BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 16-0395-EL-SSO

CASE NO. 16-0397-EL-AAM

CASE NO. 16-0396-EL-ATA

2016 ELECTRIC SECURITY PLAN

VOLUME 8 OF 8 – TESTIMONY

WITNESSES MORIN, PARKE, AND RAGA

Dayton Power and Light Company

DP&L Case No. 16-0395-EL-SSO

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DIRECT TESTIMONY
OF ROGER A. MORIN

- □ **MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION**
- □ **OPERATING INCOME**
- □ **RATE BASE**
- □ **ALLOCATIONS**
- ■ **RATE OF RETURN**
- □ **RATES AND TARIFFS**
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BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

DIRECT TESTIMONY OF

ROGER A. MORIN

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

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I. INTRODUCTION

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

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Emeritus Professor of Finance at the Robinson College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government. I am testifying on behalf of The Dayton Power and Light Company ("DP&L" or "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

Q. PLEASE SUMMARIZE YOUR ACADEMIC AND BUSINESS CAREER.

A. I have taught at the Wharton School of Finance, University of Pennsylvania, Amos Tuck School of Business at Dartmouth College, Drexel University, University of Montreal, McGill University, and Georgia State University. I was a faculty member of Advanced Management Research International, and I am currently a faculty member of The

Management Exchange Inc. and Exnet, Inc. (now “SNL Center for Financial Education LLC” or “SNL”), where I continue to conduct frequent national executive-level education seminars throughout the United States and Canada. In the last 30 years, I have conducted numerous national seminars on “Utility Finance,” “Utility Cost of Capital,” “Alternative Regulatory Frameworks,” and “Utility Capital Allocation,” which I have developed on behalf of The Management Exchange Inc. and the SNL Center for Financial Education.

I have authored or co-authored several books, monographs, and articles in academic scientific journals on the subject of finance. They have appeared in a variety of journals, including The Journal of Finance, The Journal of Business Administration, International Management Review, and Public Utilities Fortnightly. I published a widely-used treatise on regulatory finance, Utilities’ Cost of Capital, Public Utilities Reports, Inc., Arlington, Va. 1984. In late 1994, the same publisher released my book, Regulatory Finance, a voluminous treatise on the application of finance to regulated utilities. A revised and expanded edition of this book, The New Regulatory Finance, was published in 2006. I have been engaged in extensive consulting activities on behalf of numerous corporations, legal firms, and regulatory bodies in matters of financial management and corporate litigation. Exhibit RAM-1 describes my professional credentials in more detail.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON COST OF CAPITAL BEFORE UTILITY REGULATORY COMMISSIONS?

A. Yes, I have been a cost of capital witness before nearly 50 regulatory bodies in North America, including the Public Utilities Commission of Ohio (the "Commission" or "PUCO"), Federal Energy Regulatory Commission ("FERC"), and the Federal Communications Commission ("FCC"). I have also testified before the following state, provincial, and other local regulatory commissions:

Alabama	Florida	Missouri	Ontario
Alaska	Georgia	Montana	Oregon
Alberta	Hawaii	Nevada	Pennsylvania
Arizona	Illinois	New Brunswick	Quebec
Arkansas	Indiana	New Hampshire	South Carolina
British Columbia	Iowa	New Jersey	South Dakota
California	Kentucky	New Mexico	Tennessee
City of New Orleans	Louisiana	New York	Texas
Colorado	Maine	Newfoundland	Utah
CRTC	Manitoba	North Carolina	Vermont
Delaware	Maryland	North Dakota	Virginia
District of Columbia	Michigan	Nova Scotia	Washington
FCC	Minnesota	Ohio	West Virginia
FERC	Mississippi	Oklahoma	Nebraska

The details of my participation in regulatory proceedings are provided in Exhibit RAM-1.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my direct testimony in this proceeding is to present an independent appraisal of the fair and reasonable rate of return on common equity ("ROE") on the capital invested in the generation capacity component of the electric operations of DP&L in the state of Ohio. Based upon this appraisal, I have formed my professional judgment as to a ROE on such capital that would: (1) be fair to the ratepayer, (2) allow the Company to attract capital on reasonable terms, (3) maintain the Company's financial integrity, and (4) be comparable to returns offered on comparable risk investments. I will testify in this proceeding as to that opinion.

This testimony and accompanying exhibits were prepared by me or under my direct supervision and control. The source documents for my testimony are Company records, public documents, commercial data sources, and my personal knowledge and experience.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following:

- Exhibit RAM-1 (Dr. Morin's Resume)
- Exhibit RAM-2 (Dr. Morin's DP&L Distribution Rate Case Testimony)

III. RETURN ON EQUITY

Q. DID YOU PROVIDE ROE TESTIMONY IN THE COMPANY'S RECENTLY FILED ELECTRIC DISTRIBUTION CASE?

A. Yes, I did. Exhibit RAM-2 is a copy of that testimony.

Q. IS THE RANGE IN ROE RESULTS YOU PROVIDED IN THAT TESTIMONY STILL VALID UNDER CURRENT CAPITAL MARKET CONDITIONS?

A. Yes, it is. Capital market conditions have not changed to an extent that would warrant a change in my recommendation.

Q. PLEASE STATE YOUR FINDINGS CONCERNING DP&L'S COST OF COMMON EQUITY IN ITS RECENTLY-FILED DISTRIBUTION CASE.

A. In the Company's recently-filed electric distribution case, Case No. 15-1830-EL-AIR, the ROE results ranged from 9.6% to 10.7%. To arrive at this range, I performed a Discounted Cash Flow ("DCF") analysis on a group of investment-grade dividend-paying combination gas and electric utilities using Value Line's and analysts' growth forecasts. I also performed four risk premium analyses. For the first two risk premium studies, I applied the Capital Asset Pricing Model ("CAPM") and an empirical approximation of the CAPM using current market data. The other two risk premium analyses were performed on historical and allowed risk premium data from electric utility industry aggregate data, using the forecast yield on long-term US Treasury bonds.

In that case, I recommended the adoption of a ROE in the upper half of that range, namely 10.5%. That ROE was based on the Company's higher-than-average investment risk compared to other regulated utilities, specifically DP&L's high external financing requirements relative to its rate base and common equity capital base, on the uncertainty surrounding the Company's appropriate capital structure to be employed for ratemaking, on the unique business risks in the Ohio jurisdiction, and on the economic conditions in the local economy.

Moreover, my recommended ROE in that case was based on the Commission's adoption of the Company's proposed 50% common equity ratio for ratemaking purposes for reasons explained in that testimony.

Q. WHAT RATE OF RETURN ON COMMON EQUITY ARE YOU RECOMMENDING IN THIS CASE?

A. I am recommending a ROE at the top end of the aforementioned range, 10.7%.

Q. PLEASE EXPLAIN THE REASONS FOR RECOMMENDING THE UPPER END OF THAT RANGE IN THIS CASE.

A. DP&L's generation function presents unique market circumstances in the state of Ohio and its risks exceed those of electric distribution operations. Under current Ohio legislation, DP&L's electric generation is sold in a competitive market in Ohio, and its retail customers have the ability to switch to alternative suppliers for their electric generation service. Competitive retail electric suppliers can and do supply power to DP&L's current customers in Ohio, and the Company has experienced an increase in customer switching in recent years. Since the Company's electric security plan ("ESP") was implemented in 2009, the Company has experienced deteriorating financial results because of both low market prices in the generation market and greater competitive forces in Ohio. The continuing sluggish economy of Ohio, along with low power prices, exacerbates margin losses. Regulatory risks remain high as well since the terms of the regulatory compact in Ohio include periodic price testing for Commission-approved ESPs that may extend beyond three year terms and contain earnings caps on utilities.

These evolving market conditions will continue to impact DP&L's results of operations. Increased competition resulting from deregulation or restructuring efforts in Ohio, coupled with the rules governing ESPs whereby every three to four years the Commission periodically alters a utility's standard service offer model, would continue to have a significant adverse impact on DP&L's financial position, results of operations or cash flow.

Q. DOES A RELIABLE ELECTRICITY RIDER ("RER") MITIGATE THE RISKS FACING A OHIO GENCO?

A. Yes, a RER would lower the risks, since it would provide some measure of rate support for the Ohio Genco. That is why I have started with the same ROE range that I used for the DP&L distribution function. The required ROE for a merchant generation plant would be significantly higher.

Q. WOULD IT BE IN THE BEST INTERESTS OF CUSTOMERS FOR THE COMMISSION TO APPROVE A 10.7% ROE FOR DP&L'S ELECTRICITY GENERATION OPERATIONS?

A. Yes. A ROE of 10.7% fairly compensates investors, maintains the Company's credit strength, and attracts the capital needed for capital investments. Adopting a lower ROE would increase costs for customers.

Q. PLEASE EXPLAIN HOW A LOWER ALLOWED ROE CAN INCREASE BOTH THE FUTURE COST OF EQUITY AND DEBT FINANCING.

A. If a company is authorized a ROE below the level required by equity investors, the company or its parent will find it difficult to access equity. Investors will not provide equity capital at the current market price if the earnable return on equity is below the level they require given the risks of an equity investment in the company. The equity market corrects this by generating a stock price in equilibrium that reflects the valuation of the potential earnings stream from an equity investment at the risk-adjusted return equity investors require. In the case of a company that has been authorized a return below the level investors believe is appropriate for the risk they bear, the result is a decrease in the utility's market price per share of common stock. This effect reduces the financial viability of equity financing in two ways. First, because the company's price per share of common stock decreases, the net proceeds from issuing common stock are reduced. Second, since the company's market-to-book ratio decreases with the decrease in the share price of common stock, the potential risk from dilution of equity investments reduces investors' inclination to purchase new issues of common stock. The ultimate effect is that the company will have to rely more on debt financing to meet its capital needs.

As the company relies more on debt financing, its capital structure becomes more leveraged. Because debt payments are a fixed financial obligation to the company, and income available to common equity is subordinate to fixed charges, these debt payments decrease the operating income available for dividend and earnings growth. Consequently, equity investors face greater uncertainty about future dividends and earnings from the company. As a result, the company's equity becomes a riskier investment. The risk of default on the company's bonds also increases, making the company's debt a riskier investment. This risk increases the cost to the company from both debt and equity financing and increases the possibility the company will not have access to the capital markets for its outside financing needs. Ultimately, to ensure that DP&L has access to capital markets for its capital needs, a fair and reasonable authorized ROE of 10.7% is required.

The Company must secure outside funds from capital markets to finance required plant and equipment investments irrespective of capital market conditions, interest rate conditions and the quality consciousness of market participants. Thus, rate relief requirements and supportive regulatory treatment, including approval of my recommended ROE, are essential requirements.

Q. WHAT CAPITAL STRUCTURE ASSUMPTION UNDERLIES YOUR RECOMMENDED RETURN ON DP&L'S COMMON EQUITY CAPITAL?

A. As was the case in the distribution case, my recommended ROE for DP&L's generation function is predicated on the adoption of a capital structure consisting of 50% common equity capital for ratemaking purposes. The basis of that recommendation is fully described in my electric distribution case testimony attached as Exhibit RAM-2.

IV. CONCLUSION

Q. DR. MORIN, WHAT IS YOUR FINAL CONCLUSION REGARDING DP&L'S COST OF COMMON EQUITY CAPITAL?

A. Based on the results of all my analyses, the application of my professional judgment, and the risk circumstances of DP&L, it is my opinion that a just and reasonable ROE for DP&L's electricity generation operations in the State of Ohio is 10.7%.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

RESUME OF ROGER A. MORIN

(Winter 2016)

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Indian Harbour
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(404) 229-2857 cellular
(902) 823-0000 summer office

E-MAIL ADDRESS: profmorin@mac.com

EMPLOYER 1980-2015: Georgia State University
Robinson College of Business
Atlanta, GA 30303

RANK: Emeritus Professor of Finance

HONORS: Distinguished Professor of Finance for Regulated Industry,
Director Center for the Study of Regulated Industry,
Robinson College of Business, Georgia State University.

EDUCATIONAL HISTORY

- Bachelor of Electrical Engineering, McGill University, Montreal, Canada, 1967.

- Master of Business Administration, McGill University, Montreal, Canada, 1969.

- PhD in Finance & Econometrics, Wharton School of Finance, University of Pennsylvania, 1976.

EMPLOYMENT HISTORY

- Lecturer, Wharton School of Finance, Univ. of Pennsylvania, 1972-3
- Assistant Professor, University of Montreal School of Business, 1973-1976.
- Associate Professor, University of Montreal School of Business, 1976-1979.
- Professor of Finance, Georgia State University, 1979-2011
- Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, Robinson College of Business, Georgia State University, 1985-2009
- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986
- Emeritus Professor of Finance, Georgia State University, 2007-16

OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.
- Member Board of Directors, Financial Research Institute of Canada, 1974-1980.
- Co-founder and Director Canadian Finance Research Foundation, 1977.
- Vice-President of Research, Garmaise-Thomson & Associates, Investment Management Consultants, 1980-1981.
- Member Board of Directors, Executive Visions Inc., 1985-2016
- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991.
- Member Board of Directors, Hotel Equities Inc., 2009-2016

PROFESSIONAL CLIENTS

AGL Resources

AT & T Communications

Alagasco - Energen

Alaska Anchorage Municipal Light & Power

Alberta Power Ltd.

Allete

Alliant Energy

AmerenUE

American Water

Ameritech

Arkansas Western Gas

ATC Transmission

Baltimore Gas & Electric – Constellation Energy

Bangor Hydro-Electric

B.C. Telephone

B C GAS

Bell Canada

Bellcore

Bell South Corp.

Bruncor (New Brunswick Telephone)

Burlington-Northern

C & S Bank

California Pacific

Cajun Electric

Canadian Radio-Television & Telecomm. Commission

Canadian Utilities

Canadian Western Natural Gas

Cascade Natural Gas

Centel

Centra Gas

Central Illinois Light & Power Co

Central Telephone

Central & South West Corp.

CH Energy

Chattanooga Gas Company

Cincinnatti Gas & Electric

Cinergy Corp.

Citizens Utilities

City Gas of Florida

CN-CP Telecommunications

Commonwealth Telephone Co.

Columbia Gas System

Consolidated Edison

Consolidated Natural Gas

Constellation Energy

Delmarva Power & Light Co

Deerpath Group

Detroit Edison Company

Dayton Power & Light Co.

DPL Energy

Duke Energy Indiana

Duke Energy Kentucky

Duke Energy Ohio

DTE Energy

Edison International

Edmonton Power Company

Elizabethtown Gas Co.

Emera

Energen

Engraph Corporation

Entergy Corp.

Entergy Arkansas Inc.

Entergy Gulf States, Inc.

Entergy Louisiana, Inc.

Entergy Mississippi Power

Entergy New Orleans, Inc.

First Energy

Florida Water Association

Fortis

Garmaise-Thomson & Assoc., Investment Consultants

Gaz Metropolitain

General Public Utilities

Georgia Broadcasting Corp.

Georgia Power Company

GTE California - Verizon

GTE Northwest Inc. - Verizon

GTE Service Corp. - Verizon

GTE Southwest Incorporated - Verizon

Gulf Power Company

Havasu Water Inc.

Hawaiian Electric Company

Hawaiian Elec & Light Co

Heater Utilities – Aqua - America

Hope Gas Inc.

Hydro-Quebec

ICG Utilities

Illinois Commerce Commission

Island Telephone

ITC Holdings

Jersey Central Power & Light

Kansas Power & Light

KeySpan Energy

Maine Public Service

Manitoba Hydro

Maritime Telephone

Maui Electric Co.

Metropolitan Edison Co.

Minister of Natural Resources Province of Quebec

Minnesota Power & Light

Mississippi Power Company

Missouri Gas Energy

Mountain Bell

National Grid PLC

Nevada Power Company

New Brunswick Power

Newfoundland Power Inc. - Fortis Inc.

New Market Hydro

New Tel Enterprises Ltd.

New York Telephone Co.

NextEra Energy

Niagara Mohawk Power Corp

Norfolk-Southern

Northeast Utilities

Northern Telephone Ltd.

Northwestern Bell

Northwestern Utilities Ltd.

Nova Scotia Power

Nova Scotia Utility and Review Board

NUI Corp.

NV Energy

NYNEX

Oklahoma G & E

Ontario Telephone Service Commission

Orange & Rockland

PNM Resources

PPL Corp

Pacific Northwest Bell

People's Gas System Inc.

People's Natural Gas

Pennsylvania Electric Co.

Pepco Holdings

Potomac Electric Power Co.

Price Waterhouse

PSI Energy

Public Service Electric & Gas

Public Service of New Hampshire

Public Service of New Mexico

Puget Sound Energy

Quebec Telephone

Regie de l’Energie du Quebec

Rockland Electric

Rochester Telephone

SNL Center for Financial Execution

San Diego Gas & Electric

SaskPower

Sempra

Sierra Pacific Power Company

Source Gas

Southern Bell

Southern States Utilities

Southern Union Gas

South Central Bell

Sun City Water Company

TECO Energy

The Southern Company

Touche Ross and Company

TransEnergie

Trans-Quebec & Maritimes Pipeline

TXU Corp

US WEST Communications

Union Heat Light & Power

Utah Power & Light

Vermont Gas Systems Inc.

Wisconsin Power & Light

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73
- Hydro-Quebec, "Capital Budgeting Under Uncertainty," 1974-75
- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78
- Investment Dealers Association of Canada, 1977-78
- Financial Research Foundation, bi-annual seminar, 1975-79
- Advanced Management Research (AMR), faculty member, 1977-80
- Financial Analysts Federation, Educational chapter: "Financial Futures Contracts" seminar
- Exnet Inc. a.k.a. The Management Exchange Inc., faculty member 1981-2008:

  National Seminars: *Risk and Return on Capital Projects*
  Cost of Capital for Regulated Utilities
  Capital Allocation for Utilities
  Alternative Regulatory Frameworks
  Utility Directors' Workshop
  Shareholder Value Creation for Utilities
  Fundamentals of Utility Finance
  Contemporary Issues in Utility Finance

- SNL Center for Financial Education. faculty member 2008-2016.
  National Seminars: *Essentials of Utility Finance*

- Georgia State University College of Business, Management

Development Program, faculty member, 1981-1994.

EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Corporate Finance

Rate of Return

Capital Structure

Generic Cost of Capital

Costing Methodology

Depreciation

Flow-Through vs Normalization

Revenue Requirements Methodology

Utility Capital Expenditures Analysis

Risk Analysis

Capital Allocation

Divisional Cost of Capital, Unbundling

Incentive Regulation & Alternative Regulatory Plans

Shareholder Value Creation

Value-Based Management

REGULATORY BODIES

Alabama Public Service Commission

Alaska Regulatory Commission

Alberta Public Service Board

Arizona Corporation Commission

Arkansas Public Service Commission

British Columbia Board of Public Utilities

California Public Service Commission

Canadian Radio-Television & Telecommunications Comm.

City of New Orleans Council

Colorado Public Utilities Commission

Delaware Public Service Commission

District of Columbia Public Service Commission

Federal Communications Commission

Federal Energy Regulatory Commission

Florida Public Service Commission

Georgia Public Service Commission

Georgia Senate Committee on Regulated Industries

Hawaii Public Utilities Commission

Illinois Commerce Commission

Indiana Utility Regulatory Commission

Iowa Utilities Board

Kentucky Public Service Commission

Louisiana Public Service Commission

Maine Public Utilities Commission

Manitoba Board of Public Utilities

Maryland Public Service Commission

Michigan Public Service Commission

Minnesota Public Utilities Commission

Mississippi Public Service Commission

Missouri Public Service Commission

Montana Public Service Commission

National Energy Board of Canada

Nebraska Public Service Commission

Nevada Public Utilities Commission

New Brunswick Board of Public Commissioners

New Hampshire Public Utilities Commission

New Jersey Board of Public Utilities

New Mexico Public Regulation Commission

New Orleans City Council

New York Public Service Commission

Newfoundland Board of Commissioners of Public Utilities

North Carolina Utilities Commission

Nova Scotia Board of Public Utilities

Ohio Public Utilities Commission

Oklahoma Corporation Commission

Ontario Telephone Service Commission

Ontario Energy Board

Oregon Public Utility Service Commission

Pennsylvania Public Utility Commission

Quebec Regie de l'Energie

Quebec Telephone Service Commission

South Carolina Public Service Commission

South Dakota Public Utilities Commission

Tennessee Regulatory Authority

Texas Public Utility Commission

Utah Public Service Commission

Vermont Department of Public Services

Virginia State Corporation Commission

Washington Utilities & Transportation Commission

West Virginia Public Service Commission

SERVICE AS EXPERT WITNESS

Southern Bell, So. Carolina PSC, Docket #81-201C

Southern Bell, So. Carolina PSC, Docket #82-294C

Southern Bell, North Carolina PSC, Docket #P-55-816

Metropolitan Edison, Pennsylvania PUC, Docket #R-822249

Pennsylvania Electric, Pennsylvania PUC, Docket #R-822250

Georgia Power, Georgia PSC, Docket # 3270-U, 1981

Georgia Power, Georgia PSC, Docket # 3397-U, 1983

Georgia Power, Georgia PSC, Docket # 3673-U, 1987

Georgia Power, F.E.R.C., Docket # ER 80-326, 80-327

Georgia Power, F.E.R.C., Docket # ER 81-730, 80-731

Georgia Power, F.E.R.C., Docket # ER 85-730, 85-731

Bell Canada, CRTC 1987

Northern Telephone, Ontario PSC

GTE-Quebec Telephone, Quebec PSC, Docket 84-052B

Newtel., Nfld. Brd of Public Commission PU 11-87

CN-CP Telecommunications, CRTC

Quebec Northern Telephone, Quebec PSC

Edmonton Power Company, Alberta Public Service Board

Kansas Power & Light, F.E.R.C., Docket # ER 83-418

NYNEX, FCC generic cost of capital Docket #84-800

Bell South, FCC generic cost of capital Docket #84-800

American Water Works - Tennessee, Docket #7226

Burlington-Northern - Oklahoma State Board of Taxes

Georgia Power, Georgia PSC, Docket # 3549-U

GTE Service Corp., FCC Docket #84-200

Mississippi Power Co., Miss. PSC, Docket U-4761

Citizens Utilities, Ariz. Corp. Comm., Docket U2334-86020

Quebec Telephone, Quebec PSC, 1986, 1987, 1992

Newfoundland L & P, Nfld. Brd. Publ Comm. 1987, 1991

Northwestern Bell, Minnesota PSC, Docket P-421/CI-86-354

GTE Service Corp., FCC Docket #87-463

Anchorage Municipal Power & Light, Alaska PUC, 1988

New Brunswick Telephone, N.B. PUC, 1988

Trans-Quebec Maritime, Nat'l Energy Brd. of Cda, '88-92

Gulf Power Co., Florida PSC, Docket #88-1167-EI

Mountain States Bell, Montana PSC, #88-1.2

Mountain States Bell, Arizona CC, #E-1051-88-146

Georgia Power, Georgia PSC, Docket # 3840-U, l989

Rochester Telephone, New York PSC, Docket # 89-C-022

Noverco - Gaz Metro, Quebec Natural Gas PSC, #R-3164-89

GTE Northwest, Washington UTC, #U-89-3031

Orange & Rockland, New York PSC, Case 89-E-175

Central Illinois Light Company, ICC, Case 90-0127

Peoples Natural Gas, Pennsylvania PSC, Case

Gulf Power, Florida PSC, Case # 891345-EI

ICG Utilities, Manitoba BPU, Case 1989

New Tel Enterprises, CRTC, Docket #90-15

Peoples Gas Systems, Florida PSC

Jersey Central Pwr & Light, N.J. PUB, Case ER 89110912J

Alabama Gas Co., Alabama PSC, Case 890001

Trans-Quebec Maritime Pipeline, Cdn. Nat'l Energy Board

Mountain Bell, Utah PSC,

Mountain Bell, Colorado PUB

South Central Bell, Louisiana PS

Hope Gas, West Virginia PSC

Vermont Gas Systems, Vermont PSC

Alberta Power Ltd., Alberta PUB

Ohio Utilities Company, Ohio PSC

Georgia Power Company, Georgia PSC

Sun City Water Company

Havasu Water Inc.

Centra Gas (Manitoba) Co.

Central Telephone Co. Nevada

AGT Ltd., CRTC 1992

BC GAS, BCPUB 1992

California Water Association, California PUC 1992

Maritime Telephone 1993

BCE Enterprises, Bell Canada, 1993

Citizens Utilities Arizona gas division 1993

PSI Resources 1993-5

CILCORP gas division 1994

GTE Northwest Oregon 1993

Stentor Group 1994-5

Bell Canada 1994-1995

PSI Energy 1993, 1994, 1995, 1999

Cincinnati Gas & Electric 1994, 1996, 1999, 2004

Southern States Utilities, 1995

CILCO 1995, 1999, 2001

Commonwealth Telephone 1996

Edison International 1996, 1998

Citizens Utilities 1997

Stentor Companies 1997

Hydro-Quebec 1998

Entergy Gulf States Louisiana 1998, 1999, 2001, 2002, 2003

Detroit Edison, 1999, 2003

Entergy Gulf States, Texas, 2000, 2004

Hydro Quebec TransEnergie, 2001, 2004

Sierra Pacific Company, 2000, 2001, 2002, 2007, 2010

Nevada Power Company, 2001

Mid American Energy, 2001, 2002

Entergy Louisiana Inc. 2001, 2002, 2004

Mississippi Power Company, 2001, 2002, 2007

Oklahoma Gas & Electric Company, 2002 -2003

Public Service Electric & Gas, 2001, 2002

NUI Corp (Elizabethtown Gas Company), 2002

Jersey Central Power & Light, 2002

San Diego Gas & Electric, 2002, 2012, 2014

New Brunswick Power, 2002

Entergy New Orleans, 2002, 2008

Hydro-Quebec Distribution 2002

PSI Energy 2003

Fortis – Newfoundland Power & Light 2002

Emera – Nova Scotia Power 2004

Hydro-Quebec TransEnergie 2004

Hawaiian Electric 2004

Missouri Gas Energy 2004

AGL Resources 2004

Arkansas Western Gas 2004

Public Service of New Hampshire 2005

Hawaiian Electric Company 2005, 2008, 2009

Delmarva Power & Light Company 2005, 2009

Union Heat Power & Light 2005

Puget Sound Energy 2006, 2007, 2009

Cascade Natural Gas 2006

Entergy Arkansas 2006-7

Bangor Hydro 2006-7

Delmarva 2006, 2007, 2009

Potomac Electric Power Co. 2006, 2007, 2009

Duke Energy Ohio, 2007, 2008, 2009

Duke Energy Kentucky 2009

Consolidated Edison 2007 Docket 07-E-0523

Duke Energy Ohio Docket 07-589-GA-AIR

Hawaiian Electric Company Docket 05-0315

Sierra Pacific Power Docket ER07-1371-000

Public Service New Mexico Docket 06-00210-UT

Detroit Edison Docket U-15244

Potomac Electric Power Docket FC-1053

Delmarva, Delaware, Docket 09-414

Atlantic City Electric, New Jersey, Docket ER-09080664

Maui Electric Co, Hawaii, Docket 2009-0163, 2011

Niagara Mohawk, New York, Docket 10E-0050

Sierra Pacific Power Docket No. 10-06001

Gaz Metro, Regie de l’Energie (Quebec), Docket 2012 R-3752-2011

California Pacific Electric Company, LLC, California PUC, Docket A-12-02-014

Duke Energy Ohio, Ohio Case No. 11-XXXX-EL-SSO

San Diego Gas & Electric, FERC, 2012, 2014

San Diego Gas & Electric, California PUC, 2012, Docket A-12-04

Southern California Gas, California PUC, 2012, Docket A-12-04

Puget Sound Electric

Puget Sound Electric

Duke Energy of Ohio

Duke Energy of Kentucky

Duke Energy of Ohio

Dayton Power & Light

Missouri American Water

California Power Electric Company

PROFESSIONAL AND LEARNED SOCIETIES

- Engineering Institute of Canada, 1967-1972
- Canada Council Award, recipient 1971 and 1972
- Canadian Association Administrative Sciences, 1973-80
- American Association of Decision Sciences, 1974-1978
- American Finance Association, 1975-2002
- Financial Management Association, 1978-2002

ACTIVITIES IN PROFESSIONAL ASSOCIATIONS AND MEETINGS

- Chairman of meeting on "New Developments in Utility Cost of Capital", Southern Finance Association, Atlanta, Nov. 1982

- Chairman of meeting on "Public Utility Rate of Return", Southeastern Public Utility Conference, Atlanta, Oct. 1982

- Chairman of meeting on "Current Issues in Regulatory Finance", Financial Management Association, Atlanta, Oct. 1983

- Chairman of meeting on "Utility Cost of Capital", Financial Management Association, Toronto, Canada, Oct. 1984.

- Committee on New Product Development, FMA, 1985

- Discussant, "Tobin's Q Ratio", paper presented at Financial Management Association, New York, N.Y., Oct. 1986

- Guest speaker, "Utility Capital Structure: New Developments", National Society of Rate of Return Analysts 18th Financial Forum, Wash., D.C. Oct. 1986

- Opening address, "Capital Expenditures Analysis: Methodology vs Mythology," Bellcore Economic Analysis Conference, Naples Fl, 1988.

- Guest speaker, "Mythodology in Regulatory Finance", Society of Utility Rate of Return Analysts (SURFA), Annual Conference, Wash., D.C. February 2007.

PAPERS PRESENTED:

"An Empirical Study of Multi-Period Asset Pricing," annual meeting of Financial Management Assoc., Las Vegas Nevada, 1987.

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OFFICES IN PROFESSIONAL ASSOCIATIONS

- President, International Hewlett-Packard Business Computers Users Group, 1977

- Chairman Program Committee, International HP Business Computers Users Group, London, England, 1975

- Program Coordinator, Canadian Assoc. of Administrative Sciences, 1976

- Member, New Product Development Committee, Financial Management Association, 1985-1986

- Reviewer: Journal of Financial Research
  Financial Management
  Financial Review
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BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 15-1830-EL-AIR
CASE NO. 15-1831-EL-AAM
CASE NO. 15-1832-EL-ATA

DIRECT TESTIMONY
OF DR. ROGER A. MORIN

- □ **MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION**
- □ **OPERATING INCOME**
- □ **RATE BASE**
- □ **ALLOCATIONS**
- ■ **RATE OF RETURN**
- □ **RATES AND TARIFFS**
- □ **OTHER**

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

DIRECT TESTIMONY OF

DR. ROGER A. MORIN

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

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I. <u>INTRODUCTION</u>

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

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Emeritus Professor of Finance at the Robinson College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government. I am testifying on behalf of The Dayton Power and Light Company ("DP&L" or the "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

Q. PLEASE SUMMARIZE YOUR ACADEMIC AND BUSINESS CAREER.

A. I have taught at the Wharton School of Finance, University of Pennsylvania, Amos Tuck School of Business at Dartmouth College, Drexel University, University of Montreal, McGill University, and Georgia State University. I was a faculty member of Advanced Management Research International, and I am currently a faculty member of The Management Exchange Inc. and Exnet, Inc. (now SNL Center for Financial Education LLC or "SNL"), where I continue to conduct frequent national executive-level education seminars throughout the United States and Canada. In the last 30 years, I have conducted numerous national seminars on "Utility Finance," "Utility Cost of Capital," "Alternative Regulatory Frameworks," and "Utility Capital Allocation," which I have developed on behalf of The Management Exchange Inc. and the SNL Center for Financial Education.

I have authored or co-authored several books, monographs, and articles in academic scientific journals on the subject of finance. They have appeared in a variety of journals, including The Journal of Finance, The Journal of Business Administration, International Management Review, and Public Utilities Fortnightly. I published a widely-used treatise on regulatory finance, Utilities' Cost of Capital, Public Utilities Reports, Inc., Arlington, Va. 1984. In late 1994, the same publisher released my book, Regulatory Finance, a voluminous treatise on the application of finance to regulated utilities. A revised and expanded edition of this book, The New Regulatory Finance, was published in 2006. I have been engaged in extensive consulting activities on behalf of numerous corporations, legal firms, and regulatory bodies in matters of financial management and corporate litigation. Exhibit RAM-1 describes my professional credentials in more detail.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON COST OF CAPITAL BEFORE UTILITY REGULATORY COMMISSIONS?

A. Yes, I have been a cost of capital witness before nearly 50 regulatory bodies in North America, including the Public Utilities Commission of Ohio ("PUCO" or the "Commission"), Federal Energy Regulatory Commission ("FERC"), and the Federal Communications Commission ("FCC"). I have also testified before the following state, provincial, and other local regulatory commissions:

Alabama	Florida	Missouri	Ontario
Alaska	Georgia	Montana	Oregon
Alberta	Hawaii	Nevada	Pennsylvania
Arizona	Illinois	New Brunswick	Quebec
Arkansas	Indiana	New Hampshire	South Carolina
British Columbia	Iowa	New Jersey	South Dakota
California	Kentucky	New Mexico	Tennessee
City of New Orleans	Louisiana	New York	Texas
Colorado	Maine	Newfoundland	Utah
CRTC	Manitoba	North Carolina	Vermont
Delaware	Maryland	North Dakota	Virginia
District of Columbia	Michigan	Nova Scotia	Washington
FCC	Minnesota	Ohio	West Virginia
FERC	Mississippi	Oklahoma	Nebraska

The details of my participation in regulatory proceedings are provided in <u>Exhibit RAM-1</u>.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony in this proceeding is two-fold: 1) to present an independent appraisal of the fair and reasonable rate of return on common equity ("ROE") on the common equity capital invested in The Dayton Power and Light Company's electricity distribution operations in the State of Ohio, and 2) to recommend a fair and reasonable capital structure for ratemaking purposes that is consistent with the recommended ROE. Based upon this appraisal, I have formed my professional judgment as to a return on such capital that would: (1) be fair to ratepayers, (2) allow the Company to attract the capital needed for infrastructure and reliability investments on reasonable terms, (3) maintain the Company's financial integrity, and (4) be comparable to returns offered on comparable risk investments. I will testify in this proceeding as to that opinion.

Q. PLEASE IDENTIFY THE EXHIBITS AND APPENDICES ACCOMPANYING YOUR TESTIMONY.

A. I support the following exhibits and appendices:

- Exhibit RAM-1 Resume of Roger A. Morin
- Exhibit RAM-2 Electric Utilities DCF Analysis: Value Line Growth Projections
- Exhibit RAM-3 Electric Utilities DCF Analysis: Analysts' Growth Forecasts
- Exhibit RAM-4 Electric Utility Beta Estimates
- Exhibit RAM-5 S&P's Electric Utility Common Stocks Over Long-Term Treasury Bonds Annual Premium Analysis
- Exhibit RAM-6 Market Risk Premium Calculations
- Exhibit RAM-7 Allowed Risk Premiums: Electric Utility Industry
- Exhibit RAM-8 Electric Utility Debt Ratios
- Exhibit RAM-9 Standard & Poor's Risk Matrix Criteria
- Exhibit RAM-10 Corporate Bond Yields
- Appendix RAM-A CAPM, Empirical CAPM
- Appendix RAM-B Flotation Cost Allowance

These exhibits and appendices relate directly to points in my testimony, and are described in further detail in connection with the discussion of those points in my testimony.

Q. PLEASE SUMMARIZE YOUR FINDINGS CONCERNING DP&L'S COST OF COMMON EQUITY.

A. Based on the results of various methodologies, current capital market conditions, and current economic industry conditions, I recommend the adoption of a ROE of 10.5%. This recommended ROE is based on the Commission's adoption of the Company's proposed 50% common equity ratio for ratemaking purposes. A ROE of 10.5% for DP&L is required in order for the Company to: (i) attract capital on reasonable terms, (ii) maintain its financial integrity, and (iii) earn a return commensurate with returns on comparable risk investments.

My ROE range is derived from cost of capital studies that I performed using the financial models available to me and from the application of my professional judgment to the results. I applied various cost of capital methodologies, including the Discounted Cash Flow ("DCF"), Risk Premium, and Capital Asset Pricing Model ("CAPM"), to a group of investment-grade dividend-paying combination gas and electric utilities which are covered in Value Line's Electric Utility Composite. The companies were required to have the majority of their revenues from regulated utility operations.

My recommended rate of return reflects the application of my professional judgment to the results in light of the indicated returns from my Risk Premium, CAPM, and DCF analyses and DP&L's higher than average investment risk. Moreover, my recommended return is predicated on the assumption that the Company's target common equity percentage of 50% will be approved by the Commission.

The results from the various methodologies were adjusted upward by 30 basis points in order to account for DP&L's higher than average investment risk compared to other regulated utilities. As explained later in my testimony, this adjustment is based principally on DP&L's high external financing requirements relative to its rate base and common equity capital base, on the uncertainty surrounding the Company's appropriate capital structure to be employed for ratemaking, on the unique business risks in the Ohio jurisdiction, and on the economic conditions in the local economy.

Q. WOULD IT BE IN THE BEST INTERESTS OF RATEPAYERS FOR THE COMMISSION TO APPROVE A 10.5% ROE FOR DP&L'S ELECTRICITY DISTRIBUTION OPERATIONS?

A. Yes. My analysis shows that a ROE of 10.5% fairly compensates investors, maintains the Company's credit strength, and attracts the capital needed for utility infrastructure and reliability capital investments. Adopting a lower ROE would increase costs for ratepayers.

Q. PLEASE EXPLAIN HOW LOW ALLOWED ROES CAN INCREASE BOTH THE FUTURE COST OF EQUITY AND DEBT FINANCING.

A. If a utility is authorized a ROE below the level required by equity investors, the utility or its parent will find it difficult to access the equity. Investors will not provide equity capital at the current market price if the earnable return on equity is below the level they require given the risks of an equity investment in the utility. The equity market corrects this by generating a stock price in equilibrium that reflects the valuation of the potential earnings stream from an equity investment at the risk-adjusted return equity investors require. In the case of a utility that has been authorized a return below the level investors believe is appropriate for the risk they bear, the result is a decrease in the utility's market price per share of common stock. This reduces the financial viability of equity financing in two ways. First, because the utility's price per share of common stock decreases, the net proceeds from issuing common stock are reduced. Second, since the utility's market to book ratio decreases with the decrease in the share price of common stock, the potential risk from dilution of equity investments reduces investors' inclination to purchase new issues of common stock. The ultimate effect is the utility will have to rely more on debt financing to meet its capital needs.

As the company relies more on debt financing, its capital structure becomes more leveraged. Because debt payments are a fixed financial obligation to the utility, and income available to common equity is subordinate to fixed charges, this decreases the operating income available for dividend and earnings growth. Consequently, equity investors face greater uncertainty about future dividends and earnings from the firm. As a result, the firm's equity becomes a riskier investment. The risk of default on the company's bonds also increases, making the utility's debt a riskier investment. This increases the cost to the utility from both debt and equity financing and increases the possibility the company will not have access to the capital markets for its outside financing needs. Ultimately, to ensure that DP&L has access to capital markets for its capital needs, a fair and reasonable authorized ROE of 10.5% is required.

The Company must secure outside funds from capital markets to finance required utility plant and equipment investments irrespective of capital market conditions, interest rate conditions and the quality consciousness of market participants. Thus, rate relief requirements and supportive regulatory treatment, including approval of my recommended ROE, are essential requirements.

Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. The remainder of my testimony is divided into five additional sections:

(III) Regulatory Framework and Rate of Return;

(IV) Cost of Equity Estimates;

(V) Summary of Results;

(VI) Capital Structure; and

(VII) Conclusion.

Section III discusses the rudiments of rate of return regulation and the basic notions underlying rate of return. Section IV contains the application of DCF, Risk Premium, and CAPM tests. Section V summarizes the results. Section VI recommends a capital structure to be used for ratemaking. Section VII concludes the analysis.

III. REGULATORY FRAMEWORK AND RATE OF RETURN

Q. PLEASE EXPLAIN HOW A REGULATED COMPANY'S RATES SHOULD BE SET UNDER TRADITIONAL COST OF SERVICE REGULATION.

A. Under the traditional regulatory process, a regulated company's rates should be set so that the company recovers its costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's required rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to enable the company to earn a return commensurate with the cost of those funds.

Funds can be obtained in two general forms, debt capital and equity capital. The cost of debt funds can be easily ascertained from an examination of the contractual interest payments. The cost of common equity funds, that is, investors' required rate of return, is more difficult to estimate. It is the purpose of the next section of my testimony to estimate a fair and reasonable ROE range for DP&L's cost of common equity capital.

Q. WHAT FUNDAMENTAL PRINCIPLES UNDERLIE THE DETERMINATION OF A FAIR AND REASONABLE ROE?

A. The heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return. There are two landmark United States Supreme Court cases that define the legal principles underlying the regulation of a public utility's rate of return and provide the foundations for the notion of a fair return:

1. *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va*, 262 U.S. 679 (1923), and

2. *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

The *Bluefield* case set the standard against which just and reasonable rates of return are measured:

> *A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public <u>equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties</u> ... The <u>return should be reasonable</u>, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to <u>maintain and support its credit and enable it to raise money</u> necessary for the proper discharge of its public duties.*

Bluefield Water Works & Improvement Co., 262 U.S. at 692 (emphasis added).

The *Hope* case expanded on the guidelines to be used to assess the reasonableness of the allowed return. The Court reemphasized its statements in the *Bluefield* case and recognized that revenues must cover "capital costs." The Court stated:

> *From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock ... By that standard <u>the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks</u>. That return, moreover, should be sufficient to <u>assure confidence in the financial integrity</u> of the enterprise, so as to maintain its credit and attract capital.*

Hope Natural Gas Co., 320 U.S. at 603 (emphasis added).

The United States Supreme Court reiterated the criteria set forth in *Hope* in *Fed. Power Comm'n v. Memphis Light, Gas & Water Div.*, 411 U.S. 458 (1973), in *Permian Basin Rate Cases*, 390 U.S. 747 (1968), and most recently in *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989). In the *Permian Basin Rate Cases*, the Supreme Court stressed that a regulatory agency's rate of return order should --

> *reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed.*

Permian Basin Rate Cases, 390 U.S. at 792.

Therefore, the "end result" of this Commission's decision should be to allow DP&L the opportunity to earn a return on equity that is: (1) commensurate with returns on investments in other firms having corresponding risks, (2) sufficient to assure confidence in the Company's financial integrity, and (3) sufficient to maintain the Company's creditworthiness and ability to attract capital on reasonable terms.

Q. HOW IS THE FAIR RATE OF RETURN DETERMINED?

A. The aggregate return required by investors is called the "cost of capital." The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the Company. It is the composite weighted cost of the various classes of capital (*e.g.*, bonds, preferred stock, common stock) used by the utility, with the weights reflecting the proportions of the total capital that each class of capital represents. The fair return in dollars is obtained by multiplying the rate of return set by the regulator by the utility's "rate base." The rate base is essentially the net book value of the utility's plant and other assets used to provide utility service in a particular jurisdiction.

While utilities like DP&L enjoy varying degrees of monopoly in the sale of public utility services, they, or their parent companies, must compete with everyone else in the free, open market for the input factors of production, whether labor, materials, machines, or capital, including the capital investments required to support the electricity network. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices that are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities and other investorowned businesses must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on debt capital, or the expected return on equity. In order to attract the necessary capital, electric utility facilities must compete with alternative uses of capital and offer a return commensurate with the associated risks.

Q. HOW DOES THE CONCEPT OF A FAIR RETURN RELATE TO THE CONCEPT OF OPPORTUNITY COST?

A. The concept of a fair return is intimately related to the economic concept of "opportunity cost." When investors supply funds to a utility by buying its stocks or bonds, they are not only postponing consumption, giving up the alternative of spending their dollars in some other way, they are also exposing their funds to risk and forgoing returns from investing their money in alternative comparable risk investments. The compensation they require is the price of capital. If there are differences in the risk of the investments, competition among firms for a limited supply of capital will bring different prices. The capital markets translate these differences in risk into differences in required return, in much the same way that differences in the characteristics of commodities are reflected in different prices.

The important point is that the required return on capital is set by supply and demand, and is influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities.

Q. WHAT ECONOMIC AND FINANCIAL CONCEPTS HAVE GUIDED YOUR ASSESSMENT OF THE COMPANY'S COST OF COMMON EQUITY?

A. Two fundamental economic principles underlie the appraisal of the Company's cost of equity, one relating to the supply side of capital markets, the other to the demand side.

On the supply side, the first principle asserts that rational investors maximize the performance of their portfolios only if they expect the returns on investments of comparable risk to be the same. If not, rational investors will switch out of those investments yielding lower returns at a given risk level in favor of those investment activities offering higher returns for the same degree of risk. This principle implies that a company will be unable to attract capital funds unless it can offer returns to capital suppliers that are comparable to those achieved on competing investments of similar risk.

On the demand side, the second principle asserts that a company will continue to invest in real physical assets if the return on these investments equals, or exceeds, the company's cost of capital. This principle suggests that a regulatory board should set rates at a level sufficient to create equality between the return on physical asset investments and the company's cost of capital.

Q. HOW DOES THE COMPANY OBTAIN ITS CAPITAL AND HOW IS ITS OVERALL COST OF CAPITAL DETERMINED?

A. The funds employed by the Company are obtained in two general forms, debt capital and equity capital. The cost of debt funds can be ascertained easily from an examination of the contractual interest payments. The cost of common equity funds, that is, equity investors' required rate of return, is more difficult to estimate because the dividend payments received from common stock are not contractual or guaranteed in nature. They are uneven and more risky.

Once a cost of common equity estimate has been developed, it can then easily be combined with the embedded cost of debt based on the utility's capital structure, in order to arrive at the overall cost of capital (overall rate of return).

Q. WHAT IS THE MARKET REQUIRED RATE OF RETURN ON EQUITY CAPITAL?

A. The market required rate of return on common equity, or cost of equity, is the return demanded by the equity investor. Investors establish the price for equity capital through their buying and selling decisions in capital markets. Investors set return requirements according to their perception of the risks inherent in the investment, recognizing the opportunity cost of forgone investments in other companies, and the returns available from other investments of comparable risk.

Q. WHAT MUST BE CONSIDERED IN ESTIMATING A FAIR ROE?

A. The basic premise is that the allowable ROE should be commensurate with returns on investments in other firms having corresponding risks. The allowed return should be sufficient to assure confidence in the financial integrity of the firm, in order to maintain creditworthiness and ability to attract capital on reasonable terms. The "attraction of capital" standard focuses on investors' return requirements that are generally determined using market value methods, such as the Risk Premium, CAPM, or DCF methods. These market value tests define "fair return" as the return investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. This is a market rate of return, defined in terms of anticipated dividends and capital gains as determined by expected changes in stock prices, and reflects the opportunity cost of capital. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by the suppliers of funds is commensurate with that available from alternative investments of comparable risk.

IV. COST OF EQUITY CAPITAL ESTIMATES

Q. DR. MORIN, HOW DID YOU ESTIMATE THE FAIR ROE FOR DP&L UNDER CURRENT CAPITAL MARKET CONDITIONS?

A. I employed three methodologies: (1) the DCF, (2) the Risk Premium, and (3) the CAPM. All three are market-based methodologies and are designed to estimate the return required by investors on the common equity capital committed to DP&L. I applied the aforementioned methodologies to a group of combination gas and electric utilities as a reference group for DP&L.

Q. WHY DID YOU USE MORE THAN ONE APPROACH FOR ESTIMATING THE COST OF EQUITY?

A. No one single method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring activities. The advantage of using several different approaches is that the results of each one can be used to check the others.

As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of common equity.

As I have stated, there are three broad generic methods available to measure the cost of equity: DCF, Risk Premium, and CAPM. All three of these methods are accepted and used by the financial community and firmly supported in the financial literature. The weight accorded to any one method may very well vary depending on unusual circumstances in capital market conditions.

Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the method and on the reasonableness of the proxies used to validate the theory and apply the method. Each method has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of equity reflected in that price, just as there is no guarantee that a single CAPM or Risk Premium result constitutes the perfect explanation of a stock's price or the cost of equity.

Q. ARE THERE ANY PRACTICAL DIFFICULTIES IN APPLYING COST OF CAPITAL METHODOLOGIES IN THE CURRENT ENVIRONMENT OF VOLATILITY IN CAPITAL MARKETS AND ECONOMIC UNCERTAINTY?

A. Yes, there are. The traditional cost of equity estimation methodologies are difficult to implement when you are dealing with the instability and volatility in the capital markets and the highly uncertain economy both in the U.S. and abroad. This is not only because stock prices are volatile at this time, but also because utility company historical data have become less meaningful for an industry experiencing substantial change, for example, the transition to stringent renewable standards and the need to secure vast amounts of external capital over the next decade, regardless of capital market conditions. Past earnings and dividend trends may simply not be indicative of the future. For example, historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors, including the sluggish economy, restructuring, and falling margins. As a result, this historical data may not be representative of the future long-term earning power of these companies. Moreover, historical growth rates may not be necessarily representative of future trends for several electric utilities involved in mergers and acquisitions, as these companies going forward are not the same companies for which historical data are available.

In short, given the volatility in capital markets and economic uncertainties, the utilization of multiple methodologies is critical, and reliance on a single methodology is highly hazardous.

A. DCF Estimates

Q. PLEASE DESCRIBE THE DCF APPROACH TO ESTIMATING THE COST OF EQUITY CAPITAL.

A. According to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. One widely used method to measure these anticipated benefits in the case of a non-static company is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the traditional DCF model:

$$K_e = D_1/P_o + g$$

where: K_e = investors' expected return on equity

D_1 = expected dividend at the end of the coming year

P_o = current stock price

g = expected growth rate of dividends, earnings, stock price, and book value

The traditional DCF formula states that under certain assumptions, which are described in the next paragraph, the equity investor's expected return, K_e, can be viewed as the sum of an expected dividend yield, D_1/P_o, plus the expected growth rate of future dividends and stock price, g. The returns anticipated at a given market price are not directly observable and must be estimated from statistical market information. The idea of the market value approach is to infer 'K_e' from the observed share price, the observed dividend, and an estimate of investors' expected future growth.

The assumptions underlying this valuation formulation are well known, and are discussed in detail in Chapter 4 of my reference book, Regulatory Finance, and Chapter 8 of my new reference text, The New Regulatory Finance. The standard DCF model requires the following main assumptions: (1) a constant average growth trend for both dividends and earnings, (2) a stable dividend payout policy, (3) a discount rate in excess of the expected growth rate, and (4) a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends. The standard DCF model also assumes that dividends are paid at the end of each year when in fact dividend payments are normally made on a quarterly basis.

Q. HOW DID YOU ESTIMATE DP&L'S COST OF EQUITY WITH THE DCF MODEL?

A. I applied the DCF model to a group of investment-grade, dividend-paying, combination gas and electric utilities with the majority of their revenues from regulated operations that are covered in the Value Line database.

In order to apply the DCF model, two components are required: the expected dividend yield (D_1/P_0), and the expected long-term growth (g). The expected dividend (D_1) in the annual DCF model can be obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

Q. HOW DID YOU ESTIMATE THE DIVIDEND YIELD COMPONENT OF THE DCF MODEL?

A. From a conceptual viewpoint, the stock price to employ in calculating the dividend yield is the current price of the security at the time of estimating the cost of equity. This is because the current stock prices provide a better indication of expected future prices than any other price in an efficient market. An efficient market implies that prices adjust rapidly to the arrival of new information. Therefore, current prices reflect the fundamental economic value of a security. A considerable body of empirical evidence indicates that capital markets are efficient with respect to a broad set of information. This implies that observed current prices represent the fundamental value of a security, and that a cost of capital estimate should be based on current prices.

In implementing the DCF model, I have used the dividend yields reported in the Value Line Investment Analyzer ("VLIA") on-line database. Basing dividend yields on average results from a large group of companies reduces the concern that the vagaries of individual company stock prices will result in an unrepresentative dividend yield.

Q. WHY DID YOU MULTIPLY THE SPOT DIVIDEND YIELD BY (1 + g) RATHER THAN BY (1 + 0.5g)?

A. Some analysts multiply the spot dividend yield by one plus one half the expected growth rate (1 + 0.5g) rather than the conventional one plus the expected growth rate (1 + g). This procedure understates the return expected by the investor.

The fundamental assumption of the basic annual DCF model is that dividends are received annually at the end of each year and that the first dividend is to be received one year from now. Thus, the appropriate dividend to use in a DCF model is the full prospective dividend to be received at the end of the year. Since the appropriate dividend to use in a DCF model is the prospective dividend one year from now rather than the dividend one-half year from now, multiplying the spot dividend yield by (1 + 0.5g) understates the proper dividend yield.

Moreover, the basic annual DCF model ignores the time value of quarterly dividend payments and assumes dividends are paid once a year at the end of the year. Multiplying the spot dividend yield by (1 + g) is actually a conservative attempt to capture the reality of quarterly dividend payments. Use of this method is conservative in the sense that the annual DCF model fully ignores the more frequent compounding of quarterly dividends.

Q. HOW DID YOU ESTIMATE THE GROWTH COMPONENT OF THE DCF MODEL?

A. The principal difficulty in calculating the required return by the DCF approach is in ascertaining the growth rate that investors currently expect. Since no explicit estimate of expected growth is observable, proxies must be employed.

As proxies for expected growth, I examined the consensus growth estimate developed by professional analysts. Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by large reputable organizations, and the data are readily available and are representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model.

Growth rate forecasts of several analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated by Zacks Investment Research Inc. and Yahoo Finance. I used analysts' long-term growth forecasts contained in Yahoo Finance as proxies for investors' growth expectations in applying the DCF model. I also used Value Line's growth forecasts as additional proxies.

Q. WHY DID YOU REJECT THE USE OF HISTORICAL GROWTH RATES IN APPLYING THE DCF MODEL TO ELECTRIC UTILITIES?

A. I have rejected historical growth rates as proxies for expected growth in the DCF calculation for two reasons. First, historical growth patterns are already incorporated in analysts' growth forecasts that should be used in the DCF model, and are therefore redundant. Second, published studies in the academic literature demonstrate that growth forecasts made by security analysts are reasonable indicators of investor expectations, and that investors rely on analysts' forecasts. This considerable literature is summarized in Chapter 9 of my most recent textbook, <u>The New Regulatory Finance</u>.

Q. DID YOU CONSIDER ANY OTHER METHOD OF ESTIMATING EXPECTED GROWTH TO APPLY THE DCF MODEL?

A. Yes, I did. I considered using the so-called "sustainable growth" method, also referred to as the "retention growth" method. According to this method, future growth is estimated by multiplying the fraction of earnings expected to be retained by the company, 'b', by the expected return on book equity, ROE, as follows:

where: g = expected growth rate in earnings/dividends

b = expected retention ratio

ROE = expected return on book equity

Q. DO YOU HAVE ANY RESERVATIONS IN REGARDS TO THE SUSTAINABLE GROWTH METHOD?

A. Yes, I do. First, the sustainable method of predicting growth contains a logic trap: the method requires an estimate of expected return on book equity to be implemented. But if the expected return on book equity input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Second, the empirical finance literature demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock prices and price/earnings ratios, as analysts' growth forecasts. I therefore chose not to rely on this method.

Q. DID YOU CONSIDER DIVIDEND GROWTH IN APPLYING THE DCF MODEL?

A. No, not at this time. The reason is that as a practical matter, while there is an abundance of earnings growth forecasts, there are very few forecasts of dividend growth. Moreover, it is widely expected that some utilities will continue to lower their dividend payout ratios over the next several years in response to heightened business risk and the need to fund very large construction programs over the next decade. Dividend growth has remained largely stagnant in past years as utilities are increasingly conserving financial resources in order to hedge against rising business risks and finance large infrastructure investments.

As a result, investors' attention has shifted from dividends to earnings. Therefore, earnings growth provides a more meaningful guide to investors' long-term growth expectations. Indeed, it is growth in earnings that will support future dividends and share prices.

Q. IS THERE ANY EMPIRICAL EVIDENCE DOCUMENTING THE IMPORTANCE OF EARNINGS IN EVALUATING INVESTORS' EXPECTATIONS?

A. Yes, there is an abundance of evidence attesting to the importance of earnings in assessing investors' expectations. First, the sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. To illustrate, Value Line, Yahoo Finance, Zacks Investment, First Call Thompson, Reuters, and Multex provide comprehensive compilations of investors' earnings forecasts. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Second, Value Line's principal investment rating assigned to individual stocks, Timeliness Rank, is based primarily on earnings, which accounts for 65% of the ranking.

Q. HOW DID YOU APPROACH THE COMPOSITION OF COMPARABLE GROUPS IN ORDER TO ESTIMATE DP&L'S COST OF EQUITY WITH THE DCF METHOD?

A. Because DP&L is not publicly traded, the DCF model cannot be applied to DP&L and proxies must be used. There are two possible approaches in forming proxy groups of companies.

The first approach is to apply cost of capital estimation techniques to a select group of companies directly comparable in risk to DP&L. These companies are chosen by the application of stringent screening criteria to a universe of electric utility stocks in an attempt to identify companies with the same investment risk as DP&L. Examples of screening criteria include bond rating, beta risk, size, percentage of revenues from electric utility operations, and common equity ratio. The end result is a small sample of companies with a risk profile similar to that of DP&L, provided the screening criteria are defined and applied correctly.

The second approach is to apply cost of capital estimation techniques to a large group of electric utilities representative of the electric utility industry average and then make adjustments to account for any difference in investment risk between the company and the industry average, if any. As explained below, in view of substantial changes in circumstances in the electric utility industry, I have chosen the latter approach.

In the current unstable capital market environment, it is important to select relatively large sample sizes representative of the electric utility industry as a whole, as opposed to small sample sizes consisting of a handful of companies. This is because the equity market as a whole and electric utility industry capital market data is volatile at this time. As a result of this volatility, the composition of small groups of companies is very fluid, with companies exiting the sample due to dividend suspensions or reductions, insufficient or unrepresentative historical data due to recent mergers, impending merger or acquisition, and changing corporate identities due to restructuring activities.

From a statistical standpoint, confidence in the reliability of the DCF model result is considerably enhanced when applying the DCF model to a large group of companies. Any distortions introduced by measurement errors in the two DCF components of equity return for individual companies, namely dividend yield and growth are mitigated. Utilizing a large portfolio of companies reduces the influence of either overestimating or underestimating the cost of equity for any one individual company. For example, in a large group of companies, positive and negative deviations from the expected growth will tend to cancel out owing to the law of large numbers, provided that the errors are independent.[1] The average growth rate of several companies is less likely to diverge from expected growth than is the estimate of growth for a single firm. More generally, the assumptions of the DCF model are more likely to be fulfilled for a large group of companies than for any single firm or for a small group of companies.

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[1] If σ_i^2 represents the average variance of the errors in a group of N companies, and σ_{ij} the average covariance between the errors, then the variance of the error for the group of N companies, σ_N^2 is:

$$\sigma_N^2 = \frac{1}{N}\bar{\sigma}_i^2 + \frac{N-1}{N}\bar{\sigma}_{ij}$$

If the errors are independent, the covariance between them (σ_{ij}) is zero, and the variance of the error for the group is reduced to:

$$\sigma_N^2 = \frac{1}{N}\sigma_i^2$$

As N gets progressively larger, the variance gets smaller and smaller.

Moreover, small samples are subject to measurement error, and in violation of the Central Limit Theorem of statistics.[2] From a statistical standpoint, reliance on robust sample sizes mitigates the impact of possible measurement errors and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due to a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring.

The point of all this is that the use of a handful of companies in a highly fluid and unstable industry produces fragile and statistically unreliable results. A far safer procedure is to employ large sample sizes representative of the industry as a whole and apply subsequent risk adjustments to the extent that the company's risk profile differs from that of the industry average.

Q. CAN YOU DESCRIBE YOUR PROXY GROUP FOR DP&L'S UTILITY BUSINESS?

A. As a proxy for DP&L, I examined a group of investment-grade dividend-paying combination gas and electric utilities as defined in AUS Utility Reports May 2015 and covered in Value Line's Electric Utility industry group, meaning that these companies all

[2] The Central Limit Theorem describes the characteristics of the distribution of values we would obtain if we were able to draw an infinite number of random samples of a given size from a given population and we calculated the mean of each sample. The Central Limit Theorem asserts: [1] The mean of the sampling distribution of means is equal to the mean of the population from which the samples were drawn. [2] The variance of the sampling distribution of means is equal to the variance of the population from which the samples were drawn divided by the size of the samples. [3] If the original population is distributed normally, the sampling distribution of means will also be normal. If the original population is not normally distributed, the sampling distribution of means will increasingly approximate a normal distribution as sample size increases.

possess utility distribution assets similar to DP&L's. I began with all the companies designated as electric utilities by Value Line, that is, with Standard Industrial Classification codes 4911 to 4913. Foreign companies, private partnerships, private companies, non-dividend paying companies, and companies below investment-grade (with a Moody's bond rating below Baa3 as reported in AUS Utility Reports May 2015) were eliminated, as well as those companies whose market capitalization was less than $1 billion, in order to minimize any stock price anomalies due to thin trading[3]. The final group of companies, shown on Exhibit RAM-2, only includes those companies with at least 50% of their revenues from regulated utility operations.

I stress that this proxy group must be viewed as a portfolio of comparable risk. It would be inappropriate to select any particular company or subset of companies from this group and infer the cost of common equity from that company or subset alone.

Q. WHAT DCF RESULTS DID YOU OBTAIN USING VALUE LINE GROWTH PROJECTIONS?

A. Page 1 of Exhibit RAM-2 shows the raw dividend yield and growth input data for the 26 companies, while page 2 displays the DCF analysis. Exelon, Chesapeake Utilities, MDU Resources, and NiSource were eliminated since less than 50% of their revenues are subject to regulation. Eversource Energy (formerly Northeast Utilities) was added since

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[3] This is necessary in order to minimize the well-known thin trading bias in measuring beta.

it was omitted from the AUS Utility Reports database. Unitil was eliminated because it was not included in the Value Line Electric universe.

As shown on Column 3, line 28 of page 2 of Exhibit RAM-2, the average long-term earnings per share growth forecast obtained from Value Line is 5.46% for this group. Combining this growth rate with the average expected dividend yield of 3.99% shown in Column 4 produces an estimate of equity costs of 9.46% for the group shown in Column 5. Recognition of flotation costs brings the cost of equity estimate to 9.67% for the group, shown in Column 6. The need for a flotation cost allowance is discussed at length later in my testimony. If we eliminate the outlying result of 4.49% for Integrys since it is barely, if at all, equal to the cost of debt, the average ROE for the group is 9.9%.

Q. WHAT DCF RESULTS DID YOU OBTAIN USING THE ANALYSTS' CONSENSUS GROWTH FORECAST?

A. From the original sample of 26 companies shown on page 1 of Exhibit RAM-3, Entergy was eliminated on account of its negative projected growth rate. For the remaining 25 companies shown on page 2 of Exhibit RAM-3, using the consensus analysts' earnings growth forecast of 5.42% instead of the Value Line forecast, the cost of equity for the group is 9.39%, unadjusted for flotation cost. Recognition of flotation costs brings the cost of equity estimate to 9.60%, shown in Column 6, line 27.

Q. PLEASE SUMMARIZE YOUR DCF ESTIMATES.

A. The table below summarizes the DCF estimates:

DCF STUDY	ROE
Electric Utilities Value Line Growth	9.9%
Electric Utilities Analysts Growth	9.6%

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR RISK PREMIUM ANALYSES.

A. In order to quantify the risk premium for DP&L, I have performed four risk premium studies. The first two studies deal with aggregate stock market risk premium evidence using two versions of the CAPM methodology and the other two studies deal with the electric utility industry.

B. <u>CAPM Estimates</u>

Q. PLEASE DESCRIBE YOUR APPLICATION OF THE CAPM RISK PREMIUM APPROACH.

A. My first two risk premium estimates are based on the CAPM and on an empirical approximation to the CAPM ("ECAPM"). The CAPM is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is stated as follows:

$$K = R_F + \beta(R_M - R_F)$$

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, R_F, plus a risk premium determined by $\beta(R_M - R_F)$. The bracketed expression $(R_M - R_F)$ expression is known as the market risk premium ("MRP"). To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the MRP, $(R_M - R_F)$. For the risk-free rate, I used 4.5%, based on forecast interest rates on long-term U.S. Treasury bonds. For beta, I used 0.77 based on Value Line estimates, and for the MRP, I used 7.2% based on both historical and prospective studies. These inputs to the CAPM are explained below.

Q. HOW DID YOU ARRIVE AT YOUR RISK-FREE RATE ESTIMATE OF 4.5% IN YOUR CAPM AND RISK PREMIUM ANALYSES?

A. To implement the CAPM and Risk Premium methods, an estimate of the risk-free return is required as a benchmark. I relied on noted economic forecasts which call for a rising trend in interest rates in response to the recovering economy, renewed inflation, and record high federal deficits. Value Line, Global Insight, Wall Street Journal Survey, and the Congressional Budget Office all project higher long-term Treasury bond rates in the future.

Q. WHY DID YOU RELY ON LONG-TERM BONDS INSTEAD OF SHORT-TERM BONDS?

A. The appropriate proxy for the risk-free rate in the CAPM is the return on the longest term Treasury bond possible. This is because common stocks are very long-term instruments more akin to very long-term bonds rather than to short-term Treasury bills or intermediate-term Treasury notes. In a risk premium model, the ideal estimate for the risk-free rate has a term to maturity equal to the security being analyzed. Since common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely, the yield on the longest-term possible government bonds, that is the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM. The expected common stock return is based on very long-term cash flows, regardless of an individual's holding time period. Moreover, utility asset investments generally have very long-term useful lives and should correspondingly be matched with very long-term maturity financing instruments.

While long-term Treasury bonds are potentially subject to interest rate risk, this is only true if the bonds are sold prior to maturity. A substantial fraction of bond market participants, usually institutional investors with long-term liabilities (e.g., pension funds and insurance companies), in fact hold bonds until they mature, and therefore are not subject to interest rate risk. Moreover, institutional bondholders neutralize the impact of interest rate changes by matching the maturity of a bond portfolio with the investment planning period, or by engaging in hedging transactions in the financial futures markets. The merits and mechanics of such immunization strategies are well documented by both academicians and practitioners.

Another reason for utilizing the longest maturity Treasury bond possible is that common equity has an infinite life span, and the inflation expectations embodied in its market-required rate of return will therefore be equal to the inflation rate anticipated to prevail over the very long term. The same expectation should be embodied in the risk-free rate used in applying the CAPM model. It stands to reason that the yields on 30-year Treasury bonds will more closely incorporate within their yields the inflation expectations that influence the prices of common stocks than do short-term Treasury bills or intermediate-term U.S. Treasury notes.

Among U.S. Treasury securities, 30-year Treasury bonds have the longest term to maturity and the yields on such securities should be used as proxies for the risk-free rate in applying the CAPM. Therefore, I have relied on the yield on 30-year Treasury bonds in implementing the CAPM and risk premium methods.

Q. ARE THERE OTHER REASONS WHY YOU REJECT SHORT-TERM INTEREST RATES AS PROXIES FOR THE RISK-FREE RATE IN IMPLEMENTING THE CAPM?

A. Yes. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. Short-term rates are largely administered rates. For example, Treasury bills are used by the Federal Reserve as a policy vehicle to stimulate the economy and to control the money supply, and are used by foreign governments, companies, and individuals as a temporary safe-house for money.

As a practical matter, it makes no sense to match the return on common stock to the yield on 90-day Treasury Bills. This is because short-term rates, such as the yield on 90-day Treasury Bills, fluctuate widely, leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day Treasury Bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days.

As a conceptual matter, short-term Treasury Bill yields reflect the impact of factors different from those influencing the yields on long-term securities such as common stock. For example, the premium for expected inflation embedded into 90-day Treasury Bills is likely to be far different than the inflationary premium embedded into long-term securities yields. On grounds of stability and consistency, the yields on long-term Treasury bonds match more closely with common stock returns.

Q. WHAT IS YOUR ESTIMATE OF THE RISK-FREE RATE IN APPLYING THE CAPM?

A. All the noted interest rate forecasts that I am aware of point to significantly higher interest rates over the next several years. The table below reports the forecast yields on 30-year US Treasury bonds from Global Insight and Value Line.

Table 2

30-Year Treasury Yield Forecasts

	2016	2017	2018	2019
Global Insight	3.8	4.3	4.4	4.4
Value Line	4.1	4.7	4.9	5.0
AVERAGE	**4.0**	**4.5**	**4.7**	**4.7**

Global Insight forecasts a yield of 3.8% in 2016, 4.3% in 2017, 4.5% in 2018, and 4.4 in 2019, and 4.5% thereafter. Value Line's quarterly economic review dated May 2015 forecasts a yield of 4.1% in 2016, 4.7% in 2017, 4.9% in 2018, and 5.0 in 2019.[4] The average 30-year long-term bond yield forecast from the two sources is 4.0% in 2016, 4.5% in 2017, 4.7% in 2018, and 4.7% in 2019. The average over the 2016-2019 period is 4.5%. The rising yield forecasts are consistent with the upward-sloping yield curve observed at this time. The Congressional Budget Office ("CBO") projects that the average interest rate on 10-year Treasury notes will rise from 2.6% to 4.6% in latest economic review dated March 2015[5], suggesting an increase of 200 basis points in the cost of long-term financing. In response to record high federal deficits, higher anticipated inflation, and eventual full economic recovery the Wall Street economic forecast web site also points to a rise in the interest rate on 10-year Treasury bonds from 2.17% to 3.75%, an increase of 158 basis points[6]. Based on this consistent evidence, a long-term bond yield forecast of 4.5% is a reasonable estimate of the expected risk-free rate for purposes of forward-looking CAPM/ECAPM and Risk Premium analyses in the current economic environment.

Q. WHY DID YOU IGNORE THE CURRENT LEVEL OF INTEREST RATES IN DEVELOPING YOUR PROXY FOR THE RISK-FREE RATE IN A CAPM ANALYSIS?

A. The CAPM is a forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM

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[4] Global Insight forecasts are for 30-year bonds, while Value Line forecasts are for 10-year bonds. 50 basis points were added to the 10-year forecasts based on the historical 50 basis points spread between 10 and 30-year yields.

[5] "Updated Budget Projections 2015-2025", CBO, March 2015

[6] See web site projects.wsj.com/econforecast

must be applied using data that reflects the expectations of actual investors in the market. While investors examine history as a guide to the future, it is the expectations of future events that influence security values and the cost of capital.

Q. HOW DID YOU SELECT THE BETA FOR YOUR CAPM ANALYSIS?

A. A major thrust of modern financial theory as embodied in the CAPM is that perfectly diversified investors can eliminate the company-specific component of risk, and that only market risk remains. The latter is technically known as "beta" (β), or "systematic risk". The beta coefficient measures change in a security's return relative to that of the market. The beta coefficient states the extent and direction of movement in the rate of return on a stock relative to the movement in the rate of return on the market as a whole. It indicates the change in the rate of return on a stock associated with a one percentage point change in the rate of return on the market, and thus measures the degree to which a particular stock shares the risk of the market as a whole. Modern financial theory has established that beta incorporates several economic characteristics of a corporation that are reflected in investors' return requirements.

As an operating subsidiary of the AES Corporation, DP&L is not publicly traded, and therefore, proxies must be used. In the discussion of DCF estimates of the cost of common equity earlier, I examined a sample of investment-grade dividend-paying combination gas and electric utilities covered by Value Line that have at least 50% of their revenues from regulated electric utility operations. The average beta for this group is 0.77. Please see Exhibit RAM-5 for the beta estimates of this sample of electric utilities.

Based on these results, I shall use 0.77, as an estimate for the beta applicable to the average risk electric utility.

Q. WHAT MRP DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the MRP, I used 7.2%. This estimate was based on the results of both forward-looking and historical studies of long-term risk premiums.

Q. CAN YOU DESCRIBE THE HISTORICAL MRP STUDY USED IN YOUR CAPM ANALYSIS?

A. Yes. The historical MRP estimate is based on the results obtained in Morningstar's (formerly Ibbotson Associates) 2015 Classic Yearbook, which compiles historical returns from 1926 to 2014. This well-known study shows that a very broad market sample of common stocks outperformed long-term U.S. Government bonds by 6.0%. The historical MRP over the income component of long-term Government bonds rather than over the total return is 7.0%. Morningstar recommends the use of the latter as a more reliable estimate of the historical MRP, and I concur with this viewpoint. The historical MRP should be computed using the income component of bond returns because the intent, even using historical data, is to identify an expected MRP. This is because the income component of total bond return (*i.e.,* the coupon rate) is a far better estimate of expected return than the total return (*i.e.,* the coupon rate + capital gain), because both realized capital gains and realized losses are largely unanticipated by bond investors. The long-horizon (1926-2014) MRP (based on income returns, as required) is 7.0%.

Q. ON WHAT MATURITY BOND DOES THE MORNINGSTAR HISTORICAL RISK PREMIUM DATA RELY?

A. Because 30-year bonds were not always traded or even available throughout the entire 1926-2014 period covered in the Morningstar Study of historical returns, the latter study relied on bond return data based on 20-year Treasury bonds. Given that the normal yield curve is virtually flat above maturities of 20 years over most of the period covered in the Morningstar study, the difference in yield is not material.

Q. WHY DID YOU USE LONG TIME PERIODS IN ARRIVING AT YOUR HISTORICAL MRP ESTIMATE?

A. Because realized returns can be substantially different from prospective returns anticipated by investors when measured over short time periods, it is important to employ returns realized over long time periods rather than returns realized over more recent time periods when estimating the MRP with historical returns. Therefore, a risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge.

I have therefore ignored realized risk premiums measured over short time periods. Instead, I relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate MRP minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

To the extent that the estimated historical equity risk premium follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. Since I found no evidence that the MRP in common stocks has changed over time, at least prior to the onslaught of the financial crisis of 2008-2009 which has now partially subsided, that is, no significant serial correlation in the Morningstar study prior to that time, it is reasonable to assume that these quantities will remain stable in the future.

Q. SHOULD STUDIES OF HISTORICAL RISK PREMIUMS RELY ON ARITHMETIC AVERAGE RETURNS OR GEOMETRIC AVERAGE RETURNS?

A. Whenever relying on historical risk premiums, only arithmetic average returns over long periods are appropriate for forecasting and estimating the cost of capital, and geometric average returns are not.[7]

Q. PLEASE EXPLAIN HOW THE ISSUE OF WHAT IS THE PROPER "MEAN" ARISES IN THE CONTEXT OF ANALYZING THE COST OF EQUITY?

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7 See Roger A. Morin, Regulatory Finance: Utilities' Cost of Capital, Chapter 11 (1994); Roger A. Morin, The New Regulatory Finance: Utilities' Cost of Capital, Chapter 4 (2006); Richard A Brealey, et al., Principles of Corporate Finance (8th ed. 2006).

A. The issue arises in applying methods that derive estimates of a utility's cost of equity from historical relationships between bond yields and earned returns on equity for individual companies or portfolios of several companies. Those methods produce series of numbers representing the annual difference between bond yields and stock returns over long historical periods. The question is how to translate those series into a single number that can be added to a current bond yield to estimate the current cost of equity for a stock or a portfolio. Calculating geometric and arithmetic means are two ways of converting series of numbers to a single, representative figure.

Q. IF BOTH ARE "REPRESENTATIVE" OF THE SERIES, WHAT IS THE DIFFERENCE BETWEEN THE TWO?

A. Each represents different information about the series. The geometric mean of a series of numbers is the value which, if compounded over the period examined, would have made the starting value to grow to the ending value. The arithmetic mean is simply the average of the numbers in the series. Where there is any annual variation (volatility) in a series of numbers, the arithmetic mean of the series, which reflects volatility, will always exceed the geometric mean, which ignores volatility. Because investors require higher expected returns to invest in a company whose earnings are volatile than one whose earnings are stable, the geometric mean is not useful in estimating the expected rate of return which investors require to make an investment.

Q. CAN YOU PROVIDE A NUMERICAL EXAMPLE TO ILLUSTRATE THIS DIFFERENCE BETWEEN GEOMETRIC AND ARITHMETIC MEANS?

A. Yes. The following table compares the geometric and arithmetic mean returns of a hypothetical Stock A, whose yearly returns over a ten-year period are very volatile, with those of a hypothetical Stock B, whose yearly returns are perfectly stable during that period. Consistent with the point that geometric returns ignore volatility, the geometric mean returns for the two series are identical (11.6% in both cases), whereas the arithmetic mean return of the volatile stock (26.7%) is much higher than the arithmetic mean return of the stable stock (11.6%):

If relying on geometric means, investors would require the same expected return to invest in both of these stocks, even though the volatility of returns in Stock A is very high while Stock B exhibits perfectly stable returns. That is clearly contrary to the most basic financial theory, that is, the higher the risk the higher the expected return.

Table 3

Geometric vs. Arithmetic Returns

YEAR	STOCKA	STOCK B
2005	50.0%	11.6%
2006	-54.7%	11.6%
2007	98.5%	11.6%
2008	42.2%	11.6%
2009	-32.3%	11.6%
2010	-39.2%	11.6%
2011	153.2%	11.6%
2012	-10.0%	11.6%
2013	38.9%	11.6%
2014	20.0%	11.6%
Arithmetic Mean Return	26.7%	11.6%
Geometric Mean Return	11.6%	11.6%

Chapter 4 Appendix A of my book <u>The New Regulatory Finance</u> contains a detailed and rigorous discussion of the impropriety of using geometric averages in estimating the cost

of capital. Briefly, the disparity between the arithmetic average return and the geometric average return raises the question as to what purposes should these different return measures be used. The answer is that the geometric average return should be used for measuring historical returns that are compounded over multiple time periods. The arithmetic average return should be used for future-oriented analysis, where the use of expected values is appropriate. It is inappropriate to average the arithmetic and geometric average return; they measure different quantities in different ways.

Q. CAN YOU DESCRIBE THE PROSPECTIVE MRP STUDY USED IN YOUR CAPM ANALYSIS?

A. Yes. I applied a prospective DCF analysis to the aggregate equity market using Value Line's VLIA software. The computations are shown in Exhibit RAM-4. The dividend yield on the dividend-paying stocks covered in Value Line's full database is currently 1.2% (VLIA 05/2015 edition), and the average projected long-term growth rate is 10.5%. Adding the dividend yield to the growth component produces an expected market return on aggregate equities of 11.7%. Subtracting the forecast risk-free rate of 4.5% from the latter, the implied risk premium is 7.3% over long-term U.S. Treasury bonds.

The average of the historical MRP of 7.0% and the prospective MRP of 7.3% is 7.2%, which is my final estimate of the MRP for purposes of implementing the CAPM.

Q. IS YOUR MRP ESTIMATE OF 7.2% CONSISTENT WITH THE ACADEMIC LITERATURE ON THE SUBJECT?

A. Yes, it is, although in the upper portion of the range. In their authoritative corporate finance textbook, Professors Brealey, Myers, and Allen[8] conclude from their review of the fertile literature on the MRP that a range of 5% to 8% is reasonable for the MRP in the United States. My own survey of the MRP literature, which appears in Chapter 5 of my latest textbook, The New Regulatory Finance, is also quite consistent with this range.

Q. WHAT IS YOUR RISK PREMIUM ESTIMATE OF THE AVERAGE RISK UTILITY'S COST OF EQUITY USING THE CAPM APPROACH?

A. Inserting those input values into the CAPM equation, namely a risk-free rate of 4.5%, a beta of 0.77, and a MRP of 7.2%, the CAPM estimate of the cost of common equity is: 4.5% + 0.77 x 7.2% = 10.0%. This estimate becomes 10.2% with flotation costs, discussed later in my Testimony.

Q. CAN YOU DESCRIBE YOUR APPLICATION OF THE EMPIRICAL VERSION OF THE CAPM?

A. There have been countless empirical tests of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. This literature is summarized in Chapter 6 of my latest book, The New Regulatory Finance. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM.

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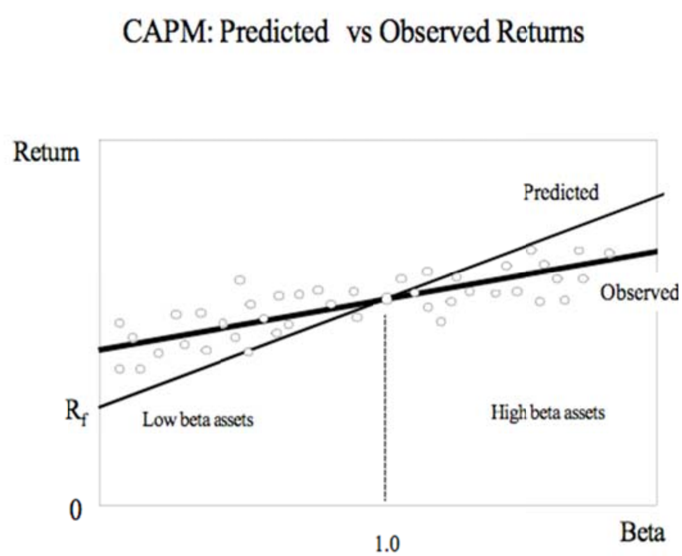
8 Richard A. Brealey, Stewart C. Myers, and Paul Allen, Principles of Corporate Finance, 8th Edition, Irwin McGraw-Hill, 2006.

That is, empirical research has long shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.

A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return required from high-beta securities, based on the empirical evidence. This is one of the most well-known results in finance, and it is displayed graphically below.



A number of variations on the original CAPM theory have been proposed to explain this finding. The ECAPM makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + \alpha + \beta \times (MRP - \alpha)$$

where the symbol alpha, α , represents the "constant" of the risk-return line, MRP is the market risk premium (R_M - R_F), and the other symbols are defined as usual.

Inserting the long-term risk-free rate as a proxy for the risk-free rate, an alpha in the range of 1% - 2%, and reasonable values of beta and the MRP in the above equation produces results that are indistinguishable from the following more tractable ECAPM expression:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta\,(R_M - R_F)$$

An alpha range of 1% - 2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. In other words, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. This is also because the use of adjusted betas rather than the use of raw betas also incorporates some of the desired effect of using the ECAPM.[9] Thus, it is reasonable to apply a conservative alpha adjustment.

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[9] The regression tendency of betas to converge to 1.0 over time is very well known and widely discussed in the financial literature. As a result of this beta drift, several commercial beta producers adjust their forecasted betas toward 1.00 in an effort to improve their forecasts. Value Line, Bloomberg, and Merrill Lynch betas are adjusted for their long-term tendency to regress toward 1.0 by giving approximately 66% -weight to the measured raw beta and approximately 33% weight to the prior value of 1.0 for each stock:

$$\beta_{adjusted} = 0.33 + 0.66\ \beta_{raw}$$

Appendix RAM-A contains a full discussion of the ECAPM, including its theoretical and empirical underpinnings. In short, the following equation provides a viable approximation to the observed relationship between risk and return, and provides the following cost of equity capital estimate:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\;\beta\;(R_M - R_F)$$

Inserting 4.5% for the risk-free rate R_F, a MRP of 7.2% for (R_M - R_F) and a beta of 0.77 in the above equation, the return on common equity is 10.5%. This estimate becomes 10.7% with flotation costs, discussed later in my Testimony.

Q. IS THE USE OF THE ECAPM CONSISTENT WITH THE USE OF ADJUSTED BETAS?

A. Yes, it is. Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line, Bloomberg, and Morningstar. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease in beta. The observed return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprise two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to the previous graph, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas.

Q. PLEASE SUMMARIZE YOUR CAPM ESTIMATES.

A. The table below summarizes the common equity estimates obtained from the CAPM studies.

Table 4
CAPM Results

CAPM Method	ROE
Traditional CAPM	10.2%
Empirical CAPM	10.7%

C. Historical Risk Premium Estimate

Q. PLEASE DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE ELECTRIC UTILITY INDUSTRY USING TREASURY BOND YIELDS.

A. A historical risk premium for the utility industry was estimated with an annual time series analysis applied to the utility industry as a whole over the 1930-2014 period, using Standard and Poor's Utility Index ("S&P Index") as an industry proxy. The analysis is depicted on Exhibit RAM-6. The risk premium was estimated by computing the actual realized return on equity capital for the S&P Utility Index for each year, using the actual stock prices and dividends of the index, and then subtracting the long-term Treasury bond return for that year.

As shown on Exhibit RAM-6, the average risk premium over the period was 5.5% over long-term Treasury bond yields. Given the risk-free rate of 4.5%, and using the historical estimate of 5.5% for bond returns, the implied cost of equity is 4.5% + 5.5% = 10.0% without flotation costs and 10.2% with the flotation cost allowance discussed later in my testimony.

It is noteworthy that the risk premium estimate of 5.5% obtained from the historical risk premium study is identical to the risk premium produced by the CAPM, that is, a beta of 0.77 times the MRP of 7.2% equals 5.5% also.

Q. ARE RISK PREMIUM STUDIES WIDELY USED?

A. Yes, they are. Risk Premium analyses are widely used by analysts, investors, economists, and expert witnesses. Most college-level corporate finance and/or investment management texts, including Investments by Bodie, Kane, and Marcus[10], which is a recommended textbook for Chartered Financial Analyst ("CFA") certification and examination, contain detailed conceptual and empirical discussion of the risk premium approach. Risk Premium analysis is typically recommended as one of the three leading methods of estimating the cost of capital. Professor Brigham's best-selling corporate finance textbook, for example, Corporate Finance: A Focused Approach[11], recommends the use of risk premium studies, among others. Techniques of risk premium analysis are widespread in investment community reports. Professional certified financial analysts

[10] McGraw-Hill Irwin, 2002.

[11] Fourth edition, South-Western, 2011.

are certainly well versed in the use of this method. The only difference is that I rely on long-term Treasury yields instead of the yields on A-rated utility bonds.

Q. ARE YOU CONCERNED ABOUT THE REALISM OF THE ASSUMPTIONS THAT UNDERLIE THE HISTORICAL RISK PREMIUM METHOD?

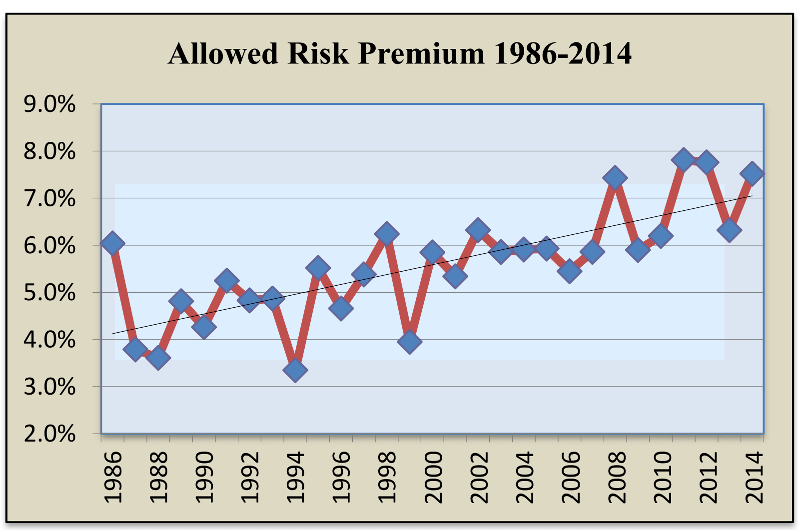
A. No, I am not, for they are no more restrictive than the assumptions that underlie the DCF model or the CAPM. While it is true that the method looks backward in time and assumes that the risk premium is constant over time, these assumptions are not necessarily restrictive. By employing returns realized over long time periods rather than returns realized over more recent time periods, investor return expectations and realizations converge. Realized returns can be substantially different from prospective returns anticipated by investors, especially when measured over short time periods. By ensuring that the risk premium study encompasses the longest possible period for which data are available, short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge, or else, investors would be reluctant to invest money.

D. Allowed Risk Premiums

Q. PLEASE DESCRIBE YOUR ANALYSIS OF ALLOWED RISK PREMIUMS IN THE ELECTRIC UTILITY INDUSTRY.

A. To estimate the electric utility industry's cost of common equity, I also examined the historical risk premiums implied in the ROEs allowed by regulatory commissions for electric utilities over the 1986-2014 period for which data were available, relative to the contemporaneous level of the long-term Treasury bond yield. The analysis is shown on Exhibit RAM-7. This variation of the risk premium approach is reasonable because allowed risk premiums are presumably based on the results of market-based methodologies (DCF, Risk Premium, CAPM, *etc.*) presented to regulators in rate hearings and on the actions of objective unbiased investors in a competitive marketplace. Historical allowed ROE data are readily available over long periods on a quarterly basis from Regulatory Research Associates (now SNL) and easily verifiable from SNL publications and past commission decision archives.

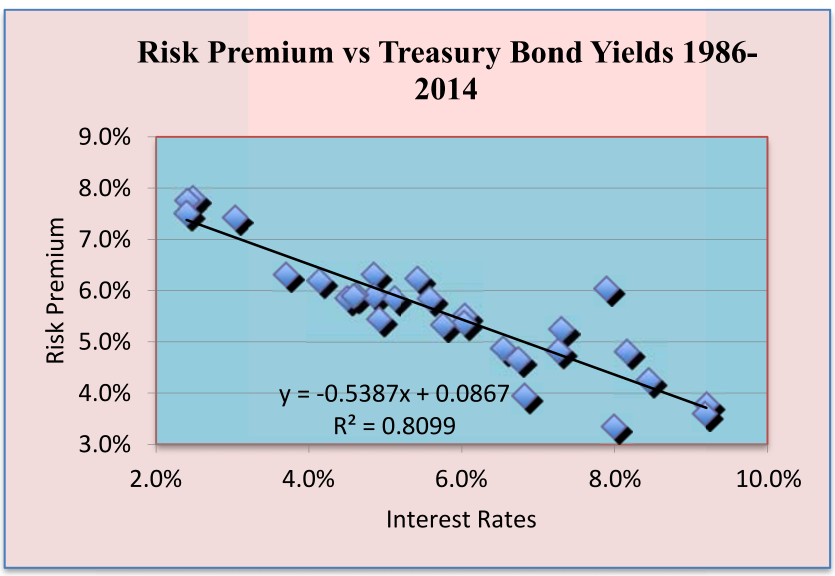
The average ROE spread over long-term Treasury yields was 5.6% over the entire 1986-2014 period for which data were available from SNL. It is interesting to note that this estimate is nearly identical to the previous estimate of 5.5% obtained from both the historical risk premium and the CAPM analyses. The graph below shows the year-by-year allowed risk premium. The escalating trend of the risk premium in response to lower interest rates and rising competition is noteworthy.



A careful review of these ROE decisions relative to interest rate trends reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium ("RP") and interest rates ("YIELD") emerges over the 1986-2014 period:

$$RP = 8.6700 - 0.5387 \text{ YIELD} \qquad R^2 = 0.81$$

The relationship is highly statistically significant[12] as indicated by the very high R^2. The graph below shows a clear inverse relationship between the allowed risk premium and interest rates as revealed in past ROE decisions.



Inserting the long-term Treasury bond yield of 4.5% in the above equation suggests a risk premium estimate of 6.2%, implying a cost of equity of 10.7%.

[12] The coefficient of determination R^2, sometimes called the "goodness of fit measure," is a measure of the degree of explanatory power of a statistical relationship. It is simply the ratio of the explained portion to the total sum of squares. The higher R^2 the higher is the degree of the overall fit of the estimated regression equation to the sample data.

Q. DO INVESTORS TAKE INTO ACCOUNT ALLOWED RETURNS IN FORMULATING THEIR RETURN EXPECTATIONS?

A. Yes, they do. Investors do indeed take into account returns granted by various regulators in formulating their risk and return expectations, as evidenced by the availability of commercial publications disseminating such data, including Value Line and SNL (formerly Regulatory Research Associates). Allowed returns, while certainly not a precise indication of a particular company's cost of equity capital, are nevertheless important determinants of investor growth perceptions and investor expected returns.

Q. PLEASE SUMMARIZE YOUR RISK PREMIUM ESTIMATES.

A. Table 5 below summarizes the ROE estimates obtained from the two risk premium studies.

Table 5

Risk Premium Method	**ROE**
Historical Risk Premium Electric	10.2%
Allowed Risk Premium	10.7%

E. <u>Need for Flotation Cost Adjustment</u>

Q. PLEASE DESCRIBE THE NEED FOR A FLOTATION COST ALLOWANCE.

A. All the market-based estimates reported above include an adjustment for flotation costs. The simple fact of the matter is that issuing common equity capital is not free. Flotation costs associated with stock issues are similar to the flotation costs associated with bonds and preferred stocks. Flotation costs are not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. This is done routinely for bond and preferred stock issues by most regulatory commissions, including FERC. Clearly, the common equity capital accumulated by the Company is not cost-free. The flotation cost allowance to the cost of common equity capital is discussed and applied in most corporate finance textbooks; it is unreasonable to ignore the need for such an adjustment.

Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component is the compensation to the security underwriter for his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (e.g., printing, legal, prospectus). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure."

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs have not been expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. Appendix RAM-B to my testimony discusses flotation costs in detail, and shows: (1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital; (2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated; and (3) that flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. The flotation adjustment is also analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the Company issues new debt capital in the future, until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock that has no finite life, flotation costs are not amortized. Thus, the recovery of flotation costs requires an upward adjustment to the allowed return on equity.

A simple example will illustrate the concept. A stock is sold for $100, and investors require a 10% return, that is, $10 of earnings. But if flotation costs are 5%, the Company nets $95 from the issue, and its common equity account is credited by $95. In order to generate the same $10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in excess of 10% must be allowed on this reduced equity base, here 10.53%.

According to the empirical finance literature discussed in Appendix RAM-B, total flotation costs amount to 4% for the direct component and 1% for the market pressure component, for a total of 5% of gross proceeds. This in turn amounts to approximately 20 basis points, depending on the magnitude of the dividend yield component. To illustrate, dividing the average expected dividend yield of around 4.0% for utility stocks by 0.95 yields 4.2%, which is 20 basis points higher.

Sometimes, the argument is made that flotation costs are real and should be recognized in calculating the fair return on equity, but only at the time when the expenses are incurred. In other words, as the argument goes, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument is valid only if the Company has already been compensated for these costs. If not, the argument is without merit. My own recommendation is that investors be compensated for flotation costs on an on-going basis rather than through expensing, and that the flotation cost adjustment continue for the entire time that these initial funds are retained in the firm.

In theory, flotation costs could be expensed and recovered through rates as they are incurred. This procedure, although simple in implementation, is not considered appropriate, however, because the equity capital raised in a given stock issue remains on the utility's common equity account and continues to provide benefits to ratepayers indefinitely. It would be unfair to burden the current generation of ratepayers with the full costs of raising capital when the benefits of that capital extend indefinitely. The common practice of capitalizing rather than expensing eliminates the intergenerational transfers that would prevail if today's ratepayers were asked to bear the full burden of flotation costs of bond/stock issues in order to finance capital projects designed to serve future as well as current generations. Moreover, expensing flotation costs requires an estimate of the market pressure effect for each individual issue, which is likely to prove unreliable. A more reliable approach is to estimate market pressure for a large sample of stock offerings rather than for one individual issue.

There are several sources of equity capital available to a firm including: common equity issues, conversions of convertible preferred stock, dividend reinvestment plans, employees' savings plans, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure. The flotation cost allowance is a composite factor that reflects the historical mix of sources of equity. The allowance factor is a build-up of historical flotation cost adjustments associated with and traceable to each component of equity at its source. It is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity. A practical solution is to identify general categories and assign one factor to each category. My recommended flotation cost allowance is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the Company.

Q. DR. MORIN, CAN YOU PLEASE ELABORATE ON THE MARKET PRESSURE COMPONENT OF FLOTATION COST?

A. The indirect component, or market pressure component of flotation costs represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue, reflecting the basic economic fact that when the supply of securities is increased following a stock or bond issue, the price falls. The market pressure effect is real, tangible, measurable, and negative. According to the empirical finance literature cited in <u>Appendix RAM-B</u>, the market pressure component of the flotation cost adjustment is approximately 1% of the gross proceeds of an issuance. The announcement of the sale of large blocks of stock produces a decline in a company's stock price, as one would expect given the increased supply of common stock.

Q. IS A FLOTATION COST ADJUSTMENT REQUIRED FOR AN OPERATING SUBSIDIARY LIKE DP&L THAT DOES NOT TRADE PUBLICLY?

A. Yes, it is. It is sometimes alleged that a flotation cost allowance is inappropriate if the utility is a subsidiary whose equity capital is obtained from its owners, in this case, the AES Corporation. This objection is unfounded since the parent-subsidiary relationship does not eliminate the costs of a new issue, but merely transfers them to the parent. It would be unfair and discriminatory to subject parent shareholders to dilution while individual shareholders are absolved from such dilution. Fair treatment must consider that, if the utility-subsidiary had gone to the capital markets directly, flotation costs would have been incurred.

V. <u>SUMMARY: COST OF EQUITY RESULTS</u>

Q. PLEASE SUMMARIZE YOUR RESULTS AND RECOMMENDATION.

A. To arrive at my final recommendation, I performed a DCF analysis on a group of investment-grade dividend-paying combination gas and electric utilities using Value Line's and analysts' growth forecasts. I also performed four risk premium analyses. For the first two risk premium studies, I applied the CAPM and an empirical approximation of the CAPM using current market data. The other two risk premium analyses were performed on historical and allowed risk premium data from electric utility industry aggregate data, using the current yield on long-term US Treasury bonds. The results are summarized in Table 6 below.

Table 6 Summary of Results

STUDY	ROE
Traditional CAPM	10.2%
Empirical CAPM	10.7%
Hist. Risk Premium Electric Utility Industry	10.2%
Allowed Risk Premium	10.7%
DCF Electric Utilities Value Line Growth	9.9%
DCF Electric Utilities Analyst Growth	9.6%

The results range from 9.6% to 10.7% with a midpoint of 10.2%. The average result is also 10.2% and so is the median. The truncated mean result is 10.3%[13]. The results from the various methodologies are remarkably consistent, increasing the confidence in the reliability and reasonableness of the results. Based on those central results, I shall use 10.2% as my base ROE estimate for the average risk electric utility.

I stress that no one individual method provides an exclusive foolproof formula for determining a fair return, but each method provides useful evidence so as to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is hazardous when dealing with investor expectations. Moreover, the advantage of using several different approaches is that the results of each one can be used to check the others. Thus, the results shown in the above table must be viewed as a whole rather than each as a stand-alone. It would be inappropriate to select any particular number from the summary table and infer the cost of common equity from that number alone.

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[13] The truncated mean is obtained by removing the high and low results and computing the average of the remaining observations.

Q. SHOULD THE COST OF EQUITY ESTIMATE BE ADJUSTED UPWARD TO ACCOUNT FOR DP&L BEING MORE RISKY THAN THE AVERAGE ELECTRIC UTILITY?

A. Yes, it should. The cost of equity estimates derived from the comparable groups reflect the risk of the average electric utility. To the extent that these estimates are drawn from a less risky group of companies, the expected equity return applicable to the riskier DP&L is downward-biased.

Q. WHAT ASPECTS OF DP&L'S INVESTMENT RISK PROFILE DIFFERENTIATE THE COMPANY FROM ITS PEERS?

A. The two principal risk factors that differentiate the Company from its peers include a very large infrastructure-related capital investments relative to the size of the Company's rate base and to the size of its common equity capital base, and regulatory uncertainties with regard to the proper treatment of the Company's capital structure for ratemaking purposes.

Q. CAN YOU COMMENT ON THE FIRST RISK FACTOR?

A. Yes. Higher than average business risks result from a very ambitious capital expenditure program which will require approximately $420 million dollar of financing over the next five years for new utility infrastructure investments in order to improve reliability, upgrade the electricity distribution system, support growth, and enhance reliability. To place that number in proper perspective, the Company's rate base is $684 million and its presumed eventual common equity balance is expected to be approximately 50% of that amount, or $315 million. In other words, the company is expected to spend an amount equal to about two thirds of its rate base ($420/$684 = 0.61%), that is, an increase of 61% of its rate base over the next five years, and more than its presumed common equity capital balance of $315 million.

Because of the Company's large construction program over the next few years, rate relief requirements and regulatory treatment uncertainty will increase regulatory risks as well. Generally, regulatory risks include approval risks, lags and delays, potential rate base exclusions, and potential disallowances. Continued regulatory support from the Commission will be required. Reviews of the economic and environmental aspects of new construction can consume as much as one year before approval or denial. Uncertainty of approval increases forecasting and planning risks and complicates the utility's ability to devise an optimum energy distribution system. Regulatory approval for financings required for new construction may also be required, injecting additional risks.

Q. CAN YOU COMMENT ON THE SECOND RISK FACTOR?

A. The second risk factor relates to the uncertainties surrounding the Company's capital structure following the separation of its generation assets and to the appropriate capital structure to be used for ratemaking. The Company's current (actual) capital structure consists of 62% debt and 38% common equity. After the separation of its generation assets, it is expected that the Company will manage its capital structure with a target of 50% debt and 50% equity capital. In approving DP&L's generation separation plan, the Commission ordered the Company to achieve a 50% common equity, and management expects to do so.

Q. ARE THERE ADDITIONAL RISK FACTORS THAT THE COMMISSION SHOULD CONSIDER?

A. Yes, there are additional risk factors that distinguish the Company from its peers, including: First, there are unique business risks in the Ohio jurisdiction. Since the Company's electric security plan ("ESP") was implemented in 2009, the Company has experienced customer losses and deteriorating financial results because of both low market prices in the generation market and greater competitive forces in Ohio. Second, the continuing slow recovery of the Ohio economy, along with low power prices, exacerbate margin losses and customer switching. Third, regulatory risks remain higher than average since the terms of the regulatory compact in Ohio include periodic price testing for Commission-approved ESPs that extend beyond three year terms and earnings caps on utilities. Hence the need for a strong capital structure consisting of at least 50% common equity in order to offset these additional risk factors.

VI. CAPITAL STRUCTURE

Q. WHAT CAPITAL STRUCTURE ASSUMPTION UNDERLIES YOUR RECOMMENDED RETURN ON DP&L'S COMMON EQUITY CAPITAL?

A. My recommended ROE for DP&L is predicated on the adoption of a certification period capital structure consisting of 50% common equity capital for ratemaking purposes.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED CAPITAL STRUCTURE CONSISTING OF 50% DEBT AND 50% COMMON EQUITY CAPITAL?

A. My recommendation is based on several factors. First, I have examined the capital structures adopted by regulators for electric utilities. The April 2015 edition of SNL Energy's (formerly Regulatory Research Associates) "*Regulatory Focus: Major Rate Case Decisions*" reports an average percentage of common equity in capital structure of 52% adopted by regulators for electric utilities and 50% for natural gas distribution utilities for 2015.

Second I have examined the actual capital structures of my comparable group of electric utilities. Exhibit RAM-8 displays the long-term debt ratios for the peer group of companies as reported in Value Line. The average debt ratio is 51%, implying a common equity ratio of 49%.

Third, I have examined the credit agencies' financial ratio benchmarks for various bond rating categories for electric utilities. Both S&P and Moody's publish a matrix of financial ratios that correspond to their respective assessment of the investment risk of utility companies and related bond rating.

Table 7 below reproduces Moody's range for a utility company's debt ratio and related bond rating, one of its three primary financial ratios that it uses as guidance in its credit review for utility companies. The vast majority of electric utilities have a bond rating of high Baa to low single A. For a single A bond rating, which I consider optimal, the debt ratio range is 35%-45% with a midpoint of 40%, implying a common equity ratio of 60%. For a Baa bond rating, the corresponding debt ratio range is 45% - 55% with a midpoint of 50%, or a 50% common equity ratio.

Table 7 Moody's Debt Ratio Benchmark

Bond Rating	Debt/capital %

Aaa	<25
Aa	25-35
A	**35-45**
Baa	**45-55**
Ba	55-65
B	>65

S&P publishes ranges for three primary financial ratios that it uses as guidance in its credit review for utility companies. One of the three core financial ratio benchmarks on which it relies in its credit rating process is the debt ratio. Exhibit RAM-9 replicates S&P's risk matrix criteria which includes business and financial risk categories. [14/] As shown on the upper panel of the exhibit, the business risk profile categories are "Excellent," "Strong," "Satisfactory," "Fair," "Weak," and "Vulnerable." Most utilities have a business risk profile of "Excellent" or "Strong."

As shown on the middle panel, the financial risk profile categories are "Minimal," "Modest," "Intermediate," "Significant," "Aggressive," and "Highly Leveraged." Most electric utilities have a "Intermediate" or "Significant" financial risk profile coupled with a business risk profile of "Excellent" or Strong", and are therefore rated in the A-BBB range, as shown in the darkened cell entries.

The third panel of the exhibit shows S&P's range for a utility company's debt ratio. For those utilities with "Intermediate" financial risk, the debt ratio range is 35%-45% with a midpoint of 40%, implying a common equity ratio of 60%, the same result as S&P. For

[14/] S&P updated its 2008 credit metric guidelines in 2009, and incorporated utility metric benchmarks with the general corporate rating metrics. *Standard & Poor's RatingsDirect*: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.

those utilities with "Significant" financial risk, the corresponding debt ratio range is 45% - 55% with a midpoint of 50%, or a 50% common equity ratio, again the same result as S&P.

It is clear from an optimal bond rating perspective that a common equity ratio of at least 50% is desirable.

Fourth, as I stated earlier, it is the expectations of future events that influence security values and ROE, including financial risks, i.e., capital structure. Therefore, it stands to reason that the ROE should be properly matched with the expected capital structure to prevail in the future, namely, 50% common equity.

The aforementioned risk factors, separately or together, provide independent validation of the use of a 50/50 capital structure as a proxy for the temporary situation the Company will be facing as it prepares for and implements separation of its generation business. These factors provide a proxy for the type of capital structure investors demand, as well as one that this Commission has ordered. (Case No. 13-2420-EL-UNC) I note that in its order approving the separation of DP&L's generation assets, the PUCO stated that it expects DP&L to have a 50/50 debt/equity capital structure.

Q. SHOULD PREFERRED STOCK BE TREATED AS COMMON EQUITY IN THE 50/50 CAPITAL STRUCTURE?

A. No, it should not. As far as common shareholders are concerned, preferred stock is senior capital, as is debt capital. As a result, any preferred stock that DP&L has issued should be excluded from the 50% common equity component of the capital structure that I reference. The 50% of the capital structure that is not common equity, and that I refer to as "debt" should comprise both long term debt and preferred stock, and each should be assigned a separate and distinct cost. Company Witness MacKay discusses the cost of each and how those costs are derived.

Q. YOU STATED EARLIER IN YOUR TESTIMONY THAT YOU ADJUSTED YOUR RECOMMENDED ROE UPWARD BY 30 BASIS POINTS TO ACCOUNT FOR DP&L'S HIGHER LEVEL OF RISK COMPARED TO THE INDUSTRY. WHAT IS THE BASIS FOR THE 30 BASIS POINTS ADJUSTMENT?

A. I increased the ROE of 10.2% derived from a sample of companies representative of the electric utility industry by 30 basis points (0.30%), from 10.2% to 10.5% in order to reflect the higher relative risk of the Company. The 30 basis points adjustment is based on two reference points: 1) bond yield differentials between utility bonds rated A and those rated BBB, and 2) observed beta differentials.

I examined the difference in yield between utility bonds rated A and those rated BBB for my first reference point. The current yield differential between A-rated and BBB-rated utility bonds is 33 basis points as reported in Value Line.

I also examined the differences in yield between corporate bonds of various ratings over the recent past. <u>Exhibit RAM-10</u> displays the differences in yield between corporate bonds on a monthly basis since June 2014. The upper panel shows the yields themselves while the second panel shows the yield differentials ("yield spreads"). Since most electric utilities are rated in the Baa3 to low A range, I focused my attention on the Baa2 – A3 and Baa2 – Baa1 spreads. In February 2015, the Baa2-A3 spread was 45 basis points and the Baa2-Baa1 was 17 basis points, for an average of 31 basis points. If we focus on the June 2014 – February 2015 period as a whole, the corresponding average spread for the whole period was 27 basis points

For the second reference point, the CAPM formula was referenced to approximate the return (cost of equity) differences implied by the differences in the betas between the average electric utility company and DP&L. The basic form of the CAPM, as discussed earlier, states that the return differential is given by the differential in beta times the MRP. To the extent that the Company's beta would be approximately one half standard deviation higher than the electric utility industry average, that is, 0.04, the return differential implied by the difference of 0.04 in beta is given by 0.035 times the MRP. Using an estimate of 7.2% for the MRP discussed earlier in my testimony in implementing the CAPM, the return adjustment is 7.2 x .04 = 29 basis points.

In summary, the reference points suggest an upward ROE adjustment for DP&L of 31, 27, and 29 basis points, respectively. Based on all these considerations, I estimate the risk premium to be 30 basis points.

VII. CONCLUSION

Q. DR. MORIN, WHAT IS YOUR FINAL CONCLUSION REGARDING DP&L'S COST OF COMMON EQUITY CAPITAL?

A. Based on the results of all my analyses, the application of my professional judgment, and the risk circumstances of DP&L, it is my opinion that a just and reasonable ROE for DP&L's electricity distribution operations in the State of Ohio is 10.5%.

Q. DR. MORIN, WHAT CAPITAL STRUCTURE ASSUMPTION UNDERLIES YOUR RECOMMENDED RETURN ON DP&L'S COMMON EQUITY CAPITAL?

A. My recommended return on common equity for DP&L is predicated on the adoption of a test year capital structure consisting of 50% common equity capital.

Q. IS DP&L'S FINANCIAL RISK IMPACTED BY THE AUTHORIZED ROE?

A. Yes, very much so. A low ROE increases the likelihood that DP&L will have to rely on debt financing for its capital needs. This creates the specter of a spiraling cycle that further increases risks to both equity and debt investors; the resulting increase in financing costs is ultimately borne by the utility's customers through higher capital costs and rates of returns. As the Company relies more on debt financing, its capital structure becomes more leveraged. Since debt payments are a fixed financial obligation to the utility, this decreases the operating income available for dividend growth. Consequently, equity investors face greater uncertainty about the future dividend potential of the firm. As a result, the Company's equity becomes a riskier investment. The risk of default on the Company's bonds also increases, making the utility's debt a riskier investment. This increases the cost to the utility from both debt and equity financing and increases the possibility the Company will not have access to the capital markets for its outside financing needs, or if so, at prohibitive costs.

Q. IS IT IMPORTANT THAT DP&L'S CREDIT RATING IS RESTORED TO A STRONG INVESTMENT-GRADE LEVEL?

A. Yes, absolutely. The Company's bonds (the "Secured Rating" that Company Witness MacKay references in his testimony) are currently rated BBB- by S&P and Baa2 by Moody's. The former is one step away from the "high yield" (a.k.a. junk bond) level and among the lowest in the industry. The Commission should be, and DP&L management is, committed to restore DP&L to a strong investment grade level as rapidly as reasonably practical so that it will continue to be able to provide reliable and reasonably-priced electric service as a state regulated entity as it has in the past. To achieve this goal, the Commission must continue to demonstrate its commitment to DP&L's financial integrity through positive and supportive actions in this and other proceedings. Authorizing the cost of equity capital and capital structure that I have recommended will support DP&L's return to a strong investment grade credit standing, especially as it works through the effect of generation separation.

It is imperative that the Commission commit itself to restoring the investment grade creditworthiness of DP&L as rapidly as reasonably practical so that DP&L will continue being able to provide reliable and reasonably-priced electric service as a state regulated entity as it has in the past and raise the very large quantities of capital required over the next five years at reasonable cost.

Q. IF CAPITAL MARKET CONDITIONS CHANGE SIGNIFICANTLY BETWEEN THE DATE OF FILING YOUR PREPARED TESTIMONY AND THE DATE ORAL TESTIMONY IS PRESENTED, WOULD THIS CAUSE YOU TO REVISE YOUR ESTIMATED COST OF EQUITY?

A. Perhaps. Capital market conditions are volatile and uncertain at this time. Interest rates and security prices do change over time, and risk premiums change also, although much more sluggishly. If substantial changes were to occur between the filing date and the time my oral testimony is presented, I would evaluate those changes and their impact on my testimony accordingly.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

RESUME OF ROGER A. MORIN

(Fall 2015)

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Indian Harbour
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PRESENT EMPLOYER: Georgia State University
Robinson College of Business
Atlanta, GA 30303

RANK: Emeritus Professor of Finance

HONORS: Distinguished Professor of Finance for Regulated Industry,
Director Center for the Study of Regulated Industry,
Robinson College of Business, Georgia State University.

EDUCATIONAL HISTORY

- Bachelor of Electrical Engineering, McGill University, Montreal, Canada, 1967.
- Master of Business Administration, McGill University, Montreal, Canada, 1969.
- PhD in Finance & Econometrics, Wharton School of Finance, University of Pennsylvania, 1976.

EMPLOYMENT HISTORY

- Lecturer, Wharton School of Finance, Univ. of Pennsylvania, 1972-3
- Assistant Professor, University of Montreal School of Business, 1973-1976.
- Associate Professor, University of Montreal School of Business, 1976-1979.
- Professor of Finance, Georgia State University, 1979-2011
- Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, Robinson College of Business, Georgia State University, 1985-2009
- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986
- Emeritus Professor of Finance, Georgia State University, 2007-15

OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.
- Member Board of Directors, Financial Research Institute of Canada, 1974-1980.
- Co-founder and Director Canadian Finance Research Foundation, 1977.
- Vice-President of Research, Garmaise-Thomson & Associates, Investment Management Consultants, 1980-1981.
- Member Board of Directors, Executive Visions Inc., 1985-2015
- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991.
- Member Board of Directors, Hotel Equities Marriott, Inc., 2009-2015

PROFESSIONAL CLIENTS

AGL Resources

AT & T Communications

Alagasco - Energen

Alaska Anchorage Municipal Light & Power

Alberta Power Ltd.

Allete

AmerenUE

American Water

Ameritech

Arkansas Western Gas

Baltimore Gas & Electric – Constellation Energy

Bangor Hydro-Electric

B.C. Telephone

B C GAS

Bell Canada

Bellcore

Bell South Corp.

Bruncor (New Brunswick Telephone)

Burlington-Northern

C & S Bank

California Pacific

Cajun Electric

Canadian Radio-Television & Telecomm. Commission

Canadian Utilities

Canadian Western Natural Gas

Cascade Natural Gas

Centel

Centra Gas

Central Illinois Light & Power Co

Central Telephone

Central & South West Corp.

CH Energy

Chattanooga Gas Company

Cincinnatti Gas & Electric

Cinergy Corp.

Citizens Utilities

City Gas of Florida

CN-CP Telecommunications

Commonwealth Telephone Co.

Columbia Gas System

Consolidated Edison

Consolidated Natural Gas

Constellation Energy

Delmarva Power & Light Co

Deerpath Group

Detroit Edison Company

Duke Energy Indiana

Duke Energy Kentucky

Duke Energy Ohio

DTE Energy

Edison International

Edmonton Power Company

Elizabethtown Gas Co.

Emera

Energen

Engraph Corporation

Entergy Corp.

Entergy Arkansas Inc.

Entergy Gulf States, Inc.

Entergy Louisiana, Inc.

Entergy Mississippi Power

Entergy New Orleans, Inc.

First Energy

Florida Water Association

Fortis

Garmaise-Thomson & Assoc., Investment Consultants

Gaz Metropolitain

General Public Utilities

Georgia Broadcasting Corp.

Georgia Power Company

GTE California - Verizon

GTE Northwest Inc. - Verizon

GTE Service Corp. - Verizon

GTE Southwest Incorporated - Verizon

Gulf Power Company

Havasu Water Inc.

Hawaiian Electric Company

Hawaiian Elec & Light Co

Heater Utilities – Aqua - America

Hope Gas Inc.

Hydro-Quebec

ICG Utilities

Illinois Commerce Commission

Island Telephone

ITC Holdings

Jersey Central Power & Light

Kansas Power & Light

KeySpan Energy

Maine Public Service

Manitoba Hydro

Maritime Telephone

Maui Electric Co.

Metropolitan Edison Co.

Minister of Natural Resources Province of Quebec

Minnesota Power & Light

Mississippi Power Company

Missouri Gas Energy

Mountain Bell

National Grid PLC

Nevada Power Company

New Brunswick Power

Newfoundland Power Inc. - Fortis Inc.

New Market Hydro

New Tel Enterprises Ltd.

New York Telephone Co.

NextEra Energy

Niagara Mohawk Power Corp

Norfolk-Southern

Northeast Utilities

Northern Telephone Ltd.

Northwestern Bell

Northwestern Utilities Ltd.

Nova Scotia Power

Nova Scotia Utility and Review Board

NUI Corp.

NV Energy

NYNEX

Oklahoma G & E

Ontario Telephone Service Commission

Orange & Rockland

PNM Resources

PPL Corp

Pacific Northwest Bell

People's Gas System Inc.

People's Natural Gas

Pennsylvania Electric Co.

Pepco Holdings

Potomac Electric Power Co.

Price Waterhouse

PSI Energy

Public Service Electric & Gas

Public Service of New Hampshire

Public Service of New Mexico

Puget Sound Energy

Quebec Telephone

Regie de l’Energie du Quebec

Rockland Electric

Rochester Telephone

SNL Center for Financial Execution

San Diego Gas & Electric

SaskPower

Sempra

Sierra Pacific Power Company

Source Gas

Southern Bell

Southern States Utilities

Southern Union Gas

South Central Bell

Sun City Water Company

TECO Energy

The Southern Company

Touche Ross and Company

TransEnergie

Trans-Quebec & Maritimes Pipeline

TXU Corp

US WEST Communications

Union Heat Light & Power

Utah Power & Light

Vermont Gas Systems Inc.

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73
- Hydro-Quebec, "Capital Budgeting Under Uncertainty," 1974-75
- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78
- Investment Dealers Association of Canada, 1977-78
- Financial Research Foundation, bi-annual seminar, 1975-79
- Advanced Management Research (AMR), faculty member, 1977-80
- Financial Analysts Federation, Educational chapter: "Financial Futures Contracts" seminar
- Exnet Inc. a.k.a. The Management Exchange Inc., faculty member 1981-2008:

  National Seminars:

  Risk and Return on Capital Projects
  Cost of Capital for Regulated Utilities
  Capital Allocation for Utilities
  Alternative Regulatory Frameworks
  Utility Directors' Workshop
  Shareholder Value Creation for Utilities
  Fundamentals of Utility Finance in a Restructured Environment
  Contemporary Issues in Utility Finance

- SNL Center for Financial Education. faculty member 2008-2015.
  National Seminars: *Essentials of Utility Finance*

- Georgia State University College of Business, Management Development Program, faculty member, 1981-1994.

EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Corporate Finance

Rate of Return

Capital Structure

Generic Cost of Capital

Costing Methodology

Depreciation

Flow-Through vs Normalization

Revenue Requirements Methodology

Utility Capital Expenditures Analysis

Risk Analysis

Capital Allocation

Divisional Cost of Capital, Unbundling

Incentive Regulation & Alternative Regulatory Plans

Shareholder Value Creation

Value-Based Management

REGULATORY BODIES

Alabama Public Service Commission

Alaska Regulatory Commission

Alberta Public Service Board

Arizona Corporation Commission

Arkansas Public Service Commission

British Columbia Board of Public Utilities

California Public Service Commission

Canadian Radio-Television & Telecommunications Comm.

City of New Orleans Council

Colorado Public Utilities Commission

Delaware Public Service Commission

District of Columbia Public Service Commission

Federal Communications Commission

Federal Energy Regulatory Commission

Florida Public Service Commission

Georgia Public Service Commission

Georgia Senate Committee on Regulated Industries

Hawaii Public Utilities Commission

Illinois Commerce Commission

Indiana Utility Regulatory Commission

Iowa Utilities Board

Kentucky Public Service Commission

Louisiana Public Service Commission

Maine Public Utilities Commission

Manitoba Board of Public Utilities

Maryland Public Service Commission

Michigan Public Service Commission

Minnesota Public Utilities Commission

Mississippi Public Service Commission

Missouri Public Service Commission

Montana Public Service Commission

National Energy Board of Canada

Nebraska Public Service Commission

Nevada Public Utilities Commission

New Brunswick Board of Public Commissioners

New Hampshire Public Utilities Commission

New Jersey Board of Public Utilities

New Mexico Public Regulation Commission

New Orleans City Council

New York Public Service Commission

Newfoundland Board of Commissioners of Public Utilities

North Carolina Utilities Commission

Nova Scotia Board of Public Utilities

Ohio Public Utilities Commission

Oklahoma Corporation Commission

Ontario Telephone Service Commission

Ontario Energy Board

Oregon Public Utility Service Commission

Pennsylvania Public Utility Commission

Quebec Regie de l'Energie

Quebec Telephone Service Commission

South Carolina Public Service Commission

South Dakota Public Utilities Commission

Tennessee Regulatory Authority

Texas Public Utility Commission

Utah Public Service Commission

Vermont Department of Public Services

Virginia State Corporation Commission

Washington Utilities & Transportation Commission

West Virginia Public Service Commission

SERVICE AS EXPERT WITNESS

Southern Bell, So. Carolina PSC, Docket #81-201C

Southern Bell, So. Carolina PSC, Docket #82-294C

Southern Bell, North Carolina PSC, Docket #P-55-816

Metropolitan Edison, Pennsylvania PUC, Docket #R-822249

Pennsylvania Electric, Pennsylvania PUC, Docket #R-822250

Georgia Power, Georgia PSC, Docket # 3270-U, 1981

Georgia Power, Georgia PSC, Docket # 3397-U, 1983

Georgia Power, Georgia PSC, Docket # 3673-U, 1987

Georgia Power, F.E.R.C., Docket # ER 80-326, 80-327

Georgia Power, F.E.R.C., Docket # ER 81-730, 80-731

Georgia Power, F.E.R.C., Docket # ER 85-730, 85-731

Bell Canada, CRTC 1987

Northern Telephone, Ontario PSC

GTE-Quebec Telephone, Quebec PSC, Docket 84-052B

Newtel., Nfld. Brd of Public Commission PU 11-87

CN-CP Telecommunications, CRTC

Quebec Northern Telephone, Quebec PSC

Edmonton Power Company, Alberta Public Service Board

Kansas Power & Light, F.E.R.C., Docket # ER 83-418

NYNEX, FCC generic cost of capital Docket #84-800

Bell South, FCC generic cost of capital Docket #84-800

American Water Works - Tennessee, Docket #7226

Burlington-Northern - Oklahoma State Board of Taxes

Georgia Power, Georgia PSC, Docket # 3549-U

GTE Service Corp., FCC Docket #84-200

Mississippi Power Co., Miss. PSC, Docket U-4761

Citizens Utilities, Ariz. Corp. Comm., Docket U2334-86020

Quebec Telephone, Quebec PSC, 1986, 1987, 1992

Newfoundland L & P, Nfld. Brd. Publ Comm. 1987, 1991

Northwestern Bell, Minnesota PSC, Docket P-421/CI-86-354

GTE Service Corp., FCC Docket #87-463

Anchorage Municipal Power & Light, Alaska PUC, 1988

New Brunswick Telephone, N.B. PUC, 1988

Trans-Quebec Maritime, Nat'l Energy Brd. of Cda, '88-92

Gulf Power Co., Florida PSC, Docket #88-1167-EI

Mountain States Bell, Montana PSC, #88-1.2

Mountain States Bell, Arizona CC, #E-1051-88-146

Georgia Power, Georgia PSC, Docket # 3840-U, l989

Rochester Telephone, New York PSC, Docket # 89-C-022

Noverco - Gaz Metro, Quebec Natural Gas PSC, #R-3164-89

GTE Northwest, Washington UTC, #U-89-3031

Orange & Rockland, New York PSC, Case 89-E-175

Central Illinois Light Company, ICC, Case 90-0127

Peoples Natural Gas, Pennsylvania PSC, Case

Gulf Power, Florida PSC, Case # 891345-EI

ICG Utilities, Manitoba BPU, Case 1989

New Tel Enterprises, CRTC, Docket #90-15

Peoples Gas Systems, Florida PSC

Jersey Central Pwr & Light, N.J. PUB, Case ER 89110912J

Alabama Gas Co., Alabama PSC, Case 890001

Trans-Quebec Maritime Pipeline, Cdn. Nat'l Energy Board

Mountain Bell, Utah PSC,

Mountain Bell, Colorado PUB

South Central Bell, Louisiana PS

Hope Gas, West Virginia PSC

Vermont Gas Systems, Vermont PSC

Alberta Power Ltd., Alberta PUB

Ohio Utilities Company, Ohio PSC

Georgia Power Company, Georgia PSC

Sun City Water Company

Havasu Water Inc.

Centra Gas (Manitoba) Co.

Central Telephone Co. Nevada

AGT Ltd., CRTC 1992

BC GAS, BCPUB 1992

California Water Association, California PUC 1992

Maritime Telephone 1993

BCE Enterprises, Bell Canada, 1993

Citizens Utilities Arizona gas division 1993

PSI Resources 1993-5

CILCORP gas division 1994

GTE Northwest Oregon 1993

Stentor Group 1994-5

Bell Canada 1994-1995

PSI Energy 1993, 1994, 1995, 1999

Cincinnati Gas & Electric 1994, 1996, 1999, 2004

Southern States Utilities, 1995

CILCO 1995, 1999, 2001

Commonwealth Telephone 1996

Edison International 1996, 1998

Citizens Utilities 1997

Stentor Companies 1997

Hydro-Quebec 1998

Entergy Gulf States Louisiana 1998, 1999, 2001, 2002, 2003

Detroit Edison, 1999, 2003

Entergy Gulf States, Texas, 2000, 2004

Hydro Quebec TransEnergie, 2001, 2004

Sierra Pacific Company, 2000, 2001, 2002, 2007, 2010

Nevada Power Company, 2001

Mid American Energy, 2001, 2002

Entergy Louisiana Inc. 2001, 2002, 2004

Mississippi Power Company, 2001, 2002, 2007

Oklahoma Gas & Electric Company, 2002 -2003

Public Service Electric & Gas, 2001, 2002

NUI Corp (Elizabethtown Gas Company), 2002

Jersey Central Power & Light, 2002

San Diego Gas & Electric, 2002, 2012, 2014

New Brunswick Power, 2002

Entergy New Orleans, 2002, 2008

Hydro-Quebec Distribution 2002

PSI Energy 2003

Fortis – Newfoundland Power & Light 2002

Emera – Nova Scotia Power 2004

Hydro-Quebec TransEnergie 2004

Hawaiian Electric 2004

Missouri Gas Energy 2004

AGL Resources 2004

Arkansas Western Gas 2004

Public Service of New Hampshire 2005

Hawaiian Electric Company 2005, 2008, 2009

Delmarva Power & Light Company 2005, 2009

Union Heat Power & Light 2005

Puget Sound Energy 2006, 2007, 2009

Cascade Natural Gas 2006

Entergy Arkansas 2006-7

Bangor Hydro 2006-7

Delmarva 2006, 2007, 2009

Potomac Electric Power Co. 2006, 2007, 2009

Duke Energy Ohio, 2007, 2008, 2009

Duke Energy Kentucky 2009

Consolidated Edison 2007 Docket 07-E-0523

Duke Energy Ohio Docket 07-589-GA-AIR

Hawaiian Electric Company Docket 05-0315

Sierra Pacific Power Docket ER07-1371-000

Public Service New Mexico Docket 06-00210-UT

Detroit Edison Docket U-15244

Potomac Electric Power Docket FC-1053

Delmarva, Delaware, Docket 09-414

Atlantic City Electric, New Jersey, Docket ER-09080664

Maui Electric Co, Hawaii, Docket 2009-0163, 2011

Niagara Mohawk, New York, Docket 10E-0050

Sierra Pacific Power Docket No. 10-06001

Gaz Metro, Regie de l'Energie (Quebec), Docket 2012 R-3752-2011

California Pacific Electric Company, LLC, California PUC, Docket A-12-02-014

Duke Energy Ohio, Ohio Case No. 11-XXXX-EL-SSO

San Diego Gas & Electric, FERC, 2012

San Diego Gas & Electric, California PUC, 2012, Docket A-12-04

Southern California Gas, California PUC, 2012, Docket A-12-04

PROFESSIONAL AND LEARNED SOCIETIES

- Engineering Institute of Canada, 1967-1972
- Canada Council Award, recipient 1971 and 1972
- Canadian Association Administrative Sciences, 1973-80
- American Association of Decision Sciences, 1974-1978
- American Finance Association, 1975-2002
- Financial Management Association, 1978-2002

ACTIVITIES IN PROFESSIONAL ASSOCIATIONS AND MEETINGS

- Chairman of meeting on "New Developments in Utility Cost of Capital", Southern Finance Association, Atlanta, Nov. 1982

- Chairman of meeting on "Public Utility Rate of Return", Southeastern Public Utility Conference, Atlanta, Oct. 1982

- Chairman of meeting on "Current Issues in Regulatory Finance", Financial Management Association, Atlanta, Oct. 1983

- Chairman of meeting on "Utility Cost of Capital", Financial Management Association, Toronto, Canada, Oct. 1984.

- Committee on New Product Development, FMA, 1985

- Discussant, "Tobin's Q Ratio", paper presented at Financial Management Association, New York, N.Y., Oct. 1986

- Guest speaker, "Utility Capital Structure: New Developments", National Society of Rate of Return Analysts 18th Financial Forum, Wash., D.C. Oct. 1986

- Opening address, "Capital Expenditures Analysis: Methodology vs Mythology," Bellcore Economic Analysis Conference, Naples Fl,, 1988.

- Guest speaker, "Mythodology in Regulatory Finance", Society of Utility Rate of Return Analysts (SURFA), Annual Conference, Wash., D.C. February 2007.

PAPERS PRESENTED:

"An Empirical Study of Multi-Period Asset Pricing," annual meeting of Financial Management Assoc., Las Vegas Nevada, 1987.

"Utility Capital Expenditures Analysis: Net Present Value vs Revenue Requirements", annual meeting of Financial Management Assoc., Denver, Colorado, October 1985.

"Intervention Analysis and the Dynamics of Market Efficiency", annual meeting of Financial Management Assoc., San Francisco, Oct. 1982

"Intertemporal Market-Line Theory: An Empirical Study," annual meeting of Eastern Finance Assoc., Newport, R.I. 1981

"Option Writing for Financial Institutions: A Cost-Benefit Analysis", 1979 annual meeting Financial Research Foundation

"Free-lunch on the Toronto Stock Exchange", annual meeting of Financial Research Foundation of Canada, l978.

"Simulation System Computer Software SIMFIN", HP International Business Computer Users Group, London, 1975.

"Inflation Accounting: Implications for Financial Analysis." Institute of Certified Public Accountants Symposium, 1979.

OFFICES IN PROFESSIONAL ASSOCIATIONS

- President, International Hewlett-Packard Business Computers Users Group, 1977
- Chairman Program Committee, International HP Business Computers Users Group, London, England, 1975
- Program Coordinator, Canadian Assoc. of Administrative Sciences, 1976
- Member, New Product Development Committee, Financial Management Association, 1985-1986
- Reviewer: Journal of Financial Research
Financial Management
Financial Review
Journal of Finance

PUBLICATIONS

"Risk Aversion Revisited", Journal of Finance, Sept. 1983

"Hedging Regulatory Lag with Financial Futures," Journal of Finance, May 1983. (with G. Gay, R. Kolb)

"The Effect of CWIP on Cost of Capital," Public Utilities Fortnightly, July 1986.

"The Effect of CWIP on Revenue Requirements" Public Utilities Fortnightly, August 1986.

"Intervention Analysis and the Dynamics of Market Efficiency," Time-Series Applications, New York: North Holland, 1983. (with K. El-Sheshai)

"Market-Line Theory and the Canadian Equity Market," Journal of Business Administration, Jan. l982, M. Brennan, editor

"Efficiency of Canadian Equity Markets," International Management Review, Feb. 1978.

"Intertemporal Market-Line Theory: An Empirical Test," Financial Review, Proceedings of the Eastern Finance Association, 1981.

BOOKS

Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va., 1984.

Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 2004

Driving Shareholder Value, McGraw-Hill, January 2001.

The New Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 2006.

MONOGRAPHS

Determining Cost of Capital for Regulated Industries, Public Utilities Reports, Inc., and The Management Exchange Inc., 1982 - 1993. (with V.L. Andrews)

Alternative Regulatory Frameworks, Public Utilities Reports, Inc., and The Management Exchange Inc., 1993. (with V.L. Andrews)

Risk and Return in Capital Projects, The Management Exchange Inc., 1980. (with B. Deschamps)

Utility Capital Expenditure Analysis, The Management Exchange Inc., 1983.

Regulation of Cable Television: An Econometric Planning Model, Quebec Department of Communications, 1978.

“An Economic & Financial Profile of the Canadian Cablevision Industry,” Canadian Radio-Television & Telecommunication Commission (CRTC), 1978.

Computer Users' Manual: Finance and Investment Programs, University of Montreal Press, 1974, revised 1978.

Fiber Optics Communications: Economic Characteristics, Quebec Department of Communications, 1978.

"Canadian Equity Market Inefficiencies", Capital Market Research Memorandum, Garmaise & Thomson Investment Consultants, 1979.

MISCELLANEOUS CONSULTING REPORTS

“Operational Risk Analysis: California Water Utilities,” Calif. Water Association, 1993.

"Cost of Capital Methodologies for Independent Telephone Systems", Ontario Telephone Service Commission, March 1989.

"The Effect of CWIP on Cost of Capital and Revenue Requirements", Georgia Power Company, 1985.

"Costing Methodology and the Effect of Alternate Depreciation and Costing Methods on Revenue Requirements and Utility Finances", Gaz Metropolitan Inc., 1985.

"Simulated Capital Structure of CN-CP Telecommunications: A Critique", CRTC, 1977.

"Telecommunications Cost Inquiry: Critique," CRTC, 1977.

"Social Rate of Discount in the Public Sector", CRTC Policy Statement, 1974.

"Technical Problems in Capital Projects Analysis", CRTC Policy Statement, 1974.

RESEARCH GRANTS

"Econometric Planning Model of the Cablevision Industry," International Institute of Quantitative Economics, CRTC.

"Application of the Averch-Johnson Model to Telecommunications Utilities," Canadian Radio-Television Commission. (CRTC)

"Economics of the Fiber Optics Industry", Quebec Dept. of Communications.

"Intervention Analysis and the Dynamics of Market Efficiency", Georgia State Univ. College of Business, 1981.

"Firm Size and Beta Stability", Georgia State University College of Business, 1982.

"Risk Aversion and the Demand for Risky Assets", Georgia State University College of Business, 1981.

Chase Econometrics, Interactive Data Corp., Research Grant, $50,000 per annum, 1986-1989.

Combination Elec & Gas Utilities
DCF Analysis Value Line Growth Rates

Line No.		(1) Company Name	(2) Current Dividend Yield	(3) Projected EPS Growth
1	LNT	Alliant Energy	3.60	6.0
2	AEE	Ameren Corp.	4.05	4.5
3	AVA	Avista Corp.	4.08	5.5
4	BKH	Black Hills	3.40	9.5
5	CNP	CenterPoint Energy	4.86	5.5
6	CMS	CMS Energy Corp.	3.43	6.5
7	ED	Consol. Edison	4.23	2.0
8	D	Dominion Resources	3.59	5.5
9	DTE	DTE Energy	3.49	5.5
10	DUK	Duke Energy	4.18	5.0
11	EDE	Empire Dist. Elec.	4.40	4.0
12	ETR	Entergy Corp.	4.43	1.5
13	ES	Eversource Energy	3.50	8.5
14	TEG	Integrys Energy	3.77	0.5
15	MGE	MGE Energy	2.85	9.0
16	NEW	NorthWestern Corp.	3.69	6.5
17	POM	Pepco Holdings	4.00	7.0
18	PCG	PG&E Corp.	3.50	8.0
19	PEG	Public Serv. Enterprise	3.67	2.0
20	SCG	SCANA Corp.	4.11	5.0
21	SRE	Sempra Energy	2.62	6.0
22	TE	TECO Energy	4.80	4.0
23	UIL	UIL Holdings	3.47	4.5
24	VVC	Vectren Corp.	3.59	9.0
25	WEC	Wisconsin Energy	3.52	5.5
26	XEL	Xcel Energy Inc.	3.79	5.5

Notes:
Column 2, 3: Value Line Investment Analyzer, 05/2015

Combination Elec & Gas Utilities
DCF Analysis Value Line Growth Rates

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Projected EPS Growth	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
1	Alliant Energy	3.60	6.0	3.82	9.82	10.02
2	Ameren Corp.	4.05	4.5	4.23	8.73	8.96
3	Avista Corp.	4.08	5.5	4.30	9.80	10.03
4	Black Hills	3.40	9.5	3.72	13.22	13.42
5	CenterPoint Energy	4.86	5.5	5.13	10.63	10.90
6	CMS Energy Corp.	3.43	6.5	3.65	10.15	10.35
7	Consol. Edison	4.23	2.0	4.31	6.31	6.54
8	Dominion Resources	3.59	5.5	3.79	9.29	9.49
9	DTE Energy	3.49	5.5	3.68	9.18	9.38
10	Duke Energy	4.18	5.0	4.39	9.39	9.62
11	Empire Dist. Elec.	4.40	4.0	4.58	8.58	8.82
12	Entergy Corp.	4.43	1.5	4.50	6.00	6.23
13	Eversource Energy	3.50	8.5	3.80	12.30	12.50
14	Integrys Energy	3.77	0.5	3.79	4.29	4.49
15	MGE Energy	2.85	9.0	3.11	12.11	12.27
16	NorthWestern Corp.	3.69	6.5	3.93	10.43	10.64
17	Pepco Holdings	4.00	7.0	4.28	11.28	11.51
18	PG&E Corp.	3.50	8.0	3.78	11.78	11.98
19	Public Serv. Enterpris	3.67	2.0	3.74	5.74	5.94
20	SCANA Corp.	4.11	5.0	4.32	9.32	9.54
21	Sempra Energy	2.62	6.0	2.78	8.78	8.92
22	TECO Energy	4.80	4.0	4.99	8.99	9.25
23	UIL Holdings	3.47	4.5	3.63	8.13	8.32
24	Vectren Corp.	3.59	9.0	3.91	12.91	13.12
25	Wisconsin Energy	3.52	5.5	3.71	9.21	9.41
26	Xcel Energy Inc.	3.79	5.5	4.00	9.50	9.71
28	**AVERAGE**	3.79	5.46	3.99	9.46	**9.67**
29	**AVERAGE w/o Integrys Energy**					**9.87**

31 Notes:
32 Column 1, 2, 3: Value Line Investment Analyzer, 05/2015
33 Column 4 = Column 2 times (1 + Column 3/100)
34 Column 5 = Column 4 + Column 3
35 Column 6 = (Column 4 /0.95) + Column 3

Combination Elec & Gas Utilities
DCF Analysis Analysts' Growth Forecasts

Line No.		(1) Company Name	(2) Current Dividend Yield	(3) Analysts' Growth Forecast
1	LNT	Alliant Energy	3.60	5.5
2	AEE	Ameren Corp.	4.05	5.9
3	AVA	Avista Corp.	4.08	5.0
4	BKH	Black Hills	3.40	7.0
5	CNP	CenterPoint Energy	4.86	1.9
6	CMS	CMS Energy Corp.	3.43	6.7
7	ED	Consol. Edison	4.23	2.5
8	D	Dominion Resources	3.59	5.9
9	DTE	DTE Energy	3.49	4.5
10	DUK	Duke Energy	4.18	4.5
11	EDE	Empire Dist. Elec.	4.40	5.0
12	ETR	Entergy Corp.	4.43	-3.1
13	ES	Eversource Energy	3.50	6.6
14	TEG	Integrys Energy	3.77	5.0
15	MGEE	MGE Energy	2.85	4.0
16	NEW	NorthWestern Corp.	3.69	5.0
17	POM	Pepco Holdings	4.00	7.8
18	PCG	PG&E Corp.	3.50	4.7
19	PEG	Public Serv. Enterprise	3.67	2.9
20	SCG	SCANA Corp.	4.11	4.3
21	SRE	Sempra Energy	2.62	7.9
22	TE	TECO Energy	4.80	9.2
23	UIL	UIL Holdings	3.47	7.8
24	VVC	Vectren Corp.	3.59	5.5
25	WEC	Wisconsin Energy	3.52	5.8
26	XEL	Xcel Energy Inc.	3.79	4.6

28 Notes:
29 Columns 1 and 2: Value Line Investment Analyzer, 05/2015

Combination Elec & Gas Utilities
DCF Analysis Analysts' Growth Forecasts

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Analysts' Growth Forecast	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
1	Alliant Energy	3.60	5.5	3.80	9.30	9.50
2	Ameren Corp.	4.05	5.9	4.29	10.19	10.41
3	Avista Corp.	4.08	5.0	4.28	9.28	9.51
4	Black Hills	3.40	7.0	3.64	10.64	10.83
5	CenterPoint Energy	4.86	1.9	4.95	6.85	7.11
6	CMS Energy Corp.	3.43	6.7	3.66	10.36	10.55
7	Consol. Edison	4.23	2.5	4.34	6.84	7.06
8	Dominion Resources	3.59	5.9	3.80	9.70	9.90
9	DTE Energy	3.49	4.5	3.65	8.15	8.34
10	Duke Energy	4.18	4.5	4.37	8.87	9.10
11	Empire Dist. Elec.	4.40	5.0	4.62	9.62	9.86
12	Eversource Energy	3.50	6.6	3.73	10.33	10.53
13	Integrys Energy	3.77	5.0	3.96	8.96	9.17
14	MGE Energy	2.85	4.0	2.96	6.96	7.12
15	NorthWestern Corp.	3.69	5.0	3.87	8.87	9.08
16	Pepco Holdings	4.00	7.8	4.31	12.11	12.34
17	PG&E Corp.	3.50	4.7	3.66	8.36	8.56
18	Public Serv. Enterpris	3.67	2.9	3.78	6.68	6.88
19	SCANA Corp.	4.11	4.3	4.29	8.59	8.81
20	Sempra Energy	2.62	7.9	2.83	10.73	10.88
21	TECO Energy	4.80	9.2	5.24	14.44	14.72
22	UIL Holdings	3.47	7.8	3.74	11.54	11.74
23	Vectren Corp.	3.59	5.5	3.79	9.29	9.49
24	Wisconsin Energy	3.52	5.8	3.72	9.52	9.72
25	Xcel Energy Inc.	3.79	4.6	3.96	8.56	8.77
27	**AVERAGE**	3.77	5.42	3.97	9.39	**9.60**

Notes:
30 Column 1, 2: Value Line Investment Analyzer, 01/2015
31 Column 3: Yahoo Finance Analyst long-term earnings growth forecast, 01/2
32 Column 4 = Column 2 times (1 + Column 3/100)
33 Column 5 = Column 4 + Column 3
34 Column 6 = (Column 4 /0.95) + Column 3

Combination Elec & Gas Utilities Beta Estimates

	(1)	(2)
Line No	Company Name	Beta
1	Alliant Energy	0.80
2	Ameren Corp.	0.80
3	Avista Corp.	0.80
4	Black Hills	1.00
5	CenterPoint Energy	0.80
6	CMS Energy Corp.	0.80
7	Consol. Edison	0.60
8	Dominion Resources	0.70
9	DTE Energy	0.80
10	Duke Energy	0.60
11	Empire Dist. Elec.	0.70
12	Entergy Corp.	0.70
13	Eversource Energy	0.75
14	Integrys Energy	0.80
15	MGE Energy	0.80
16	NorthWestern Corp.	0.80
17	Pepco Holdings	0.70
18	PG&E Corp.	0.70
19	Public Serv. Enterprise	0.80
20	SCANA Corp.	0.80
21	Sempra Energy	0.80
22	TECO Energy	0.90
23	UIL Holdings	0.80
24	Vectren Corp.	0.80
25	Wisconsin Energy	0.70
26	Xcel Energy Inc.	0.70
28	**AVERAGE**	**0.77**

30 Source: Value Line Investment Analyzer 05/2015

MRP Calculations

	(1)	(2)
Dividend Yield (spot times (1+g)	D/P	1.2
Forecast Earnings Growth	g	10.5
DCF Return Value Line Index	K	11.7
Projected Risk-Free Rate	R_f	4.4
DCF Market Risk Premium	DCF MRP	7.3
Morningstar Historical Mkt Risk Premium	HIST MRP	7.0
Average Mkt Risk Premium	**AVG MRP**	**7.2**

Source: Value Line Investment Analyzer 05/2015

2015 Utility Industry Historical Risk Premium

Line No.	Year	(1) Long-Term Government Bond Yield	(2) 20 year Maturity Bond Value	(3) Gain/Loss	(4) Interest	(5) Bond Total Return	(6) S&P Utility Index Return	(7) Utility Equity Risk Premium Over Bond Returns
1	1931	4.07%	1,000.00					
2	1932	3.15%	1,135.75	135.75	40.70	17.64%	-0.54%	-18.18%
3	1933	3.36%	969.60	-30.40	31.50	0.11%	-21.87%	-21.98%
4	1934	2.93%	1,064.73	64.73	33.60	9.83%	-20.41%	-30.24%
5	1935	2.76%	1,025.99	25.99	29.30	5.53%	76.63%	71.10%
6	1936	2.55%	1,032.74	32.74	27.60	6.03%	20.69%	14.66%
7	1937	2.73%	972.40	-27.60	25.50	-0.21%	-37.04%	-36.83%
8	1938	2.52%	1,032.83	32.83	27.30	6.01%	22.45%	16.44%
9	1939	2.26%	1,041.65	41.65	25.20	6.68%	11.26%	4.58%
10	1940	1.94%	1,052.84	52.84	22.60	7.54%	-17.15%	-24.69%
11	1941	2.04%	983.64	-16.36	19.40	0.30%	-31.57%	-31.87%
12	1942	2.46%	933.97	-66.03	20.40	-4.56%	15.39%	19.95%
13	1943	2.48%	996.86	-3.14	24.60	2.15%	46.07%	43.92%
14	1944	2.46%	1,003.14	3.14	24.80	2.79%	18.03%	15.24%
15	1945	1.99%	1,077.23	77.23	24.60	10.18%	53.33%	43.15%
16	1946	2.12%	978.90	-21.10	19.90	-0.12%	1.26%	1.38%
17	1947	2.43%	951.13	-48.87	21.20	-2.77%	-13.16%	-10.39%
18	1948	2.37%	1,009.51	9.51	24.30	3.38%	4.01%	0.63%
19	1949	2.09%	1,045.58	45.58	23.70	6.93%	31.39%	24.46%
20	1950	2.24%	975.93	-24.07	20.90	-0.32%	3.25%	3.57%
21	1951	2.69%	930.75	-69.25	22.40	-4.69%	18.63%	23.32%
22	1952	2.79%	984.75	-15.25	26.90	1.17%	19.25%	18.08%
23	1953	2.74%	1,007.66	7.66	27.90	3.56%	7.85%	4.29%
24	1954	2.72%	1,003.07	3.07	27.40	3.05%	24.72%	21.67%
25	1955	2.95%	965.44	-34.56	27.20	-0.74%	11.26%	12.00%
26	1956	3.45%	928.19	-71.81	29.50	-4.23%	5.06%	9.29%
27	1957	3.23%	1,032.23	32.23	34.50	6.67%	6.36%	-0.31%
28	1958	3.82%	918.01	-81.99	32.30	-4.97%	40.70%	45.67%
29	1959	4.47%	914.65	-85.35	38.20	-4.71%	7.49%	12.20%
30	1960	3.80%	1,093.27	93.27	44.70	13.80%	20.26%	6.46%
31	1961	4.15%	952.75	-47.25	38.00	-0.92%	29.33%	30.25%
32	1962	3.95%	1,027.48	27.48	41.50	6.90%	-2.44%	-9.34%
33	1963	4.17%	970.35	-29.65	39.50	0.99%	12.36%	11.37%
34	1964	4.23%	991.96	-8.04	41.70	3.37%	15.91%	12.54%
35	1965	4.50%	964.64	-35.36	42.30	0.69%	4.67%	3.98%
36	1966	4.55%	993.48	-6.52	45.00	3.85%	-4.48%	-8.33%
37	1967	5.56%	879.01	-120.99	45.50	-7.55%	-0.63%	6.92%
38	1968	5.98%	951.38	-48.62	55.60	0.70%	10.32%	9.62%
39	1969	6.87%	904.00	-96.00	59.80	-3.62%	-15.42%	-11.80%
40	1970	6.48%	1,043.38	43.38	68.70	11.21%	16.56%	5.35%
41	1971	5.97%	1,059.09	59.09	64.80	12.39%	2.41%	-9.98%
42	1972	5.99%	997.69	-2.31	59.70	5.74%	8.15%	2.41%
43	1973	7.26%	867.09	-132.91	59.90	-7.30%	-18.07%	-10.77%
44	1974	7.60%	965.33	-34.67	72.60	3.79%	-21.55%	-25.34%
45	1975	8.05%	955.63	-44.37	76.00	3.16%	44.49%	41.33%
46	1976	7.21%	1,088.25	88.25	80.50	16.87%	31.81%	14.94%
47	1977	8.03%	919.03	-80.97	72.10	-0.89%	8.64%	9.53%

2015 Utility Industry Historical Risk Premium

Line No.	Year	(1) Long-Term Government Bond Yield	(2) 20 year Maturity Bond Value	(3) Gain/Loss	(4) Interest	(5) Bond Total Return	(6) S&P Utility Index Return	(7) Utility Equity Risk Premium Over Bond Returns
48	1978	8.98%	912.47	-87.53	80.30	-0.72%	-3.71%	-2.99%
49	1979	10.12%	902.99	-97.01	89.80	-0.72%	13.58%	14.30%
50	1980	11.99%	859.23	-140.77	101.20	-3.96%	15.08%	19.04%
51	1981	13.34%	906.45	-93.55	119.90	2.63%	11.74%	9.11%
52	1982	10.95%	1,192.38	192.38	133.40	32.58%	26.52%	-6.06%
53	1983	11.97%	923.12	-76.88	109.50	3.26%	20.01%	16.75%
54	1984	11.70%	1,020.70	20.70	119.70	14.04%	26.04%	12.00%
55	1985	9.56%	1,189.27	189.27	117.00	30.63%	33.05%	2.42%
56	1986	7.89%	1,166.63	166.63	95.60	26.22%	28.53%	2.31%
57	1987	9.20%	881.17	-118.83	78.90	-3.99%	-2.92%	1.07%
58	1988	9.18%	1,001.82	1.82	92.00	9.38%	18.27%	8.89%
59	1989	8.16%	1,099.75	99.75	91.80	19.16%	47.80%	28.64%
60	1990	8.44%	973.17	-26.83	81.60	5.48%	-2.57%	-8.05%
61	1991	7.30%	1,118.94	118.94	84.40	20.33%	14.61%	-5.72%
62	1992	7.26%	1,004.19	4.19	73.00	7.72%	8.10%	0.38%
63	1993	6.54%	1,079.70	79.70	72.60	15.23%	14.41%	-0.82%
64	1994	7.99%	856.40	-143.60	65.40	-7.82%	-7.94%	-0.12%
65	1995	6.03%	1,225.98	225.98	79.90	30.59%	42.15%	11.56%
66	1996	6.73%	923.67	-76.33	60.30	-1.60%	3.14%	4.74%
67	1997	6.02%	1,081.92	81.92	67.30	14.92%	24.69%	9.77%
68	1998	5.42%	1,072.71	72.71	60.20	13.29%	14.82%	1.53%
69	1999	6.82%	848.41	-151.59	54.20	-9.74%	-8.85%	0.89%
70	2000	5.58%	1,148.30	148.30	68.20	21.65%	59.70%	38.05%
71	2001	5.75%	979.95	-20.05	55.80	3.57%	-30.41%	-33.98%
72	2002	4.84%	1,115.77	115.77	57.50	17.33%	-30.04%	-47.37%
73	2003	5.11%	966.42	-33.58	48.40	1.48%	26.11%	24.63%
74	2004	4.84%	1,034.35	34.35	51.10	8.54%	24.22%	15.68%
75	2005	4.61%	1,029.84	29.84	48.40	7.82%	16.79%	8.97%
76	2006	4.91%	962.06	-37.94	46.10	0.82%	20.95%	20.13%
77	2007	4.50%	1,053.70	53.70	49.10	10.28%	19.36%	9.08%
78	2008	3.03%	1,219.28	219.28	45.00	26.43%	-28.99%	-55.42%
79	2009	4.58%	798.39	-201.61	30.30	-17.13%	11.94%	29.07%
80	2010	4.14%	1,059.45	59.45	45.80	10.52%	5.49%	-5.03%
81	2011	2.48%	1,260.50	260.50	41.40	30.19%	19.88%	-10.31%
82	2012	2.41%	1,011.06	11.06	24.80	3.59%	1.99%	-1.60%
83	2013	3.67%	822.57	-177.43	24.10	-15.33%	13.26%	28.59%
84	2014	2.40%	1,200.79	200.79	36.70	23.75%	28.61%	4.86%
86	**Mean**							**5.5%**

88 Source: Bloomberg Web site: Standard & Poors Utility Stock Index % Annual Change, Jan. to Dec.

89 Dec. Bond yields from Ibbotson SBBI 2015 Classic Yearbook (Morningstar) Table A-9 Long-Term Government Bonds Yields

Allwed Equity Risk Premium - Treasury Bond

Line	Date	Treasury Bond Yield[1] (1)	Authorized Electric Returns[2] (2)	Indicated Risk Premium (3)
1	1986	7.89%	13.93%	6.0%
2	1987	9.20%	12.99%	3.8%
3	1988	9.18%	12.79%	3.6%
4	1989	8.16%	12.97%	4.8%
5	1990	8.44%	12.70%	4.3%
6	1991	7.30%	12.55%	5.3%
7	1992	7.26%	12.09%	4.8%
8	1993	6.54%	11.41%	4.9%
9	1994	7.99%	11.34%	3.4%
10	1995	6.03%	11.55%	5.5%
11	1996	6.73%	11.39%	4.7%
12	1997	6.02%	11.40%	5.4%
13	1998	5.42%	11.66%	6.2%
14	1999	6.82%	10.77%	4.0%
15	2000	5.58%	11.43%	5.9%
16	2001	5.75%	11.09%	5.3%
17	2002	4.84%	11.16%	6.3%
18	2003	5.11%	10.97%	5.9%
19	2004	4.84%	10.75%	5.9%
20	2005	4.61%	10.54%	5.9%
21	2006	4.91%	10.36%	5.5%
22	2007	4.50%	10.36%	5.9%
23	2008	3.03%	10.46%	7.4%
24	2009	4.58%	10.48%	5.9%
25	2010	4.14%	10.34%	6.2%
26	2011	2.48%	10.29%	7.8%
27	2012	2.41%	10.17%	7.8%
28	2013	3.70%	10.02%	6.3%
29	2014	2.40%	9.92%	7.5%
31	**Average**	**5.72%**	**11.31%**	**5.59%**

Sources:
[1] Morninstar 2015 Classic Yearbook Table A-9
[2] SNL (Regulatory Research Associates)
Major Rate Case Decisions Calendar Year 2014

Electric Utilities Long-Term Debt Ratio

Line No.		Company Name	Debt Ratio
1	LNT	Alliant Energy	47.5
2	AEE	Ameren Corp.	45.2
3	AVA	Avista Corp.	51.0
4	BKH	Black Hills	47.9
5	CNP	CenterPoint Energy	64.4
6	CMS	CMS Energy Corp.	68.7
7	ED	Consol. Edison	48.0
8	D	Dominion Resources	65.4
9	DTE	DTE Energy	47.7
10	DUK	Duke Energy	47.7
11	EDE	Empire Dist. Elec.	50.6
12	ETR	Entergy Corp.	55.1
13	ES	Eversource Energy	46.5
14	TEG	Integrys Energy	46.9
15	MGE	MGE Energy	37.5
16	NEW	NorthWestern Corp.	53.4
17	POM	Pepco Holdings	51.2
18	PCG	PG&E Corp.	48.5
19	PEG	Public Serv. Enterpris	40.4
20	SCG	SCANA Corp.	52.6
21	SRE	Sempra Energy	51.7
22	TE	TECO Energy	56.6
23	UIL	UIL Holdings	55.6
24	VVC	Vectren Corp.	46.7
25	WEC	Wisconsin Energy	50.6
26	XEL	Xcel Energy Inc.	53.0
28		**AVERAGE**	**51.17**

Source: Value Line Investment Analyzer 5/2015

S&P Investment Risk Matrix

Business Risk/Financial Risk						
	Financial Risk Profile					
Business Risk Profil	Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
Excellent	AAA/AA+	AA	A	A-	BBB	
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair		BBB-	BB+	BB	BB-	B
Weak			BB	BB-	B+	B-
Vulnerable				B+	B	B- or below

S&P Financial Risk Indicators

Financial Risk Indicative Ratios			
	Financial Risk Profile		
	FFO/debt %	Debt/EBITDA x	Debt/Capital %
Minimal	>60	<1.5	<25
Modest	45-60	1.5-2.0	25-35
Intermediate	30-45	2.0-3.0	35-45
Significant	20-30	3.0-4.0	45-50
Aggressive	12-20	4.0-5.0	50-60
Highly Leveraged	<12	>5.0	>60

Moody's Financial Risk Indicators

Financial Risk Ratios			
	Financial Risk Benchmarks		
	CFO/debt %	CFO/interest x	Tot debt/capital %
Aaa	>40	>8.0	<25
Aa	30-50	6.0-8.0	25-35
A	22-30	4.5-6.0	35-45
Baa	13-22	2.7-4.5	45-55
Ba	21-6	1.5-2.7	55-65
B	<5	<1.5	>65

Yields & spreads: US intermediate-term corporates - Medians

Based on Corporate Bonds with Maturities of 7 Years. Methodology: Simple median yields of all regular coupon (no zero coupons or floating-rate) 7-year bonds rated by Moody's. To be included in the index, bonds must have maturities between six and eight years, and have outstanding values of more than $50 million. All yields are yield-to-maturity calculated on a semi-annual basis. Each observation is unweighted in the sample, and the yields are calculated for end-of-month values. Typically, the index will have 1000-1200 bonds each month. The median credit spreads provided on Credit Trends Yields and Spreads are different from those provided as part of Market Implied Ratings.
Archive includes: Monthly data available back to Jan-91.

Updated by the fifth business day of the month.

Rating	Feb-15	Jan-15	Dec-14	Nov-14	Oct-14	Sep-14	Aug-14	Jul-14	Jun-14
A3	2.91	2.73	3.16	3.13	3.20	3.30	3.03	3.23	3.03
Baa1	3.19	2.94	3.33	3.28	3.35	3.45	3.32	3.42	3.38
Baa2	3.36	3.18	3.59	3.50	3.56	3.53	3.40	3.53	3.43
Baa3	4.20	4.43	4.68	4.38	4.32	4.56	4.25	4.32	4.27
7-yr Treasury	1.82	1.46	1.97	1.88	2.04	2.13	2.04	2.23	2.14

Spreads (in basis points)	Feb-15	Jan-15	Dec-14	Nov-14	Oct-14	Sep-14	Aug-14	Jul-14	Jun-14	Period Average
Baa3-Baa1	1.01	1.49	1.35	1.09	0.97	1.11	0.93	0.90	0.89	
Baa3-A3	1.29	1.70	1.52	1.24	1.12	1.26	1.22	1.09	1.24	
Baa2-Baa1	0.17	0.24	0.27	0.21	0.21	0.08	0.08	0.11	0.05	0.16
Baa2-A3	0.45	0.45	0.43	0.36	0.36	0.24	0.37	0.30	0.40	0.37
AVERAGE	31									0.27

APPENDIX A
CAPM, EMPIRICAL CAPM

The Capital Asset Pricing Model (CAPM) is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that their:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is:

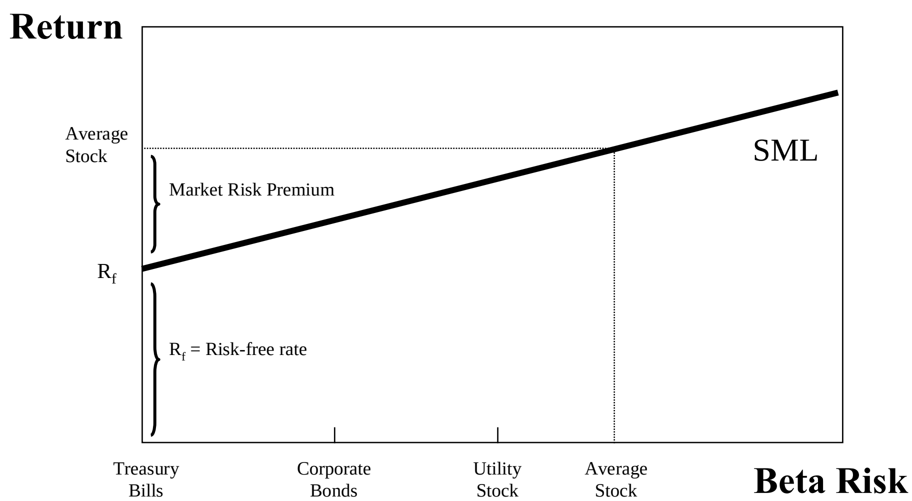
$$K = R_F + \beta(R_M - R_F) \quad (1)$$

Equation 1 is the CAPM expression which asserts that an investor expects to earn a return, K, that could be gained on a risk-free investment, R_F, plus a risk premium for assuming risk, proportional to the security's market risk, also known as beta, β**,** and the market risk premium, $(R_M - R_F)$, where R_M is the market return . The market risk premium $(R_M - R_F)$ can be abbreviated MRP so that the CAPM becomes:

$$K = R_F + \beta \times MRP \quad (2)$$

The CAPM risk-return relationship is depicted in the figure below and is typically labeled as the Security Market Line (SML) by the investment community.

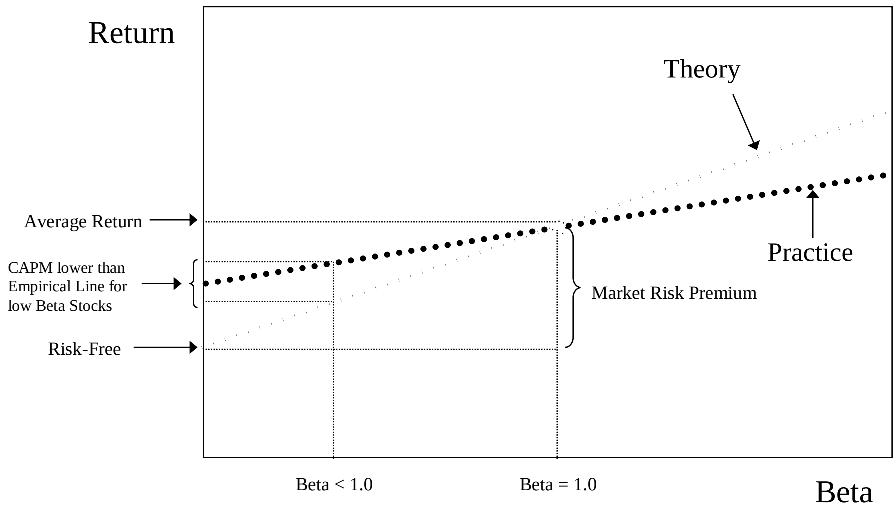
CAPM and Risk - Return
in Capital Markets



A myriad empirical tests of the CAPM have shown that the risk-return tradeoff is not as steeply sloped as that predicted by the CAPM, however. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher returns and high-beta stocks tend to have lower risk returns than predicted by the CAPM. The difference between the CAPM and the type of relationship observed in the empirical studies is depicted in the figure below. This is one of the most widely known empirical findings of the finance literature. This extensive literature is summarized in Chapter 13 of Dr. Morin's book [Regulatory Finance, Public Utilities Report Inc., Arlington, VA, 1994].

Risk vs Return

Theory vs. Practice



A number of refinements and expanded versions of the original CAPM theory have been proposed to explain the empirical findings. These revised CAPMs typically produce a risk-return relationship that is flatter than the standard CAPM prediction. The following equation makes use of these empirical findings by flattening the slope of the risk-return relationship and increasing the intercept:

$$K = R_F + \alpha + \beta (MRP - \alpha) \quad (3)$$

where α is the "alpha" of the risk-return line, a constant determined empirically, and the other symbols are defined as before. Alternatively, Equation 3 can be written as follows:

$$K = R_F + a\,MRP + (1\text{-}a)\,\beta\,MRP \quad (4)$$

where a is a fraction to be determined empirically. Comparing Equations 3 and 4, it is easy to see that alpha equals 'a' times MRP, that is, $\alpha = a \times MRP$

Theoretical Underpinnings

The obvious question becomes what would produce a risk return relationship which is flatter than the CAPM prediction, or in other words, how do you explain the presence of "alpha" in the above equation. The exclusion of variables aside from beta would produce this result. Three such variables are noteworthy: dividend yield, skewness, and hedging potential.

The dividend yield effects stem from the differential taxation on corporate dividends and capital gains. The standard CAPM does not consider the regularity of dividends received by investors. Utilities generally maintain high dividend payout ratios relative to the market, and by ignoring dividend yield, the CAPM provides biased cost of capital estimates. To the extent that dividend income is taxed at a higher rate than capital gains, investors will require higher pre-tax returns in order to equalize the after-tax returns provided by high-yielding stocks (e.g. utility stocks) with those of low-yielding stocks. In other words, high-yielding stocks must offer investors higher pre-tax returns. Even if dividends and capital gains are undifferentiated for tax purposes, there is still a tax bias in favor of earnings retention (lower dividend payout), as capital gains taxes are paid only when gains are realized.

Empirical studies by Litzenberger and Ramaswamy (1979) and Litzenberger et al. (1980) find that security returns are positively related to dividend yield as well as to beta. These results are consistent with after-tax extensions of the CAPM developed by Breenan (1973) and Litzenberger and Ramaswamy (1979) and suggest that the relationship between return, beta, and dividend yield should be estimated and employed to calculate the cost of equity capital.

As far as skewness is concerned, investors are more concerned with losing money than with total variability of return. If risk is defined as the probability of loss, it appears more logical to measure risk as the probability of achieving a return which is below the expected return. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant. As shown by Kraus and Litzenberger (1976), expected return depends on both on a stock's systematic risk (beta) and the systematic skewness. Empirical studies by Kraus and Litzenberger (1976), Friend, Westerfield, and Granito (1978), and Morin (1981) found that, in addition to beta, skewness of returns has a significant negative relationship with security returns. This result is consistent with the skewness version of the CAPM developed by Rubinstein (1973) and Kraus and Litzenberger (1976).

This is particularly relevant for public utilities whose future profitability is constrained by the regulatory process on the upside and relatively unconstrained on the downside in the face of socio-political realities of public utility regulation. The process of regulation, by restricting the upward potential for returns and responding sluggishly on the downward side, may impart some asymmetry to the distribution of returns, and is more likely to result in utilities earning less, rather than more, than their cost of capital. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant.

As far as hedging potential is concerned, investors are exposed to another kind of risk, namely, the risk of unfavorable shifts in the investment opportunity set. Merton (1973) shows that investors will hold portfolios consisting of three funds: the risk-free asset, the market portfolio, and a portfolio whose returns are perfectly negatively correlated with the riskless asset so as to hedge against unforeseen changes in the future risk-free rate. The higher the degree of protection offered by an asset against unforeseen changes in interest rates, the lower the required return, and conversely. Merton argues that low beta assets, like utility stocks, offer little protection against changes in interest rates, and require higher returns than suggested by the standard CAPM.

Another explanation for the CAPM's inability to fully explain the process determining security returns involves the use of an inadequate or incomplete market index. Empirical studies to validate the CAPM invariably rely on some stock market index as a proxy for the true market portfolio. The exclusion of several asset categories from the definition of market index mis-specifies the CAPM and biases the results found using only stock market data. Kolbe and Read (1983) illustrate the biases in beta estimates which result from applying the CAPM to public utilities. Unfortunately, no comprehensive and easily accessible data exist for several classes of assets, such as mortgages and business investments, so that the exact relation between return and stock betas predicted by the CAPM does not exist. This suggests that the empirical relationship between returns and stock betas is best estimated empirically (ECAPM) rather than by relying on theoretical and elegant CAPM models expanded to include missing assets effects. In any event, stock betas may be highly correlated with the true beta measured with the true market index.

Yet another explanation for the CAPM's inability to fully explain the observed risk-return tradeoff involves the possibility of constraints on investor borrowing that run counter to the assumptions of the CAPM. In response to this inadequacy, several versions of the CAPM have been developed by researchers. One of these versions is the so-called zero-beta, or two-factor, CAPM which provides for a risk-free return in a market where borrowing and lending rates are divergent. If borrowing rates and lending rates differ, or there is no risk-free borrowing or lending, or there is risk-free lending but no risk-free borrowing, then the CAPM has the following form:

$$K = R_Z + \beta(R_m - R_F)$$

The model, christened the zero-beta model, is analogous to the standard CAPM, but with the return on a minimum risk portfolio which is unrelated to market returns, R_Z, replacing the risk-free rate, R_F. The model has been empirically tested by Black, Jensen, and Scholes (1972), who found a flatter than predicted CAPM, consistent with the model and other researchers' findings.

The zero-beta CAPM cannot be literally employed in cost of capital projections, since the zero-beta portfolio is a statistical construct difficult to replicate.

Empirical Evidence

A summary of the empirical evidence on the magnitude of alpha is provided in the table below.

Empirical Evidence on the Alpha Factor		
Author	**Range of alpha**	**Period relied**
Black (1993)	-3.6% to 3.6%	1931-1991
Black, Jensen and Scholes (1972)	-9.61% to 12.24%	1931-1965
Fama and McBeth (1972)	4.08% to 9.36%	1935-1968
Fama and French (1992)	10.08% to 13.56%	1941-1990
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%	
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%	1926-1978
Pettengill, Sundaram and Mathur (1995)	4.6%	
Morin (1994)	2.0%	1926-1984
Harris, Marston, Mishra, and O'Brien (2003)	2.0%	1983-1998

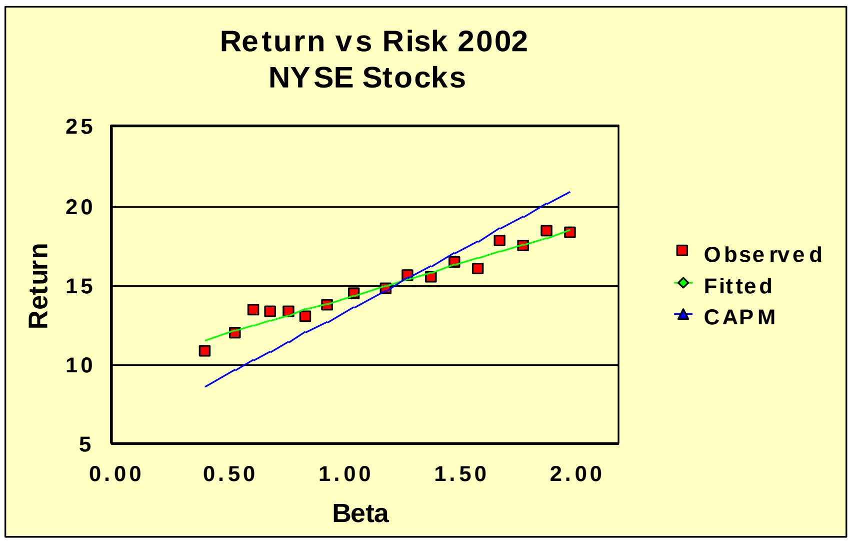
Given the observed magnitude of alpha, the empirical evidence indicates that the risk-return relationship is flatter than that predicted by the CAPM. Typical of the empirical evidence is the findings cited in Morin (1989) over the period 1926-1984 indicating that the observed expected return on a security is related to its risk by the following equation:

$$K = .0829 \quad + \quad .0520\,\beta$$

Given that the risk-free rate over the estimation period was approximately 6 percent, this relationship implies that the intercept of the risk-return relationship is higher than the 6 percent risk-free rate, contrary to the CAPM's prediction. Given that the average return on an average risk stock exceeded the risk-free rate by about 8.0 percent in that period, that is, the market risk premium (R_M - R_F) = 8 percent, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2 percent, suggesting an alpha factor of 2 percent.

Most of the empirical studies cited in the above table utilize raw betas rather than Value Line adjusted betas because the latter were not available over most of the time periods covered in these studies. A study of the relationship between return and adjusted beta is reported on Table 6-7 in Ibbotson Associates Valuation Yearbook 2001. If we exclude the portfolio of very small cap stocks from the relationship due to significant size effects, the relationship between the arithmetic mean return and beta for the remaining portfolios is flatter than predicted and the intercept slightly higher than predicted by the CAPM, as shown on the graph below. It is noteworthy that the Ibbotson study relies on adjusted betas as stated on page 95 of the aforementioned study.

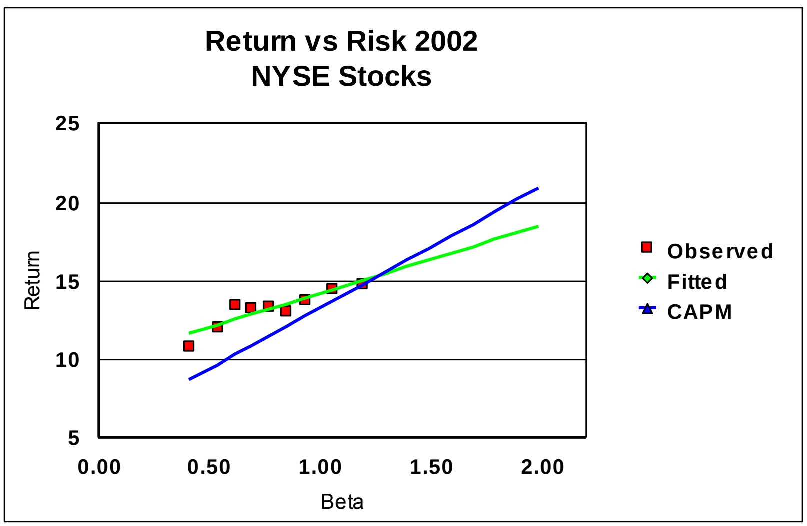
CAPM vs ECAPM



Another study by Morin in May 2002 provides empirical support for the ECAPM. All the stocks covered in the Value Line Investment Survey for Windows for which betas and returns data were available were retained for analysis. There were nearly 2000 such stocks. The expected return was measured as the total shareholder return ("TSR") reported by Value Line over the past ten years. The Value Line adjusted beta was also retrieved from the same data base. The nearly 2000 companies for which all data were available were ranked in ascending order of beta, from lowest to highest. In order to palliate measurement error, the nearly 2000 securities were grouped into ten portfolios of approximately 180 securities for each portfolio. The average returns and betas for each portfolio were as follows:

Portfolio #	Beta	Return
portfolio 1	0.41	10.87
portfolio 2	0.54	12.02
portfolio 3	0.62	13.50
portfolio 4	0.69	13.30
portfolio 5	0.77	13.39
portfolio 6	0.85	13.07
portfolio 7	0.94	13.75
portfolio 8	1.06	14.53
portfolio 9	1.19	14.78
portfolio 10	1.48	20.78

It is clear from the graph below that the observed relationship between DCF returns and Value Line adjusted betas is flatter than that predicted by the plain vanilla CAPM. The observed intercept is higher than the prevailing risk-free rate of 5.7 percent while the slope is less than equal to the market risk premium of 7.7 percent predicted by the plain vanilla CAPM for that period.



In an article published in Financial Management, Harris, Marston, Mishra, and O'Brien ("HMMO") estimate ex ante expected returns for S&P 500 companies over the period 1983-1998[1]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. They then investigate the relation between the risk premium (expected return over the 20-year U.S. Treasury Bond yield) estimates for each month to equity betas as of that same month (5-year raw betas).

The table below, drawn from HMMO Table 4, displays the average estimate prospective risk premium (Column 2) by industry and the corresponding beta estimate for that industry, both in raw form (Column 3) and adjusted form (Column 4). The latter were calculated with the traditional Value Line – Merrill Lynch – Bloomberg adjustment methodology by giving 1/3 weight of to a beta estimate of 1.00 and 2/3 weight to the raw beta estimate.

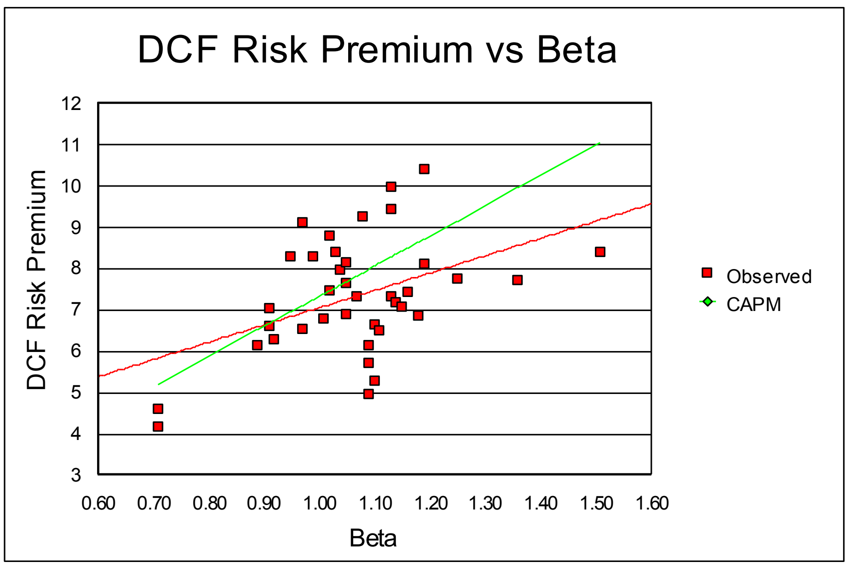
Table A-1 Risk Premium and Beta Estimates by Industry

	Industry (1)	DCF Risk Premium (2)	Raw Industry Beta (3)	Adjusted Industry Beta (4)
1	Aero	6.63	1.15	1.10
2	Autos	5.29	1.15	1.10
3	Banks	7.16	1.21	1.14
4	Beer	6.60	0.87	0.91
5	BldMat	6.84	1.27	1.18
6	Books	7.64	1.07	1.05
7	Boxes	8.39	1.04	1.03
8	BusSv	8.15	1.07	1.05
9	Chems	6.49	1.16	1.11
10	Chips	8.11	1.28	1.19
11	Clths	7.74	1.37	1.25
12	Cnstr	7.70	1.54	1.36
13	Comps	9.42	1.19	1.13
14	Drugs	8.29	0.99	0.99
15	ElcEq	6.89	1.08	1.05
16	Energy	6.29	0.88	0.92
17	Fin	8.38	1.76	1.51
18	Food	7.02	0.86	0.91
19	Fun	9.98	1.19	1.13
20	Gold	4.59	0.57	0.71
21	Hlth	10.40	1.29	1.19
22	Hsld	6.77	1.02	1.01
23	Insur	7.46	1.03	1.02
24	LabEq	7.31	1.10	1.07
25	Mach	7.32	1.20	1.13
26	Meals	7.98	1.06	1.04
27	MedEq	8.80	1.03	1.02
28	Pap	6.14	1.13	1.09
29	PerSv	9.12	0.95	0.97
30	Retail	9.27	1.12	1.08
31	Rubber	7.06	1.22	1.15

[1] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

32	Ships	1.95	0.95	0.97
33	Stee	4.96	1.13	1.09
34	Telc	6.12	0.83	0.89
35	Toys	7.42	1.24	1.16
36	Trans	5.70	1.14	1.09
37	Txtls	6.52	0.95	0.97
38	Util	4.15	0.57	0.71
39	Whlsl	8.29	0.92	0.95
	MEAN	**7.19**		

The observed statistical relationship between expected return and **adjusted beta** is shown in the graph below along with the CAPM prediction:



If the plain vanilla version of the CAPM is correct, then the intercept of the graph should be zero, recalling that the vertical axis represents returns in excess of the risk-free rate. Instead, the observed intercept is approximately 2 percent, that is approximately equal to 25 percent of the expected market risk premium of 7.2 percent shown at the bottom of Column 2 over the 1983-1998 period, as predicted by the ECAPM. The same is true for the slope of the graph. If the plain vanilla version of the CAPM is correct, then the slope of the relationship should equal the market risk premium of 7.2 percent. Instead, the observed slope of close to 5 percent is approximately equal to 75 percent of the expected market risk premium of 7.2 percent, as predicted by the ECAPM.

In short, the HMMO empirical findings are quite consistent with the predictions of the ECAPM.

Practical Implementation of the ECAPM

The empirical evidence reviewed above suggests that the expected return on a security is related to its risk by the following relationship:

$$K = R_F + \alpha + \beta\ (MRP - \alpha) \qquad (5)$$

or, alternatively by the following equivalent relationship:

$$K = R_F + a\,MRP + (1-a)\,\beta\,MRP \qquad (6)$$

The empirical findings support values of α from approximately 2 percent to 7 percent. If one is using the short-term U.S. Treasury Bills yield as a proxy for the risk-free rate, and given that utility stocks have lower than average betas, an alpha in the lower range of the empirical findings, 2 percent - 3 percent is reasonable, albeit conservative.

Using the long-term U.S. Treasury yield as a proxy for the risk-free rate, a lower alpha adjustment is indicated. This is because the use of the long-term U.S. Treasury yield as a proxy for the risk-free rate partially incorporates the desired effect of using the ECAPM[2]. An alpha in the range of 1 percent - 2 percent is therefore reasonable.

To illustrate, consider a utility with a beta of 0.80. The risk-free rate is 5 percent, the MRP is 7 percent, and the alpha factor is 2 percent. The cost of capital is determined as follows:

$$K = R_F + \alpha + \beta\ (MRP - \alpha)$$
$$K = 5\% + 2\% + 0.80(7\% - 2\%)$$
$$= 11\%$$

[2] The Security Market Line (SML) using the long-term risk-free rate has a higher intercept and a flatter slope than the SML using the short-term risk-free rate

A practical alternative is to rely on the second variation of the ECAPM:

$$K = R_F + a\,MRP + (1\text{-}a)\,\beta\,MRP$$

With an alpha of 2 percent, a MRP in the 6 percent - 8 percent range, the ‘a” coefficient is 0.25, and the ECAPM becomes[3]:

$$K = R_F + 0.25\,MRP + 0.75\,\beta\,MRP$$

Returning to the numerical example, the utility’s cost of capital is:

$$K = 5\% + 0.25 \times 7\% + 0.75 \times 0.80 \times 7\%$$
$$= 11\%$$

For reasonable values of beta and the MRP, both renditions of the ECAPM produce results that are virtually identical[4].

[3] Recall that alpha equals ‘a’ times MRP, that is, alpha = a MRP, and therefore a = alpha/MRP. If alpha is 2 percent, then a = 0.25

[4] In the Morin (1994) study, the value of “a” was actually derived by systematically varying the constant "a" in equation 6 from 0 to 1 in steps of 0.05 and choosing that value of 'a' that minimized the mean square error between the observed relationship between return and beta:

$$K = 0.0829 + .0520\,\beta$$

The value of a that best explained the observed relationship was 0.25.

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APPENDIX B

FLOTATION COST ALLOWANCE

To obtain the final cost of equity financing from the investors' expected rate of return, it is necessary to make allowance for underpricing, which is the sum of market pressure, costs of flotation, and underwriting fees associated with new issues. Allowance for market pressure should be made because large blocks of new stock may cause significant pressure on market prices even in stable markets. Allowance must also be made for company costs of flotation (including such items as printing, legal and accounting expenses) and for underwriting fees.

1. MAGNITUDE OF FLOTATION COSTS

According to empirical studies, underwriting costs and expenses average at least 4% of gross proceeds for utility stock offerings in the U.S. (See Logue & Jarrow: "Negotiations vs. Competitive Bidding in the Sale of Securities by Public Utilities", Financial Management, Fall 1978.) A study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.0%. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1% for market pressure in U.S. studies. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5%. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72%. (See Bowyer & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices", Public Utilities Fortnightly, May 22, 1980.)

Eckbo & Masulis ("Rights vs. Underwritten Stock Offerings: An Empirical Analysis", University of British Columbia, Working Paper No. 1208, Sept., 1987) found an average flotation cost of 4.175% for utility common stock offerings. Moreover, flotation costs increased progressively for smaller size issues. They also found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5%. In a classic and monumental study published in the prestigious Journal of Financial Economics by a prominent scholar, a market pressure effect of 3.14% for industrial stock issues and 0.75% for utility common stock issues was found (see Smith, C.W., "Investment Banking and the Capital Acquisition Process," Journal of Financial Economics 15, 1986). Other studies of market pressure are reported in Logue ("On the Pricing of Unseasoned Equity Offerings, Journal of Financial and Quantitative Analysis, Jan. 1973), Pettway ("The Effects of New Equity Sales Upon Utility Share Prices," Public Utilities Fortnightly, May 10 1984), and Reilly and Hatfield ("Investor Experience with New Stock Issues," Financial Analysts' Journal, Sept.- Oct. 1969). In the Pettway study, the market pressure effect for a sample of 368 public utility equity sales was in the range of 2% to 3%. Adding the direct and indirect effects of utility common stock issues, the indicated total flotation cost allowance is above 5.0%, corroborating the results of earlier studies.

As shown in the table below, a comprehensive empirical study by Lee, Lochhead, Ritter, and Zhao, “The Costs of Raising Capital,” Journal of Financial Research, Vol. XIX, NO. 1, Spring 1996, shows average direct flotation costs for equity offerings of 3.5% - 5% for stock issues between $60 and $500 million. Allowing for market pressure costs raises the flotation cost allowance to well above 5%.

FLOTATION COSTS: RAISING EXTERNAL CAPITAL
(Percent of Total Capital Raised)

Amount Raised in $ Millions	Average Flotation Cost: Common Stock	Average Flotation Cost: New Debt
$ 2 - 9. 99	13.28%	4.39%
10 - 19. 99	8.72	2.76
20 - 39. 99	6.93	2.42
40 - 59. 99	5.87	1.32
60 - 79. 99	5.18	2.34
80 - 99. 99	4.73	2.16
100 - 199. 99	4.22	2.31
200 - 499. 99	3.47	2.19
500 and Up	3.15	1.64

Note: Flotation costs for IPOs are about 17 percent of the value of common stock issued if the amount raised is less than $10 million and about 6 percent if more than $500 million is raised. Flotation costs are somewhat lower for utilities than others.

Source: Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research,* Spring 1996.

Therefore, based on empirical studies, total flotation costs including market pressure amount to approximately 5% of gross proceeds. I have therefore assumed a 5% gross total flotation cost allowance in my cost of capital analyses.

2. APPLICATION OF THE FLOTATION COST ADJUSTMENT

The section below shows: 1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital, and 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

Flotation costs are just as real as costs incurred to build utility plant. Fair regulatory treatment absolutely must permit the recovery of these costs. An analogy with bond issues is useful to understand the treatment of flotation costs in the case of common stocks.

In the case of a bond issue, flotation costs are not expensed but are rather amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. This is analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete. In the case of common stock that has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity. Roger A. Morin, Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994, provides numerical illustrations that show that even if a utility does not contemplate any additional common stock issues, a flotation cost adjustment is still permanently required. Examples there also demonstrate that the allowance applies to retained earnings as well as to the original capital.

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

$$K = D_1/P_o + g$$

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

$$r = D_1/B_o + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_o are related to market price P_o as follows:

$$P - fP = B_o$$

$$P(1 - f) = B_o$$

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

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

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

In deriving DCF estimates of fair return on equity, it is therefore necessary to apply a conservative after-tax allowance of 5% to the dividend yield component of equity cost.

Even if no further stock issues are contemplated, the flotation adjustment is still permanently required to keep shareholders whole. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated. This is demonstrated by the numerical example contained in pages 7-9 of this Appendix. Moreover, even if the stock price, hence the DCF estimate of equity return, fully reflected the lack of permanent allowance, the company always nets less than the market price. Only the net proceeds from an equity issue are used to add to the rate base on which the investor earns. A permanent allowance for flotation costs must be authorized in order to insure that in each year the investor earns the required return on the total amount of capital actually supplied.

The example shown on pages 7-9 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 7. The stock is selling in the market for $25, investors expect the firm to pay a dividend of $2.25 that will grow at a rate of 5% thereafter. The traditional DCF cost of equity is thus $k = D/P + g = 2.25/25 + .05 = 14\%$. The firm sells one share stock, incurring a flotation cost of 5%. The traditional DCF cost of equity adjusted for flotation cost is thus $ROE = D/P(1\text{-}f) + g = .09/.95 + .05 = 14.47\%$.

The initial book value (rate base) is the net proceeds from the stock issue, which are $23.75, that is, the market price less the 5% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 8, Column 1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal

DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 are simply the allowed return of 14.47% times the total common equity base. Dividends start at $2.25 and grow at 5% thereafter, which they must do if investors are to earn a 14% return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from $26.25 to $26.13 in the second year, inflicting a loss on shareholders. This is shown on page 9. The growth rate drops from 5% to 4.53%. Thus, investors only earn 9% + 4.53% = 13.53% on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

ASSUMPTIONS:

ISSUE PRICE =	$25.00
FLOTATION COST =	5.00%
DIVIDEND YIELD =	9.00%
GROWTH =	5.00%
EQUITY RETURN = (D/P + g)	**14.00%**
ALLOWED RETURN ON EQUITY = (D/P(1-f) + g)	**14.47%**

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET / BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
--------	--------	--------	--------	--------	--------	--------	--------	--------
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.438	$2.250	65.45%
2	$23.75	$1.188	$24.938	$26.250	1.0526	$3.609	$2.363	65.45%
3	$23.75	$2.434	$26.184	$27.563	1.0526	$3.790	$2.481	65.45%
4	$23.75	$3.744	$27.494	$28.941	1.0526	$3.979	$2.605	65.45%
5	$23.75	$5.118	$28.868	$30.388	1.0526	$4.178	$2.735	65.45%
6	$23.75	$6.562	$30.312	$31.907	1.0526	$4.387	$2.872	65.45%
7	$23.75	$8.077	$31.827	$33.502	1.0526	$4.607	$3.015	65.45%
8	$23.75	$9.669	$33.419	$35.178	1.0526	$4.837	$3.166	65.45%
9	$23.75	$11.340	$35.090	$36.936	1.0526	$5.079	$3.324	65.45%
10	$23.75	$13.094	$36.844	$38.783	1.0526	$5.333	$3.490	65.45%
			5.00%	**5.00%**		**5.00%**	**5.00%**	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
------	--------	--------	--------	--------	--------	--------	--------	--------
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.325	$2.250	67.67%
2	$23.75	$1.075	$24.825	$26.132	1.0526	$3.476	$2.352	67.67%
3	$23.75	$2.199	$25.949	$27.314	1.0526	$3.633	$2.458	67.67%
4	$23.75	$3.373	$27.123	$28.551	1.0526	$3.797	$2.570	67.67%
5	$23.75	$4.601	$28.351	$29.843	1.0526	$3.969	$2.686	67.67%
6	$23.75	$5.884	$29.634	$31.194	1.0526	$4.149	$2.807	67.67%
7	$23.75	$7.225	$30.975	$32.606	1.0526	$4.337	$2.935	67.67%
8	$23.75	$8.627	$32.377	$34.082	1.0526	$4.533	$3.067	67.67%
9	$23.75	$10.093	$33.843	$35.624	1.0526	$4.738	$3.206	67.67%
10	$23.75	$11.625	$35.375	$37.237	1.0526	$4.952	$3.351	67.67%
			4.53%	**4.53%**		**4.53%**	**4.53%**	

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 16-0395-EL-SSO
CASE NO. 16-0397-EL-AAM
CASE NO. 16-0396-EL-ATA

DIRECT TESTIMONY OF
NATHAN C. PARKE

- □ **MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION**
- □ **OPERATING INCOME**
- □ **RATE BASE**
- □ **ALLOCATIONS**
- □ **RATE OF RETURN**
- ■ **RATES AND TARIFFS**
- ■ **OTHER**

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

TESTIMONY OF

NATHAN C. PARKE

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Nathan Parke. My business address is 1065 Woodman Drive, Dayton, Ohio 45432.

Q. By whom and in what capacity are you employed?

A. I am employed by The Dayton Power and Light Company ("DP&L" or the "Company") as Manager, Regulatory Operations.

Q. Will you describe briefly your educational and business background?

A. I earned a Bachelor of Arts degree in Business Administration with a concentration in Management from Wilmington College in Wilmington, Ohio in 2002. I have been employed by DP&L since 2002.

Q. How long have you been Manager of Regulatory Operations?

A. I assumed my present position in November, 2010. Prior to that time, I held various positions in the Regulatory Operations department, including Supervisor and Rate Analyst. Prior to Regulatory Operations, I spent over five years as an analyst in the Power Production department of DP&L. During that time, I was involved with Operating and Maintenance ("O&M") and Capital spending plans, generation forecasting including modeling for the Corporate Plan, power plant evaluations, and overall performance reporting of the generation fleet.

Q. What are your responsibilities in your current position?

A. In my current position, I have overall responsibility for designing, tracking, and ensuring cost recovery for several of DP&L's riders. I am involved in evaluating regulatory and legislative initiatives, and regulatory commission orders that affect the Company's rates and overall regulatory operations.

Q. Have you previously provided testimony before the Public Utilities Commission of Ohio ("PUCO" or the "Commission")?

A. Yes. I have sponsored testimony before the PUCO in the Company's Fuel Rider Case Nos. 09-1012-EL-FAC and 11-5730-EL-FAC, Economic Development Rider Case No. 14-401-EL-RDR, the Company's Electric Security Plan ("ESP") Case No. 12-426-EL-SSO, as well as the Company's Distribution Rate Case No. 15-1830-EL-AIR.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to support the overall rate plan and related tariff changes, support a modification to the Reconciliation Rider to recover a deferred regulatory asset, and support a placeholder Distribution Decoupling Rider. My testimony supports the request for deferral authority relating to the over and/or under collection of the Reliable Electricity Rider ("RER") and Clean Energy Rider supported by Company Witness Hale, Standard Offer Rate supported by Company Witness Brown, Reconciliation Rider and Distribution Decoupling Rider that I support, and the Distribution Investment Rider ("DIR") supported by Company Witness Adams.

Q. Are you sponsoring any Exhibits?

A. Yes. I am sponsoring Exhibit NCP-1, which is a table that shows tariff changes, and Exhibit NCP-2, which includes the detailed calculations for the Reconciliation Rider.

III. REQUEST FOR DEFERRAL AUTHORITY

Q. Please explain the Company's request for deferral authority.

A. The request for deferral authority is related to new true-up riders the Company is requesting. The Company is proposing several new true-up riders: a Reliable Electricity Rider, Standard Offer Rate, Reconciliation Rider, Distribution Decoupling Rider, Clean Energy Rider, and Distribution Investment Rider. The Clean Energy Rider and Distribution Investment Rider will have future applications for recovery; this request is for deferral authority until such applications have been filed. The other riders have proposed rates that, if approved and implemented, will have actual expenses different from the amounts collected. Therefore, the Company needs authority to defer these variances and create a regulatory asset or liability to recognize the amounts due to or from customers. This will also allow the Company to match revenues and expenses in the appropriate periods.

IV. RATE PLAN AND TARIFFS

Q. What is DP&L's rate plan?

A. DP&L's rate plan is to update the current PUCO No. 17 Generation Tariffs to a new PUCO No. 18 to coincide with a similar Distribution proposal in Case No. 15-1830-EL-AIR. This update to the tariff sheets will bring Generation Tariffs in-line with the current needs after generation rates were blended with the Competitive Bid Process ("CBP") in the current Electric Security Plan ("ESP"). Many older tariffs that no longer apply are proposed to be eliminated and the proposed tariffs that will apply are being renumbered to better organize the Tariff sheets**.** The proposed tariffs in this case represent simplifications of our current Competitive Bid Rate ("CB Rate"), Competitive Bid True-up ("CBT") Rider, and Alternative Energy Rider ("AER") supported by Company Witness Brown. The revised tariffs will also include a new Distribution Investment Rider supported by Company Witness Adams. The maximum charge provisions that are currently contained in G12, G13, D19, and D20 are proposed to be modified as further explained later in my testimony. DP&L is proposing modifications to the G8 Alternate Generation Supplier Coordination Tariff and G9 Competitive Retail Generation Service Tariff to align them with the current practice implemented from Commission Orders in 12-426-EL-SSO, and other minor operating changes further supported below. DP&L also proposes to continue its current Energy Efficiency Rider, Economic Development Rider, and Transmission Cost Recovery Rider – Non-bypassable ("TCRR-N") that are in place today. Exhibit NCP-1 details the current tariffs, proposed tariffs in the Distribution rate case, and the proposed tariff changes in this case.

Q. How will the new PUCO No. 18 be implemented?

A. DP&L proposes in its pending distribution rate case and in this case to create a new PUCO No. 18 tariff book. The new version will be filed promptly after the Commission issues orders in those pending cases.

Q. Why is DP&L proposing the new PUCO No. 18 at this time?

A. There are changes to the Distribution tariffs proposed in the Distribution Rate case, and significant changes to the Generation tariffs in this case. Many tariffs are also being eliminated as they are no longer necessary since the CBP has been implemented. Now is the appropriate time to clean-up and renumber tariffs to simplify and make them easier to understand.

Q. What specific Tariff changes are you supporting?

A. I am supporting changes to the G8 Alternate Generation Supplier Coordination Tariff and G9 Competitive Retail Generation Service Tariff.

Q. What changes are you proposing for the G8 Tariff?

A. I am supporting changes to update and clarify certain sections, more specifically:

- Section 2.1 – Removed redundant language and provided clarity
- Section 4.1 – Removed the charge and added Shopping and Net Metering indicators to the customer information list
- Section 7.2 – Added additional language regarding PJM reconciliation and data
- Section 8.1 – Updated interval meter requirement to 200 kW to reflect current processes
- Section 8.2 – Indicated that new interval meters will be wireless
- Section 10.1 – Added clarifying language on billing services agreement, net metering, logo specifications, and early termination fee billing; removed language on fees for dual, rate-ready and consolidated billing
- Section 12.4 – Updated collateral calculation to reflect true default risk now that 100% of the Standard Service Offer is served through the CBP
- Section 18 – Updated the charge for technical support
- Section A – Moved manual interval meter read charge to G9 to reflect current processes
- Section A.3. – Moved switching fee language from G9 to G8 to reflect current processes, and
- Other minor grammar, definition consistency, and renumbering changes.

Q. What changes are you proposing for the G9 Tariff?

A. I am supporting changes to be consistent with the above mentioned updates to the G8 Tariff, more specifically:

- Indicated that new interval meters will be wireless
- Moved switching fee language to G8 to reflect current processes, and
- Moved manual interval meter read charge to G9 to reflect current processes; and updated the charge for manual interval meter reads.

Q. Why is the Company proposing these changes at this time?

A. Many of the revisions are merely to reflect changes that have already been implemented consistent with the outcome of DP&L's last ESP case. The other changes are simply updates to terms and clarifying language for the changing needs of the regulatory environment and market.

Q. Are there other proposed tariff changes at this time?

A. There are three proposed riders in the Distribution Rate case, Case No. 15-1830-EL-AIR. The rates and riders in this case assume the Uncollectible Rider will be approved in that case. In the event that it is not, DP&L will need to make adjustments in this case to address uncollectible costs in each proposed rate/rider. Additionally, to the extent the Commission determines that this case is a more appropriate forum, DP&L requests approval of the Storm Cost Recovery Rider, Uncollectible Rider, and Regulatory Compliance Rider that are fully supported in Case No. 15-1830-EL-AIR.

V. <u>RECONCILIATION RIDER</u>

Q. What is the Reconciliation Rider?

A. The Reconciliation Rider in DP&L's current Tariff book was approved in the Commission's September 4, 2013 Opinion and Order in Case No. 12-426-EL-SSO. This proposal modifies the Reconciliation Rider to allow DP&L to recover a regulatory asset related to the deferral of Ohio Valley Electric Corporation ("OVEC") related costs. The rider will have an annual true-up instead of the previous quarterly true-up.

Q. Is the Reconciliation Rider approved in the 12-426-EL-SSO case no longer applicable?

A. It is no longer applicable since the Company now supplies 100% of the Standard Offer through the Competitive Bid Process. The current Reconciliation Rider Tariff has a final rate in place and will soon be filed for a $0.0 rate. This proposal simply uses the same name and Tariff Sheet, but for a different purpose.

Q. Why is OVEC deferral recovery appropriate in the Reconciliation Rider?

A. The Reconciliation Rider will recover costs associated with the Commission's September 17, 2014 Order in DP&L’s generation separation Case No. 13-2420-EL-UNC, which required DP&L to sell its OVEC generation into PJM's day-ahead markets. This rider is proposed as the mechanism to recover the difference between DP&L's OVEC costs and the associated PJM revenue, to the extent that those amounts were not recovered through DP&L’s Fuel rider.

Q. How will this rider be charged to customers?

A. The Reconciliation Rider will be charged to all distribution customers. It will be allocated to Residential, Non-residential, and Private Outdoor Lighting based on base distribution revenue, from the previous year. The rate is set based on a projected number of customers, and it will be a per-customer charge.

Q. Where are the rate calculations for this rider?

A. The rate calculations are included as Exhibit NCP-2.

Q. What is the basis for the dollar amounts in Exhibit NCP-2?

A. The requested dollars represent net costs through December 31, 2015 that total $10,461,463. DP&L will file annually to true-up recovery and request additional dollars as necessary.

VI. DISTRIBUTION DECOUPLING RIDER

Q. What is the Distribution Decoupling Rider?

A. This rider is proposed as a placeholder tariff that initially will be set at zero and will be implemented if needed as a result of DP&L’s to-be-filed Energy Efficiency Portfolio case.

Q. Why is DP&L making this proposal now?

A. DP&L has a pending distribution rate case in which the level of its distribution revenue will be set. That distribution rate case contains volumetric rates, and a continuation of DP&L's energy efficiency programs will cause DP&L to experience less distribution revenue. This rider will decouple the distribution revenue from the kWh reductions realized through energy efficiency programs. In the Senate Bill 310 rule implementation case (14-1411-EL-ORD), on page 20 of the December 17, 2014 Commission Order, the Commission stated that the ESP is the appropriate place to set the recovery of costs through a rider separate from the Energy Efficiency Rider.

Q. How will this rider be charged to customers?

A. The Distribution Decoupling Rider will be charged to all distribution customers, and will be calculated as a percentage of base distribution charges.

VII. MAXIMUM CHARGE PROVISION

Q. What is the Maximum Charge Provision?

A. DP&L's Maximum Charge ("max charge") provision is contained in Secondary and Primary tariffs and limits a customer's total average bill in $/kWh. This provision benefits non-residential customers who have very low load factors by capping the average rate they may be charged on a monthly basis.

Q. What is the Company's proposal relating to the Maximum Charge Provision?

A. The Company's proposal is to reset the remaining components of the max charge provision and establish a process for setting the rate for future true-up filings.

Q. What components are included in the Maximum Charge Provision?

A. The Maximum Charge provision only applies to tariffs with demand charges, not energy charges. Components with demand charges have a kWh rate that is used in lieu of the demand charge when the provision applies. Through this ESP, the Company proposes that the generation rate be a kWh charge; therefore the remaining current components with demand rates are the Distribution Charge, the Service Stability Rider ("SSR"), and the Transmission Cost Recovery Rider – Non-bypassable, which are subject to the Maximum Charge provision. All three components are non-bypassable.

Q. Why is this change included in the ESP?

A. DP&L made a proposal to change its max charge provision in its previous Electric Security Plan (Case No. 12-426-EL-SSO). Through that case, DP&L was ordered to increase the average rate threshold by 2.5% per year. The Company is proposing the new methodology for how the provision is calculated and applied because DP&L is proposing to change the SSO rate structure to an all energy charge, and because in the Company's last ESP, the Commission Staff stated that the "maximum charge provision should be reevaluated at the end of the ESP term"; Staff's position was described in the September 4, 2013 Order on page 40 in Case No. 12-426-EL-SSO.

Q. How and why are you proposing to change the rate methodology?

A. The current components are inconsistent in the amount of charge relative to the average rate charged to other customers in the class. The table below shows the average rate charged to the class, the current max charge rate, and a proposed rate using this methodology. The Non-max average is the average $/kWh rate calculated from customers not billed the max rate, but the normal combination of $/kW and $/kWh rate for each component. The proposed max charge rate is 2 times the average rate for Secondary; the Primary rate is 2.5 times the average rate of non-max charge customers. The table below shows current average and proposed $/kWh rates based on 12 months of 2015:

Secondary:	Distribution	SSR	TCRR-N	Total
Non-max Average	$0.0112245	$0.0081107	$0.0053024	$0.0246376
Current Max Rate	$0.0119858	$0.0248410	$0.0159850	$0.0528118
Proposed	**$0.0224490**	**$0.0162215**	**$0.0106048**	**$0.0492753**
(2 times average)				
Primary:				
Non-max Average	$0.0048976	$0.0066907	$0.0042073	$0.0157956
Current Max Rate	$0.0042860	$0.0249517	$0.0150087	$0.0442464

Proposed *(2.5 times average)*	**$0.0122439**	**$0.0167267**	**$0.0105183**	**$0.0394889**

Q. Why are 2 times the average and 2.5 times the average appropriate?

A. The goal was to simplify the rate, make the components consistent, minimize cost shifts between customers, and minimize significant changes to customer's bills. The adjustment of 2 times the average and 2.5 times the average accomplishes those goals.

Q. Are the rates shown in the table the proposed rates in the tariffs?

A. The table is showing how the methodology will work. The three components should be initially modified at the same time using this methodology. Company Witness Hale uses this methodology in developing the proposed RER max charge rate for this case. This methodology should be used in updating the Distribution rate in its proceeding, and the methodology should also be used in the annual true-up of TCRR-N. A one-time adjustment to the rates in the table is appropriate, and then each component can be updated based on the outcome of each component's case. In other words, the one-time reset shown above should take place at the same time, but new rates going forward should be set on the 2 and 2.5 times the average methodology.

Q. What will be the result to customers with these new rates?

A. The total max charge rate is slightly less than it is today. These small changes will slightly decrease bills of customers that currently benefit from DP&L's max charge provisions.

Q. Why is it important to establish a process for setting the rate?

A. The TCRR-N is an annually adjusted rider. Having this methodology in place will assure that the rate inconsistencies do not develop over time as that component is reset each year.

Q. How is the max charge triggered, and do you propose any changes to that process?

A. The billing system calculates a customer's charges using the standard rates and then again using max charge rates, and then bills the lesser amount. There are no changes proposed to this process.

Q. Are the specific components of the maximum charge relevant to billing?

A. No, changing the individual components while maintaining the overall total will not cause variances in bills or the customers charged. A customer is either billed on all maximum charge rates, or none; it is not an individual component calculation.

VIII. CONCLUSION

Q. Please summarize your testimony.

A. The overall rate plan, including the tariff changes, request for deferral authority, Distribution Decoupling Rider, and Reconciliation Rider, is appropriate and should be approved.

Q. Does this conclude your direct testimony?

A. Yes.

Current Tariff List - PUCO No. 17			Action	Proposed Tariff List - PUCO No. 18	
Tariff No.	Tariff Description			Tariff No.	Tariff Description
D01	Table of Contents		N	D01	Table of Contents
D02	Tariff Index		N	D02	Tariff Index
D03	Applications and Contract For Service		N	D03	Applications and Contract For Service
D04	Credit Requirements of Customer		N	D04	Credit Requirements of Customer
D05	Billing and Payment for Electric Service		N	D05	Billing and Payment for Electric Service
D06	Disconnection/Reconnection of Service		N	D06	Disconnection/Reconnection of Service
D07	Meters and Metering Equipment: Location and Installation		N	D07	Meters and Metering Equipment: Location and Installation
D08	Service Facilities: Location and Installation		N	D08	Service Facilities: Location and Installation
D09	Equipment on Customer's Premises		N	D09	Equipment on Customer's Premises
D10	Use and Character of Service		N	D10	Use and Character of Service
D11	Emergency Electrical Procedures		N	D11	Emergency Electrical Procedures
D12	Extension of Electric Facilities		N	D12	Extension of Electric Facilities
D13	Extension of Electric Facilities to House Trailer Parks		N	D13	Extension of Electric Facilities to House Trailer Parks
D14	Definitions and Amendments		N	D14	Definitions and Amendments
D15	Additional Charges		N	D15	Additional Charges
D16	Open Access Terms and Conditions		N	D16	Open Access Terms and Conditions
D17	Residential		N	D17	Residential
D18	Residential Heating		N	D18	Residential Heating
D19	Secondary		N	D19	Secondary
D20	Primary		N	D20	Primary
D21	Primary-Substation		N	D21	Primary-Substation
D22	High Voltage		N	D22	High Voltage
D23	Private Outdoor Lighting		N	D23	Private Outdoor Lighting
D24	School		R	D24	Reserved For Future Use (Case No. 15-1830-EL-AIR)
D25	Street Lighting		N	D25	Street Lighting
D26	Miscellaneous Service Charges		N	D26	Miscellaneous Service Charges
D27	Reserved For Future Use		R	D27	Uncollectible Rider (Case No. 15-1832-EL-ATA)
D28	Universal Service Fund Rider		N	D28	Universal Service Fund Rider
D29	Reconciliation Rider		R	D29	Reconciliation Rider
D30	Storm Cost Recovery Rider		R	D30	Storm Cost Recovery Rider (Case No. 15-1832-EL-ATA)
D31	Reserved For Future Use		R	D31	Regulatory Compliance Rider (Case No. 15-1832-EL-ATA)
D32	Reserved For Future Use		R	D32	Distribution Decoupling Rider
D33	Excise Tax Surcharge Rider		N	D33	Excise Tax Surcharge Rider
D34	Switching Fees		N	D34	Switching Fees
D35	Interconnection Service		N	D35	Interconnection Service
D36	Reserved For Future Use		R	D36	Distribution Investment Rider
D37	Reserved For Future Use		N	D37	Reserved For Future Use
D38	Energy Efficiency Rider		N	D38	Energy Efficiency Rider
D39	Economic Development Rider		N	D39	Economic Development Rider
T01	Table of Contents		N	T01	Table of Contents
T02	Tariff Index		N	T02	Tariff Index
T03	Application and Contract For Service		N	T03	Application and Contract For Service
T04	Credit Requirements of Customer		N	T04	Credit Requirements of Customer
T05	Billing and Payment for Electric Service		N	T05	Billing and Payment for Electric Service
T06	Use and Character of Service		N	T06	Use and Character of Service
T07	Definitions and Amendments		N	T07	Definitions and Amendments
T08	Transmission Cost Recovery Rider – Non-bypassable		N	T08	Transmission Cost Recovery Rider – Non-bypassable
T09	Transmission Cost Recovery Rider – Bypassable	2	E		
T10-T15	Reserved For Future Use		E		
G01	Table of Contents		N	G01	Table of Contents
G02	Tariff Index		N	G02	Tariff Index
G03	Application and Contract For Service		N	G03	Application and Contract For Service
G04	Credit Requirements of Customer		N	G04	Credit Requirements of Customer
G05	Billing and Payment for Electric Service		N	G05	Billing and Payment for Electric Service
G06	Use and Character of Service		N	G06	Use and Character of Service
G07	Definitions and Amendments		N	G07	Definitions and Amendments
G08	Alternate Generation Supplier Coordination Tariff		R	G08	Alternate Generation Supplier Coordination Tariff
G09	Competitive Retail Generation Service		R	G09	Competitive Retail Generation Service
G10	Standard Offer Residential	2	R	G10	Standard Offer Rate
G11	Standard Offer Residential Heating	2	R	G11	Reliable Electricty Rider
G12	Standard Offer Secondary	2	R	G12	Clean Energy Rider
G13	Standard Offer Primary	2	E		
G14	Standard Offer Primary-Substation	2	E		
G15	Standard Offer High Voltage	2	E		
G16	Standard Offer Private Outdoor Lighting	2	E		
G17	Standard Offer School	2	E		
G18	Standard Offer Street Lighting	2	E		
G19	Competitive Bidding Rate	3	E		
G20	Reserved for Future Use		E		
G21	Cogeneration	4	E		
G22	Reserved for Future Use		E		
G23	Adjustable Rate	4	E		
G24-G25	Reserved for Future Use		E		
G26	Alternative Energy Rider		E		
G27	PJM RPM Rider	2	E		
G28	Fuel Rider	2	E		
G29	Service Stability Rider	3	E		
G30	Competitive Bid True-Up Rider	5	E		

Legend
N - No Change
R - Revised
E - Eliminate
1 - Proposed tariff
2 - Not applicable after 100% CBP
3 - Renumbering tariffs for better organization
4 - No longer applicable
5 - Proposing to include functions in Standard Offer Rate

* Transmission and Generation tariffs with a "N" action designation may include proposed changes to version numbers and language references

The Dayton Power and Light Company
Case No. 16-0395-EL-SSO
Summary of Proposed Reconciliation Rider Rates

Data: Actual & Estimated	Exhibit NCP-2
Type of Filing: Original	
Work Paper Reference No(s).: None	Witness Responsible: Nathan C. Parke

Line (A)	Description (B)	Unit (C)		Rate (D)	Source (E)
1	**Reconciliation Rider Rates**				
2	Residential	$/month	$	1.30	Page 2, Col (H), Line 2
3	Non-Residential	$/month	$	4.67	Page 2, Col (H), Line 3
4	Private Outdoor Lighting	$/month	$	0.52	Page 2, Col (H), Line 9

The Dayton Power and Light Company
Case No. 16-0395-EL-SSO
Summary of Proposed Reconciliation Rider Rates

Data: Actual & Estimated
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible: Nathan C. Parke

Line (A)	Description (B)	Annual Revenue Requirement (C) Page 3, Line 6	Distribution Revenue ($) (D) (Internal Records)	Allocators (E) (E) = (D) / Sum (D)	Allocated Rev. Requirement (F) (F) = (C) * (E)	Forecasted Bills (G) (RJA Exhibit-3)	Proposed Rates (per Bill) (H) (H) = (F) / (G)
1	**Revenue Requirement**	**$ 10,767,587**					
2	**Residential**		**$ 142,086,900**	**66.93%**	**$ 7,206,902**	**5,531,690**	**$ 1.30**
3	**Non-Residential**		**$ 67,899,719**	**31.98%**	**$ 3,443,995**	**737,613**	**$ 4.67**
4	Secondary		$ 54,738,408			728,887	
5	Primary		$ 11,842,680			5,866	
6	Primary Substation		$ 594,268			96	
7	High Voltage		$ 29,160			108	
8	Streetlighting		$ 695,203			2,656	
9	**Private Outdoor Lighting**		**$ 2,300,582**	**1.08%**	**$ 116,690**	**226,038**	**$ 0.52**

The Dayton Power and Light Company
Case No. 16-0395-EL-SSO
Summary of Proposed Reconciliation Rider Rates
January 2017 - December 2017

Line	Description		Balance Jan 1, 2017	Source
(A)	(B)		(C)	(G)
1	OVEC Deferral	$	10,461,163	Internal Records
2	Carrying Costs	$	278,501	Page 4, Col (H)
3				
4	Total	$	10,739,664	Line 1 + Line 2
5	Gross Revenue Conversion Factor		1.0026	Adjustment for CAT
6	**Total to be Recovered**	**$**	**10,767,587**	Line 4 * Line 5

The Dayton Power and Light Company
Case No. 16-0395-EL-SSO
Summary of Proposed Reconciliation Rider Rates
January 2017 - December 2017

Data: Actual & Estimated | Exhibit NCP-2
Type of Filing: Original | Page 4 of 4
Work Paper Reference No(s).: None | Witness Responsible: Nathan C. Parke

		MONTHLY ACTIVITY							CARRYING COST CALCULATION	
Line	Period	First of Month Balance	Additional Charges	Amount Collected (CR)	NET AMOUNT	End of Month before Carrying Cost	Carrying Cost @ 5.29%	End of Month Balance	Less: One-half Monthly Amount	Total Applicable to Carrying Cost
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
					(F) = (D) + (E)	(G) = (C) + (F)	(H) = (K) * (5.29% / 12)	(I) = (G) + (H)	(J) = - (F) * 0.5	(K) = (G) + (J)
1	Jan-17	$ 10,461,163		$ (894,972)	$ (894,972)	$ 9,566,191	$ 44,144	$ 9,610,334	$ 447,486	$ 10,013,677
2	Feb-17	$ 9,610,334		$ (894,972)	$ (894,972)	$ 8,715,363	$ 40,393	$ 8,755,755	$ 447,486	$ 9,162,849
3	Mar-17	$ 8,755,755		$ (894,972)	$ (894,972)	$ 7,860,783	$ 36,626	$ 7,897,409	$ 447,486	$ 8,308,269
4	Apr-17	$ 7,897,409		$ (894,972)	$ (894,972)	$ 7,002,437	$ 32,842	$ 7,035,279	$ 447,486	$ 7,449,923
5	May-17	$ 7,035,279		$ (894,972)	$ (894,972)	$ 6,140,307	$ 29,041	$ 6,169,348	$ 447,486	$ 6,587,793
6	Jun-17	$ 6,169,348		$ (894,972)	$ (894,972)	$ 5,274,376	$ 25,224	$ 5,299,600	$ 447,486	$ 5,721,862
7	Jul-17	$ 5,299,600		$ (894,972)	$ (894,972)	$ 4,404,628	$ 21,390	$ 4,426,018	$ 447,486	$ 4,852,114
8	Aug-17	$ 4,426,018		$ (894,972)	$ (894,972)	$ 3,531,046	$ 17,539	$ 3,548,585	$ 447,486	$ 3,978,532
9	Sep-17	$ 3,548,585		$ (894,972)	$ (894,972)	$ 2,653,613	$ 13,671	$ 2,667,283	$ 447,486	$ 3,101,099
10	Oct-17	$ 2,667,283		$ (894,972)	$ (894,972)	$ 1,772,311	$ 9,786	$ 1,782,097	$ 447,486	$ 2,219,797
11	Nov-17	$ 1,782,097		$ (894,972)	$ (894,972)	$ 887,125	$ 5,883	$ 893,008	$ 447,486	$ 1,334,611
12	Dec-17	$ 893,008		$ (894,972)	$ (894,972)	$ (1,964)	$ 1,964	$ 0	$ 447,486	$ 445,522
13										
14						**Total**	$ 278,501			

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 16-0395-EL-SSO
CASE NO. 16-0397-EL-AAM
CASE NO. 16-0396-EL-ATA

DIRECT TESTIMONY
OF THOMAS A. RAGA

- □ **MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION**
- □ **OPERATING INCOME**
- □ **RATE BASE**
- □ **ALLOCATIONS**
- □ **RATE OF RETURN**
- □ **RATES AND TARIFFS**
- ■ **OTHER**

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

DIRECT TESTIMONY OF

THOMAS A. RAGA

ON BEHALF OF
<u>THE DAYTON POWER AND LIGHT COMPANY</u>

<u>TABLE OF CONTENTS</u>

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Thomas A. Raga. My business address is 1065 Woodman Drive, Dayton, Ohio 45432.

Q. In what capacity are you employed?

A. I am President and Chief Executive Officer of The Dayton Power and Light Company ("DP&L").

Q. How long have you been in your present position?

A. I assumed my present position in February, 2015. I have been employed by DP&L since 2010, initially as its Director of Government Relations. In 2012, I was appointed Executive Director of the DP&L Foundation and added DP&L's community relations function to the expanded job of Director of Government Relations & Community Relations. Later, I was named Vice President of External Relations adding DP&L's environmental, health and safety, corporate communications and resource planning teams to my group. Prior to my current position, I served as Vice President of Public Relations for DP&L.

Q. What are your responsibilities in your current position?

A. I am part of the team responsible for ensuring that our customers receive safe and reliable electric services and that those services are provided in accordance with applicable federal and state laws and regulations. I am a member of the leadership team responsible for developing and implementing the long-term strategy for the business. I am also involved in external efforts relating to governmental and regulatory affairs, customers, interacting with state and community leaders and regulators on matters relevant to DP&L's business in Ohio. I am responsible for the Company's community relations, economic development efforts, energy efficiency, resource planning and corporate communications as well as DP&L's charitable contributions.

Q. Will you describe briefly your educational and business background?

A. I received a Bachelor of Science degree in Agricultural Economics and Business Management from Cornell University. I was employed for twelve years working in management, marketing and sales for Copart, Inc. During that time, I was elected to local office as a township trustee in Warren County, Ohio. In 2000, I was elected to the Ohio House of Representatives. After completing six years of service in the legislature, I joined Sinclair Community College in Dayton, Ohio, as its Sr. Director of Regional Strategy and Development. Later, at Sinclair, I worked as Vice President of Advancement.

Q. Have you previously provided testimony before the Public Utilities Commission of Ohio ("PUCO" or the "Commission")?

A. Yes. I have sponsored testimony before the Commission in Case No. 15-1830-EL-AIR, DP&L's pending distribution rate case.

Q. What are the purposes of this testimony?

A. The purposes of this testimony are to: (1) provide an overview and high-level summary of DP&L's proposal and the underlying reasons for this filing; (2) summarize the economic benefits that will accrue to DP&L customers and the Ohio economy as a whole from the Reliable Electricity Rider ("RER") proposal, including a description of future risks and how those risks are allocated between DP&L and its customers; (3) introduce the importance of the Ohio generation plants in maintaining fuel diversity, price stability, reliability and economic development; and (4) introduce the witnesses who will be addressing these issues and others in greater detail.

II. <u>SUMMARY OF PROPOSAL AND UNDERLYING REASONS FOR THE FILING</u>

Q. What is DP&L proposing in this proceeding?

A. DP&L is proposing an Electric Security Plan ("ESP") for a term of January 1, 2017 through December 31, 2026. This ESP is designed to promote economic growth and stability in Ohio by allowing at-risk generation plants to remain operational. If those plants were to close, then the adverse effects would include $26.5 billion in economic losses in Ohio, the loss of almost 19,000 jobs, and an increase in reliability risks. This ESP is in the customers' best interests not only because it avoids those risks, but also because customers will receive $454.8 million in credits under the proposed RER. Additionally, the ESP among other things, will (a) retain customers' option to shop for a competitive electric supplier, (b) maintain the 100% competitive bidding structure for non-shopping customers (c) introduce a distribution investment rider to support continued investment in distribution system reliability (d) introduce a clean energy rider that will facilitate future investment in renewable and advanced technologies, and (e) maintain DP&L's financial integrity and its ability to provide reliable, safe and stable customer service. The ESP proposal also addresses items such as: simplifying the tariff sheets applicable to the price-to-compare, requesting recovery of approximately $10M of regulatory assets, and establishing new riders, initially set at zero, such as a distribution decoupling rider, related to energy reductions from DP&L's energy efficiency programs.

Q. Please describe the proposed RER.

A. The RER is a mechanism that will result in a non-bypassable charge or credit for a period of 10 years that will operate counter-cyclically to changes in the costs and revenues associated with supplying electricity. Beginning January 1, 2017, the RER will be set at a level determined within this proceeding and will be adjusted each year, with the Commission and its staff maintaining full audit rights and review.

The Company's coal plants, which will be transferred to an unregulated affiliate ("Ohio Genco") upon separation, are included in the Company's proposed RER. The plants included in the Rider are:

(1) Stuart Units 1 – 4
(2) Killen
(3) Miami Fort Units 7 & 8
(4) Zimmer
(5) Conesville Unit 4
(6) Ohio Valley Electric Corporation ("OVEC")

Under the RER, prior to the start of each calendar year, projections will be made of annual variances between (1) the revenue requirement for the fleet of coal-fired generation units (including return on and of invested capital, income taxes, and fixed O&M), and (2) the revenues expected to be earned by that fleet from the sale of capacity (net of capacity penalties), energy (net of fuel, emission allowance costs, and variable operating costs), and ancillary services to PJM markets. The annual variance would be transferred between DP&L and Ohio Genco. That amount would either be a credit or a charge to customers in the form of the RER.

Q: Why is DP&L proposing a RER?

A. DP&L witness testimony will detail how short-term market conditions challenge the continuing operation of the fully environmentally-compliant, baseload plants. The RER will help maintain rate stability by acting as an offset against energy price volatility while promoting Ohio generation fuel supply diversity in a market that is being pushed toward a singular fuel supply. Further, the RER supports system reliability and economic benefits to Ohio. Testimony of Company Witness Harrison shows that the closure of these Ohio plants would cause $26.5 billion of economic losses in Ohio over the ten year period, which would include: (a) a loss of 19,000 Ohio jobs, (b) a loss of nearly $190 million in tax revenues per year, (c) an increase in electricity prices for the state, and (d) a drop in disposable income for Ohio consumers and businesses. Beyond the direct and indirect jobs that would be at risk without the RER, in-state generation supports Ohio jobs and new economic development efforts. Generally, businesses looking to relocate or expand in Ohio want assurances that reliable electric service is available at stable prices. The RER supports this need and the state and local economies will benefit from the continued stable wages and taxes. Further, the in-state plants provide reliability benefits which would otherwise require, at a minimum, transmission investment as supported by Company Witness Grande-Moran.

Q: What external conditions drive the need for the RER?

A. As discussed in the testimony of Company Witnesses Jackson, Miller, and Malinak, the plants are currently at risk of being closed due to short-term conditions in the market. As discussed in the testimony of Company Witnesses Miller and Grande-Moran, the closure of those plants would create significant reliability risks in Ohio. Further, as discussed in greater detail by Company Witness Harrison, the retirement of these power plants will result in significantly higher electric prices and will cost the State of Ohio $26.5 billion in reduced economic activity over the ten year period. The direct and multiplier effects would be felt throughout Ohio, but are particularly devastating to the communities near the power plants that are heavily reliant on the power plants as a source of good jobs for their citizens and for a large share of the property taxes used to fund the schools and other local services. In fact, Company Witness Harrison estimates that if the plants were retired, $1.5 billion of tax revenues would be forfeited and nearly 19,000 Ohio jobs would be lost.

Q. Are there factors that have led to a gap between revenues and costs for the generating assets?

A. Yes, economic factors that have caused that gap are discussed in the testimony of Company Witnesses Miller and Jackson. In addition to the insufficient capacity and energy revenues explained by Company Witness Jackson, several other factors present challenges. First, a steady stream of new environmental regulations and new enforcement approaches by federal and state environmental agencies appear likely to require significant additional investment in order to keep necessary Ohio coal-fired power plants running. Second, within PJM markets, the inclusion of demand-response programs as a "capacity resource" that are treated similarly to generation has resulted in lower capacity prices within PJM. These policy decisions create a gap between revenues and costs that seriously jeopardizes the continued viability of important baseload power plants.

Q. Are there reasons why the proposed RER is non-bypassable?

A. The RER should be non-bypassable because it will benefit all of DP&L's customers. Specifically, by avoiding early retirement of the plants, the RER will promote reliability and provide substantial economic benefits that will benefit all of DP&L's customers. Since all of DP&L's customers will benefit, it is reasonable that the RER be non-bypassable.

Q: Can you summarize why the Commission should approve an RER?

A: Yes. Based on the expert view of Company Witness Meehan, market prices are forecast to rise significantly during the RER term. The RER is expected to be a charge to customers in the early years but a credit to customers in later years, with a net benefit to customers of $454.8 million (see the testimony of Company Witness Malinak).

Further, as explained in the testimony of Company Witnesses Jackson, Miller and Malinak, after the transfer of the generation assets to a non-regulated affiliate, certain generation assets will be at risk of closure. The closure of those assets would have significant adverse effects:

1. The closure would have $26.5 billion in adverse economic impacts (i.e., lost jobs, taxes) (see the testimony of Company Witness Harrison).
    - The closure of the plants in Ohio would significantly decrease supply, and cause a corresponding increase in market prices
    - The closure would cause the loss of almost 19,000 jobs
    - The closure would cause the loss of tax revenues of almost $1.5 billion
    - The closures would result in electricity price increases and job loss that will reduce the disposable income of consumers and businesses to spend on other products and services

2. The closure would cause the expenditure of $112 million in new transmission lines to be constructed (see the testimony of Company Witness Grande-Moran) in order to maintain reliability across the system.

3. The closure would increase reliability risks (see the testimony of Company Witnesses Miller and Grande-Moran).

III. BENEFITS AND THE ALLOCATION OF RISKS OF THE RELIABLE ELECTRICITY RIDER

Q. What are the benefits of the Reliable Electricity Rider?

A. The RER will provide a level of price stability that will allow the Company to keep the plants operational during the ten-year RER period. As a result, the RER benefits DP&L's customers, the local communities in which the power plants are located, the State of Ohio as a whole, and the Company. I will summarize each of these benefits in turn.

Q. What are the benefits to DP&L customers?

A. By helping to ensure that the plants remain open, the RER provides numerous benefits for DP&L's customers.

First, during all 10 years, the RER is designed to act counter-cyclically and, thus, is designed to provide a partial price hedge to customers against the market price volatility that they will face. As a result of current policies within Ohio, all of DP&L's customers are subject to market priced electric supply, either from a Competitive Retail Electric Service ("CRES") provider or as the result of taking Standard Service Offer ("SSO") service where the supply is obtained through a series of auctions. Among other market-based costs, CRES providers and the SSO auction winners pay PJM capacity prices to serve load within the Dayton zone. Those costs get passed through to customers.

Lower wholesale market prices can result in lower retail prices that benefit customers; but market prices can also be highly volatile and can rise rapidly to customers' detriment. With the RER in place, price volatility will be reduced, although not eliminated. If CRES and SSO suppliers are charging more, the same economic factors would allow Ohio Genco to receive more for its capacity and energy. This would cause the RER to be reduced, and if the market price increase is high enough, the RER would be a "negative" number. That means that customers would receive a bill credit from DP&L against their higher CRES provider charges or the higher charges from SSO auction winners when those prices are reset through subsequent SSO auctions. Conversely, if capacity and energy market prices fall, customers should benefit from the price drop through their CRES or SSO supply charges, offset by an increase in the RER. The net result is that market volatility in the supply side of the customer bill will be offset by changes in the RER, resulting in more stable customer bills.

Second, as discussed in the testimony of Company Witness Harrison, market prices would rise throughout Ohio if the plants were to close. The RER thus helps avoid increased market prices by keeping plants open.

Third, as discussed in the testimony of Company Witness Grande-Moran, if the plants were to close, it would cost $112 million to construct new transmission lines in an effort to maintain system reliability.

Fourth, as discussed in the testimony of Company Witnesses Miller and Grande-Moran, even after new transmission lines were constructed, there would still be reliability risks in the region if the plants were closed, particularly if there was another Polar Vortex-type event. Keeping the plants open thus promotes reliability in extreme weather.

Q. What are the benefits to the local communities and the State of Ohio?

A. Those benefits are supported and discussed in greater detail by Company Witness Harrison. In summary, local communities receive direct and indirect benefits from having a power plant located within or near their community. Substantial property tax revenues are paid each year to support schools and other local services. The power plant is often the largest or one of the largest employers in the area and these are jobs that typically pay well, and include health, pension and other benefits. The power plant is also a major customer for goods and services in the region. Much of the employees' earnings are likely going to be spent locally, resulting in millions of dollars in indirect economic benefits to the owners of local stores, restaurants and other businesses. The State of Ohio similarly benefits from the taxes paid by the power plant owner and its employees and from all the enhanced economic activity.

In this regard, Stuart Station, near Aberdeen, Ohio, has 375 employees with a total payroll of $27 million. It pays over $5.6 million in property taxes every year to Adams County. Similarly, Killen Station, near Manchester, Ohio has 110 employees with a total payroll of $7.8 million. It pays over $2.4 million in property taxes every year to Adams County.

Q. How does the Company benefit?

A. As discussed by Company Witness Jackson, the RER provides cash flow certainty for the generation assets, and will enable on-going investments and ensure the long term economic viability of these facilities.

Q. Please explain how the implementation of this Reliable Electricity Rider is critical for the broader proposals included in this ESP and in supporting Ohio's energy policy?

A. This RER will enable the Company and its parent DPL Inc. to maintain their financial integrity as described in Company Witness Malinak's testimony; and recapitalize their balance sheets as required by the Commission and described by Company Witness Jackson, allowing for the investment in those programs that are critical for Ohio's energy future.

IV. <u>OTHER SUPPORTING WITNESSES</u>

Q. Please identify the witnesses who are filing supportive testimony and the areas that each will cover.

A. The following witnesses are submitting testimony in the following areas in support of the Company's ESP:

Witness	**Topic**
Robert J. Adams	Distribution Investment Rider rate design; typical bill impacts
Eric R. Brown	Competitive bidding process; renewable energy in competitive bidding process; competitive bidding prices; Standard Offer Rate design
Angelique Collier	Compliance with environmental regulations
Carlos Grande-Moran	Reliability effects of closure of at-risk generation plants
Claire E. Hale	RER rate design; Clean Energy Rider; information sharing and Commission oversight
Kevin L. Hall	Distribution Investment Rider
David Harrison	Economic impact of closure of generation plants
Craig L. Jackson	DP&L's financial statements; DP&L's request for an RER; cost of long-term debt; severability clause; significantly excessive earnings test
Robert J. Lee	Competitive Bidding Plan
R. Jeffrey Malinak	Financial need of the RER generation plants and DPL Inc.; ESP v. MRO test
Eugene T. Meehan	Projected market prices; price effects of closure of at-risk plants
Mark E. Miller	DP&L's generation assets; risks facing those assets
Roger A. Morin	Reasonable return on equity
Nathan C. Parke	Overall rate plan; tariff changes; Reconciliation Rider; Distribution Decoupling Rider
Thomas A. Raga	Overview of case filing

V. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.