourage utilities to make smart investments, reduce long run costs, and improve service quality without rate shock or unnecessarily frequent rate cases. Utilities can be encouraged to promote energy efficiency and peak load management aggressively. Stakeholders to regulation across America should give priority attention to these options and consider which combination of remedies to regulatory lag works best in their situation.

The **Edison Electric Institute (EEI)** is the association of U.S. shareholder-owned electric companies. Our members serve 95% of the ultimate customers in the shareholder-owned segment of the industry, and represent approximately 70% of the U.S. electric power industry. We also have as Affiliate members more than 80 International electric companies, and as Associate members more than 200 industry suppliers and related organizations.

Organized in 1933, EEI works closely with all of its members, representing their interests and advocating equitable policies in legislative and regulatory arenas.

EEI provides public policy leadership, critical industry data, market opportunities, strategic business intelligence, one-of-a-kind conferences and forums, and top-notch products and services.

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Trends in the Input Prices and Productivity of Northeast Power Distributors

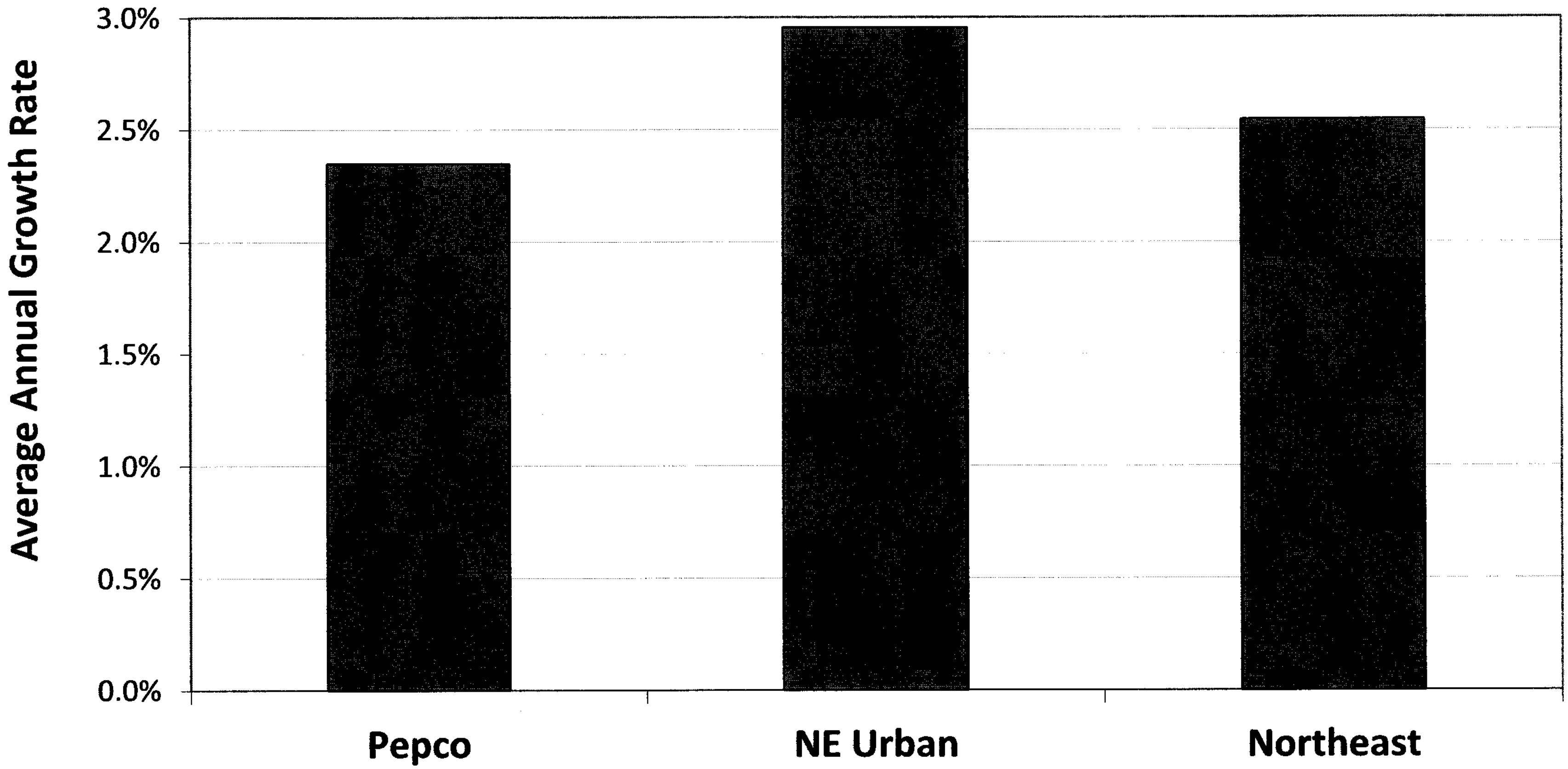
	Input Price Inflation [A]			Total Factor Productivity Growth [B]			Inflation-Productivity Gap [A - B]		
Year	Pepco	NE Urban	Northeast	Pepco	NE Urban	Northeast	Pepco	NE Urban	Northeast
1999	2.18%	1.31%	2.76%	-0.88%	-1.55%	-0.30%	3.06%	2.86%	3.06%
2000	2.10%	1.90%	2.47%	3.78%	0.57%	3.76%	-1.69%	1.33%	-1.29%
2001	2.70%	3.66%	3.58%	-0.87%	-2.64%	-1.40%	3.57%	6.30%	4.98%
2002	2.48%	2.04%	2.92%	-6.68%	2.77%	2.26%	9.15%	-0.73%	0.66%
2003	4.04%	4.05%	3.70%	2.78%	1.43%	-1.71%	1.26%	2.62%	5.42%
2004	1.59%	2.49%	2.29%	4.85%	2.32%	3.96%	-3.26%	0.17%	-1.68%
2005	4.06%	3.42%	3.31%	0.95%	-1.89%	-0.12%	3.11%	5.31%	3.43%
2006	3.23%	3.38%	3.21%	3.54%	0.56%	1.46%	-0.31%	2.82%	1.76%
2007	0.14%	3.55%	2.72%	-2.49%	-1.13%	-0.87%	2.63%	4.67%	3.59%
2008	5.28%	3.45%	3.37%	2.93%	1.03%	0.44%	2.35%	2.42%	2.94%
2009	4.00%	3.59%	4.38%	-0.22%	0.27%	1.73%	4.22%	3.32%	2.66%
2010	2.95%	3.22%	3.51%	-1.15%	-1.16%	-1.52%	4.09%	4.38%	5.03%
Average Annual Growth Rate									
1999-2010	**2.89%**	**3.00%**	**3.19%**	**0.54%**	**0.05%**	**0.64%**	**2.35%**	**2.96%**	**2.55%**

Data Sources: FERC Form 1 (power distributor cost and bond yield), Form EIA-861 (customers), US Bureau of Labor Statistics (labor price indexes), Global Insight (power distributor material and service price indexes), Whitman, Requardt & Associates (power distribution construction cost index), and Regulatory Research Associates (electric utility allowed ROE)

Northeast Sample: Atlantic City Electric, Baltimore Gas & Electric, Bangor Hydro-Electric, Central Maine Power, Central Vermont Public Service, Connecticut Light & Power, Consolidated Edison, Duquesne Light, Green Mountain Power, Jersey Central Power, Maine Public Service, Metropolitan Edison, NSTAR Electric, Orange & Rockland Utilities, PECO Energy, Pennsylvania Electric, Pennsylvania Power, Potomac Electric Power, Public Service of New Hampshire, Public Service Electric & Gas, Rochester Gas & Electric, United Illuminating, West Penn Power, and Western Massachusetts Electric

Northeast Urban Sample: Baltimore Gas & Electric, Consolidated Edison, Duquesne Light, NSTAR Electric, PECO Energy, Potomac Electric Power, Public Service Electric & Gas, Rochester Gas & Electric

Inflation-Productivity Gap of Northeast Power Distributors, 1999-2010



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AVERAGE ANNUAL ELECTRICITY USE PER RESIDENTIAL & COMMERCIAL CUSTOMER 1926-2010

Year	Residential				Commercial	
	U.S.		D.C. and Maryland		U.S.	
	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
1926	409				3,088	
1927	428	4.5%			3,288	6.27%
1928	452	5.4%			3,487	5.87%
1929	490	8.1%			3,831	9.42%
1930	542	10.2%			4,031	5.10%
1931	582	7.2%			3,832	-5.08%
1932	605	3.7%			3,492	-9.29%
1933	593	-1.9%			3,353	-4.04%
1934	620	4.5%			3,533	5.23%
1935	665	6.9%			3,768	6.44%
1936	720	7.9%			4,165	10.01%
1937	791	9.4%			4,301	3.22%
1938	838	5.8%			4,451	3.43%
1939	880	4.8%			4,661	4.60%
1940	934	6.0%			4,926	5.53%
1941	965	3.3%			5,103	3.54%
1942	1,012	4.7%			5,668	10.49%
1943	1,065	5.1%			5,933	4.57%
1944	1,142	7.0%			6,141	3.46%
1945	1,216	6.2%			6,055	-1.41%
1946	1,296	6.4%			6,165	1.80%
1947	1,397	7.5%			6,776	9.45%
1948	1,519	8.4%			7,254	6.82%
1949	1,643	7.8%			7,561	4.14%
1950	1,786	8.3%			8,191	8.00%
1951	1,964	9.5%			9,150	11.07%
1952	2,130	8.1%			9,677	5.60%
1953	2,312	8.2%			10,530	8.45%
1954	2,514	8.4%			10,951	3.92%
1955	2,714	7.6%			11,347	3.55%
1956	2,928	7.6%			12,068	6.16%
1957	3,138	6.9%			12,992	7.38%
1958	3,328	5.9%			13,574	4.38%
1959	3,541	6.2%			14,964	9.75%
1960	3,791	6.8%	3,171		15,366	2.65%
1961	3,976	4.8%	3,421	7.60%	19,707	24.88%
1962	4,220	6.0%	3,546	3.59%	20,641	4.63%
1963	4,389	3.9%	3,719	4.75%	23,026	10.93%
1964	4,653	5.8%	3,987	6.96%	25,163	8.88%
1965	4,878	4.7%	4,308	7.74%	27,239	7.93%
1966	5,211	6.6%	4,736	9.47%	29,973	9.56%
1967	5,522	5.8%	5,010	5.63%	31,993	6.52%
1968	5,985	8.0%	5,632	11.70%	34,405	7.27%
1969	6,516	8.5%	6,166	9.06%	37,016	7.32%
1970	6,995	7.1%			39,764	7.16%
1971	7,297	4.2%			41,706	4.77%
1972	7,598	4.0%			44,129	5.65%

1973	7,981	4.9%			47,466	7.29%
1974	7,822	-2.0%			46,350	-2.38%
1975	8,077	3.2%			48,663	4.87%
1976	8,267	2.3%			50,352	3.41%
1977	8,592	3.9%			52,464	4.11%
1978	8,732	1.6%			52,550	0.16%
1979	8,745	0.1%			52,726	0.33%
1980	8,940	2.2%			54,040	2.46%
1981	8,769	-1.9%			52,979	-1.98%
1982	8,684	-1.0%			51,819	-2.21%
1983	8,740	0.6%			53,144	2.53%
1984	8,899	1.8%			54,716	2.91%
1985	8,827	-0.8%			55,478	1.38%
1986	9,002	2.0%			56,731	2.23%
1987	9,204	2.2%	10,378		58,004	2.22%
1988	9,506	3.2%	10,824	4.21%	60,073	3.51%
1989	9,470	-0.4%	10,894	0.65%	60,607	0.89%
1990	9,517	0.5%	10,698	-1.82%	61,887	2.09%
1991	9,720	2.1%	11,209	4.67%	62,308	0.68%
1992	9,405	-3.3%	10,733	-4.34%	61,091	-1.97%
1993	9,863	4.8%	11,552	7.36%	63,432	3.76%
1994	9,856	-0.1%	11,366	-1.62%	64,420	1.55%
1995	10,032	1.8%	11,470	0.91%	66,620	3.36%
1996	10,276	2.4%	11,826	3.05%	67,327	1.06%
1997	10,049	-2.2%	11,180	-5.61%	68,572	1.83%
1998	10,363	3.1%	11,313	1.18%	70,526	2.81%
1999	10,372	0.1%	11,641	2.86%	71,196	0.95%
2000	10,674	2.9%	11,707	0.57%	73,540	3.24%
2001	10,459	-2.0%	11,653	-0.47%	72,848	-0.95%
2002	10,849	3.7%	12,230	4.83%	72,031	-1.13%
2003	10,878	0.3%	12,580	2.83%	72,433	0.56%
2004	10,879	0.0%	13,019	3.43%	74,092	2.26%
2005	11,256	3.4%	13,088	0.53%	75,574	1.98%
2006	11,035	-2.0%	12,218	-6.88%	75,688	0.15%
2007	11,232	1.8%	12,695	3.83%	76,900	1.59%
2008	11,045	-1.7%	12,131	-4.55%	76,069	-1.09%
2009	10,900	-1.3%	11,971	-1.32%	74,433	-2.17%
2010p	11,528	5.6%			75,591	1.54%

Multiyear Averages

1927-1930	**478**	**7.1%**	**N/A**	**N/A**	**3,659**	**6.67%**
1931-1940	**723**	**5.4%**	**N/A**	**N/A**	**4,048**	**2.00%**
1941-1950	**1,304**	**6.5%**	**N/A**	**N/A**	**6,485**	**5.08%**
1951-1960	**2,836**	**7.5%**	**N/A**	**N/A**	**12,062**	**6.29%**
1961-1970	**5,235**	**6.1%**	**<u>4,503</u>**	**<u>7.39%</u>**	**28,893**	**9.51%**
1971-1980	**8,205**	**2.5%**	**N/A**	**N/A**	**49,045**	**3.07%**
1981-1990	**9,062**	**0.6%**	**N/A**	**N/A**	**56,544**	**1.36%**
1991-2000	**10,061**	**1.1%**	**11,400**	**0.90%**	**66,903**	**1.73%**
2001-2010	**11,006**	**0.8%**	***12,398***	***0.25%***	**74,566**	**0.28%**

Sources: U.S. Department of Energy, Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," and Form EIA-826, "Monthly Electric Utility Sales and Revenues Report with State Distributions," and EIA-0035, "Monthly Energy Review."

Shaded rows signify the economy spent at least 1 full quarter of that year in recession (Source: The National Bureau of Economic Research).

Italics signify average taken from 2001-2009 due to lack of data from 2010.

Underlined numbers signify averages taken from 1961-1969 due to lack of data from 1970.

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Trends in the Unit Base-Rate Cost of Northeast Power Distributors

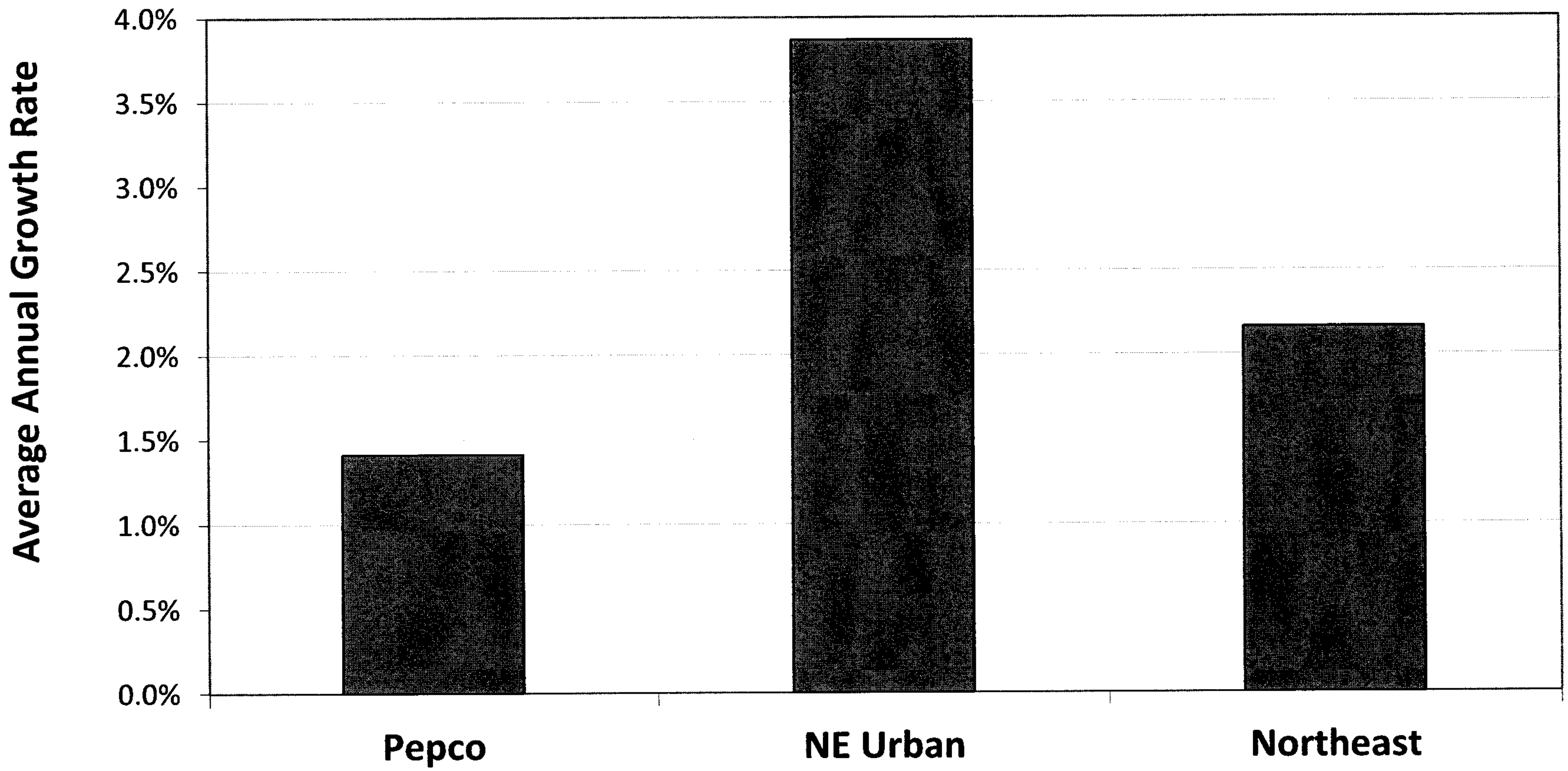
Year	Pepco	NE Urban	Northeast
2004	-1.66%	0.02%	-3.67%
2005	3.51%	3.33%	1.86%
2006	-0.51%	7.80%	3.73%
2007	2.23%	2.08%	2.00%
2008	-4.52%	2.70%	1.91%
2009	5.17%	4.72%	4.00%
2010	5.68%	6.41%	5.30%
Average Annual Growth Rate 2004-2010	**1.41%**	**3.87%**	**2.16%**

Data Sources: FERC Form 1 (power distributor cost and bond yield), Form EIA-861 (customers), and Regulatory Research Associates (electric utility allowed ROE)

Northeast Sample: Baltimore Gas & Electric, Central Maine Power, Connecticut Light & Power, Consolidated Edison, Jersey Central Power, Maine Public Service, Metropolitan Edison, PECO Energy, Potomac Electric Power, Public Service Electric & Gas, United Illuminating, West Penn Power, and Western Massachusetts Electric

Northeast Urban Sample: Baltimore Gas & Electric, Consolidated Edison, PECO Energy, Potomac Electric Power, Public Service Electric & Gas

Trends in the Unit Base-Rate Cost of Northeast Power Distributors, 2004-2010



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How Gas Distributor Credit Metrics Differ by Use of Capex Recovery Mechanisms, 2007-2009

Company Name	S&P Corporate Credit Rating	Rate of Return on Capital (%)	EBITDA/Interest Coverage	FFO/debt (%)
Use Capex Recovery Mechanisms				
Alabama Gas	BBB/BBB+	12.5	8.0	44.1
Atlanta Gas Light	A-	N/A	N/A	N/A
Indiana Gas	A-	8.6	4.7	21.4
Laclede Gas	A	7.2	3.3	14.1
Northwest Natural Gas	AA-	10.5	5.5	19.7
Averages	**A-/A**	**9.7**	**5.4**	**24.8**
No Capex Recovery Mechanisms				
Baltimore Gas & Electric	BBB/BBB+	5.8	4.3	21.0
Bay State Gas	BBB-	N/A	N/A	N/A
Berkshire Gas	N/A	6.2	4.4	20.0
Boston Gas	A-	N/A	N/A	N/A
Colonial Gas	A-	N/A	N/A	N/A
Central Hudson Gas & Electric	A	9.5	4.5	15.9
Central Illinois Light	BB+/BBB-	12.5	7.8	32.8
Central Illinois Public Service	BB+/BBB-	4.6	3.7	17.7
Connecticut Natural Gas	BBB+/A-	N/A	N/A	N/A
Illinois Power	BB+/BBB-	5.6	2.7	14.7
Michigan Consolidated Gas	BBB	6.4	3.3	16.2
National Fuel Gas	BBB/BBB+	14.2	7.4	36.8
Nicor Gas	AA	6.8	6.6	22.5
North Shore Gas	BBB+/A-	6.5	3.5	13.8
NSTAR Gas	A+	N/A	N/A	N/A
Orange & Rockland Utilities	A-/A	8.7	4.3	16.1
PECO Energy	BBB/BBB+	9.6	6.0	17.1
Peoples Gas Light & Coke	BBB+/A-	N/A	N/A	N/A
Piedmont Natural Gas	A	10.9	5.0	22.7
Public Service Co. of North Carolina	BBB+/A-	7.8	4.7	22.9
Questar Gas	BBB+/A-	9.7	4.6	23.4
Rochester Gas & Electric	BBB/BBB+	7.6	3.1	16.0
Southern California Gas	A	13.3	6.5	26.8
Southern Connecticut Gas	BBB+/A-	4.9	3.3	17.7
Southwest Gas	BBB-/BBB	7.6	4.6	21.2
Washington Gas Light	AA-	11.0	6.7	27.0
Wisconsin Gas	A-	N/A	N/A	N/A
Yankee Gas Services	BBB	5.2	4.0	18.6
Averages	**BBB+/A-**	**8.3**	**4.8**	**21.0**
Indeterminate				
Atmos Energy	BBB/BBB+	9.5	4.0	21.1
Keyspan Energy Delivery Long Island	A	N/A	N/A	N/A
Keyspan Energy Delivery New York	A	N/A	N/A	N/A
Narragansett Electric	A-	N/A	N/A	N/A
New Jersey Natural Gas	A/A+	9.6	6.0	25.7
Niagara Mohawk Power	A-	N/A	N/A	N/A
Public Service Electric & Gas	BBB	8.8	4.8	17.5
South Jersey Gas	BBB+	8.8	5.4	20.0
Averages	**A-**	**9.2**	**5.1**	**21.1**
All Companies	**BBB+/A-**	**8.6**	**4.9**	**21.5**

Source of data for gas utilities: Standard & Poor's Ratings Direct, *Credit Stats: Gas Utilities -- U.S.* August 20, 2010. Group averages of corporate credit rating computed by PEG Research for the fiscal years 2007-2009. All other averages provided by Standard & Poor's.

Source of data for combined gas and electric utilities: Standard & Poor's Ratings Direct, *Credit Stats: Electric Utilities -- U.S.* August 20, 2010. Group averages of corporate credit ratings computed by PEG Research for the fiscal years 2007-2009. All other averages provided by Standard & Poor's.

How Electric Utility Credit Metrics Differ by Use of Capex Recovery Mechanisms, 2007-2009

Company Name	S&P Corporate Credit Rating	Rate of Return on Capital (%)	EBITDA/Interest Coverage	FFO/debt (%)
Use Capex Recovery Mechanisms				
Alabama Power	A	9.6	5.2	23.0
Appalachian Power	BBB	5.5	2.7	8.9
Cleveland Electric Illuminating	BBB	9.6	4.0	7.4
Columbus Southern Power	BBB	13.9	6.1	23.3
Dayton Power & Light	BBB/BBB+	15.3	13.6	48.1
Duke Energy Indiana	A-	8.2	5.5	19.0
Florida Power & Light	A	9.6	6.9	35.1
Georgia Power	A	9.2	5.0	20.3
Indianapolis Power & Light	BB+/BBB-	N/A	N/A	N/A
Kansas Gas & Electric	BBB-	N/A	N/A	N/A
Kentucky Power	BBB	5.8	3.3	14.8
Kentucky Utilities	BBB+	N/A	N/A	N/A
Louisville Gas & Electric	BBB+	N/A	N/A	N/A
MidAmerican Energy	A-	9.2	5.0	24.1
Mississippi Power	A	11.4	8.7	24.9
Northern States Power MN	BBB+	9.1	4.7	23.2
Ohio Edison	BBB	9.5	4.1	15.9
Ohio Power	BBB	8.5	4.5	16.6
Pacific Gas & Electric	BBB+	10.2	4.4	23.9
PPL Electric Utilities	A-	8.6	5.0	23.3
Progress Energy Florida	BBB+	9.6	4.1	15.5
Public Service Co. of Colorado	BBB+	8.4	4.4	18.3
Public Service Co. of New Hampshire	BBB	7.6	4.3	13.0
Southern California Edison	BBB+	10.5	4.0	24.6
Toledo Edison	BBB	10.4	4.1	23.8
Averages	**BBB+**	**9.5**	**5.2**	**21.3**
No Capex Recovery Mechanisms				
AEP Texas Central	BBB	7.0	4.3	9.0
AEP Texas North	BBB	8.5	4.8	20.2
Arizona Public Service	BBB-	7.1	4.5	20.8
Baltimore Gas & Electric	BBB/BBB+	5.8	4.3	21.0
Black Hills Power	BBB-	8.5	4.2	19.8
Central Hudson Gas & Electric	A	9.5	4.5	15.9
Central Illinois Light	BB+/BBB-	12.5	7.8	32.8
Central Illinois Public Service	BB+/BBB-	4.6	3.7	17.7
Central Maine Power	BBB+	7.0	4.7	15.9
Cleco Power	BBB	7.8	3.0	9.1
Connecticut Light & Power	BBB	7.1	4.2	13.4
Consumers Energy	BBB-	8.6	4.1	21.9
Detroit Edison	BBB	8.4	5.2	20.4
Duke Energy Carolinas	A-	8.9	4.4	22.2
Duke Energy Kentucky	A-	7.5	5.4	22.9
Duquesne Light	BBB-	N/A	N/A	N/A
El Paso Electric	BBB	9.2	3.9	20.3
Empire District Electric	BBB-	6.8	3.3	15.2
Entergy Arkansas	BBB	6.3	4.6	19.9
Entergy Gulf States Louisiana	N/A	7.5	3.4	21.8
Entergy Louisiana	BBB	N/A	N/A	N/A
Entergy Mississippi	BBB	7.5	4.6	18.8
Entergy New Orleans	BBB-	10.9	4.1	42.8
Entergy Texas	N/A	5.9	2.4	7.7
Green Mountain Power	BBB	N/A	N/A	N/A
Gulf Power	A	9.2	5.4	19.5
Hawaii Electric Light	BBB	N/A	N/A	N/A
Hawaiian Electric	BBB	6.8	4.4	14.0
Idaho Power	BBB/BBB+	6.6	3.7	11.6
Illinois Power	BB+/BBB-	5.6	2.7	14.7

Company Name	S&P Corporate Credit Rating	Rate of Return on Capital (%)	EBITDA/Interest Coverage	FFO/debt (%)
Interstate Power & Light	BBB+	9.4	5.2	25.6
Jersey Central Power & Light	BBB	8.5	7.6	25.6
Kansas City Power & Light	BBB	6.8	4.0	15.2
Kansas City Power & Light - GMO	BB+/BBB-	N/A	N/A	N/A
Massachusetts Electric	A-	N/A	N/A	N/A
Maui Electric	BBB	N/A	N/A	N/A
Metropolitan Edison	BBB	8.4	5.5	16.3
Monongahela Power	BBB-	N/A	N/A	N/A
Narragansett Electric	A-	N/A	N/A	N/A
Nevada Power	BB-/BB	7.0	2.4	11.2
Niagara Mohawk Power	A-	N/A	N/A	N/A
Northern Indiana Public Service	BBB-	N/A	N/A	N/A
Northern States Power WI	A-	8.8	6.0	29.1
NSTAR Electric	A+	10.4	7.8	20.6
Orange & Rockland Utilities	A-/A	8.7	4.3	16.1
PacifiCorp	A-	8.0	4.0	20.2
PECO Energy	BBB/BBB+	9.6	6.0	17.1
Pennsylvania Electric	BBB	8.8	5.0	12.3
Pennsylvania Power	BBB	N/A	N/A	N/A
Potomac Edison	BBB-	N/A	N/A	N/A
Potomac Electric Power	BBB	7.1	4.0	17.2
Progress Energy Carolinas	BBB+	11.1	5.6	27.1
Public Service Co. of New Mexico	BB	3.5	2.1	12.9
Rochester Gas & Electric	BBB/BBB+	7.6	3.1	16.0
Rockland Electric	A-/A	N/A	N/A	N/A
Sierra Pacific Power	BB-/BB	7.4	3.2	14.2
Southern Indiana Gas & Electric	A-	9.2	5.3	23.5
Southwestern Electric Power	BBB	6.6	2.9	15.5
Southwestern Public Service	BBB+	5.9	3.2	12.8
Tampa Electric	BBB-/BBB	9.6	4.4	23.6
Texas-New Mexico Power	BB	5.5	3.5	16.6
Tucson Electric Power	BB/BB+	8.2	3.6	18.3
Union Electric	BBB-	7.3	3.7	19.2
West Penn Power	BBB-	N/A	N/A	N/A
Western Massachusetts Electric	BBB	6.0	4.7	14.5
Wisconsin Electric Power	A-	5.5	4.6	19.1
Wisconsin Power & Light	A-	9.2	4.5	25.7
Wisconsin Public Service	A-/A	9.7	5.6	24.4
Average	**BBB**	**7.8**	**4.4**	**18.9**
Indeterminate				
Atlantic City Electric	BBB	7.6	4.3	16.2
CenterPoint Energy Houston Electric	BBB	9.1	5.2	21.0
Commonwealth Edison	BB+/BBB-	5.2	2.8	13.4
Duke Energy Ohio	A-	5.5	6.8	27.8
Indiana Michigan Power	BBB	8.7	2.8	18.7
Oklahoma Gas & Electric	BBB+	9.2	5.9	31.0
Oncor Electric Delivery	BBB/BBB+	9.0	4.0	15.9
Portland General Electric	BBB+	7.6	3.8	17.4
Public Service Co. of Oklahoma	BBB	5.7	3.0	16.6
Public Service Electric & Gas	BBB	8.8	4.8	17.5
South Carolina Electric & Gas	BBB+/A-	8.3	4.3	15.7
Virginia Electric & Power	A-	8.6	4.4	21.0
Average	**BBB/BBB+**	**7.8**	**4.3**	**19.4**

Source of data: Standard & Poor's Ratings Direct, *Credit Stats: Electric Utilities -- U.S.* August 20, 2010. Group averages of corporate credit ratings computed by PEG Research for the fiscal years 2007-2009. All other averages provided by Standard & Poor's.

M. N. LOWRY
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO ______ (B)-8

Average O&M Unit Cost Growth of US Power Distributors by Test Year, 1999-2010

	Customers	O&M Cost[1]	O&M Unit Cost
Forward TY	1.07%	2.89%	1.83%
Historical TY	1.19%	3.47%	2.27%
Other TY	0.66%	1.81%	1.15%

[1] Distributor O&M expenses are defined as the sum of distribution, customer account (net of uncollectibles), and sales expenses, as reported on the FERC Form 1.

Data Sources: FERC Form 1 (cost) and Form EIA-861 (customers)

M. N. LOWRY
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO ______ (B)-9

Potomac Electric Power Comany - District of Columbia
2012 Utility Distribution Reliability Investment Recovery Mechanism (RIM) Revenue Requirement

	Rate	January	February	March	April	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Period Total
Rate Base														
CWIP														
Beg of period		0	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	
Activity														
Capex (1)		7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	
Closings to Plant		0	(7,449,079)	(7,449,079)	(7,449,079)	(7,449,079)	(7,449,079)	(7,449,079)	(7,449,079)	(7,449,079)	(7,449,079)	(7,449,079)	(7,449,079)	
End of period		7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	
Average		3,724,540	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	
Plant in Service														
Beg of period		0	0	7,449,079	14,898,159	22,347,238	29,796,317	37,245,397	44,694,476	52,143,555	59,592,635	67,041,714	74,490,793	
Activity		0	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	7,449,079	
End of period		0	7,449,079	14,898,159	22,347,238	29,796,317	37,245,397	44,694,476	52,143,555	59,592,635	67,041,714	74,490,793	81,939,873	
Average		0	3,724,540	11,173,619	18,622,698	26,071,778	33,520,857	40,969,936	48,419,016	55,868,095	63,317,174	70,766,254	78,215,333	
Depreciation Reserve														
Beg of period		0	0	7,635	30,541	68,718	122,165	190,883	274,871	374,130	488,660	618,460	763,531	
Activity		0	7,635	22,906	38,177	53,447	68,718	83,988	99,259	114,530	129,800	145,071	160,341	
End of period		0	7,635	30,541	68,718	122,165	190,883	274,871	374,130	488,660	618,460	763,531	923,872	
Average		0	3,818	22,906	64,900	129,800	217,606	328,318	461,936	618,460	797,890	1,000,225	1,225,467	
Deferred Tax Balance														
Beg of period		0	0	3,270	13,082	29,434	52,327	81,760	117,735	160,250	209,307	264,904	327,042	
Activity		0	3,270	9,811	16,352	22,893	29,434	35,975	42,515	49,056	55,597	62,138	68,679	
End of period		0	3,270	13,082	29,434	52,327	81,760	117,735	160,250	209,307	264,904	327,042	395,720	
Average		0	1,635	9,811	27,799	55,597	93,207	140,628	197,860	264,904	341,759	428,425	524,902	
Net Rate Base - Average		**0**	**3,719,087**	**11,140,902**	**18,530,000**	**25,886,380**	**33,210,044**	**40,500,990**	**47,759,219**	**54,984,731**	**62,177,526**	**69,337,604**	**76,464,964**	
Earnings														
Expenses	Rate													
Book Depreciation	2.46%	0	7,635	22,906	38,177	53,447	68,718	83,988	99,259	114,530	129,800	145,071	160,341	
Current Taxes (2)	41.4838%	0	(6,438)	(19,313)	(32,189)	(45,065)	(57,940)	(70,816)	(83,692)	(96,567)	(109,443)	(122,319)	(135,194)	
Deferred Taxes (2)	41.4838%	0	3,270	9,811	16,352	22,893	29,434	35,975	42,515	49,056	55,597	62,138	68,679	
Total Expenses		0	4,468	13,404	22,339	31,275	40,211	49,147	58,083	67,018	75,954	84,890	93,826	
Earnings		**0**	**(4,468)**	**(13,404)**	**(22,339)**	**(31,275)**	**(40,211)**	**(49,147)**	**(58,083)**	**(67,018)**	**(75,954)**	**(84,890)**	**(93,826)**	
Revenue Requirement														
Rate Base + CWIP		3,724,540	11,168,166	18,589,981	25,979,079	33,335,460	40,659,123	47,950,070	55,208,299	62,433,811	69,626,606	76,786,683	83,914,044	
ROE		10.75%	10.75%	10.75%	10.75%	10.75%	10.75%	10.75%	10.75%	10.75%	10.75%	10.75%	10.75%	
ROR		8.64%	8.64%	8.64%	8.64%	8.64%	8.64%	8.64%	8.64%	8.64%	8.64%	8.64%	8.64%	
Earnings - Rate Base		26,817	80,411	133,848	187,049	240,015	292,746	345,241	397,500	449,523	501,312	552,864	604,181	
Earnings - Expense		-	(4,468)	(13,404)	(22,339)	(31,275)	(40,211)	(49,147)	(58,083)	(67,018)	(75,954)	(84,890)	(93,826)	
Total Earnings Effect		(26,817)	(84,879)	(147,252)	(209,389)	(271,291)	(332,957)	(394,387)	(455,582)	(516,542)	(577,266)	(637,754)	(698,007)	
Revenue Conversion Factor		1.708927	1.708927	1.708927	1.708927	1.708927	1.708927	1.708927	1.708927	1.708927	1.708927	1.708927	1.708927	
Revenue Requirement		**45,828**	**145,051**	**251,642**	**357,830**	**463,616**	**568,999**	**673,979**	**778,557**	**882,732**	**986,505**	**1,089,875**	**1,192,843**	**$ 7,437,458**

(1)	RIM Distribution Capex		$83,662,308
	RIM Subtransmisssion Capex	$14,029,015	
	% Allocated to District of Columbia	40.82%	5,726,644
	Total Pepco DC RIM Capex		$89,388,952

(2) Tax depreciation assumes 20 yr tax life

J. M. CANNELL
Direct Testimony
DC P.S.C. - July, 2011

Introduced as:
PEPCO ______ (C)

POTOMAC ELECTRIC POWER COMPANY

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF JULIE M. CANNELL
FORMAL CASE NO. ____

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

A. My name is Julie M. Cannell. My business address is P.O. Box 199, Purchase, New York 10577. I am the president of my own advisory firm, J.M. Cannell, Inc.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. My firm, J.M. Cannell, Inc., provides investor-related advisory services to electric utility companies and other firms and organizations with an interest in the industry. Prior to establishing my firm in February 1997, I was employed by the New York-based investment manager, Lord Abbett & Company, from June 1978 to January 31, 1997. During my tenure with Lord Abbett, I was a securities analyst specializing in the electric utility and telecommunications services industries; portfolio manager of America's Utility Fund, an equity utility mutual fund, for which Lord Abbett was a sub-advisor; portfolio manager of numerous institutional equity portfolios; and co-director of Lord Abbett's Equity Research Department.

My educational credentials include a B.A. from Mary Baldwin College, M.Ln. from Emory University, and M.B.A. from Columbia University. I am also a Chartered Financial Analyst (C.F.A.). I have been a member of the Wall Street Utility Group, an organization of security and credit rating analysts having an expertise in the utility industry, for over thirty years.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON THE PERSPECTIVE OF INVESTORS BEFORE UTILITY REGULATORY COMMISSIONS?

A. Yes, I have. I have submitted pre-filed testimony on behalf of investor-owned utilities before Public Service or Public Utility Commissions in the states of Arizona, Colorado, Connecticut, Kansas, Maryland, Massachusetts, Minnesota, Missouri, Nevada, New York, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Texas, Vermont, Virginia, Washington, and Wisconsin. The details of my participation in regulatory proceedings are provided in PEPCO (C)-1.

Q. HAVE YOU HAD ADDITIONAL REGULATORY EXPERIENCE?

A. Yes. As a consultant to the Edison Electric Institute (EEI), I was extensively involved between 2004 and 2009 in an ongoing initiative geared toward fostering and improving communications between state regulators and the investment community. This effort has centered on a series of forums held throughout the United States bringing together these two constituencies, sponsored by EEI and facilitated by Gee Strategies president Robert Gee, former chairman of the Texas Public Utilities Commission. In addition to helping structure these dialogues, my role was to moderate panel discussions of equity and debt security analysts.

I have also conducted several studies of investor perceptions of regulatory issues. Further, I have written articles addressing the implications for utilities and state regulators of various topical issues, including the current electric industry capital expenditure cycle, and, more recently, the financial crisis.

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

A. I am providing Direct Testimony on behalf of Potomac Electric Power Company (Pepco or the Company).

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY?

A. I will address the perspective of investors in regard to the Company's rate proposal and will provide comments on several areas: (1) investors' perspective of risk due to the investment commitments currently being undertaken by electric utilities in general and the Company in particular; (2) investors' perception of risk as impacted by current macroeconomic conditions; (3)

investors' expectations for a constructive regulatory environment for Pepco so as to ensure the Company's continued access to the capital markets; and (4) investors' expectations for Pepco's return on equity (ROE).

Q. WHAT IN YOUR EXPERIENCE ALLOWS YOU TO PROVIDE TESTIMONY ABOUT INVESTORS' PERSPECTIVES AND EXPECTATIONS?

A. As a securities analyst, I specialized in the electric utility industry and the individual companies comprising it. And as a portfolio manager, I applied that knowledge, along with investment fundamentals, in making investment decisions on behalf of institutions and individual investors. My experience has given me familiarity with the information and tools that investors use in making decisions with respect to expected returns on equity. Moreover, I have reviewed the various reports of security and credit rating agency analysts, which have addressed the Company and its current regulatory situation. Further, I have familiarized myself with the Company's fundamentals and its planned investment levels.

Q. AS AN ANALYST OR PORTFOLIO MANAGER, DID YOU FOLLOW THE COMPANY?

A. Yes. I followed Pepco when it was a stand alone entity, prior to its 2002 merger with Conectiv Energy to form Pepco Holdings, Inc.

Q. **PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.**

A. There are four parts to my testimony.

I. INVESTORS' REQUIREMENTS FOR INCREASED RETURNS IN UTILITY INVESTMENTS. This section discusses the investment risk of electric utilities; specifically, why the current construction cycle has increased the risk of investing in the industry. It also addresses how regulatory risk has risen due to this higher capital spending.

II. THE MACROECONOMIC ENVIRONMENT. This section discusses the elevated risk created by the global economic crisis.

III. INVESTORS' EXPECTATIONS FOR RETURNS AND PERCEPTIONS OF THE CURRENT PROCEEDING. This section focuses on who investors are, how they actually make their decisions, a review of the investment community's perceptions of the Company and of the District of Columbia regulation. This review is based on a number of recent publications in which investment analysts discuss their perceptions of the Company and its regulatory environment.

IV. INVESTOR EXPECTATIONS FOR RETURN ON EQUITY FOR PEPCO. This section discusses how investors would view the Company's request for an authorized ROE of 10.75%.

I. INVESTORS' REQUIREMENTS FOR INCREASED RETURNS IN UTILITY INVESTMENTS

Q. PLEASE EXPLAIN WHY THE INVESTMENT COMMUNITY'S VIEW OF AN ELECTRIC UTILITY'S STOCK IS IMPORTANT TO THE UTILITY AND ITS CUSTOMERS.

A. Electric utilities are in the business of providing their customers with safe, reliable, and efficient service. This requires extensive investment in distribution and transmission infrastructure, which makes the electric utility business capital-intensive. Investors provide the capital necessary to maintain and expand a utility's infrastructure, which in turn enables utilities like the Company to provide safe, reliable, and efficient service to customers.

The terms on which the Company is able to obtain that capital have a direct and measurable impact on customers and the amounts they pay for electric service.

Q. PLEASE PROVIDE AN EXAMPLE.

A. If credit rating agencies such as Moody's Investors Service (Moody's), Standard & Poor's (S&P), or Fitch Ratings (Fitch) believe that the utility's revenues will be diminished by adverse business or regulatory decisions, those rating agencies could lower their credit ratings for the utility, which would raise the cost of debt. And, because the cost of debt is a component of the weighted average cost of capital, the increased costs of capital would eventually be passed on to customers in the form of higher rates.

The same is true for equity investors. If individual or institutional investors believe that the return they are offered is too low in light of the risk involved, they will either sell their stock or elect not to purchase the stock, which generally drives the stock price down. Although lower stock prices would appear at first blush to be a concern only to investors, they also affect customers. When a utility has to go to the equity markets to obtain capital, a low stock price requires it to issue more shares of stock to obtain the same amount of money than it would have received for fewer shares if the per share price had been higher. The resulting increase in the number of shares outstanding requires more dollars to be expended toward dividends, resulting in less retained earnings for reinvestment in the company.

The corollary is that when investors believe that they are investing in a company where regulation is fair, consistent, and provides a reasonable rate of return, those investors charge less for their capital. And when debt and equity investors demand less for their capital, utility rates remain lower and utilities have more ready access to the capital markets. Thus, a utility and its customers have a shared interest in meeting the expectations of investors and credit rating agencies. Regulators share this interest as well, because fair treatment of one utility decreases the costs of capital for all utilities in that regulatory jurisdiction.

Q. **ARE YOU SUGGESTING THAT THE DISTRICT OF COLUMBIA PUBLIC SERVICE COMMISSION'S (COMMISSION) DECISIONS SHOULD BE DICTATED BY INVESTORS?**

A. Not at all. I realize that the Commission must apply the law to the facts that are presented to it and that it must balance the interests of investors and customers. My point is that the Commission's decision on rate of return is not simply a zero-sum game. If the rate of return strikes an appropriate balance between the utility and customers, both benefit. If the rate of return is set too low, both the utility and customers are adversely impacted because the cost of capital increases over the long term.

Q. **CAN YOU BRIEFLY DESCRIBE YOUR UNDERSTANDING OF THE APPLICABLE LEGAL STANDARD WITH RESPECT TO A UTILITY'S REASONABLE ROE?**

A. Yes. The U.S. Supreme Court addressed this issue in its *Bluefield* and *Hope* decisions. These decisions held that a public utility is entitled to a return on equity adequate to assure confidence in the financial soundness of the utility, to maintain its credit, and to enable it to attract the capital necessary to operate its business on reasonable terms compared to firms of similar risk.

Q. **IN YOUR TESTIMONY, YOU REFER TO THE EXPECTATIONS OF INVESTORS WITH RESPECT TO PEPCO'S RETURN ON EQUITY. ARE THOSE EXPECTATIONS CONSISTENT WITH THE LEGAL STANDARD YOU SUMMARIZE ABOVE?**

A. Yes. I believe that the investor viewpoint is consistent with consideration of the public good. As I explain elsewhere, both investors and customers benefit when a utility is financially sound, has strong credit, and is able to attract capital on reasonable terms.

Q. **HOW HAS THE RISK OF INVESTING IN ELECTRIC UTILITIES CHANGED IN RECENT YEARS?**

A. It has become clear to investors and others that the industry is now in a period of significant capital expenditures. This new construction cycle reflects the need utilities in general have to replace aging infrastructure; to meet new environmental requirements and expectations; to address the need for grid enhancements, including those associated with interconnecting renewable resources; to provide technological advancements such as smart grid technologies; and to add new base-load and intermediate generation resources to meet growing customer needs. The resulting increase in capital expenditures from all of the investments set forth above means that utilities will be more active in capital markets and, therefore, will be more exposed to the risks and uncertainties in those markets. It bears mention, of course, that Pepco does not own generation now and does not plan to during the rate-effective period. But it does compete for capital with companies that do own generation.

Electric utilities will also be more exposed to regulatory risks, since a significant expansion of capital spending by electric utilities usually results in rate proceedings to recover the costs associated with that capital. As a result, regulatory exposure has become a key focus for investors as utilities face a series of rate cases in order to recover the required costs they are incurring to supplement and replace aging infrastructure, to meet environmental requirements, and to meet other costs. These risks are in addition to the other risks posed by the technological, economic, environmental and other policy changes that also affect the industry. It is because of these increased risks that investors no longer perceive electric utilities as a group as being the "safe havens" they once were.

Q. HAVE INVESTORS' GOALS FOR UTILITY INVESTMENTS CHANGED IN RESPONSE TO THESE INCREASED RISKS?

A. No. Investors' goals for electric utility investments have not fundamentally changed. They still look to electric utilities primarily as defensive investments, and still look for stable performance and regular dividends as the reason to invest in electric utilities. But investors also understand that the investment risk in electric stocks has risen significantly, and their expectations of returns have changed accordingly.

In the end, investors have a very large universe of stocks from which to select; with few exceptions, they have no requirement to own electric utility stocks. To the extent that they do invest within the utility sector, investors must be discriminating in their stock selection. As a result, utilities with strong financial metrics operating in constructive regulatory environments will have stronger investment appeal than utilities with weak metrics and less favorable regulation.

Q. HOW DO INVESTORS VIEW STATE REGULATION IN THE CONTEXT OF A MAJOR CAPITAL EXPENDITURE CYCLE?

A. Nationally, in the past several years, rate case filings in the electric industry have become much more frequent. From an investor's perspective, each regulatory proceeding introduces a period of uncertainty for a utility. Among the unknowns are the ROE the company will be given the opportunity to earn, the equity base on which that return can be earned, the extent to which costs—both historical and future—can be recovered. The utility's future earnings power is thrown into question until the case is decided. Because that earnings power is the basis for an investment in the company, the stability and constructiveness of state regulatory policies are critical concerns to investors.

Q. HOW ARE THE FOREGOING UNCERTAINTIES RELEVANT TO TRANSMISSION AND DISTRIBUTION (T&D) UTILITIES SUCH AS PEPCO?

A. A number of the factors discussed above are relevant to the Company. In this proceeding, for example, elements that investors will focus on include cost recovery, the equity component of capital structure, and of course the ultimate ROE that is allowed.

Q. PLEASE ELABORATE ON THE UNCERTAINTY SURROUNDING ALLOWED RETURNS ON EQUITY.

A. According to data provided by Regulatory Research Associates (RRA),[1] average allowed ROEs fell from 12.70% in 1990 to 10.36% in 2007. In 2008, however, average

[1] Regulatory Research Associates. "Major Rate Case Decisions - January-March 2011." April 7, 2011.

ROEs began to increase slightly, to 10.46%, with 2009 rising marginally, to 10.48%. The average allowed ROE in 2010 fell to 10.34%, and through the first quarter of 2011 was 10.35%. While the upward trend in 2008 and 2009 is encouraging, the experience since then could suggest some erosion in allowed levels is beginning.

Q. PLEASE ADDRESS HOW INVESTORS ASSESS THE SPECIFIC RISKS THE COMPANY IS FACING IN RELATION TO THE NEW CAPITAL INVESTMENT CYCLE.

A. Investors understand that Pepco is involved in the industry-wide construction and capital investment cycle. PHI's three utility subsidiaries have a five-year operating electric construction budget of $3.8 billion, excluding expenditures for smart grid technologies and the Mid-Atlantic Power Pathway. Pepco accounts for almost 50% of that total, with planned investments in the District of Columbia and Maryland of $1.9 billion over the 2011-2015 period. During this period, both PHI and the Company will need to access the capital markets. Pepco (and its parent, which supplies it with equity) will thus be exposed to market vicissitudes and pricing levels.

Q. DOES THE COMPANY FACE FURTHER RISKS?

A. Yes. With its planned capital spending, it is clear that Pepco will face regular rate cases. Recovery of the substantial costs of maintaining, renewing, expanding, and replacing a mature utility infrastructure is likely to require base rate cases routinely during the coming years.

Q. ARE INVESTORS CONCERNED ABOUT REGULATORY LAG IN REGARD TO PEPCO?

A. As noted by RRA, District of Columbia regulatory practice uses an average original-cost rate base, with partially-forecasted data sometimes permitted.[2] In the instant proceeding, the test year is the six months ending September 30, 2011, incorporating six months of actual and six months of projected data. While the forecast component of the test year is supportive of the Company's ability to earn the ROE authorized by the Commission, the six months of actual data will prevent Pepco from being kept fully whole. As a result, investors will have questions about the timing and certainty of the utility's cash recovery of costs. It is thus reasonable to expect investors to increase somewhat the risk premiums they would require to supply the Company with capital, given this regulatory structure.

In short, while investors place a strong emphasis on the absolute level of ROE a company is permitted, of

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[2] Regulatory Research Associates. "District of Columbia Public Service Commission." Referenced section updated 9/29/10.

equal or perhaps greater importance is a utility's ability to actually earn that allowed return. With regulatory lag still present in the District, ROEs authorized by the Commission should be toward the high end of a reasonable range determined by quantitative ROE analyses in order to provide a utility with at least a more reasonable opportunity to earn a fair, or closer to a fair, ROE.

Q. YOU HAVE DISCUSSED THE MOUNTING RISKS YOU SEE THE COMPANY FACING. DO THOSE RISKS HAVE THE POTENTIAL TO REDUCE ITS EARNINGS AND CASH FLOW STREAMS AND INCREASE THEIR VOLATILITY?

A. Yes, they could, due to the fact that the foregoing factors are in large part beyond Pepco's control. Where risk factors are more clearly within the Company's control, investors can evaluate the importance and effect of those risks based on their assessment of the strength of the Company's management, and guidance about how Pepco plans to mitigate or avoid the risks in question. In this case, the nature of the risk is such that the Company's investors have little guidance and more uncertainty. Uncertainty leads to investor concern and demands for higher investment returns.

II. THE MACROECONOMIC ENVIRONMENT

Q. WHAT MACROECONOMIC CHALLENGES ARE UTILITIES FACING AT THE PRESENT TIME?

A. The United States and, indeed, the world economies are or have been in recession and grappling with a very serious financial crisis. While few industries are untouched by these circumstances, utilities are particularly vulnerable because of their capital-intensive nature and the magnitude of the construction expenditures they now face.

Q. HOW HAS THE FINANCIAL CRISIS AFFECTED THE INDUSTRY?

A. With the demise of a number of investment and commercial banks, coupled with the significant weakening of surviving institutions, access to capital was initially difficult for most companies and impossible for others. Indeed, for a period of several weeks in September 2008, the debt markets were completely closed to any company. While some stability has returned to the capital markets, the unprecedented volatility and uncertainty that has characterized the markets since the fall of 2008 negatively impacted the terms and increased the cost of capital.

In this environment, set in the context of rising capital expenditures for the industry at large and the Company specifically, it is important that the Commission recognize that investors require a level of return that reflects the increased level of risk.

Q. WHAT ARE THE REGULATORY IMPLICATIONS OF THIS FINANCIAL CRISIS?

A. The current environment presents a distinct challenge to the utility industry. The industry must retain access to capital on reasonable terms during this period of market uncertainty in order to provide safe and reliable service to customers. This will require balanced and consistent regulation. Maintaining a solid regulatory compact will be critical.

Q. PLEASE ELABORATE.

A. The regulatory compact means that utilities will take the risk to invest in the infrastructure and assets needed to provide safe, reliable, and efficient electric service, and that regulators will support that investment by providing timely recovery of costs, reasonable returns on prudently invested capital, and regulatory treatment that, in general, is fair, predictable and balanced. It does not involve favoring any one group of interested parties in the regulatory process over others, but recognizes the key relationship between investment of capital by the utility, and the need for recovery of operating costs, capital and returns to support prudent investment.

Q. ARE THE COMPANY'S CURRENT CREDIT RATINGS CAUSE FOR CONCERN IN ITS OBTAINING ACCESS TO THE CAPITAL MARKETS?

A. Yes. As previously discussed, the turmoil in the financial markets has resulted in no company – no matter how financially strong – having carte blanche access to debt and equity financing. The stronger the company, the better the odds that financing would be available, but there are no guarantees. As will be discussed later, all three credit rating agencies currently have a stable outlook on the Company. However, a variety of circumstances, including a lack of regulatory support, could cause that perspective to change negatively.

Q. WHAT FACTORS SUGGEST THAT IMPROVEMENT MAY STILL BE SLOW TO COME IN THE ECONOMY, WITH ATTENDANT NEGATIVE IMPLICATIONS FOR THE MARKETS?

A. News sources contain articles on almost a daily basis conveying that the economy is still in a recovery mode and the opportunity for additional shocks to the system exists. For example, the Federal Reserve Board's recent continuation of its accommodative monetary policy, heretofore an important stabilizing force in the markets, is serving to foster increased concerns about the mounting size of the federal deficit as well as its impact on the dollar relative to other currencies. Indeed, as its current program of Quantitative Easing

(QE2) draws to an expected close in June, the Federal Reserve Board has acknowledged that it will be faced with a delicate balancing act of maintaining a weak but rebounding economy while not fueling inflationary pressures in the process. And as was vividly demonstrated in the November 12-13, 2010 meeting of the G-20 nations in Seoul, Korea, foreign countries are highly disturbed about the impact that the U.S.' accommodative monetary policy is having on the level of the dollar versus other currencies.

Another major problematic area is commercial real estate, which has billions of dollars of loans coming due and limited prospects of repayment. A crisis in this area could exacerbate ongoing problems in the already weak banking sector. And the possibility of markets being disrupted by unanticipated events from around the world always exists. For example, serious concerns exist over the sovereign debt of some of the European nations-Spain just months ago, and Greece, Ireland and Portugal currently. In tandem with these debt worries is the significant question of whether the Euro market will survive. In short, given the unstable economic and political backdrop that still exists globally, there are numerous possibilities for circumstances and/or events that could plunge the financial markets back into a crisis mode. In sum, substantial risk still exists.

III. INVESTORS' EXPECTATIONS FOR RETURNS AND PERCEPTIONS OF THE CURRENT PROCEEDING

Q. WHY IS THE PERCEPTION OF REGULATORY CLIMATE OF SUCH IMPORTANCE TO INVESTORS?

A. Equity investors today still seek companies that can offer stability in earnings and dividends. Fixed income investors look for stable and adequate cash flows to ensure payment of principal and interest when due, as indicated by stable credit ratings. The ability to pay dividends and sustain credit ratings is directly related to the consistency and sufficiency of a utility's earnings, which depend in large part on how the utility is regulated and managed. If there is uncertainty about whether regulation will allow a utility the opportunity to earn a reasonable return in future years, then that lack of predictability will lead investors to avoid holding investment positions in the utility, all other things being equal.

As a result, investors selecting electric utility stocks today place a very high value on consistent and constructive regulation. And, with a new round of base rate case filings underway in the industry, the quality of regulation is receiving increased investor scrutiny.

Q. IN YOUR EXPERIENCE AS AN ANALYST AND PORTFOLIO MANAGER, COULD A PERCEIVED CHANGE IN A COMPANY'S REGULATORY CLIMATE AFFECT YOUR INVESTMENT OPINION?

A. Absolutely. During my tenure as an institutional investor, a utility's regulatory environment was a critical factor in my assessment of its investment attractiveness. An adverse regulatory decision could be a key determinant in my recommendation or decision to sell a stock already owned or not to make an investment in one under consideration.

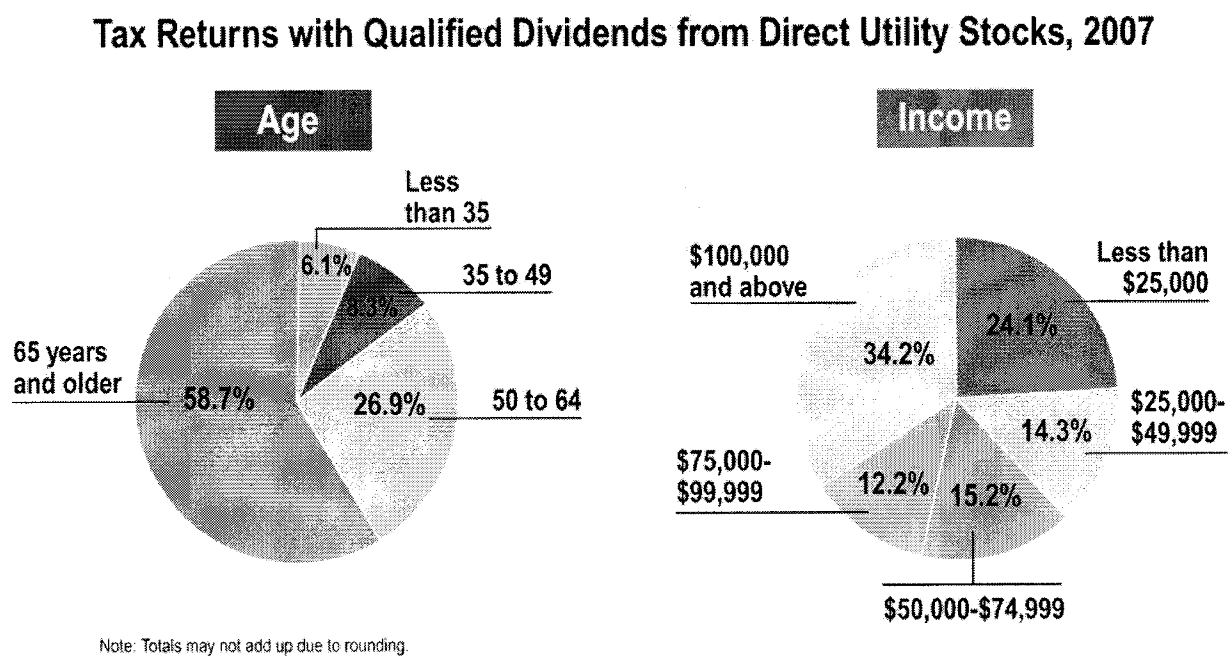
Q. WHO ARE TYPICAL INVESTORS IN UTILITY STOCKS?

A. There are two kinds of investors: individuals, who generally seek stability and income from their utility holdings, and institutions, which generally seek total return (i.e., price appreciation plus dividend income) from their utility investments.

Q. PLEASE PROVIDE MORE DETAIL ON INDIVIDUAL INVESTORS.

A. Individuals can own stocks through two avenues: either outright in his or her own name, or through a variety of institutional vehicles. In the latter option, which will be discussed later, a person purchases shares in a mutual fund or other investment vehicle, or has a direct interest in a pension fund that is managed by professional or institutional investors.

As noted previously, individual investors typically seek stability and income in their utility holdings. According to a recent study authored by Ernst & Young[3], the individual who directly owns utility stocks is older and not in the highest income bracket. Using the Internal Revenue Service's Statistics of Income on tax returns with qualified dividends and information from a variety of sources on investors' portfolio holdings, Ernst & Young estimated the age and income distribution from direct investors in utility stocks in 2007 as follows:



As the foregoing charts illustrate, 86% of the outright owners of utility stocks are aged 50 and older; 59% are

[3] Ernst & Young. The Beneficiaries of the Dividend Tax Rate Reduction; A Profile of Utility Shareholders. Prepared for the Edison Electric Institute and the American Gas Association. January 2010.

aged 65 and older; 66% have incomes of less than $100,000; and 38% have income less than $50,000. This data suggests that the typical owners of utility stocks are older individuals who hold utilities to supplement their retirement income.

Q. WHAT ARE THE IMPLICATIONS OF THESE DEMOGRAPHICS FOR INDIVIDUAL INVESTORS IN UTILITY STOCKS?

A. Because the vast majority of utility individual shareholders are older and desirous of supplemental income, it is important for utilities to produce strong earnings that can support the dividend income that these holders need. As will be discussed later in greater detail, PHI currently offers a very competitive dividend yield to shareholders. While the common dividend has not been increased since January 2008 and the payout constitutes a disproportionately high percentage of earnings at the present time, analysts are forecasting an earnings rebound in coming years that would reduce that percentage.

Q. TURN NOW, PLEASE, TO INSTITUTIONAL INVESTORS. HAS THE INVESTMENT INDUSTRY ITSELF CHANGED IN RECENT YEARS?

A. Yes. In recent years, institutional investors and hedge funds have grown dramatically in the amount of capital they control. This growth has had a significant impact on the speed with which the market reacts to unfavorable developments. It has led the market to be much more reactive and much less forgiving than it may have been in the past. In the context of a regulatory decision, investors will not necessarily wait, as they would have in the past, to see how the ramifications of a decision might play out. Rather, they simply sell their shares if a regulator's decision runs counter to their expectations.

Q. WHY ARE INSTITUTIONAL INVESTORS OF SUCH IMPORTANCE GENERALLY?

A. Because of the sheer size of their investment positions, institutions can effectively direct the course of individual securities, and sometimes can move the market as a whole. Institutional investors include financial institutions such as: various types of public retirement funds, mutual funds, investment companies, insurance companies, and commercial and investment banks. They approach the investment selection process from the standpoint of a portfolio. An investment portfolio is a collection of stocks selected to achieve the highest possible return within a commensurate level of risk. Therefore, institutional investors keep electric utilities in their portfolios only when such stocks contribute to achieving the desired risk/return relationship.

It should be remembered that, generally, the customers of institutional investors are individuals and it is they who ultimately gain or suffer loss from changes in the value of the institution's investments. Anyone who has a stake in a retirement plan, owns a mutual fund, has a trust fund, or pays insurance premiums, for example, is directly or indirectly a client of an institutional investor. But the individuals who make the decisions concerning these investments are paid money managers, and how they see their responsibilities to the clients they serve, and the way that their performance is judged, have a great deal to do with how they react to developments in the market.

Q. WHY ARE INSTITUTIONAL INVESTORS IMPORTANT TO PEPCO?

A. Institutional investors today hold roughly 58% of parent company PHI's total common shares. Such investors warrant significant attention due to their ability to change dramatically the market for the parent shares. Because institutional investors own large blocks of shares relative to the volumes typically traded, their activity in moving in or out of the company's shares is often noticeable as a significant change in the price and volume of shares being traded for the company. This change may be picked up by other institutional investors, by the investment community in general, and eventually by individual investors. These other entities will then look to see what is driving this trend in the stock and whether the trend is likely to continue or disappear. If they see support for the trend, they may follow the lead of the firms that initially began to move the market, and by following the leaders, the late movers may further strengthen the trend.

Q. **WHY MIGHT AN INSTITUTIONAL INVESTOR CHOOSE NOT TO HOLD INVESTMENTS IN A PARTICULAR ELECTRIC UTILITY?**

A. Several factors might be drivers. First, institutional investors have fiduciary responsibilities. For example, managers of pension assets fall under Federal ERISA laws, which mandate that a portfolio manager's decisions meet the so-called "prudent man" standard. That is to say, he or she is expected not to make investment decisions that are unduly risky or to retain stocks that are unduly risky given the investment goals of the portfolio and the function of the stock within it.

In addition, institutional investors have performance pressures. It is not enough for stocks in a portfolio simply to increase in value. Rather, relative performance is what counts. Investment performance is gauged against the returns earned by a market proxy (such as S&P's 500 Index) or a peer group of investments (i.e., those with a similar style, such as value, growth, growth & income, small cap, etc.). Mutual fund rating organizations such as Morningstar track and publicize the relative performance for mutual funds, while various pension consultants perform the same service for their client organizations.

Q. WHAT HAPPENS WHEN AN INSTITUTIONAL INVESTOR UNDERPERFORMS?

A. The results can vary, but, eventually, underperformance will result in lost business and personnel changes. Mutual fund shareholders can sell their fund shares. A pension plan sponsor can fire the professional investor or reduce the assets under its investor's management. And, of course, poor performance also disadvantages the individual who has entrusted his monies to the institution for management.

Q. HOW LONG A PERIOD DOES AN INSTITUTIONAL INVESTOR HAVE BEFORE PERFORMANCE BECOMES AN ISSUE?

A. Again, it can vary. But there is little argument that institutional investors no longer have the luxury of a long time horizon in which to show performance. Investors need and want results. And, with the public visibility that investment results now have (through organizations such as Morningstar and the various pension consultants) and the resulting performance pressure, most investment organizations are now operating with a much shorter time horizon than in years past. Generally speaking, a long investment time horizon today can be as short as 12-18 months. So, a stock that is unlikely to perform within the prescribed time horizon is usually not attractive for purchase or continued investment by an institutional investor.

Q. WHAT DOES THIS MEAN FOR INVESTMENTS IN REGULATED UTILITIES SPECIFICALLY?

A. This shortened time frame means that if there is bad news, institutional investors are more likely to react quickly. In the instance of a rate proceeding, these investors are unlikely to wait to see what the outcome of the next rate decision will be. That would represent an opportunity cost to them. Rather, institutional investors would be more prone to sell their shares on the news of an adverse regulatory outcome. This would not be good for customers either, for the reasons discussed earlier.

Q. HOW HAVE YOU GAUGED INVESTORS' PERCEPTIONS OF THE ISSUES IN THIS PROCEEDING?

A. To supplement my own knowledge of the industry, I have reviewed various reports related to the Company and its parent written by investment analysts. A clear picture of investors' perceptions emerges from these reports, which is in keeping with my own views.

Q. PLEASE DISCUSS INVESTORS' GENERAL VIEWS OF REGULATION.

A. One of the key factors analysts use to evaluate the quality of a regulatory climate is the consistency of a Commission's decisions. Investors value certainty and predictability; a lack of consistency in a Commission's actions or decisions serves to increase the investment risk associated with a utility. Where there is a predictable track record of regulatory decisions and actions, investors are able to anticipate reliably the future actions of a Commission. That reduces risk and supports reasonable valuations—i.e., the market supports a higher price for the Company's stock and a lower interest rate on bonds, which decreases a company's cost of capital.

In a study I prepared in 2005 for EEI on investors' perceptions of state regulation[4], respondents were asked to cite the regulatory factors they felt characterized a constructive environment, as well as those that characterize a non-constructive environment. On the positive side of the ledger, one of the most important considerations for investors was a regulatory climate that is "fair, stable, predictable, and consistent."

Q. **TURN NOW TO THE VIEWPOINT OF CREDIT RATING AGENCIES. PLEASE COMMENT ON HOW THE AGENCIES PERCEIVE THE COMPANY AND ITS REGULATORY SITUATION.**

A. Pepco's credit ratings are all investment grade. S&P's long term issuer rating on the Company is BBB+; Moody's Baa2; and Fitch's is BBB+. All three agencies have a stable outlook on the Company.

Q. **WHAT ROLE DO CREDIT AGENCIES PLAY IN INVESTORS' EXPECTATIONS?**

A. In the wake of financial disasters, bankruptcies, and the ensuing severe erosion in investor confidence that began early in this decade, credit issues became critically important not only to fixed income investors, but also to equity investors. While credit downgrades initially impacted only the most troubled companies, a

[4] J.M. Cannell, Inc. State Utility Regulation: As Assessment of Investor Perceptions. Prepared for the Edison Electric Institute. August 2005.

spillover effect soon was experienced by healthy utilities. Part of this was due to the fact that the rating agencies came under harsh criticism that they had failed to detect problems early enough in companies such as Enron Corp. As a result, they began to heighten their scrutiny of all entities under their watch and became far more proactive in making rating changes. As well, "headline risk" began to come into play, as investors worried that—when credit problems in an industry are in the headlines—any company in the sector could be vulnerable to a downgrade. Thus, equity investors now closely watch the actions of the credit agencies, because any change in ratings can signal underlying problems and have a significant impact on a company's stock price.

Q. WHY IS HAVING AN INVESTMENT-GRADE CREDIT RATING IMPORTANT?

A. In simple terms, the higher the credit rating, the greater the access to debt capital and the less it costs to borrow. In turn, lower borrowing costs translate into lower customer rates. But on a slightly more complex level, when a debt rating nears or enters non-investment grade or "junk" status, interest costs begin to rise significantly because lenders need a higher return as compensation for the much higher risk they are incurring. It bears mention that credit rating downgrades occur more readily than do upgrades. Further, when a credit rating is officially non-investment grade, many financial institutions are no longer permitted to hold the bonds of the company in question. That company's debt is considered to be unsafe and thus unfit for inclusion in conservative investment portfolios.

Q. **PLEASE COMMENT ON THE IMPACT A NON-INVESTMENT GRADE CREDIT RATING HAS ON MARKET ACCESS.**

A. When a company is rated below investment grade, not only does it have to pay more for its debt, but its access to the credit markets is also fragile and uncertain. This is particularly true during times of heightened market instability, when investors tend to gravitate toward investments that are of a higher quality and thus perceived to be safer. Unfortunately, it is often during tumultuous periods that a company's need for credit is heightened, and it is at just those times that the credit spigot can be closed off. In more extreme situations, that lack of credit availability can cause a company's financials to spiral out of control, potentially resulting in bankruptcy.

The impact of a non-investment grade credit rating or the worst-case setting of a bankruptcy has a very deleterious impact on ratepayers. Because financing expense is a legitimate cost of service, customer rates must rise to reflect those higher costs. But, equally important, the company operations can be negatively impacted if a company is forced to take measures to conserve available cash.

Q. WHY IS A UTILITY'S REGULATORY ENVIRONMENT IMPORTANT TO THE RATING AGENCIES?

A. The rating agencies appraise companies on the basis of creditworthiness. Rating agencies also evaluate current financial soundness and attempt to discern how that might change in the future. One of the key factors in assessing a utility's financial picture is the regulatory climate in which the company operates, because regulators influence the utility's capital structure and establish allowed returns that may be earned on that capital. Thus, a regulatory environment characterized by consistency and predictability is one that lends itself to a company's having a sounder financial base. Conversely, a regulatory situation defined by a lack of stability can have a deleterious impact on a utility's credit profile.

Q. PLEASE DISCUSS MOODY'S RATING ON PEPCO.

A. The agency's assessments fit within the framework of its ratings method, in which the key factors it examines in its ratings are articulated and quantified.[5] Regulation is clearly of paramount importance: "regulatory framework" and "ability to recover costs and earn returns" each carry a 25% weighting. The other ratings factors are diversification (10%) and financial strength and liquidity (40%).

Q. PLEASE ELABORATE ON MOODY'S VIEWS REGARDING "REGULATORY FRAMEWORK."

A. Moody's notes that "the predictability and supportiveness of the regulatory framework" in which a utility operates is a "key credit consideration." The agency said it examines various factors of a regulatory environment, including "how developed the regulatory framework is; its track record for predictability and stability in terms of decision making; and the strength of the regulator's authority over utility regulatory issues. A utility operating in a stable, reliable, and highly predictable regulatory environment will be scored higher on this factor than a utility operating in a regulatory environment that exhibits a high degree of uncertainty or unpredictability."[6]

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[5] Moody's Electric Service, "Rating Methodology: Regulated Electric and Gas Utilities." August 2009.

[6] Id.

Q. WHAT ABOUT THE SECOND REGULATION-RELATED FACTOR, "ABILITY TO RECOVER COSTS AND EARN RETURNS?"

A. Moody's states "the ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated utilities, as the lack of timely recovery of such costs has caused financial stress for utilities on several occasions." The agency pointed to the fact that regulatory disputes which ended in insufficient or delayed rate relief were a factor in four of the six major investor-owned utility bankruptcies in the U.S. over the last 50 years. Moody's also opined that "currently, the utility industry's sizeable capital expenditure requirements for infrastructure needs will create a growing and ongoing need for rate relief for recovery of these expenditures at a time when the global economy has slowed."[7]

Q. WHAT SPECIFIC FACTORS DRIVE MOODY'S RATINGS OF PEPCO?

A. Moody's identifies four factors[8]:

- Operates in challenging regulatory environments
- Adequate cost recovery mechanisms and liquidity profile
- Significant capital spending program
- Strong historical financial metrics likely to be slightly pressured going forward

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[7] Id.
[8] Moody's Investors Service. "Credit Opinion: Potomac Electric Power Company." July 7, 2010.

Q. PLEASE ELABORATE ON THE AGENCY'S VIEWS OF THE DRIVERS.

A. In regard to Pepco's regulatory environment, the first factor noted above, Moody's scores the Company as a high Ba, which is on the lower end of the ranking scale-"as a result of the unpredictable and challenging regulatory environments in which it operates." The agency notes that the District of Columbia historically has been viewed as a "challenging regulatory environment due to a trend of authorizing return on equity (ROE) at levels slightly below industry averages." The firm does note favorably, however, that the Commission "has been more supportive of the recovery of costs as evidenced by the approval of a Bill Stabilization Adjustment (BSA) effective in November 2009."

Regarding the second ratings driver, ability to recover costs and earn returns, Moody's scores Pepco at the high Baa level. This assessment reflects the BSA and other minor riders on the positive side of the spectrum, offset by "a downward trend in the utility's earned return on equity to slightly more than 7% in 2009 from approximately 9% in 2008 and 11% in 2007. The agency does, however, anticipate improvement in earned returns with the implementation of rate increases.

As to the third ratings driver, significant capital spending program, Moody's expects Pepco's capex program to be financed with a mix of internally generated cash, debt, and PHI equity contributions. In addressing the fourth driver, a strong historical financial profile, the agency observed that Pepco's current financial metrics indicate a slightly higher rating. Moody's cautioned, however, that prospective metrics are expected to be "pressured to levels more indicative of a mid-Baa rating" with the onset of Pepco's large construction program.

Q. HOW DOES MOODY'S SUMMARIZE ITS OUTLOOK ON PEPCO?

A. The agency explained that its stable outlook on the Company reflects an expectation for continuation of an adequate financial profile as capital expansion ensues, "and that future distribution rate case filings will be constructive."

Q. WHAT IS FITCH'S PERSPECTIVE ON THE COMPANY?

A. In a recent affirmation of Pepco's and sister companies' Delmarva Power & Light's and Atlantic City Electric's ratings, Fitch expressed a relatively salutary opinion regarding the regulatory environment:

> Pepco's rating and Stable Outlook reflect the low business risk of its regulated electric transmission and distribution operations in Maryland and the District of Columbia. Regulation in both jurisdictions is constructive, allowing for timely recovery of power procurement costs, Federal Energy Commission (FERC) approved formula rates in retail rates, and energy efficiency and demand response costs.[9]

[9] Fitch Ratings. "Fitch Affirms IDRs of Pepco, Delmarva Power & Light, and

Q. DOES FITCH HAVE ANY REGULATORY-RELATED CONCERNS ABOUT THE COMPANY?

A. Yes. The agency noted Pepco's large spending program and consequent need to file frequent rate cases:

> Pepco has a large capital expenditure plan of $2.5 billion over 2010-14. A major portion of this for the proposed Mid-Atlantic Power Pathway (MAPP) and other FERC regulated transmission investments. … Pepco is also making substantial investments in Advanced Metering Infrastructure (AMI) and smart grid. Fitch expects the heavy capex cycle to pressure leverage measures, yet remain consistent with Pepco's 'BBB+' IDR. … It is Fitch's expectation that Pepco continues to finance its planned capex with a balanced mix of debt and equity infusion from the parent. Key rating drivers considered include customer growth, frequency and likely outcome of future rate cases and execution of the large capex plan.
>
> Rating concerns include persistent regulatory lag that causes Pepco to file frequent rate cases, thus exposing the company to macro factors such as the overall state of the economy, interest rates and local politics.[10]

Q. WHAT IS S&P'S OUTLOOK FOR THE COMPANY?

A. The rating agency expressed its expectation that the excellent business profile will be sustained due to PHI's "focusing on the three regulated T&D utilities and not increase unregulated operations beyond a nominal contribution to consolidated operating income."[11] Consistent with that view, S&P further expects a strengthening in cash flow protection and debt leverage

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Atlantic City Electric; Outlooks Stable." September 2, 2010.

[10] Id.

measures along with an increase in utility cash flows and decline in consolidated debt levels.

Q. HOW DOES S&P VIEW THE COMPANY'S REGULATORY ENVIRONMENT AND OUTLOOK?

A. In describing Pepco's weaknesses, S&P headed the list with "regulatory environments considered less credit supportive." It went on to say, though, that it expects PHI to "reach constructive regulatory outcomes to avoid any meaningful rises in business risk." The agency noted that it could change its stable outlook to negative if, among other factors, "expected rate recovery is less than expected, or financial measures do not achieve our expected levels on a sustained basis."[12]

Q. WHAT INFERENCES DO YOU DRAW FROM THE CREDIT RATING AGENCIES' VIEWS OF PEPCO AND ITS REGULATORY ENVIRONMENT?

A. Moody's evaluates companies within an articulated ratings method. Of the four factors the firm reviews, the regulatory framework and ability to recover costs and earn returns account for half of the evaluation. Specific to Pepco, Moody's characterizes the utility's regulatory environments as unpredictable and challenging, particularly due to authorized ROE levels that are below industry averages. However, the agency views favorably the fact that the District of Columbia has been more

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[11] Standard & Poor's. "Potomac Electric Power." July 16, 2010.

supportive of cost recovery mechanisms. Fitch considers the District of Columbia regulatory environment (along with that of Maryland) to be relatively salutary. The agency did, however, note Pepco's large prospective capital expenditure program as well as the persistent regulatory lag that will prompt frequent rate case filings. S&P in 2010 upgraded PHI and its subsidiaries to reflect the expected strengthening of credit quality from a refocus on utility operations following the divestment of merchant generating assets. The agency, while viewing PHI's state regulatory environments as less credit supportive, also voiced its belief that constructive business outcomes will be reached so as to minimize any meaningful rise in business risk. In sum, the three agencies have a somewhat mixed opinion about Pepco's regulatory climate.

Q. PLEASE TURN YOUR ATTENTION NOW TO THE OPINIONS OF EQUITY INVESTORS. HOW DO THEY VIEW THE COMPANY?

A. Analysts are keenly aware that PHI in mid-2010 completed the sale of its merchant generation assets and can now fully focus on its regulated utilities. With those operations expected to provide 90-95% of the corporation's earnings prospectively, investors are placing a renewed emphasis on the company's regulatory

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[12] Id.

environments. They also view PHI's dividend as an investment attribute, particularly given the opportunity present with stronger earnings growth ahead to reduce the above-average payout ratio.

Q. YOU PREVIOUSLY DISCUSSED THE IMPORTANCE OF THE DIVIDEND TO INDIVIDUAL INVESTORS IN UTILITY STOCKS. IS THE DIVIDEND ALSO IMPORTANT TO INSTITUTIONAL INVESTORS?

A. Yes. While individual investors primarily seek the additional income that a utility dividend affords them, institutions focus on total return, which is comprised of appreciation in the price of a stock along with dividend income. In the case of PHI, the $1.08 per share annual dividend rate currently represents a payout greater than the $0.91 earned in 2009 and a high proportion (87%) of 2010's earnings of $1.24. That high payout provides a very attractive dividend yield, which is in excess of that available from most utility and other investments. Institutions understand that a dividend rate that exceeds or constitutes the lion's share of earnings is not sustainable. In PHI's case, however, the expectation is for the dividend to be maintained, and for earnings to grow into the dividend rate. As JP Morgan noted:

> **Strong dividend should put a floor under the stock.** We believe further downside in POM shares is unlikely given its high dividend yield. Management has consistently reiterated its commitment to the dividend. We note, however, that we project that its payout ratio

> remains relatively high. 2010E EPS represent a transition year as the company is divesting its unregulated business, but POM must drive sufficient EPS in 2011 and beyond to bring its payout ratio more in line with the industry. We project that EPS growth will help reduce its payout ratio through 2012, but we note that we believe the company has limited margin for error because of its high payout ratio starting point.[13]

The firm's opinion is echoed by a number of other investment firms, including Soleil Securities, Oppenheimer, and Wellington Shields:

> Despite the >100% payout of current operating earnings, POM's commitment to its $1.08/shr dividend has never wavered, and we view it as secure.[14]

> Its dividend continues to be one of its primary investment drivers. With the divestiture of Conectiv Energy, PHI's dividend payout ratio rose to 119% in 2009. We believe that PHI will be able to 'grow into' its dividend in the next three years, as we expect earnings to rise with the increase in the distribution and transmission investments. Based on our analysis, we believe that it is not likely that PHI's dividend will be reduced in the next three years.[15]

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> In addition to the growth story, the dividend remains one of the most compelling features of POM shares. Despite recent earnings challenges, we believe that management remains committed to the current dividend. Given our

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[13] J.P. Morgan. "Pepco Holdings: Upgrading to Neutral; Negative Catalyst Did Not Materialize as we Expected; Yield Support Likely Limits Downside." July 22, 2010.

[14] Soleil Securities. "Pepco Holdings: Yield Play; Price Target Unchanged." September 9, 2010.

[15] Oppenheimer. "Pepco Holdings, Inc. Balancing Large Capex and Dividend Obligation; Initiate at Perform." September 28, 2010.

> EPS and cash flow growth expectations, we believe that dividend growth could be restored in the 2015-2016 time frame. Due to the EPS growth we expect, we project that the dividend payout ratio could continuously decline from about 85% in 2010 to closer to 71%-74% by 2013. The potential decline in the dividend payout should instill considerable investor confidence in the attractive dividend. Therefore, in our opinion, the company's dividend is secure and the level of security should improve materially over the next five years. The current indicated dividend of $0.27, $1.08 provides a current indicated yield of over 6.0%, attractive relative to nearly all peer utility stocks, and certainly relative to the broad market, and Treasury yields, in our view.[16]

Q. WHY SHOULD PHI'S DIVIDEND BE MAINTAINED AND NOT REDUCED OR OMITTED?

A. Because both individual and institutional investors place great value on PHI's dividend, a reduction in or omission of the payout would remove a strong rationale for an investment in the company. A negative dividend action would be particularly ill-advised during this period of high capital expenditures for PHI and its utility subsidiaries. Just as some debt investors are prohibited from owning non-investment grade credits, some equity investors have dividend income as a mandatory investment criterion. Further, as previously noted, individual investors in PHI's stock have come to rely on the income produced by their investment. A reduction of

[16] Wellington Shields & Co. LLC. "Pepco Holdings, Inc.; Reducing Estimates Modestly, Prospective Growth and Stock Remain Attractive." March 17,2011.

PHI's dividend would be a particular hardship to those lower income investors on fixed incomes. In short, maintaining PHI's dividend at its current level is critical to the company.

Q. IS PHI'S DIVIDEND ALSO IMPORTANT TO CUSTOMERS?

A. Yes. On November 17, 2010, the National Association of Utility Regulatory Commissioners (NARUC) adopted a Resolution urging Congress to retain the existing lower dividend tax rates, due to expire on December 31.[17] In its Resolution, NARUC made the following points regarding utility dividends:

- Raising dividend tax rates would make it more difficult for dividend-paying companies to attract investors. This is especially true for the extremely capital-intensive electric utility industry.
- Infrastructure projects created by utilities are an important source of high-quality jobs that will help keep America competitive.
- The higher cost of capital driven by higher income taxes on dividends, combined with utilities' need for extremely large amounts of capital, *will translate into higher utility customer rates*. (Emphasis added)

The regulators' points about utility dividends in general are also true for PHI specifically.

[17] National Association of Utility Regulatory Commissioners. "Resolution Urging Retention of the Lower Dividend Income Tax Rates." November 17,2010.

Q. IN ADDITION TO THE INFRASTRUCTURE INVESTMENTS CITED BY OPPENHEIMER, WHAT OTHER FACTORS DO ANALYSTS CONSIDER IMPORTANT IN HELPING GROW EARNINGS AND FURTHER SECURE THE SAFETY OF THE DIVIDEND?

A. Regulation is a frequently cited factor.

Q. PLEASE ELABORATE.

A. As noted previously, regulation is a critical element in determining the return on equity a utility is permitted and its ability to actually achieve it. The dividend payout is an outgrowth of the earnings level. The investment firm Edward Jones noted in its research its belief that future rate increases will help to support the dividend and thus lower the risk of its being reduced. Wunderlich Securities confirmed the importance of regulation to earnings: "Earnings growth in '11 and '12 is driven largely by rate increases in regulated operations."[18] The firm recently affirmed that viewpoint: As expected, recent rate increases had a significant impact on earnings."[19]

Q. CAN YOU BE MORE SPECIFIC ON INVESTORS' VIEWS REGARDING THE COMPANY'S REGULATORY SITUATION?

A. Yes. In addressing the subject of regulation as it pertains to Pepco and its parent PHI, analysts' comments

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[18] Wunderlich Securities. "Pepco Holdings, Inc.: 2Q EPS Better Than Expected; Increase Estimates and Maintain Hold." August 10, 2010.
[19] Wunderlich Securities. "1Q Better Than Expected; Raise Estimates and Target Price." May 9, 2011.

revolve around several topics: regulatory risk in general, regulatory lag, regulatory mechanisms, allowed ROE levels, and state/case-specific commentary.

Q. PLEASE DISCUSS ANALYSTS' VIEWS OF GENERAL REGULATORY RISK ASSOCIATED WITH THE COMPANY AND ITS PARENT.

A. Any utility falling under the jurisdiction of a state regulatory body will obviously be impacted by the rulings of that commission; the potential for regulatory risk is thus common to any regulated utility. The degree to which that factor is pronounced is determined by the quality of the regulatory environment. In the case of PHI, analysts have some reservations about the quality of the regulatory climates in the states in which the parent's subsidiaries operate, with some describing the company's collective regulatory environment as "challenging" and having "room for improvement." Moreover, investors are keenly aware of how critical constructive regulation is to PHI's and its subsidiaries' financial health. As Oppenheimer noted, "In our view, creating and maintaining a constructive regulatory environment and reasonable rate case outcomes are key to playing out PHI's strategy successfully."[20] Wellington Shields offers a similar opinion:

> As in all electric utilities, regulatory decisions are critical. The company faces a

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[20] Oppenheimer, op. cit.

number of critical regulatory decisions over the next several years that will help shape the fundamental outlook for the company. Regulatory outcomes are never more important than when a company is expanding aggressively. The company must achieve satisfactory regulatory outcomes on a timely basis to avoid excessive regulatory lag and weak earned returns. If the various regulators do not approve satisfactory revenue requirements to adequately support Pepco's [PHI's] capital program in a timely fashion, they will adversely affect Pepco's [PHI's] prospective financial performance. Without significant capital tracker/rider support for Pepco's [PHI's] capital plan, this is the one risk we are most concerned about."[21]

In a recent report, the Wellington Shields' analyst, now at Williams Capital, expands on that viewpoint:

> Given Pepco's transformation and the renewed focus on more aggressive utility growth, significant regulatory hurdles also remain a challenge to achieving the kind of earnings and cash flow we expect. The company's regulatory jurisdictions are certainly some of the less investor friendly in the country, yielding uncertainty regarding timely cost recovery and earned returns.[22]

Q. YOU REFERRED TO OTHER ISSUES IMPORTANT TO INVESTORS SUCH AS REGULATORY LAG, ALLOWED ROE LEVELS, AND REGULATORY MECHANISMS.

A. Regulatory lag impedes a utility's ability to earn its allowed ROE. PHI's subsidiaries have several sources of regulatory lag, including, importantly, the absence of regulatory mechanisms that would serve to mitigate the earnings gap. Investors have expressed clear concern

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[21] Wellington Shields. "Pepco Holdings." November 30, 2010.

that the PHI utilities are subject to large amounts of regulatory lag. For example, Wells Fargo stated: "In addition, the lack of rate riders and forward looking test years make it challenging for the regulated utilities to earn their allowed ROE even immediately after new rates are implemented."[23] Indeed, SunTrust Robinson Humphrey has quantified its 2011 and 2012 earnings per share estimates of $1.25 and $1.35, respectively, as assuming the sizeable sums of $0.35 and $0.27 of regulatory lag in PHI's utility portfolio in 2011 and 2012, respectively.[24] In other words, the analyst's 2011 EPS estimate would have been $1.60 and the 2012 estimate would have been $1.62, in the absence of regulatory lag.

Wellington Shields provides perhaps the most forceful statement of the deleterious affect that regulatory lag has on the PHI utilities. The firm notes that a persistence of regulatory lag would impair PHI's earnings growth, heighten concerns over dividend safety, and affect the company's access to the capital markets on reasonable terms:

> Should regulatory lag prove onerous during Pepco's [PHI's] construction build-out, it will certainly adversely affect Pepco's [PHI's]

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[22] Williams Capital Research. "Pepco Holdings, Inc." June 21, 2011.

[23] Wells Fargo Securities. "Pepco Holdings, Inc: POM: Upgrading Rating to Outperform; T&D Growth Story with Attractive Yield." May 25, 2010.

[24] SunTrust Robinson Humphrey. "Pepco Holdings, Inc.: 4Q Above Our Estimate Primarily due to Favorable Tax Treatment." February 28, 2011.

> ability to attract the debt and equity financing that will be necessary to support the company's construction program on favorable terms. Failing to achieve satisfactory, timely return on Pepco's [PHI's] capital expansion will also affect the dividend. While we are currently comfortable with the direction of Pepco's [PHI's] fundamental prospects and the current dividend, weak earned returns on rate base could slow the improvement in the dividend coverage that will be important to reducing investor anxiety over the high dividend payout ratio and in turn affect the pricing of significant new equity over the next five years.[25]

Q. ARE INVESTORS AWARE OF THE COMPANY'S EFFORTS TO MITIGATE REGULATORY LAG?

A. Yes. As SunTrust Robinson Humphrey and Wunderlich Securities respectively noted,

> **Final resolution of the Delmarva Power electric rate case in Maryland should provide more clarity on POM's ability to reduce regulatory lag (which we currently estimate at $0.33 per share).** As part of the Delmarva Power rate case settlement, which was filed on May 25th, the parties agreed to initiate a separate discussion on how to mitigate regulatory lag and reach their conclusions 100 days after the approval of the settlement by the Maryland PSC (which is expected by June 15th). We note that POM has suggested two lag reduction mechanisms: reliability investment tracker and automatic annual rate adjustments. If POM is successful in implementing a lag reduction mechanism in this proceeding, it could be applied to the company's other utilities as well. Our current estimates assume that the regulatory lag is reduced to $0.20 by 2013.[26]

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[25] Wellington Shields & Co. LLC, op.cit., November 30, 2010.
[26] SunTrust Robinson Humphrey. "Pepco Holdings, Inc.: Regulatory Developments Key to Earnings (and Stock Price) Outlook." May 27, 2011.

> **Regulatory lag continues to be key challenge.** … Regulatory lag versus allowed returns equates to $0.30 in EPS. It appears POM will be a serial filer of rate cases over the next few years, and while the company intends to seek mechanisms such as trackers and forward test years to help eliminate regulatory lag, our sense is that it will take several rounds of cases to meaningfully reduce this lag.[27]

Indeed, Company Witness Lowry's testimony details a number of options that the Commission could adopt to mitigate regulatory lag, including revenue decoupling, multiyear revenue caps, cost trackers, and fully forecast test years.

It bears mention that, in the 2005 Investor Perception study previously referenced in my testimony, investors expressed support for mechanisms that improve the regulatory process in general. For example, when queried as to which areas or regulatory treatment could bear improvement, over half the analysts' responses referenced regulatory flexibility and mechanisms. As to specific mechanisms, the study sought analyst views on future test years and CWIP in rate base. 83% of respondents endorsed the use of a future (versus historical) test year, and 97% supported placing CWIP in rate base.[28] These mechanisms would offer a number of benefits, chief among them greater certainty regarding

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[27] Wunderlich Securities. "Pepco Holdings, Inc.: Tough Outlook for POM; Yield Provides Floor for Stock." April 11, 2011.

the recovery of costs. But, importantly, because a greater proportion of expenditures would be recovered in a more timely fashion, these mechanisms would also lengthen the time between rate cases.

Q. CAN THE USE OF SOME OF THE REGULATORY MECHANISMS DISCUSSED IN COMPANY WITNESS DR. LOWRY'S TESTIMONY THAT WORK TO REDUCE LAG ALSO HELP TO SUPPORT A COMPANY'S CREDIT QUALITY?

A. Yes. As Company Witness Dr. Lowry's testimony states, statistics published by S&P confirm that companies utilizing a forward test year had more favorable credit metrics than did utilities with historical test years. These metrics included a stronger credit rating (A- and A vs. BBB+ and A-); higher average return on capital (9.7% compared to 8.3%); improved EBITDA/interest coverage (5.4 vs. 4.8); and more robust FFO/debt ratio (24.8% compared to 21.0%).[29]

Q. YOU PREVIOUSLY CITED ALLOWED ROE LEVELS AS AN AREA OF INVESTOR CONCERN. PLEASE EXPAND ON THAT ISSUE.

A. Analysts are acutely aware that PHI's utilities in recent rate proceedings have not been allowed ROEs that are consistent with those permitted on average in most other jurisdictions. Subpar allowed ROEs, particularly

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[28] J.M. Cannell, Inc., op. cit.
[29] Lowry at 59-61.

when coupled with significant regulatory lag, have rendered the utilities incapable of realizing a competitive return. For example, Wells Fargo Securities noted:

> **Regulatory Update.** POM laid out a menu of mechanisms to reduce regulatory lag in the next round of rate filings. The strategy appears to be pursuing formula rate plans with annual updates as regulators do not have much appetite for riders. Regulators' reception to reform is uncertain at this point and we have been discouraged by recent rate outcomes, including sub-10% ROEs in Maryland and DC.[30]

Investors are hopeful, however, that ROEs will improve. This could occur through the successful combination of increased allowed return levels, coupled with measures to mitigate regulatory lag. As Wellington Shields stated:

> Given Pepco's transformation and the renewed focus on utility growth, significant regulatory hurdles also remain a challenge to achieving the kind of earnings and cash flow growth we expect. The company's regulatory jurisdictions are certainly some of the less investor friendly in the country. However, with the company's utilities generally under-earning at less than 10.0% ROEs on distribution and with a substantial capital program, we do expect material incremental earnings from distribution rate cases.[31]

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[30] Wells Fargo Securities. "Pepco Holdings: POM: Q3 Earnings And EEI Wrap-Up--Raising 2010E EPS." November 9, 2010.

[31] Wellington Shields & Co. LLC, op. cit., March 17, 2011.

Q. PLEASE SUMMARIZE INVESTORS' VIEWS OF THE COMPANY AND ITS REGULATORY ENVIRONMENT.

A. Analysts believe that PHI's recent divestment of its merchant generation assets and renewed focus on utility operations will result in improved earnings in the years ahead. The dividend payout, currently very high but expected to decline as earnings grow, provides investors with an appealing level of income. Investors understand that supportive regulation will be needed to ensure Pepco's financial health prospectively: the allowed ROE will underpin earnings and dividend growth. Regulation is viewed as a risk element for many utilities, including Pepco and its sister companies. In particular, regulatory lag is a concern for the PHI utilities, due to the absence of effective mechanisms to mitigate that lag. Investors are aware of and endorse the fact that the Company is proposing a number of options to help reduce lag. They are also hopeful that recently allowed subpar ROE levels will increase; this, along with the approval of mechanisms to combat the impact of regulatory lag, should result in a greater opportunity to earn its allowed rate of return. In turn, the safety of the dividend is reinforced.

IV. INVESTORS' EXPECTATIONS FOR RETURN ON EQUITY FOR PEPCO

Q. HOW DO YOU BELIEVE THAT THE COMPANY'S REQUEST FOR A 10.75% RETURN ON EQUITY COMPORTS WITH INVESTORS' PERCEPTIONS?

A. Investors will evaluate any ROE authorized by the Commission in light of a number of factors, including such things as the overall amount of the requested increase that is granted, which bears on the Company's ability to earn the allowed ROE, and whether or not there is a settlement in the case. The fact that an ROE is arrived at through settlement is often seen as a positive factor for investors. In this case, the Company has filed its application seeking a 10.75% ROE, which is higher than the current authorized ROE level of 9.63%, established in mid-2008. This filing reflects the rising risk levels in the macroeconomic and capital market environments, as well as recognition on the part of both credit rating agencies and investors that company-specific risks exist. Most importantly, a 10.75% authorized ROE would help maintain the Company's financial health, and assist in maintaining access to the debt and equity capital markets.

Q. COULD A RETURN ON EQUITY AWARD THAT IS CONSISTENT WITH INVESTOR EXPECTATIONS ALSO BE EXPECTED TO PROVIDE BENEFITS TO THE COMPANY'S CUSTOMERS?

A. Absolutely. A higher ROE permits the realization of a stronger earnings stream. In turn, that can improve a company's stock's valuation prospects, which results in a higher stock price. Thus, when a company needs to tap the equity markets for capital required to meet customer needs, it can get more for its money. Said another way, each share sold brings more equity into a company with the same commitment by the company to generate earnings and pay dividends to support the value of that share. In regard to debt financing, a higher ROE awarded to the Company would be viewed as a sign of constructive regulation and would be positive for the Company's credit rating, as strengthened financial metrics could potentially improve the existing credit ratings. Importantly, customers' rates will eventually reflect this lower cost of capital.

CONCLUSION

Q. PLEASE SUMMARIZE WHAT BEARING THE OPINION AND EXPECTATIONS OF INVESTORS HAVE ON THE CURRENT PROCEEDING.

A. This is a precarious time for the electric utility industry. With companies – Pepco among them – facing continued high levels of construction and other costs, and requiring reasonable access to the capital markets to fund those requirements, supportive regulation is critical. Investors are aware of these factors, and expect the Commission to make decisions in light of them that will enable the Company to meet its investment and other requirements. Current market conditions, current trends in ROE awards, and Pepco's increased risks support an increase in the last allowed ROE.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

J. M. CANNELL
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO ______ (C)-1

SUMMARY OF TESTIMONY EXPERIENCE
JULIE M. CANNELL

JURISDICTION	CASE OR DOCKET NO.	CLIENT	DATE
Maryland	9249	Delmarva P&L (Pepco Holdings, Inc.)	2011
Vermont	7627	Central Vermont Public Service Corporation	2010
Texas	38480	Texas-New Mexico Power (PNM Resources)	2010
Minnesota	E-015/GR-09-1151	Minnesota P&L (Allete, Inc.)	2010
Pennsylvania	R-2010-2161694	PPL Electric Utilities (PPL Corp.)	2010
Wisconsin	3270-UR-117	Madison G&E (MGE Energy)	2010
South Carolina	D-2009-489-E	South Carolina E&G (SCANA Corp.)	2010
Missouri	ER-2010-0036	Ameren UE (Ameren)	2010
Rhode Island	4065	Narragansett Electric (National Grid)	2009
Colorado	09AL-299E	Public Service Company of Colorado (Xcel Energy)	2009
Massachusetts	DPU 09-39	Massachusetts Electric (National Grid)	2009
Wisconsin	3270-UR-116	Madison G&E (MGE Energy)	2009
New York	08-E-0539	Consolidated Edison Company of New York (Consolidated Edison, Inc.)	2008
South Carolina	2007-229-E	South Carolina E&G (SCANA Corp.)	2007
Pennsylvania	R-00072155	PPL Electric Utilities (PPL Corp.)	2007

Jurisdiction	Case or Docket No.	Client	Date
Virginia	PUE-2006-00065	Appalachian Power Co. (American Electric Power)	2006
Arizona	E-01345A-05-0816	Arizona Utility Investors Association [Arizona Public Service docket]	2006
Texas	32093	CenterPoint Energy	2006
Pennsylvania	R-00061346	Duquesne Light	2006
Washington	UE-060181	Avista Corporation	2006
Oklahoma	PUD 200500151	Oklahoma G&E (OGE Energy)	2005
Pennsylvania	R-00049255	PPL Electric Utilities (PPL Corp.)	2004
South Carolina	2004-178-E	South Carolina E&G (SCANA Corp.)	2004
Nevada	04-6030	Nevada Power (Sierra Pacific Resources)	2004
Connecticut	01-10-10	United Illuminating (UIL Holdings)	2001
Missouri	ER 99-247; ER-99-573	St. Joseph Light & Power	1999
Kansas	97-WSRE-676-MER	Western Resources	1997
Missouri	EM-97-515		
Virginia	PUE960296	Virginia Power (Dominion Resources)	1997