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

2015 DISTRIBUTION BASE RATE CASE

BOOK III – TESTIMONY
VOLUME 3 OF 4

Dayton Power and Light Company

DP&L Case No. 15-1830-EL-AIR

Standard Filing Requirements for Rate Increase

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THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 15-1830-EL-AIR
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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

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DIRECT TESTIMONY OF

DR. ROGER A. MORIN

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

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1   I.   **INTRODUCTION**

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

3   A.   My name is Dr. Roger A. Morin. My business address is Georgia State University,

4   Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Emeritus

5   Professor of Finance at the Robinson College of Business, Georgia State University and

6   Professor of Finance for Regulated Industry at the Center for the Study of Regulated

7   Industry at Georgia State University. I am also a principal in Utility Research

8   International, an enterprise engaged in regulatory finance and economics consulting to

9   business and government. I am testifying on behalf of The Dayton Power and Light

10   Company ("DP&L" or the "Company").

11   Q.   **PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.**

12   A.   I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University,

13   Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton

14   School of Finance, University of Pennsylvania.

15   Q.   **PLEASE SUMMARIZE YOUR ACADEMIC AND BUSINESS CAREER.**

16   A.   I have taught at the Wharton School of Finance, University of Pennsylvania, Amos Tuck

17   School of Business at Dartmouth College, Drexel University, University of Montreal,

18   McGill University, and Georgia State University. I was a faculty member of Advanced

19   Management Research International, and I am currently a faculty member of The

20   Management Exchange Inc. and Exnet, Inc. (now SNL Center for Financial Education

21   LLC or "SNL"), where I continue to conduct frequent national executive-level education

1   seminars throughout the United States and Canada. In the last 30 years, I have conducted

2   numerous national seminars on "Utility Finance," "Utility Cost of Capital," "Alternative

3   Regulatory Frameworks," and "Utility Capital Allocation," which I have developed on

4   behalf of The Management Exchange Inc. and the SNL Center for Financial Education.

5   I have authored or co-authored several books, monographs, and articles in academic

6   scientific journals on the subject of finance. They have appeared in a variety of journals,

7   including The Journal of Finance, The Journal of Business Administration, International

8   Management Review, and Public Utilities Fortnightly. I published a widely-used treatise

9   on regulatory finance, Utilities' Cost of Capital, Public Utilities Reports, Inc., Arlington,

10   Va. 1984. In late 1994, the same publisher released my book, Regulatory Finance, a

11   voluminous treatise on the application of finance to regulated utilities. A revised and

12   expanded edition of this book, The New Regulatory Finance, was published in 2006. I

13   have been engaged in extensive consulting activities on behalf of numerous corporations,

14   legal firms, and regulatory bodies in matters of financial management and corporate

15   litigation. Exhibit RAM-1 describes my professional credentials in more detail.

16 **Q. HAVE YOU PREVIOUSLY TESTIFIED ON COST OF CAPITAL BEFORE**

17   **UTILITY REGULATORY COMMISSIONS?**

18 A. Yes, I have been a cost of capital witness before nearly 50 regulatory bodies in North

19   America, including the Public Utilities Commission of Ohio ("PUCO" or the

20   "Commission"), Federal Energy Regulatory Commission ("FERC"), and the Federal

21   Communications Commission ("FCC"). I have also testified before the following state,

22   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

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

2   **II.   PURPOSE OF TESTIMONY**

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

4   A.   The purpose of my testimony in this proceeding is two-fold: 1) to present an independent

5   appraisal of the fair and reasonable rate of return on common equity ("ROE") on the

6   common equity capital invested in The Dayton Power and Light Company's electricity

7   distribution operations in the State of Ohio, and 2) to recommend a fair and reasonable

8   capital structure for ratemaking purposes that is consistent with the recommended ROE.

9   Based upon this appraisal, I have formed my professional judgment as to a return on such

1   capital that would: (1) be fair to ratepayers, (2) allow the Company to attract the capital

2   needed for infrastructure and reliability investments on reasonable terms, (3) maintain the

3   Company's financial integrity, and (4) be comparable to returns offered on comparable

4   risk investments. I will testify in this proceeding as to that opinion.

5   **Q.** **PLEASE IDENTIFY THE EXHIBITS AND APPENDICES ACCOMPANYING**

6   **YOUR TESTIMONY.**

7   A.   I support the following exhibits and appendices:

8   • Exhibit RAM-1 Resume of Roger A. Morin

9   • Exhibit RAM-2 Electric Utilities DCF Analysis: Value Line Growth
10   Projections

11   • Exhibit RAM-3 Electric Utilities DCF Analysis: Analysts' Growth Forecasts

12   • Exhibit RAM-4 Electric Utility Beta Estimates

13   • Exhibit RAM-5 S&P's Electric Utility Common Stocks Over Long-Term
14   Treasury Bonds Annual Premium Analysis

15   • Exhibit RAM-6 Market Risk Premium Calculations

16   • Exhibit RAM-7 Allowed Risk Premiums: Electric Utility Industry

17   • Exhibit RAM-8 Electric Utility Debt Ratios

18   • Exhibit RAM-9 Standard & Poor's Risk Matrix Criteria

19   • Exhibit RAM-10 Corporate Bond Yields

20   • Appendix RAM-A CAPM, Empirical CAPM

21   • Appendix RAM-B Flotation Cost Allowance

22   These exhibits and appendices relate directly to points in my testimony, and are described

23   in further detail in connection with the discussion of those points in my testimony.

1 Q. **PLEASE SUMMARIZE YOUR FINDINGS CONCERNING DP&L'S COST OF**

2 **COMMON EQUITY.**

3 A. Based on the results of various methodologies, current capital market conditions, and

4 current economic industry conditions, I recommend the adoption of a ROE of 10.5%.

5 This recommended ROE is based on the Commission's adoption of the Company's

6 proposed 50% common equity ratio for ratemaking purposes. A ROE of 10.5% for

7 DP&L is required in order for the Company to: (i) attract capital on reasonable terms, (ii)

8 maintain its financial integrity, and (iii) earn a return commensurate with returns on

9 comparable risk investments.

10 My ROE range is derived from cost of capital studies that I performed using the financial

11 models available to me and from the application of my professional judgment to the

12 results. I applied various cost of capital methodologies, including the Discounted Cash

13 Flow ("DCF"), Risk Premium, and Capital Asset Pricing Model ("CAPM"), to a group of

14 investment-grade dividend-paying combination gas and electric utilities which are

15 covered in Value Line's Electric Utility Composite. The companies were required to

16 have the majority of their revenues from regulated utility operations.

17 My recommended rate of return reflects the application of my professional judgment to

18 the results in light of the indicated returns from my Risk Premium, CAPM, and DCF

19 analyses and DP&L's higher than average investment risk. Moreover, my recommended

20 return is predicated on the assumption that the Company's target common equity

21 percentage of 50% will be approved by the Commission.

1   The results from the various methodologies were adjusted upward by 30 basis points in

2   order to account for DP&L's higher than average investment risk compared to other

3   regulated utilities.   As explained later in my testimony, this adjustment is based

4   principally on DP&L's high external financing requirements relative to its rate base and

5   common equity capital base, on the uncertainty surrounding the Company's appropriate

6   capital structure to be employed for ratemaking, on the unique business risks in the Ohio

7   jurisdiction, and on the economic conditions in the local economy.

8   Q.   **WOULD IT BE IN THE BEST INTERESTS OF RATEPAYERS FOR THE**

9   **COMMISSION TO APPROVE A 10.5% ROE FOR DP&L'S ELECTRICITY**

10   **DISTRIBUTION OPERATIONS?**

11   A.   Yes. My analysis shows that a ROE of 10.5% fairly compensates investors, maintains

12   the Company's credit strength, and attracts the capital needed for utility infrastructure

13   and reliability capital investments. Adopting a lower ROE would increase costs for

14   ratepayers.

15   Q.   **PLEASE EXPLAIN HOW LOW ALLOWED ROES CAN INCREASE BOTH THE**

16   **FUTURE COST OF EQUITY AND DEBT FINANCING.**

17   A.   If a utility is authorized a ROE below the level required by equity investors, the utility or

18   its parent will find it difficult to access the equity. Investors will not provide equity

19   capital at the current market price if the earnable return on equity is below the level they

20   require given the risks of an equity investment in the utility. The equity market corrects

21   this by generating a stock price in equilibrium that reflects the valuation of the potential

22   earnings stream from an equity investment at the risk-adjusted return equity investors

1   require. In the case of a utility that has been authorized a return below the level investors

2   believe is appropriate for the risk they bear, the result is a decrease in the utility's market

3   price per share of common stock. This reduces the financial viability of equity financing

4   in two ways. First, because the utility's price per share of common stock decreases, the

5   net proceeds from issuing common stock are reduced. Second, since the utility's market

6   to book ratio decreases with the decrease in the share price of common stock, the

7   potential risk from dilution of equity investments reduces investors' inclination to

8   purchase new issues of common stock. The ultimate effect is the utility will have to rely

9   more on debt financing to meet its capital needs.

10   As the company relies more on debt financing, its capital structure becomes more

11   leveraged. Because debt payments are a fixed financial obligation to the utility, and

12   income available to common equity is subordinate to fixed charges, this decreases the

13   operating income available for dividend and earnings growth. Consequently, equity

14   investors face greater uncertainty about future dividends and earnings from the firm. As

15   a result, the firm's equity becomes a riskier investment. The risk of default on the

16   company's bonds also increases, making the utility's debt a riskier investment. This

17   increases the cost to the utility from both debt and equity financing and increases the

18   possibility the company will not have access to the capital markets for its outside

19   financing needs. Ultimately, to ensure that DP&L has access to capital markets for its

20   capital needs, a fair and reasonable authorized ROE of 10.5% is required.

21   The Company must secure outside funds from capital markets to finance required utility

22   plant and equipment investments irrespective of capital market conditions, interest rate

1   conditions and the quality consciousness of market participants. Thus, rate relief

2   requirements and supportive regulatory treatment, including approval of my

3   recommended ROE, are essential requirements.

4   **Q.   PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.**

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

6   (III)   Regulatory Framework and Rate of Return;

7   (IV)   Cost of Equity Estimates;

8   (V)   Summary of Results;

9   (VI)   Capital Structure; and

10   (VII)   Conclusion.

11   Section III discusses the rudiments of rate of return regulation and the basic notions

12   underlying rate of return. Section IV contains the application of DCF, Risk Premium,

13   and CAPM tests. Section V summarizes the results. Section VI recommends a capital

14   structure to be used for ratemaking. Section VII concludes the analysis.

15 **III.   <u>REGULATORY FRAMEWORK AND RATE OF RETURN</u>**

16 **Q.   PLEASE EXPLAIN HOW A REGULATED COMPANY'S RATES SHOULD BE**

17   **SET UNDER TRADITIONAL COST OF SERVICE REGULATION.**

18 A.   Under the traditional regulatory process, a regulated company's rates should be set so that

19   the company recovers its costs, including taxes and depreciation, plus a fair and

20   reasonable return on its invested capital. The allowed rate of return must necessarily

1   reflect the cost of the funds obtained, that is, investors' return requirements. In

2   determining a company's required rate of return, the starting point is investors' return

3   requirements in financial markets. A rate of return can then be set at a level sufficient to

4   enable the company to earn a return commensurate with the cost of those funds.

5   Funds can be obtained in two general forms, debt capital and equity capital. The cost of

6   debt funds can be easily ascertained from an examination of the contractual interest

7   payments. The cost of common equity funds, that is, investors' required rate of return, is

8   more difficult to estimate. It is the purpose of the next section of my testimony to

9   estimate a fair and reasonable ROE range for DP&L's cost of common equity capital.

10   Q.   **WHAT FUNDAMENTAL PRINCIPLES UNDERLIE THE DETERMINATION**

11   **OF A FAIR AND REASONABLE ROE?**

12   A.   The heart of utility regulation is the setting of just and reasonable rates by way of a fair

13   and reasonable return. There are two landmark United States Supreme Court cases that

14   define the legal principles underlying the regulation of a public utility's rate of return and

15   provide the foundations for the notion of a fair return:

16   1.   *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W.*

17   *Va*, 262 U.S. 679 (1923), and

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

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

20   measured:

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

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

11   The *Hope* case expanded on the guidelines to be used to assess the reasonableness of the

12   allowed return. The Court reemphasized its statements in the *Bluefield* case and

13   recognized that revenues must cover "capital costs." The Court stated:

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

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

23   The United States Supreme Court reiterated the criteria set forth in *Hope* in *Fed. Power*

24   *Comm'n v. Memphis Light, Gas & Water Div.*, 411 U.S. 458 (1973), in *Permian Basin*

25   *Rate Cases*, 390 U.S. 747 (1968), and most recently in *Duquesne Light Co. v. Barasch*,

26   488 U.S. 299 (1989). In the *Permian Basin Rate Cases*, the Supreme Court stressed that

27   a regulatory agency's rate of return order should --

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

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

2   Therefore, the "end result" of this Commission's decision should be to allow DP&L the

3   opportunity to earn a return on equity that is: (1) commensurate with returns on

4   investments in other firms having corresponding risks, (2) sufficient to assure confidence

5   in the Company's financial integrity, and (3) sufficient to maintain the Company's

6   creditworthiness and ability to attract capital on reasonable terms.

7   **Q.**   **HOW IS THE FAIR RATE OF RETURN DETERMINED?**

8   **A.**   The aggregate return required by investors is called the "cost of capital." The cost of

9   capital is the opportunity cost, expressed in percentage terms, of the total pool of capital

10   employed by the Company. It is the composite weighted cost of the various classes of

11   capital (*e.g.*, bonds, preferred stock, common stock) used by the utility, with the weights

12   reflecting the proportions of the total capital that each class of capital represents. The fair

13   return in dollars is obtained by multiplying the rate of return set by the regulator by the

14   utility's "rate base." The rate base is essentially the net book value of the utility's plant

15   and other assets used to provide utility service in a particular jurisdiction.

16   While utilities like DP&L enjoy varying degrees of monopoly in the sale of public utility

17   services, they, or their parent companies, must compete with everyone else in the free,

18   open market for the input factors of production, whether labor, materials, machines, or

19   capital, including the capital investments required to support the electricity network. The

20   prices of these inputs are set in the competitive marketplace by supply and demand, and it

21   is these input prices that are incorporated in the cost of service computation. This is just

22   as true for capital as for any other factor of production. Since utilities and other investor-

1   *owned businesses must go to the open capital market and sell their securities in*

2   *competition with every other issuer, there is obviously a market price to pay for the*

3   *capital they require, for example, the interest on debt capital, or the expected return on*

4   *equity.* In order to attract the necessary capital, electric utility facilities must compete

5   with alternative uses of capital and offer a return commensurate with the associated risks.

6   **Q.   HOW DOES THE CONCEPT OF A FAIR RETURN RELATE TO THE**

7   **CONCEPT OF OPPORTUNITY COST?**

8   A.   The concept of a fair return is intimately related to the economic concept of "opportunity

9   cost." When investors supply funds to a utility by buying its stocks or bonds, they are not

10   only postponing consumption, giving up the alternative of spending their dollars in some

11   other way, they are also exposing their funds to risk and forgoing returns from investing

12   their money in alternative comparable risk investments. The compensation they require

13   is the price of capital. If there are differences in the risk of the investments, competition

14   among firms for a limited supply of capital will bring different prices. The capital

15   markets translate these differences in risk into differences in required return, in much the

16   same way that differences in the characteristics of commodities are reflected in different

17   prices.

18   The important point is that the required return on capital is set by supply and demand,

19   and is influenced by the relationship between the risk and return expected for those

20   securities and the risks expected from the overall menu of available securities.

21   **Q.   WHAT ECONOMIC AND FINANCIAL CONCEPTS HAVE GUIDED YOUR**

22   **ASSESSMENT OF THE COMPANY'S COST OF COMMON EQUITY?**

1   A.   Two fundamental economic principles underlie the appraisal of the Company's cost of

2   equity, one relating to the supply side of capital markets, the other to the demand side.

3   On the supply side, the first principle asserts that rational investors maximize the

4   performance of their portfolios only if they expect the returns on investments of

5   comparable risk to be the same. If not, rational investors will switch out of those

6   investments yielding lower returns at a given risk level in favor of those investment

7   activities offering higher returns for the same degree of risk. This principle implies that a

8   company will be unable to attract capital funds unless it can offer returns to capital

9   suppliers that are comparable to those achieved on competing investments of similar risk.

10   On the demand side, the second principle asserts that a company will continue to invest in

11   real physical assets if the return on these investments equals, or exceeds, the company's

12   cost of capital. This principle suggests that a regulatory board should set rates at a level

13   sufficient to create equality between the return on physical asset investments and the

14   company's cost of capital.

15   Q.   **HOW DOES THE COMPANY OBTAIN ITS CAPITAL AND HOW IS ITS**

16   **OVERALL COST OF CAPITAL DETERMINED?**

17   A.   The funds employed by the Company are obtained in two general forms, debt capital and

18   equity capital. The cost of debt funds can be ascertained easily from an examination of

19   the contractual interest payments. The cost of common equity funds, that is, equity

20   investors' required rate of return, is more difficult to estimate because the dividend

21   payments received from common stock are not contractual or guaranteed in nature. They

22   are uneven and more risky.

1   Once a cost of common equity estimate has been developed, it can then easily be

2   combined with the embedded cost of debt based on the utility's capital structure, in order

3   to arrive at the overall cost of capital (overall rate of return).

4   Q.   **WHAT IS THE MARKET REQUIRED RATE OF RETURN ON EQUITY**

5   **CAPITAL?**

6   A.   The market required rate of return on common equity, or cost of equity, is the return

7   demanded by the equity investor. Investors establish the price for equity capital through

8   their buying and selling decisions in capital markets. Investors set return requirements

9   according to their perception of the risks inherent in the investment, recognizing the

10   opportunity cost of forgone investments in other companies, and the returns available

11   from other investments of comparable risk.

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

13   A.   The basic premise is that the allowable ROE should be commensurate with returns on

14   investments in other firms having corresponding risks. The allowed return should be

15   sufficient to assure confidence in the financial integrity of the firm, in order to maintain

16   creditworthiness and ability to attract capital on reasonable terms. The "attraction of

17   capital" standard focuses on investors' return requirements that are generally determined

18   using market value methods, such as the Risk Premium, CAPM, or DCF methods. These

19   market value tests define "fair return" as the return investors anticipate when they

20   purchase equity shares of comparable risk in the financial marketplace. This is a market

21   rate of return, defined in terms of anticipated dividends and capital gains as determined

22   by expected changes in stock prices, and reflects the opportunity cost of capital. The

1   economic basis for market value tests is that new capital will be attracted to a firm only if

2   the return expected by the suppliers of funds is commensurate with that available from

3   alternative investments of comparable risk.

4   **IV.**   **COST OF EQUITY CAPITAL ESTIMATES**

5   **Q.   DR. MORIN, HOW DID YOU ESTIMATE THE FAIR ROE FOR DP&L UNDER**

6   **CURRENT CAPITAL MARKET CONDITIONS?**

7   A.   I employed three methodologies: (1) the DCF, (2) the Risk Premium, and (3) the CAPM.

8   All three are market-based methodologies and are designed to estimate the return

9   required by investors on the common equity capital committed to DP&L. I applied the

10   aforementioned methodologies to a group of combination gas and electric utilities as a

11   reference group for DP&L.

12   **Q.   WHY DID YOU USE MORE THAN ONE APPROACH FOR ESTIMATING THE**

13   **COST OF EQUITY?**

14   A.   No one single method provides the necessary level of precision for determining a fair

15   return, but each method provides useful evidence to facilitate the exercise of an informed

16   judgment. Reliance on any single method or preset formula is inappropriate when

17   dealing with investor expectations because of possible measurement difficulties and

18   vagaries in individual companies' market data. Examples of such vagaries include

19   dividend suspension, insufficient or unrepresentative historical data due a recent merger,

20   impending merger or acquisition, and a new corporate identity due to restructuring

21   activities. The advantage of using several different approaches is that the results of each

22   one can be used to check the others.

1   As a general proposition, it is extremely dangerous to rely on only one generic

2   methodology to estimate equity costs. The difficulty is compounded when only one

3   variant of that methodology is employed. It is compounded even further when that one

4   methodology is applied to a single company. Hence, several methodologies applied to

5   several comparable risk companies should be employed to estimate the cost of common

6   equity.

7   As I have stated, there are three broad generic methods available to measure the cost of

8   equity: DCF, Risk Premium, and CAPM. All three of these methods are accepted and

9   used by the financial community and firmly supported in the financial literature. The

10   weight accorded to any one method may very well vary depending on unusual

11   circumstances in capital market conditions.

12   Each methodology requires the exercise of considerable judgment on the reasonableness

13   of the assumptions underlying the method and on the reasonableness of the proxies used

14   to validate the theory and apply the method. Each method has its own way of examining

15   investor behavior, its own premises, and its own set of simplifications of reality.

16   Investors do not necessarily subscribe to any one method, nor does the stock price reflect

17   the application of any one single method by the price-setting investor. There is no

18   guarantee that a single DCF result is necessarily the ideal predictor of the stock price and

19   of the cost of equity reflected in that price, just as there is no guarantee that a single

20   CAPM or Risk Premium result constitutes the perfect explanation of a stock's price or the

21   cost of equity.

22

1   **Q.**   **ARE THERE ANY PRACTICAL DIFFICULTIES IN APPLYING COST OF**

2   **CAPITAL METHODOLOGIES IN THE CURRENT ENVIRONMENT OF**

3   **VOLATILITY IN CAPITAL MARKETS AND ECONOMIC UNCERTAINTY?**

4   **A.**   Yes, there are. The traditional cost of equity estimation methodologies are difficult to

5   implement when you are dealing with the instability and volatility in the capital markets

6   and the highly uncertain economy both in the U.S. and abroad. This is not only because

7   stock prices are volatile at this time, but also because utility company historical data have

8   become less meaningful for an industry experiencing substantial change, for example, the

9   transition to stringent renewable standards and the need to secure vast amounts of

10   external capital over the next decade, regardless of capital market conditions. Past

11   earnings and dividend trends may simply not be indicative of the future. For example,

12   historical growth rates of earnings and dividends have been depressed by eroding margins

13   due to a variety of factors, including the sluggish economy, restructuring, and falling

14   margins. As a result, this historical data may not be representative of the future long-

15   term earning power of these companies. Moreover, historical growth rates may not be

16   necessarily representative of future trends for several electric utilities involved in mergers

17   and acquisitions, as these companies going forward are not the same companies for which

18   historical data are available.

19   In short, given the volatility in capital markets and economic uncertainties, the utilization

20   of multiple methodologies is critical, and reliance on a single methodology is highly

21   hazardous.

22   **A.**   **DCF Estimates**

1   **Q.**   **PLEASE DESCRIBE THE DCF APPROACH TO ESTIMATING THE COST OF**

2   ***EQUITY CAPITAL.***

3   A.   According to DCF theory, the value of any security to an investor is the expected

4   discounted value of the future stream of dividends or other benefits. One widely used

5   method to measure these anticipated benefits in the case of a non-static company is to

6   examine the current dividend plus the increases in future dividend payments expected by

7   investors. This valuation process can be represented by the following formula, which is

8   the traditional DCF model:

9
$$K_e = D_1/P_0 + g$$

10   where: K_e = investors' expected return on equity

11   D_1 = expected dividend at the end of the coming year

12   P_0 = current stock price

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

14   book value

15   The traditional DCF formula states that under certain assumptions, which are described in

16   the next paragraph, the equity investor's expected return, K_e, can be viewed as the sum of

17   an expected dividend yield, D_1/P_0, plus the expected growth rate of future dividends and

18   stock price, g. The returns anticipated at a given market price are not directly observable

19   and must be estimated from statistical market information. The idea of the market value

20   approach is to infer 'K_e' from the observed share price, the observed dividend, and an

21   estimate of investors' expected future growth.

1   The assumptions underlying this valuation formulation are well known, and are discussed

2   in detail in Chapter 4 of my reference book, Regulatory Finance, and Chapter 8 of my

3   new reference text, The New Regulatory Finance. The standard DCF model requires the

4   *following main assumptions: (1) a constant average growth trend for both dividends and*

5   earnings, (2) a stable dividend payout policy, (3) a discount rate in excess of the expected

6   growth rate, and (4) a constant price-earnings multiple, which implies that growth in

7   price is synonymous with growth in earnings and dividends. The standard DCF model

8   also assumes that dividends are paid at the end of each year when in fact dividend

9   payments are normally made on a quarterly basis.

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

11   **MODEL?**

12   **A.**   I applied the DCF model to a group of investment-grade, dividend-paying, combination

13   gas and electric utilities with the majority of their revenues from regulated operations that

14   are covered in the Value Line database.

15   In order to apply the DCF model, two components are required: the expected dividend

16   yield (D_1/P_0), and the expected long-term growth (g). The expected dividend (D_1) in the

17   annual DCF model can be obtained by multiplying the current indicated annual dividend

18   rate by the growth factor (1 + g).

19   **Q.**   **HOW DID YOU ESTIMATE THE DIVIDEND YIELD COMPONENT OF THE**

20   **DCF MODEL?**

1   A.   From a conceptual viewpoint, the stock price to employ in calculating the dividend yield

2   is the current price of the security at the time of estimating the cost of equity. This is

3   because the current stock prices provide a better indication of expected future prices than

4   any other price in an efficient market. An efficient market implies that prices adjust

5   rapidly to the arrival of new information.   Therefore, current prices reflect the

6   fundamental economic value of a security. A considerable body of empirical evidence

7   indicates that capital markets are efficient with respect to a broad set of information. This

8   implies that observed current prices represent the fundamental value of a security, and

9   that a cost of capital estimate should be based on current prices.

10   In implementing the DCF model, I have used the dividend yields reported in the Value

11   Line Investment Analyzer ("VLIA") on-line database. Basing dividend yields on average

12   results from a large group of companies reduces the concern that the vagaries of

13   individual company stock prices will result in an unrepresentative dividend yield.

14   Q.   **WHY DID YOU MULTIPLY THE SPOT DIVIDEND YIELD BY (1 + g) RATHER**

15   **THAN BY (1 + 0.5g)?**

16   A.   Some analysts multiply the spot dividend yield by one plus one half the expected growth

17   rate (1 + 0.5g) rather than the conventional one plus the expected growth rate (1 + g).

18   This procedure understates the return expected by the investor.

19   *The fundamental assumption of the basic annual DCF model is that dividends are*

20   *received annually at the end of each year and that the first dividend is to be received one*

21   *year from now. Thus, the appropriate dividend to use in a DCF model is the full*

22   *prospective dividend to be received at the end of the year. Since the appropriate dividend*

1   to use in a DCF model is the prospective dividend one year from now rather than the

2   dividend one-half year from now, multiplying the spot dividend yield by (1 + 0.5g)

3   understates the proper dividend yield.

4   Moreover, the basic annual DCF model ignores the time value of quarterly dividend

5   payments and assumes dividends are paid once a year at the end of the year. Multiplying

6   the spot dividend yield by (1 + g) is actually a conservative attempt to capture the reality

7   of quarterly dividend payments. Use of this method is conservative in the sense that the

8   annual DCF model fully ignores the more frequent compounding of quarterly dividends.

9   **Q.**   **HOW DID YOU ESTIMATE THE GROWTH COMPONENT OF THE DCF**

10   **MODEL?**

11   **A.**   The principal difficulty in calculating the required return by the DCF approach is in

12   ascertaining the growth rate that investors currently expect. Since no explicit estimate of

13   expected growth is observable, proxies must be employed.

14   As proxies for expected growth, I examined the consensus growth estimate developed by

15   professional analysts. Projected long-term growth rates actually used by institutional

16   investors to determine the desirability of investing in different securities influence

17   investors' growth anticipations. These forecasts are made by large reputable

18   organizations, and the data are readily available and are representative of the consensus

19   view of investors. Because of the dominance of institutional investors in investment

20   management and security selection, and their influence on individual investment

21   decisions, analysts' growth forecasts influence investor growth expectations and provide

22   a sound basis for estimating the cost of equity with the DCF model.

1   Growth rate forecasts of several analysts are available from published investment

2   newsletters and from systematic compilations of analysts' forecasts, such as those

3   tabulated by Zacks Investment Research Inc. and Yahoo Finance. I used analysts' long-

4   term growth forecasts contained in Yahoo Finance as proxies for investors' growth

5   expectations in applying the DCF model. I also used Value Line's growth forecasts as

6   additional proxies.

7 **Q.** **WHY DID YOU REJECT THE USE OF HISTORICAL GROWTH RATES IN**

8   **APPLYING THE DCF MODEL TO ELECTRIC UTILITIES?**

9 **A.** I have rejected historical growth rates as proxies for expected growth in the DCF

10   calculation for two reasons. First, historical growth patterns are already incorporated in

11   analysts' growth forecasts that should be used in the DCF model, and are therefore

12   redundant. Second, published studies in the academic literature demonstrate that growth

13   forecasts made by security analysts are reasonable indicators of investor expectations,

14   and that investors rely on analysts' forecasts. This considerable literature is summarized

15   in Chapter 9 of my most recent textbook, The New Regulatory Finance.

16 **Q.** **DID YOU CONSIDER ANY OTHER METHOD OF ESTIMATING EXPECTED**

17   **GROWTH TO APPLY THE DCF MODEL?**

18 **A.** Yes, I did. I considered using the so-called "sustainable growth" method, also referred to

19   as the "retention growth" method. According to this method, future growth is estimated

20   by multiplying the fraction of earnings expected to be retained by the company, 'b', by

21   the expected return on book equity, ROE, as follows:

1   where: g = expected growth rate in earnings/dividends

2   b = expected retention ratio

3   ROE = expected return on book equity

4   Q.   **DO YOU HAVE ANY RESERVATIONS IN REGARDS TO THE SUSTAINABLE**

5   **GROWTH METHOD?**

6   A.   Yes, I do. First, the sustainable method of predicting growth contains a logic trap: the

7   method requires an estimate of expected return on book equity to be implemented. But if

8   the expected return on book equity input required by the model differs from the

9   recommended return on equity, a fundamental contradiction in logic follows. Second, the

10   empirical finance literature demonstrates that the sustainable growth method of

11   determining growth is not as significantly correlated to measures of value, such as stock

12   prices and price/earnings ratios, as analysts' growth forecasts. I therefore chose not to

13   rely on this method.

14   Q.   **DID YOU CONSIDER DIVIDEND GROWTH IN APPLYING THE DCF**

15   **MODEL?**

16   A.   No, not at this time. The reason is that as a practical matter, while there is an abundance

17   of earnings growth forecasts, there are very few forecasts of dividend growth. Moreover,

18   it is widely expected that some utilities will continue to lower their dividend payout ratios

19   over the next several years in response to heightened business risk and the need to fund

20   very large construction programs over the next decade. Dividend growth has remained

21   largely stagnant in past years as utilities are increasingly conserving financial resources in

22   order to hedge against rising business risks and finance large infrastructure investments.

1   As a result, investors' attention has shifted from dividends to earnings. Therefore,

2   earnings growth provides a more meaningful guide to investors' long-term growth

3   expectations. Indeed, it is growth in earnings that will support future dividends and share

4   prices.

5   Q. **IS THERE ANY EMPIRICAL EVIDENCE DOCUMENTING THE**

6   **IMPORTANCE OF EARNINGS IN EVALUATING INVESTORS'**

7   **EXPECTATIONS?**

8   A. Yes, there is an abundance of evidence attesting to the importance of earnings in

9   assessing investors' expectations. First, the sheer volume of earnings forecasts available

10   from the investment community relative to the scarcity of dividend forecasts attests to

11   their importance. To illustrate, Value Line, Yahoo Finance, Zacks Investment, First Call

12   Thompson, Reuters, and Multex provide comprehensive compilations of investors'

13   earnings forecasts. The fact that these investment information providers focus on growth

14   in earnings rather than growth in dividends indicates that the investment community

15   regards earnings growth as a superior indicator of future long-term growth. Second,

16   Value Line's principal investment rating assigned to individual stocks, Timeliness Rank,

17   is based primarily on earnings, which accounts for 65% of the ranking.

18 Q. **HOW DID YOU APPROACH THE COMPOSITION OF COMPARABLE**

19   **GROUPS IN ORDER TO ESTIMATE DP&L'S COST OF EQUITY WITH THE**

20   **DCF METHOD?**

1   A.   Because DP&L is not publicly traded, the DCF model cannot be applied to DP&L and

2   proxies must be used. There are two possible approaches in forming proxy groups of

3   companies.

4   The first approach is to apply cost of capital estimation techniques to a select group of

5   companies directly comparable in risk to DP&L. These companies are chosen by the

6   application of stringent screening criteria to a universe of electric utility stocks in an

7   attempt to identify companies with the same investment risk as DP&L. Examples of

8   screening criteria include bond rating, beta risk, size, percentage of revenues from

9   electric utility operations, and common equity ratio. The end result is a small sample of

10   companies with a risk profile similar to that of DP&L, provided the screening criteria are

11   defined and applied correctly.

12   The second approach is to apply cost of capital estimation techniques to a large group of

13   electric utilities representative of the electric utility industry average and then make

14   adjustments to account for any difference in investment risk between the company and

15   the industry average, if any. As explained below, in view of substantial changes in

16   circumstances in the electric utility industry, I have chosen the latter approach.

17   In the current unstable capital market environment, it is important to select relatively

18   large sample sizes representative of the electric utility industry as a whole, as opposed to

19   small sample sizes consisting of a handful of companies. This is because the equity

20   market as a whole and electric utility industry capital market data is volatile at this time.

21   As a result of this volatility, the composition of small groups of companies is very fluid,

22   with companies exiting the sample due to dividend suspensions or reductions, insufficient

1 or unrepresentative historical data due to recent mergers, impending merger or

2 acquisition, and changing corporate identities due to restructuring activities.

3 From a statistical standpoint, confidence in the reliability of the DCF model result is

4 considerably enhanced when applying the DCF model to a large group of companies.

5 Any distortions introduced by measurement errors in the two DCF components of equity

6 return for individual companies, namely dividend yield and growth are mitigated.

7 Utilizing a large portfolio of companies reduces the influence of either overestimating or

8 underestimating the cost of equity for any one individual company. For example, in a

9 large group of companies, positive and negative deviations from the expected growth will

10 tend to cancel out owing to the law of large numbers, provided that the errors are

11 independent.[1] The average growth rate of several companies is less likely to diverge

12 from expected growth than is the estimate of growth for a single firm. More generally,

13 the assumptions of the DCF model are more likely to be fulfilled for a large group of

14 companies than for any single firm or for a small group of companies.

---

[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:

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

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.

1   Moreover, small samples are subject to measurement error, and in violation of the Central

2   Limit Theorem of statistics.[2] From a statistical standpoint, reliance on robust sample

3   sizes mitigates the impact of possible measurement errors and vagaries in individual

4   companies' market data. Examples of such vagaries include dividend suspension,

5   insufficient or unrepresentative historical data due to a recent merger, impending merger

6   or acquisition, and a new corporate identity due to restructuring.

7   The point of all this is that the use of a handful of companies in a highly fluid and

8   unstable industry produces fragile and statistically unreliable results. A far safer

9   procedure is to employ large sample sizes representative of the industry as a whole and

10   apply subsequent risk adjustments to the extent that the company's risk profile differs

11   from that of the industry average.

12   **Q.   CAN YOU DESCRIBE YOUR PROXY GROUP FOR DP&L'S UTILITY**

13   **BUSINESS?**

14   A.   As a proxy for DP&L, I examined a group of investment-grade dividend-paying

15   combination gas and electric utilities as defined in AUS Utility Reports May 2015 and

16   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.

1   possess utility distribution assets similar to DP&L's. I began with all the companies

2   designated as electric utilities by Value Line, that is, with Standard Industrial

3   Classification codes 4911 to 4913. Foreign companies, private partnerships, private

4   companies, non-dividend paying companies, and companies below investment-grade

5   (with a Moody's bond rating below Baa3 as reported in AUS Utility Reports May 2015)

6   were eliminated, as well as those companies whose market capitalization was less than $1

7   billion, in order to minimize any stock price anomalies due to thin trading[3]. The final

8   group of companies, shown on Exhibit RAM-2, only includes those companies with at

9   least 50% of their revenues from regulated utility operations.

10   I stress that this proxy group must be viewed as a portfolio of comparable risk. It would

11   be inappropriate to select any particular company or subset of companies from this group

12   and infer the cost of common equity from that company or subset alone.

13   Q.   **WHAT DCF RESULTS DID YOU OBTAIN USING VALUE LINE GROWTH**

14   **PROJECTIONS?**

15   A.   Page 1 of Exhibit RAM-2 shows the raw dividend yield and growth input data for the 26

16   companies, while page 2 displays the DCF analysis. Exelon, Chesapeake Utilities, MDU

17   Resources, and NiSource were eliminated since less than 50% of their revenues are

18   subject to regulation. Eversource Energy (formerly Northeast Utilities) was added since

---

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

1   it was omitted from the AUS Utility Reports database. Unitil was eliminated because it

2   was not included in the Value Line Electric universe.

3   As shown on Column 3, line 28 of page 2 of Exhibit RAM-2, the average long-term

4   earnings per share growth forecast obtained from Value Line is 5.46% for this group.

5   Combining this growth rate with the average expected dividend yield of 3.99% shown in

6   Column 4 produces an estimate of equity costs of 9.46% for the group shown in Column 5.

7   Recognition of flotation costs brings the cost of equity estimate to 9.67% for the group,

8   shown in Column 6. The need for a flotation cost allowance is discussed at length later in

9   my testimony. If we eliminate the outlying result of 4.49% for Integrys since it is barely, if

10   at all, equal to the cost of debt, the average ROE for the group is 9.9%.

11   Q.   **WHAT DCF RESULTS DID YOU OBTAIN USING THE ANALYSTS'**

12   **CONSENSUS GROWTH FORECAST?**

13   A.   From the original sample of 26 companies shown on page 1 of Exhibit RAM-3, Entergy

14   was eliminated on account of its negative projected growth rate. For the remaining 25

15   companies shown on page 2 of Exhibit RAM-3, using the consensus analysts' earnings

16   growth forecast of 5.42% instead of the Value Line forecast, the cost of equity for the

17   group is 9.39%, unadjusted for flotation cost. Recognition of flotation costs brings the

18   cost of equity estimate to 9.60%, shown in Column 6, line 27.

19   Q.   **PLEASE SUMMARIZE YOUR DCF ESTIMATES.**

20   A.   The table below summarizes the DCF estimates:

21

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. CAPM Estimates

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:

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

2 This is the seminal CAPM expression, which states that the return required by investors

3 is made up of a risk-free component, R_F, plus a risk premium determined by $\beta(R_M - R_F)$.

4 The bracketed expression $(R_M - R_F)$ expression is known as the market risk premium

5 ("MRP"). *To derive the CAPM risk premium estimate, three quantities are required: the*

6 risk-free rate (R_F), beta (β), and the MRP, $(R_M - R_F)$. For the risk-free rate, I used 4.5%,

7 based on forecast interest rates on long-term U.S. Treasury bonds. For beta, I used 0.77

8 based on Value Line estimates, and for the MRP, I used 7.2% based on both historical

9 and prospective studies. These inputs to the CAPM are explained below.

10 Q. **HOW DID YOU ARRIVE AT YOUR RISK-FREE RATE ESTIMATE OF 4.5% IN**

11 **YOUR CAPM AND RISK PREMIUM ANALYSES?**

12 A. To implement the CAPM and Risk Premium methods, an estimate of the risk-free return

13 is required as a benchmark. I relied on noted economic forecasts which call for a rising

14 trend in interest rates in response to the recovering economy, renewed inflation, and

15 record high federal deficits. Value Line, Global Insight, Wall Street Journal Survey, and

16 the Congressional Budget Office all project higher long-term Treasury bond rates in the

17 future.

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

19 **BONDS?**

20 A. The appropriate proxy for the risk-free rate in the CAPM is the return on the longest term

21 Treasury bond possible. This is because common stocks are very long-term instruments

1   more akin to very long-term bonds rather than to short-term Treasury bills or

2   intermediate-term Treasury notes. In a risk premium model, the ideal estimate for the

3   risk-free rate has a term to maturity equal to the security being analyzed. Since common

4   stock is a very long-term investment because the cash flows to investors in the form of

5   dividends last indefinitely, the yield on the longest-term possible government bonds, that

6   is the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in

7   the CAPM. The expected common stock return is based on very long-term cash flows,

8   regardless of an individual's holding time period. Moreover, utility asset investments

9   generally have very long-term useful lives and should correspondingly be matched with

10   very long-term maturity financing instruments.

11   While long-term Treasury bonds are potentially subject to interest rate risk, this is only

12   true if the bonds are sold prior to maturity. A substantial fraction of bond market

13   participants, usually institutional investors with long-term liabilities (e.g., pension funds

14   and insurance companies), in fact hold bonds until they mature, and therefore are not

15   subject to interest rate risk. Moreover, institutional bondholders neutralize the impact of

16   interest rate changes by matching the maturity of a bond portfolio with the investment

17   planning period, or by engaging in hedging transactions in the financial futures markets.

18   The merits and mechanics of such immunization strategies are well documented by both

19   academicians and practitioners.

20   Another reason for utilizing the longest maturity Treasury bond possible is that common

21   equity has an infinite life span, and the inflation expectations embodied in its market-

22   required rate of return will therefore be equal to the inflation rate anticipated to prevail

1   over the very long term. The same expectation should be embodied in the risk-free rate

2   used in applying the CAPM model. It stands to reason that the yields on 30-year

3   Treasury bonds will more closely incorporate within their yields the inflation

4   expectations that influence the prices of common stocks than do short-term Treasury

5   bills or intermediate-term U.S. Treasury notes.

6   Among U.S. Treasury securities, 30-year Treasury bonds have the longest term to

7   maturity and the yields on such securities should be used as proxies for the risk-free rate

8   in applying the CAPM. Therefore, I have relied on the yield on 30-year Treasury bonds

9   in implementing the CAPM and risk premium methods.

10   Q.   **ARE THERE OTHER REASONS WHY YOU REJECT SHORT-TERM**

11   **INTEREST RATES AS PROXIES FOR THE RISK-FREE RATE IN**

12   **IMPLEMENTING THE CAPM?**

13   A.   Yes. Short-term rates are volatile, fluctuate widely, and are subject to more random

14   disturbances than are long-term rates. Short-term rates are largely administered rates.

15   For example, Treasury bills are used by the Federal Reserve as a policy vehicle to

16   stimulate the economy and to control the money supply, and are used by foreign

17   governments, companies, and individuals as a temporary safe-house for money.

18   As a practical matter, it makes no sense to match the return on common stock to the yield

19   on 90-day Treasury Bills. This is because short-term rates, such as the yield on 90-day

20   Treasury Bills, fluctuate widely, leading to volatile and unreliable equity return estimates.

21   Moreover, yields on 90-day Treasury Bills typically do not match the equity investor's

1   planning horizon. Equity investors generally have an investment horizon far in excess of

2   90 days.

3   As a conceptual matter, short-term Treasury Bill yields reflect the impact of factors

4   different from those influencing the yields on long-term securities such as common stock.

5   For example, the premium for expected inflation embedded into 90-day Treasury Bills is

6   likely to be far different than the inflationary premium embedded into long-term

7   securities yields. On grounds of stability and consistency, the yields on long-term

8   Treasury bonds match more closely with common stock returns.

9   Q.   **WHAT IS YOUR ESTIMATE OF THE RISK-FREE RATE IN APPLYING THE**

10   **CAPM?**

11   A.   All the noted interest rate forecasts that I am aware of point to significantly higher

12   interest rates over the next several years. The table below reports the forecast yields on

13   30-year US Treasury bonds from Global Insight and Value Line.

14   **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**

15

16   Global Insight forecasts a yield of 3.8% in 2016, 4.3% in 2017, 4.5% in 2018, and 4.4 in

17   2019, and 4.5% thereafter. Value Line's quarterly economic review dated May 2015

1   forecasts a yield of 4.1% in 2016, 4.7% in 2017, 4.9% in 2018, and 5.0 in 2019.[4] The

2   average 30-year long-term bond yield forecast from the two sources is 4.0% in 2016, 4.5%

3   in 2017, 4.7% in 2018, and 4.7% in 2019. The average over the 2016-2019 period is 4.5%.

4   The rising yield forecasts are consistent with the upward-sloping yield curve observed at

5   this time. The Congressional Budget Office ("CBO") projects that the average interest rate

6   on 10-year Treasury notes will rise from 2.6% to 4.6% in latest economic review dated

7   March 2015[5], suggesting an increase of 200 basis points in the cost of long-term financing.

8   In response to record high federal deficits, higher anticipated inflation, and eventual full

9   economic recovery the Wall Street economic forecast web site also points to a rise in the

10   interest rate on 10-year Treasury bonds from 2.17% to 3.75%, an increase of 158 basis

11   points[6]. Based on this consistent evidence, a long-term bond yield forecast of 4.5% is a

12   reasonable estimate of the expected risk-free rate for purposes of forward-looking

13   CAPM/ECAPM and Risk Premium analyses in the current economic environment.

14   **Q.**   **WHY DID YOU IGNORE THE CURRENT LEVEL OF INTEREST RATES IN**

15   **DEVELOPING YOUR PROXY FOR THE RISK-FREE RATE IN A CAPM**

16   **ANALYSIS?**

17   A.   The CAPM is a forward-looking model based on expectations of the future. As a result,

18   in order to produce a meaningful estimate of investors' required rate of return, the CAPM

---

[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

1   must be applied using data that reflects the expectations of actual investors in the market.

2   While investors examine history as a guide to the future, it is the expectations of future

3   events that influence security values and the cost of capital.

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

5   A.   A major thrust of modern financial theory as embodied in the CAPM is that perfectly

6   diversified investors can eliminate the company-specific component of risk, and that only

7   market risk remains. The latter is technically known as "beta" (β), or "systematic risk".

8   The beta coefficient measures change in a security's return relative to that of the market.

9   The beta coefficient states the extent and direction of movement in the rate of return on a

10   stock relative to the movement in the rate of return on the market as a whole. It indicates

11   the change in the rate of return on a stock associated with a one percentage point change

12   in the rate of return on the market, and thus measures the degree to which a particular

13   stock shares the risk of the market as a whole. Modern financial theory has established

14   that beta incorporates several economic characteristics of a corporation that are reflected

15   in investors' return requirements.

16   As an operating subsidiary of the AES Corporation, DP&L is not publicly traded, and

17   therefore, proxies must be used. In the discussion of DCF estimates of the cost of

18   common equity earlier, I examined a sample of investment-grade dividend-paying

19   combination gas and electric utilities covered by Value Line that have at least 50% of

20   their revenues from regulated electric utility operations. The average beta for this group

21   is 0.77. Please see Exhibit RAM-5 for the beta estimates of this sample of electric

22   utilities.

1   Based on these results, I shall use 0.77, as an estimate for the beta applicable to the

2   average risk electric utility.

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

4 A. For the MRP, I used 7.2%. This estimate was based on the results of both forward-

5   looking and historical studies of long-term risk premiums.

6 **Q. CAN YOU DESCRIBE THE HISTORICAL MRP STUDY USED IN YOUR CAPM**

7   **ANALYSIS?**

8 A. Yes. The historical MRP estimate is based on the results obtained in Morningstar's

9   (formerly Ibbotson Associates) 2015 Classic Yearbook, which compiles historical returns

10   from 1926 to 2014. This well-known study shows that a very broad market sample of

11   common stocks outperformed long-term U.S. Government bonds by 6.0%. The historical

12   MRP over the income component of long-term Government bonds rather than over the

13   total return is 7.0%. Morningstar recommends the use of the latter as a more reliable

14   estimate of the historical MRP, and I concur with this viewpoint. The historical MRP

15   should be computed using the income component of bond returns because the intent, even

16   using historical data, is to identify an expected MRP. This is because the income

17   component of total bond return (*i.e.,* the coupon rate) is a far better estimate of expected

18   return than the total return (*i.e.,* the coupon rate + capital gain), because both realized

19   capital gains and realized losses are largely unanticipated by bond investors. The long-

20   horizon (1926-2014) MRP (based on income returns, as required) is 7.0%.

1   **Q.**   **ON WHAT MATURITY BOND DOES THE MORNINGSTAR HISTORICAL**

2   **RISK PREMIUM DATA RELY?**

3   **A.**   Because 30-year bonds were not always traded or even available throughout the entire

4   1926-2014 period covered in the Morningstar Study of historical returns, the latter study

5   relied on bond return data based on 20-year Treasury bonds. Given that the normal yield

6   curve is virtually flat above maturities of 20 years over most of the period covered in the

7   Morningstar study, the difference in yield is not material.

8   **Q.**   **WHY DID YOU USE LONG TIME PERIODS IN ARRIVING AT YOUR**

9   **HISTORICAL MRP ESTIMATE?**

10   **A.**   Because realized returns can be substantially different from prospective returns

11   anticipated by investors when measured over short time periods, it is important to employ

12   returns realized over long time periods rather than returns realized over more recent time

13   periods when estimating the MRP with historical returns. Therefore, a risk premium

14   study should consider the longest possible period for which data are available. Short-run

15   periods during which investors earned a lower risk premium than they expected are offset

16   by short-run periods during which investors earned a higher risk premium than they

17   expected. Only over long time periods will investor return expectations and realizations

18   converge.

19   I have therefore ignored realized risk premiums measured over short time periods.

20   Instead, I relied on results over periods of enough length to smooth out short-term

21   aberrations, and to encompass several business and interest rate cycles. The use of the

22   entire study period in estimating the appropriate MRP minimizes subjective judgment

1   and encompasses many diverse regimes of inflation, interest rate cycles, and economic

2   cycles.

3   To the extent that the estimated historical equity risk premium follows what is known in

4   statistics as a random walk, one should expect the equity risk premium to remain at its

5   historical mean. Since I found no evidence that the MRP in common stocks has changed

6   over time, at least prior to the onslaught of the financial crisis of 2008-2009 which has

7   now partially subsided, that is, no significant serial correlation in the Morningstar study

8   prior to that time, it is reasonable to assume that these quantities will remain stable in the

9   future.

10   **Q.   SHOULD STUDIES OF HISTORICAL RISK PREMIUMS RELY ON**

11   **ARITHMETIC AVERAGE RETURNS OR GEOMETRIC AVERAGE**

12   **RETURNS?**

13   A.   Whenever relying on historical risk premiums, only arithmetic average returns over long

14   periods are appropriate for forecasting and estimating the cost of capital, and geometric

15   average returns are not.[7]

16   **Q.   PLEASE EXPLAIN HOW THE ISSUE OF WHAT IS THE PROPER "MEAN"**

17   **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).

1   A.   The issue arises in applying methods that derive estimates of a utility's cost of equity

2   from historical relationships between bond yields and earned returns on equity for

3   individual companies or portfolios of several companies. Those methods produce series

4   of numbers representing the annual difference between bond yields and stock returns over

5   long historical periods. The question is how to translate those series into a single number

6   that can be added to a current bond yield to estimate the current cost of equity for a stock

7   or a portfolio. Calculating geometric and arithmetic means are two ways of converting

8   series of numbers to a single, representative figure.

9   Q.   **IF BOTH ARE "REPRESENTATIVE" OF THE SERIES, WHAT IS THE**

10   **DIFFERENCE BETWEEN THE TWO?**

11   A.   Each represents different information about the series. The geometric mean of a series of

12   numbers is the value which, if compounded over the period examined, would have made

13   the starting value to grow to the ending value. The arithmetic mean is simply the average

14   of the numbers in the series. Where there is any annual variation (volatility) in a series of

15   numbers, the arithmetic mean of the series, which reflects volatility, will always exceed

16   the geometric mean, which ignores volatility. Because investors require higher expected

17   returns to invest in a company whose earnings are volatile than one whose earnings are

18   stable, the geometric mean is not useful in estimating the expected rate of return which

19   investors require to make an investment.

20   Q.   **CAN YOU PROVIDE A NUMERICAL EXAMPLE TO ILLUSTRATE THIS**

21   **DIFFERENCE BETWEEN GEOMETRIC AND ARITHMETIC MEANS?**

1   A.   Yes. The following table compares the geometric and arithmetic mean returns of a

2   hypothetical Stock A, whose yearly returns over a ten-year period are very volatile, with

3   those of a hypothetical Stock B, whose yearly returns are perfectly stable during that

4   period. Consistent with the point that geometric returns ignore volatility, the geometric

5   mean returns for the two series are identical (11.6% in both cases), whereas the arithmetic

6   mean return of the volatile stock (26.7%) is much higher than the arithmetic mean return

7   of the stable stock (11.6%):

8   *If relying on geometric means, investors would require the same expected return to invest*

9   *in both of these stocks, even though the volatility of returns in Stock A is very high while*

10   *Stock B exhibits perfectly stable returns. That is clearly contrary to the most basic financial*

11   *theory, that is, the higher the risk the higher the expected return.*

12

Table 3

13

Geometric vs. Arithmetic Returns

14

YEAR	STOCK A	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%

15

16   Chapter 4 Appendix A of my book <u>The New Regulatory Finance</u> contains a detailed and

17   *rigorous discussion of the impropriety of using geometric averages in estimating the cost*

1   of capital.   Briefly, the disparity between the arithmetic average return and the geometric

2   average return raises the question as to what purposes should these different return

3   measures be used.   The answer is that the geometric average return should be used for

4   measuring historical returns that are compounded over multiple time periods.   The

5   arithmetic average return should be used for future-oriented analysis, where the use of

6   expected values is appropriate.   It is inappropriate to average the arithmetic and

7   geometric average return; they measure different quantities in different ways.

8   Q.   **CAN YOU DESCRIBE THE PROSPECTIVE MRP STUDY USED IN YOUR**

9   **CAPM ANALYSIS?**

10   A.   Yes.   I applied a prospective DCF analysis to the aggregate equity market using Value

11   Line's VLIA software.   The computations are shown in Exhibit RAM-4.   The dividend

12   yield on the dividend-paying stocks covered in Value Line's full database is currently

13   1.2% (VLIA 05/2015 edition), and the average projected long-term growth rate is 10.5%.

14   Adding the dividend yield to the growth component produces an expected market return

15   on aggregate equities of 11.7%. Subtracting the forecast risk-free rate of 4.5% from the

16   latter, the implied risk premium is 7.3% over long-term U.S. Treasury bonds.

17   The average of the historical MRP of 7.0% and the prospective MRP of 7.3% is 7.2%,

18   which is my final estimate of the MRP for purposes of implementing the CAPM.

19   Q.   **IS YOUR MRP ESTIMATE OF 7.2% CONSISTENT WITH THE ACADEMIC**

20   **LITERATURE ON THE SUBJECT?**

1   A.   Yes, it is, although in the upper portion of the range. In their authoritative corporate

2   finance textbook, Professors Brealey, Myers, and Allen[8] conclude from their review of

3   the fertile literature on the MRP that a range of 5% to 8% is reasonable for the MRP in

4   the United States. My own survey of the MRP literature, which appears in Chapter 5 of

5   my latest textbook, The New Regulatory Finance, is also quite consistent with this range.

6   Q.   **WHAT IS YOUR RISK PREMIUM ESTIMATE OF THE AVERAGE RISK**

7   **UTILITY' S COST OF EQUITY USING THE CAPM APPROACH?**

8   A.   Inserting those input values into the CAPM equation, namely a risk-free rate of 4.5%, a

9   beta of 0.77, and a MRP of 7.2%, the CAPM estimate of the cost of common equity is:

10   4.5% + 0.77 x 7.2% = 10.0%. This estimate becomes 10.2% with flotation costs,

11   discussed later in my Testimony.

12   Q.   **CAN YOU DESCRIBE YOUR APPLICATION OF THE EMPIRICAL VERSION**

13   **OF THE CAPM?**

14   A.   There have been countless empirical tests of the CAPM to determine to what extent

15   security returns and betas are related in the manner predicted by the CAPM. This

16   literature is summarized in Chapter 6 of my latest book, The New Regulatory Finance.

17   The results of the tests support the idea that beta is related to security returns, that the

18   risk-return tradeoff is positive, and that the relationship is linear. The contradictory

19   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.

1   That is, empirical research has long shown that low-beta securities earn returns

2   somewhat higher than the CAPM would predict, and high-beta securities earn less than

3   predicted.

4   A CAPM-based estimate of cost of capital underestimates the return required from low-

5   beta securities and overstates the return required from high-beta securities, based on the

6   empirical evidence.   This is one of the most well-known results in finance, and it is

7   displayed graphically below.

CAPM: Predicted vs Observed Returns

8
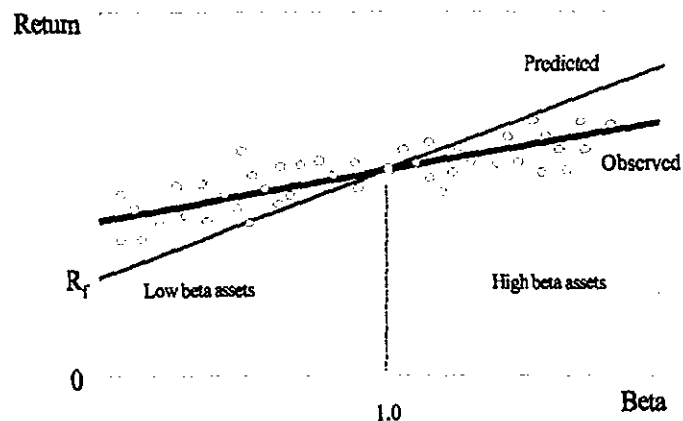
9   A number of variations on the original CAPM theory have been proposed to explain

10   this finding.   The ECAPM makes use of these empirical findings.   The ECAPM

11   estimates the cost of capital with the equation:

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

1   where the symbol alpha, α, represents the "constant" of the risk-return line, MRP is

2   the market risk premium (R_M - R_F), and the other symbols are defined as usual.

3   Inserting the long-term risk-free rate as a proxy for the risk-free rate, an alpha in the

4   range of 1% - 2%, and reasonable values of beta and the MRP in the above equation

5   produces results that are indistinguishable from the following more tractable ECAPM

6   expression:

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

8   An alpha range of 1% - 2% is somewhat lower than that estimated empirically. The use

9   of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta

10   stocks such as regulated utilities. This is because the use of a long-term risk-free rate

11   rather than a short-term risk-free rate already incorporates some of the desired effect of

12   using the ECAPM. In other words, the long-term risk-free rate version of the CAPM

13   has a higher intercept and a flatter slope than the short-term risk-free version which has

14   been tested. This is also because the use of adjusted betas rather than the use of raw

15   betas also incorporates some of the desired effect of using the ECAPM.[9] Thus, it is

16   reasonable to apply a conservative alpha adjustment.

---

[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:

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

1   <u>Appendix RAM-A</u> contains a full discussion of the ECAPM, including its theoretical and

2   empirical underpinnings.   In short, the following equation provides a viable

3   approximation to the observed relationship between risk and return, and provides the

4   following cost of equity capital estimate:

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

6   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

7   in the above equation, the return on common equity is 10.5%.   This estimate becomes

8   10.7% with flotation costs, discussed later in my Testimony.

9   **Q.   IS THE USE OF THE ECAPM CONSISTENT WITH THE USE OF ADJUSTED**

10   **BETAS?**

11   A.   Yes, it is.   Some have argued that the use of the ECAPM is inconsistent with the use of

12   adjusted betas, such as those supplied by Value Line, Bloomberg, and Morningstar.   This

13   is because the reason for using the ECAPM is to allow for the tendency of betas to

14   regress toward the mean value of 1.00 over time, and, since Value Line betas are already

15   adjusted for such trend, an ECAPM analysis results in double-counting.   This argument is

16   erroneous.   Fundamentally, the ECAPM is not an adjustment, increase or decrease in

17   beta.   The observed return on high beta securities is actually lower than that produced by

18   the CAPM estimate.   The ECAPM is a formal recognition that the observed risk-return

19   tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence.   The

20   ECAPM and the use of adjusted betas comprise two separate features of asset pricing.

21   Even if a company's beta is estimated accurately, the CAPM still understates the return

22   for low-beta stocks.   Even if the ECAPM is used, the return for low-beta securities is

1   understated if the betas are understated. Referring back to the previous graph, the

2   ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment.

3   Both adjustments are necessary. Moreover, the use of adjusted betas compensates for

4   interest rate sensitivity of utility stocks not captured by unadjusted betas.

5   **Q.   PLEASE SUMMARIZE YOUR CAPM ESTIMATES.**

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

7   studies.

8   **Table 4**
9   **CAPM Results**

CAPM Method	ROE
Traditional CAPM	10.2%
Empirical CAPM	10.7%

10

11   **C.   Historical Risk Premium Estimate**

12   **Q.   PLEASE DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF**

13   **THE ELECTRIC UTILITY INDUSTRY USING TREASURY BOND YIELDS.**

14   A.   A historical risk premium for the utility industry was estimated with an annual time series

15   analysis applied to the utility industry as a whole over the 1930-2014 period, using

16   Standard and Poor's Utility Index ("S&P Index") as an industry proxy. The analysis is

17   depicted on Exhibit RAM-6. The risk premium was estimated by computing the actual

18   realized return on equity capital for the S&P Utility Index for each year, using the actual

19   stock prices and dividends of the index, and then subtracting the long-term Treasury bond

20   return for that year.

1   As shown on <u>Exhibit RAM-6</u>, the average risk premium over the period was 5.5% over

2   long-term Treasury bond yields. Given the risk-free rate of 4.5%, and using the historical

3   estimate of 5.5% for bond returns, the implied cost of equity is 4.5% + 5.5% = 10.0%

4   without flotation costs and 10.2% with the flotation cost allowance discussed later in my

5   testimony.

6   It is noteworthy that the risk premium estimate of 5.5% obtained from the historical risk

7   premium study is identical to the risk premium produced by the CAPM, that is, a beta of

8   0.77 times the MRP of 7.2% equals 5.5% also.

9   **Q.**   **ARE RISK PREMIUM STUDIES WIDELY USED?**

10   A.   Yes, they are. Risk Premium analyses are widely used by analysts, investors, economists,

11   and expert witnesses. Most college-level corporate finance and/or investment

12   management texts, including <u>Investments</u> by Bodie, Kane, and Marcus[10], which is a

13   recommended textbook for Chartered Financial Analyst ("CFA") certification and

14   examination, contain detailed conceptual and empirical discussion of the risk premium

15   approach. Risk Premium analysis is typically recommended as one of the three leading

16   methods of estimating the cost of capital. Professor Brigham's best-selling corporate

17   finance textbook, for example, <u>Corporate Finance: A Focused Approach</u>[11], recommends

18   the use of risk premium studies, among others. Techniques of risk premium analysis are

19   widespread in investment community reports. Professional certified financial analysts

---

[10] McGraw-Hill Irwin, 2002.

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

1   are certainly well versed in the use of this method. The only difference is that I rely on

2   long-term Treasury yields instead of the yields on A-rated utility bonds.

3   **Q.   ARE YOU CONCERNED ABOUT THE REALISM OF THE ASSUMPTIONS**

4   **THAT UNDERLIE THE HISTORICAL RISK PREMIUM METHOD?**

5   A.   No, I am not, for they are no more restrictive than the assumptions that underlie the DCF

6   model or the CAPM. While it is true that the method looks backward in time and

7   assumes that the risk premium is constant over time, these assumptions are not

8   necessarily restrictive. By employing returns realized over long time periods rather than

9   returns realized over more recent time periods, investor return expectations and

10   realizations converge. Realized returns can be substantially different from prospective

11   returns anticipated by investors, especially when measured over short time periods. By

12   ensuring that the risk premium study encompasses the longest possible period for which

13   data are available, short-run periods during which investors earned a lower risk premium

14   than they expected are offset by short-run periods during which investors earned a higher

15   risk premium than they expected. Only over long time periods will investor return

16   expectations and realizations converge, or else, investors would be reluctant to invest

17   money.

18   **D.   Allowed Risk Premiums**

19   **Q.   PLEASE DESCRIBE YOUR ANALYSIS OF ALLOWED RISK PREMIUMS IN**

20   **THE ELECTRIC UTILITY INDUSTRY.**

21   A.   To estimate the electric utility industry's cost of common equity, I also examined the

22   historical risk premiums implied in the ROEs allowed by regulatory commissions for

1   electric utilities over the 1986-2014 period for which data were available, relative to the

2   contemporaneous level of the long-term Treasury bond yield. The analysis is shown on

3   Exhibit RAM-7. This variation of the risk premium approach is reasonable because

4   allowed risk premiums are presumably based on the results of market-based

5   methodologies (DCF, Risk Premium, CAPM, *etc.*) presented to regulators in rate

6   hearings and on the actions of objective unbiased investors in a competitive marketplace.

7   Historical allowed ROE data are readily available over long periods on a quarterly basis

8   from Regulatory Research Associates (now SNL) and easily verifiable from SNL

9   publications and past commission decision archives.

10   The average ROE spread over long-term Treasury yields was 5.6% over the entire 1986-

11   2014 period for which data were available from SNL. It is interesting to note that this

12   estimate is nearly identical to the previous estimate of 5.5% obtained from both the

13   historical risk premium and the CAPM analyses. The graph below shows the year-by-

14   year allowed risk premium. The escalating trend of the risk premium in response to

15   lower interest rates and rising competition is noteworthy.

Allowed Risk Premium 1986-2014
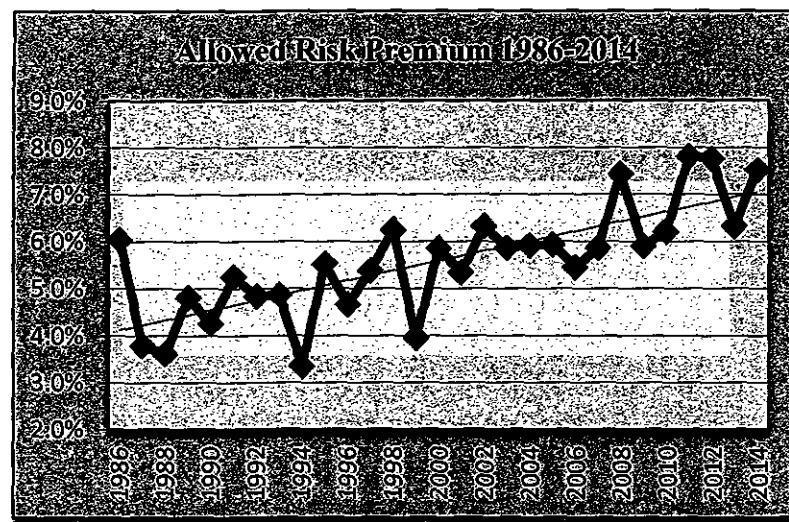
1   A careful review of these ROE decisions relative to interest rate trends reveals a

2   narrowing of the risk premium in times of rising interest rates, and a widening of the

3   premium as interest rates fall. The following statistical relationship between the risk

4   premium ("RP") and interest rates ("YIELD") emerges over the 1986-2014 period:

5                    $RP = 8.6700 - 0.5387\ YIELD$ $R^2 = 0.81$

6   The relationship is highly statistically significant[12] as indicated by the very high R^2. The

7   graph below shows a clear inverse relationship between the allowed risk premium and

8   interest rates as revealed in past ROE decisions.
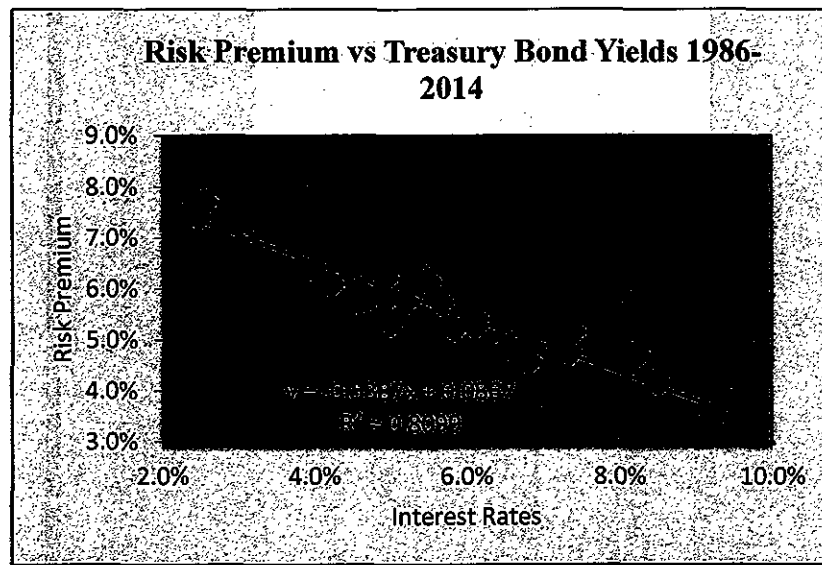
9   Inserting the long-term Treasury bond yield of 4.5% in the above equation suggests a risk

10   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.

1   Q.   DO INVESTORS TAKE INTO ACCOUNT ALLOWED RETURNS IN

2   FORMULATING THEIR RETURN EXPECTATIONS?

3   A.   Yes, they do. Investors do indeed take into account returns granted by various regulators

4   in formulating their risk and return expectations, as evidenced by the availability of

5   commercial publications disseminating such data, including Value Line and SNL

6   (formerly Regulatory Research Associates). Allowed returns, while certainly not a

7   precise indication of a particular company's cost of equity capital, are nevertheless

8   important determinants of investor growth perceptions and investor expected returns.

9   Q.   PLEASE SUMMARIZE YOUR RISK PREMIUM ESTIMATES.

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

11   studies.

12   **Table 5**

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

13   E.   **Need for Flotation Cost Adjustment**

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

15   A.   All the market-based estimates reported above include an adjustment for flotation costs.

16   The simple fact of the matter is that issuing common equity capital is not free. Flotation

17   costs associated with stock issues are similar to the flotation costs associated with bonds

18   and preferred stocks. Flotation costs are not expensed at the time of issue, and therefore

19   must be recovered via a rate of return adjustment. This is done routinely for bond and

1   preferred stock issues by most regulatory commissions, including FERC. Clearly, the

2   common equity capital accumulated by the Company is not cost-free. The flotation cost

3   allowance to the cost of common equity capital is discussed and applied in most

4   corporate finance textbooks; it is unreasonable to ignore the need for such an adjustment.

5   Flotation costs are very similar to the closing costs on a home mortgage. In the case of

6   issues of new equity, flotation costs represent the discounts that must be provided to

7   place the new securities. Flotation costs have a direct and an indirect component. The

8   direct component is the compensation to the security underwriter for his

9   marketing/consulting services, for the risks involved in distributing the issue, and for any

10   operating expenses associated with the issue (e.g., printing, legal, prospectus). The

11   indirect component represents the downward pressure on the stock price as a result of the

12   increased supply of stock from the new issue. The latter component is frequently referred

13   to as "market pressure."

14   Investors must be compensated for flotation costs on an ongoing basis to the extent that

15   such costs have not been expensed in the past, and therefore the adjustment must

16   continue for the entire time that these initial funds are retained in the firm. Appendix

17   RAM-B to my testimony discusses flotation costs in detail, and shows: (1) why it is

18   necessary to apply an allowance of 5% to the dividend yield component of equity cost by

19   dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital; (2)

20   why the flotation adjustment is permanently required to avoid confiscation even if no

21   further stock issues are contemplated; and (3) that flotation costs are only recovered if the

22   rate of return is applied to total equity, including retained earnings, in all future years.

1   By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized

2   over the life of the bond, and the annual amortization charge is embedded in the cost of

3   service. The flotation adjustment is also analogous to the process of depreciation, which

4   allows the recovery of funds invested in utility plant. The recovery of bond flotation

5   expense continues year after year, irrespective of whether the Company issues new debt

6   capital in the future, until recovery is complete, in the same way that the recovery of past

7   investments in plant and equipment through depreciation allowances continues in the

8   future even if no new construction is contemplated. In the case of common stock that has

9   no finite life, flotation costs are not amortized. Thus, the recovery of flotation costs

10   requires an upward adjustment to the allowed return on equity.

11   A simple example will illustrate the concept. A stock is sold for $100, and investors

12   require a 10% return, that is, $10 of earnings. But if flotation costs are 5%, the Company

13   nets $95 from the issue, and its common equity account is credited by $95. In order to

14   generate the same $10 of earnings to the shareholders, from a reduced equity base, it is

15   clear that a return in excess of 10% must be allowed on this reduced equity base, here

16   10.53%.

17   According to the empirical finance literature discussed in Appendix RAM-B, total

18   flotation costs amount to 4% for the direct component and 1% for the market pressure

19   component, for a total of 5% of gross proceeds. This in turn amounts to approximately

20   20 basis points, depending on the magnitude of the dividend yield component. To

21   illustrate, dividing the average expected dividend yield of around 4.0% for utility stocks

22   by 0.95 yields 4.2%, which is 20 basis points higher.

1   Sometimes, the argument is made that flotation costs are real and should be recognized in

2   calculating the fair return on equity, but only at the time when the expenses are incurred.

3   In other words, as the argument goes, the flotation cost allowance should not continue

4   indefinitely, but should be made in the year in which the sale of securities occurs, with no

5   need for continuing compensation in future years. This argument is valid only if the

6   Company has already been compensated for these costs. If not, the argument is without

7   merit. My own recommendation is that investors be compensated for flotation costs on

8   an on-going basis rather than through expensing, and that the flotation cost adjustment

9   continue for the entire time that these initial funds are retained in the firm.

10   In theory, flotation costs could be expensed and recovered through rates as they are incurred.

11   This procedure, although simple in implementation, is not considered appropriate, however,

12   because the equity capital raised in a given stock issue remains on the utility's common

13   equity account and continues to provide benefits to ratepayers indefinitely. It would be

14   unfair to burden the current generation of ratepayers with the full costs of raising capital

15   when the benefits of that capital extend indefinitely. The common practice of capitalizing

16   rather than expensing eliminates the intergenerational transfers that would prevail if today's

17   ratepayers were asked to bear the full burden of flotation costs of bond/stock issues in order

18   to finance capital projects designed to serve future as well as current generations. Moreover,

19   expensing flotation costs requires an estimate of the market pressure effect for each

20   individual issue, which is likely to prove unreliable. A more reliable approach is to estimate

21   market pressure for a large sample of stock offerings rather than for one individual issue.

1   There are several sources of equity capital available to a firm including: common equity

2   issues, conversions of convertible preferred stock, dividend reinvestment plans,

3   employees' savings plans, warrants, and stock dividend programs. Each carries its own

4   set of administrative costs and flotation cost components, including discounts,

5   commissions, corporate expenses, offering spread, and market pressure. The flotation

6   cost allowance is a composite factor that reflects the historical mix of sources of equity.

7   The allowance factor is a build-up of historical flotation cost adjustments associated with

8   and traceable to each component of equity at its source. It is impractical and

9   prohibitively costly to start from the inception of a company and determine the source of

10   all present equity. A practical solution is to identify general categories and assign one

11   factor to each category. My recommended flotation cost allowance is a weighted average

12   cost factor designed to capture the average cost of various equity vintages and types of

13   equity capital raised by the Company.

14   **Q.**   **DR. MORIN, CAN YOU PLEASE ELABORATE ON THE MARKET PRESSURE**

15   **COMPONENT OF FLOTATION COST?**

16   **A.**   The indirect component, or market pressure component of flotation costs represents the

17   downward pressure on the stock price as a result of the increased supply of stock from the

18   new issue, reflecting the basic economic fact that when the supply of securities is

19   increased following a stock or bond issue, the price falls. The market pressure effect is

20   real, tangible, measurable, and negative. According to the empirical finance literature

21   cited in Appendix RAM-B, the market pressure component of the flotation cost

22   adjustment is approximately 1% of the gross proceeds of an issuance. The announcement

1   of the sale of large blocks of stock produces a decline in a company's stock price, as one

2   would expect given the increased supply of common stock.

3   **Q.**   **IS A FLOTATION COST ADJUSTMENT REQUIRED FOR AN OPERATING**

4   **SUBSIDIARY LIKE DP&L THAT DOES NOT TRADE PUBLICLY?**

5   **A.**   Yes, it is. It is sometimes alleged that a flotation cost allowance is inappropriate if the

6   utility is a subsidiary whose equity capital is obtained from its owners, in this case, the

7   AES Corporation. This objection is unfounded since the parent-subsidiary relationship

8   does not eliminate the costs of a new issue, but merely transfers them to the parent. It

9   would be unfair and discriminatory to subject parent shareholders to dilution while

10   individual shareholders are absolved from such dilution. Fair treatment must consider

11   that, if the utility-subsidiary had gone to the capital markets directly, flotation costs

12   would have been incurred.

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

14   **Q.**   **PLEASE SUMMARIZE YOUR RESULTS AND RECOMMENDATION.**

15   **A.**   To arrive at my final recommendation, I performed a DCF analysis on a group of

16   investment-grade dividend-paying combination gas and electric utilities using Value

17   Line's and analysts' growth forecasts. I also performed four risk premium analyses. For

18   the first two risk premium studies, I applied the CAPM and an empirical approximation

19   of the CAPM using current market data. The other two risk premium analyses were

20   performed on historical and allowed risk premium data from electric utility industry

21   aggregate data, using the current yield on long-term US Treasury bonds. The results are

22   summarized in Table 6 below.

1 **Table 6 Summary of Results**

2

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.

1   **Q.   SHOULD THE COST OF EQUITY ESTIMATE BE ADJUSTED UPWARD TO**

2   **ACCOUNT FOR DP&L BEING MORE RISKY THAN THE AVERAGE**

3   **ELECTRIC UTILITY?**

4   A.   Yes, it should. The cost of equity estimates derived from the comparable groups reflect

5   the risk of the average electric utility. To the extent that these estimates are drawn from a

6   less risky group of companies, the expected equity return applicable to the riskier DP&L

7   is downward-biased.

8   **Q.   WHAT ASPECTS OF DP&L'S INVESTMENT RISK PROFILE**

9   **DIFFERENTIATE THE COMPANY FROM ITS PEERS?**

10   A.   The two principal risk factors that differentiate the Company from its peers include a very

11   large infrastructure-related capital investments relative to the size of the Company's rate

12   base and to the size of its common equity capital base, and regulatory uncertainties with

13   regard to the proper treatment of the Company's capital structure for ratemaking

14   purposes.

15   **Q.   CAN YOU COMMENT ON THE FIRST RISK FACTOR?**

16   A.   Yes. Higher than average business risks result from a very ambitious capital expenditure

17   program which will require approximately $420 million dollar of financing over the next

18   five years for new utility infrastructure investments in order to improve reliability,

19   upgrade the electricity distribution system, support growth, and enhance reliability. To

20   place that number in proper perspective, the Company's rate base is $684 million and its

21   presumed eventual common equity balance is expected to be approximately 50% of that

1   amount, or $315 million. In other words, the company is expected to spend an amount

2   equal to about two thirds of its rate base ($420/$684 = 0.61%), that is, an increase of 61%

3   of its rate base over the next five years, and more than its presumed common equity

4   capital balance of $315 million.

5   Because of the Company's large construction program over the next few years, rate relief

6   requirements and regulatory treatment uncertainty will increase regulatory risks as well.

7   Generally, regulatory risks include approval risks, lags and delays, potential rate base

8   exclusions, and potential disallowances. Continued regulatory support from the

9   Commission will be required. Reviews of the economic and environmental aspects of

10   new construction can consume as much as one year before approval or denial.

11   Uncertainty of approval increases forecasting and planning risks and complicates the

12   utility's ability to devise an optimum energy distribution system. Regulatory approval

13   for financings required for new construction may also be required, injecting additional

14   risks.

15   Q.   CAN YOU COMMENT ON THE SECOND RISK FACTOR?

16   A.   The second risk factor relates to the uncertainties surrounding the Company's capital

17   structure following the separation of its generation assets and to the appropriate capital

18   structure to be used for ratemaking. The Company's current (actual) capital structure

19   consists of 62% debt and 38% common equity. After the separation of its generation

20   assets, it is expected that the Company will manage its capital structure with a target of

21   50% debt and 50% equity capital. In approving DP&L's generation separation plan, the

22   Commission ordered the Company to achieve a 50% common equity, and management

1   expects to do so.

2   Q.   ARE THERE ADDITIONAL RISK FACTORS THAT THE COMMISSION

3   SHOULD CONSIDER?

4   A.   Yes, there are additional risk factors that distinguish the Company from its peers,

5   including: First, there are unique business risks in the Ohio jurisdiction. Since the

6   Company's electric security plan ("ESP") was implemented in 2009, the Company has

7   experienced customer losses and deteriorating financial results because of both low

8   market prices in the generation market and greater competitive forces in Ohio. Second,

9   the continuing slow recovery of the Ohio economy, along with low power prices,

10   exacerbate margin losses and customer switching. Third, regulatory risks remain higher

11   than average since the terms of the regulatory compact in Ohio include periodic price

12   testing for Commission-approved ESPs that extend beyond three year terms and earnings

13   caps on utilities. Hence the need for a strong capital structure consisting of at least 50%

14   common equity in order to offset these additional risk factors.

15   VI.   CAPITAL STRUCTURE

16   Q.   WHAT   CAPITAL   STRUCTURE   ASSUMPTION   UNDERLIES   YOUR

17   RECOMMENDED RETURN ON DP&L'S COMMON EQUITY CAPITAL?

18   A.   My recommended ROE for DP&L is predicated on the adoption of a certification period

19   capital structure consisting of 50% common equity capital for ratemaking purposes.

20   Q.   WHAT IS THE BASIS FOR YOUR RECOMMENDED CAPITAL STRUCTURE

21   CONSISTING OF 50% DEBT AND 50% COMMON EQUITY CAPITAL?

1 A. My recommendation is based on several factors. First, I have examined the capital

2 structures adopted by regulators for electric utilities. The April 2015 edition of SNL

3 Energy's (formerly Regulatory Research Associates) *"Regulatory Focus: Major Rate*

4 *Case Decisions"* reports an average percentage of common equity in capital structure of

5 52% adopted by regulators for electric utilities and 50% for natural gas distribution

6 utilities for 2015.

7 Second I have examined the actual capital structures of my comparable group of electric

8 utilities. Exhibit RAM-8 displays the long-term debt ratios for the peer group of

9 companies as reported in Value Line. The average debt ratio is 51%, implying a common

10 equity ratio of 49%.

11 Third, I have examined the credit agencies' financial ratio benchmarks for various bond

12 rating categories for electric utilities. Both S&P and Moody's publish a matrix of

13 financial ratios that correspond to their respective assessment of the investment risk of

14 utility companies and related bond rating.

15 Table 7 below reproduces Moody's range for a utility company's debt ratio and related

16 bond rating, one of its three primary financial ratios that it uses as guidance in its credit

17 review for utility companies. The vast majority of electric utilities have a bond rating of

18 high Baa to low single A. For a single A bond rating, which I consider optimal, the debt

19 ratio range is 35%-45% with a midpoint of 40%, implying a common equity ratio of

20 60%. For a Baa bond rating, the corresponding debt ratio range is 45% - 55% with a

21 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

1

2   S&P publishes ranges for three primary financial ratios that it uses as guidance in its

3   credit review for utility companies. One of the three core financial ratio benchmarks on

4   which it relies in its credit rating process is the debt ratio. <u>Exhibit RAM-9</u> replicates

5   S&P's risk matrix criteria which includes business and financial risk categories. [14/]   As

6   shown on the upper panel of the exhibit, the business risk profile categories are

7   "Excellent," "Strong," "Satisfactory," "Fair," "Weak," and "Vulnerable." Most utilities

8   have a business risk profile of "Excellent" or "Strong."

9   As shown on the middle panel, the financial risk profile categories are "Minimal,"

10   "Modest," "Intermediate," "Significant," "Aggressive," and "Highly Leveraged." Most

11   electric utilities have a "Intermediate" or "Significant" financial risk profile coupled with

12   a business risk profile of "Excellent" or Strong", and are therefore rated in the A-BBB

13   range, as shown in the darkened cell entries.

14   The third panel of the exhibit shows S&P's range for a utility company's debt ratio. For

15   those utilities with "Intermediate" financial risk, the debt ratio range is 35%-45% with a

16   midpoint of 40%, implying a common equity ratio of 60%, the same result as S&P. For

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[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.

1   those utilities with "Significant" financial risk, the corresponding debt ratio range is 45%

2   - 55% with a midpoint of 50%, or a 50% common equity ratio, again the same result as

3   S&P.

4   It is clear from an optimal bond rating perspective that a common equity ratio of at least

5   50% is desirable.

6   Fourth, as I stated earlier, it is the expectations of future events that influence security

7   values and ROE, including financial risks, i.e., capital structure. Therefore, it stands to

8   reason that the ROE should be properly matched with the expected capital structure to

9   prevail in the future, namely, 50% common equity.

10   The aforementioned risk factors, separately or together, provide independent validation of

11   the use of a 50/50 capital structure as a proxy for the temporary situation the Company

12   will be facing as it prepares for and implements separation of its generation business.

13   These factors provide a proxy for the type of capital structure investors demand, as well

14   as one that this Commission has ordered. (Case No. 13-2420-EL-UNC) I note that in its

15   order approving the separation of DP&L's generation assets, the PUCO stated that it

16   expects DP&L to have a 50/50 debt/equity capital structure.

17 Q. **SHOULD PREFERRED STOCK BE TREATED AS COMMON EQUITY IN THE**

18   **50/50 CAPITAL STRUCTURE?**

19 A. No, it should not. As far as common shareholders are concerned, preferred stock is

20   senior capital, as is debt capital. As a result, any preferred stock that DP&L has issued

21   should be excluded from the 50% common equity component of the capital structure that

22   I reference. The 50% of the capital structure that is not common equity, and that I refer

1   to as "debt" should comprise both long term debt and preferred stock, and each should be

2   assigned a separate and distinct cost. Company Witness MacKay discusses the cost of

3   each and how those costs are derived.

4   Q.   **YOU STATED EARLIER IN YOUR TESTIMONY THAT YOU ADJUSTED**

5   **YOUR RECOMMENDED ROE UPWARD BY 30 BASIS POINTS TO ACCOUNT**

6   **FOR DP&L'S HIGHER LEVEL OF RISK COMPARED TO THE INDUSTRY.**

7   **WHAT IS THE BASIS FOR THE 30 BASIS POINTS ADJUSTMENT?**

8   A.   I increased the ROE of 10.2% derived from a sample of companies representative of the

9   electric utility industry by 30 basis points (0.30%), from 10.2% to 10.5% in order to

10   reflect the higher relative risk of the Company. The 30 basis points adjustment is based

11   on two reference points: 1) bond yield differentials between utility bonds rated A and

12   those rated BBB, and 2) observed beta differentials.

13   I examined the difference in yield between utility bonds rated A and those rated BBB for

14   my first reference point. The current yield differential between A-rated and BBB-rated

15   utility bonds is 33 basis points as reported in Value Line.

16   I also examined the differences in yield between corporate bonds of various ratings over

17   the recent past. Exhibit RAM-10 displays the differences in yield between corporate

18   bonds on a monthly basis since June 2014. The upper panel shows the yields themselves

19   while the second panel shows the yield differentials ("yield spreads"). Since most

20   electric utilities are rated in the Baa3 to low A range, I focused my attention on the Baa2

21   – A3 and Baa2 – Baa1 spreads. In February 2015, the Baa2-A3 spread was 45 basis

22   points and the Baa2-Baa1 was 17 basis points, for an average of 31 basis points. If we

1   focus on the June 2014 – February 2015 period as a whole, the corresponding average

2   spread for the whole period was 27 basis points

3   For the second reference point, the CAPM formula was referenced to approximate the

4   return (cost of equity) differences implied by the differences in the betas between the

5   average electric utility company and DP&L. The basic form of the CAPM, as discussed

6   earlier, states that the return differential is given by the differential in beta times the

7   MRP. To the extent that the Company's beta would be approximately one half standard

8   deviation higher than the electric utility industry average, that is, 0.04, the return

9   differential implied by the difference of 0.04 in beta is given by 0.035 times the MRP.

10   Using an estimate of 7.2% for the MRP discussed earlier in my testimony in

11   implementing the CAPM, the return adjustment is 7.2 x .04 = 29 basis points.

12   In summary, the reference points suggest an upward ROE adjustment for DP&L of 31,

13   27, and 29 basis points, respectively. Based on all these considerations, I estimate the

14   risk premium to be 30 basis points.

15   **VII.   CONCLUSION**

16   **Q.   DR. MORIN, WHAT IS YOUR FINAL CONCLUSION REGARDING DP&L'S**

17   **COST OF COMMON EQUITY CAPITAL?**

18   A.   Based on the results of all my analyses, the application of my professional judgment, and

19   the risk circumstances of DP&L, it is my opinion that a just and reasonable ROE for

20   DP&L's electricity distribution operations in the State of Ohio is 10.5%.

1   **Q. DR. MORIN, WHAT CAPITAL STRUCTURE ASSUMPTION UNDERLIES**

2   **YOUR RECOMMENDED RETURN ON DP&L'S COMMON EQUITY**

3   **CAPITAL?**

4   A.   My recommended return on common equity for DP&L is predicated on the adoption of a

5   test year capital structure consisting of 50% common equity capital.

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

7   A.   Yes, very much so. A low ROE increases the likelihood that DP&L will have to rely on

8   debt financing for its capital needs. This creates the specter of a spiraling cycle that

9   further increases risks to both equity and debt investors; the resulting increase in

10   financing costs is ultimately borne by the utility's customers through higher capital costs

11   and rates of returns. As the Company relies more on debt financing, its capital structure

12   becomes more leveraged. Since debt payments are a fixed financial obligation to the

13   utility, this decreases the operating income available for dividend growth. Consequently,

14   equity investors face greater uncertainty about the future dividend potential of the firm.

15   As a result, the Company's equity becomes a riskier investment. The risk of default on

16   the Company's bonds also increases, making the utility's debt a riskier investment. This

17   increases the cost to the utility from both debt and equity financing and increases the

18   possibility the Company will not have access to the capital markets for its outside

19   financing needs, or if so, at prohibitive costs.

20   **Q. IS IT IMPORTANT THAT DP&L'S CREDIT RATING IS RESTORED TO A**

21   **STRONG INVESTMENT-GRADE LEVEL?**

1   A.   Yes, absolutely. The Company's bonds (the "Secured Rating" that Company Witness

2   MacKay references in his testimony) are currently rated BBB- by S&P and Baa2 by

3   Moody's. The former is one step away from the "high yield" (a.k.a. junk bond) level and

4   among the lowest in the industry. The Commission should be, and DP&L management

5   is, committed to restore DP&L to a strong investment grade level as rapidly as reasonably

6   practical so that it will continue to be able to provide reliable and reasonably-priced

7   electric service as a state regulated entity as it has in the past. To achieve this goal, the

8   Commission must continue to demonstrate its commitment to DP&L's financial integrity

9   through positive and supportive actions in this and other proceedings. Authorizing the

10   cost of equity capital and capital structure that I have recommended will support DP&L's

11   return to a strong investment grade credit standing, especially as it works through the

12   effect of generation separation.

13   It is imperative that the Commission commit itself to restoring the investment grade

14   creditworthiness of DP&L as rapidly as reasonably practical so that DP&L will continue

15   being able to provide reliable and reasonably-priced electric service as a state regulated

16   entity as it has in the past and raise the very large quantities of capital required over the

17   next five years at reasonable cost.

18   Q.   **IF CAPITAL MARKET CONDITIONS CHANGE SIGNIFICANTLY BETWEEN**

19   **THE DATE OF FILING YOUR PREPARED TESTIMONY AND THE DATE**

20   **ORAL TESTIMONY IS PRESENTED, WOULD THIS CAUSE YOU TO REVISE**

21   **YOUR ESTIMATED COST OF EQUITY?**

1   A.   Perhaps. Capital market conditions are volatile and uncertain at this time. Interest rates

2   and security prices do change over time, and risk premiums change also, although much

3   more sluggishly. If substantial changes were to occur between the filing date and the

4   time my oral testimony is presented, I would evaluate those changes and their impact on

5   my testimony accordingly.

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

7   A.   Yes.

RESUME OF ROGER A. MORIN

(Fall 2015)

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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, 1989

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, 1978.

"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", <u>Journal of Finance</u>, Sept. 1983

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

"The Effect of CWIP on Cost of Capital," <u>Public Utilities Fortnightly</u>, July 1986.

"The Effect of CWIP on Revenue Requirements" <u>Public Utilities Fortnightly</u>, August 1986.

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

"Market-Line Theory and the Canadian Equity Market," <u>Journal of Business Administration</u>, Jan. 1982, M. Brennan, editor

"Efficiency of Canadian Equity Markets," <u>International Management Review</u>, Feb. 1978.

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

BOOKS

<u>Utilities' Cost of Capital</u>, Public Utilities Reports Inc., Arlington, Va., 1984.

<u>Regulatory Finance</u>, Public Utilities Reports Inc., Arlington, Va., 2004

<u>Driving Shareholder Value</u>, McGraw-Hill, January 2001.

<u>The New Regulatory Finance</u>, 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

			(1)	(2) Current Dividend Yield	(3) Projected EPS Growth
Line No.		Company Name			
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

		(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Company Name	Current Dividend Yield	Projected EPS Growth	% Expected Divid Yield	Cost of Equity	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.		Company Name	(1) Current Dividend Yield	(2) 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

	(1)	(2)	(3)	(4)	(5)	(6)
		Current	Analysts'	% Expected		
Line		Dividend	Growth	Divid	Cost of	
No.	Company Name	Yield	Forecast	Yield	Equity	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

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Year	Long-Term Government Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	S&P Utility Index Return	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	2-16	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:

$$\text{EXPECTED RETURN} \quad = \quad \text{RISK-FREE RATE} + \text{RISK PREMIUM}$$

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

$$K = R_F + \beta(R_M - R_F) \tag{1}$$

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:

$$K = R_F + \beta \times MRP \tag{2}$$

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

Return

Average Stock

Market Risk Premium

R_f

R_f = Risk-free rate

SML

Treasury Bills · Corporate Bonds · Utility Stock · Average Stock · **Beta Risk**
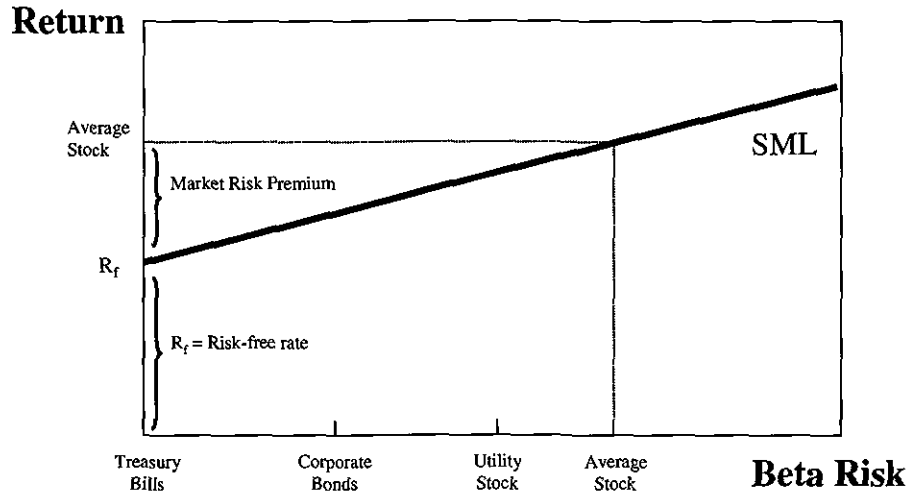
A myriad empirical tests of the CAPM have shown that the risk-return tradeoff is not as steeply sloped as that predicted by the CAPM, however. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the 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].

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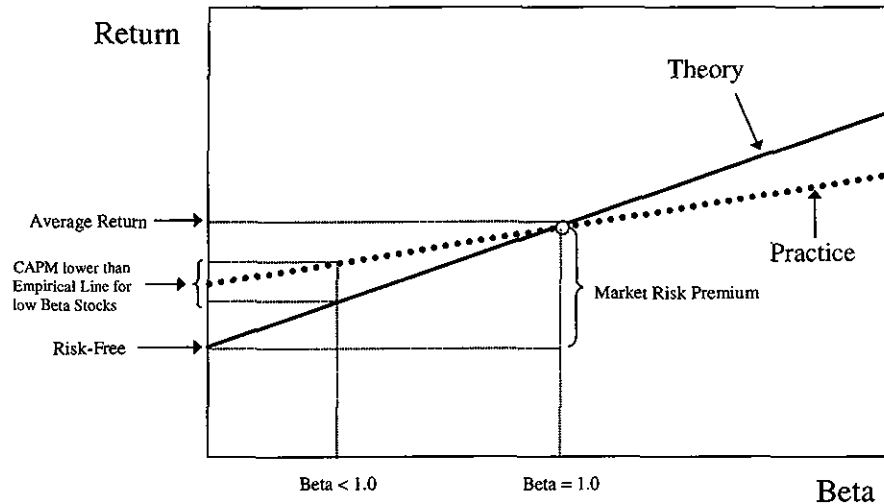
A number of refinements and expanded versions of the original CAPM theory have been proposed to explain the empirical findings. These revised CAPMs typically produce a risk-return relationship that is flatter than the standard CAPM prediction. The following equation makes use of these empirical findings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

$$K = R_F + \alpha + \beta (MRP - \alpha) \tag{3}$$

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:

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

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, $\alpha = a \times MRP$

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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

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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

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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.

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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:

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

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

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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
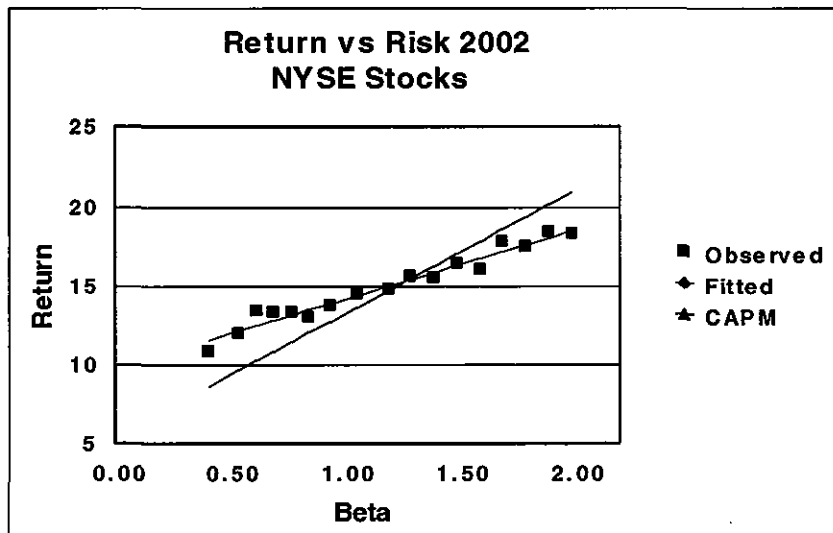
Another study by Morin in May 2002 provides empirical support for the ECAPM. All the stocks covered in the Value Line Investment Survey for Windows for which betas and returns data were available were retained for analysis. There were nearly 2000 such stocks. The expected return was measured as the total 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.
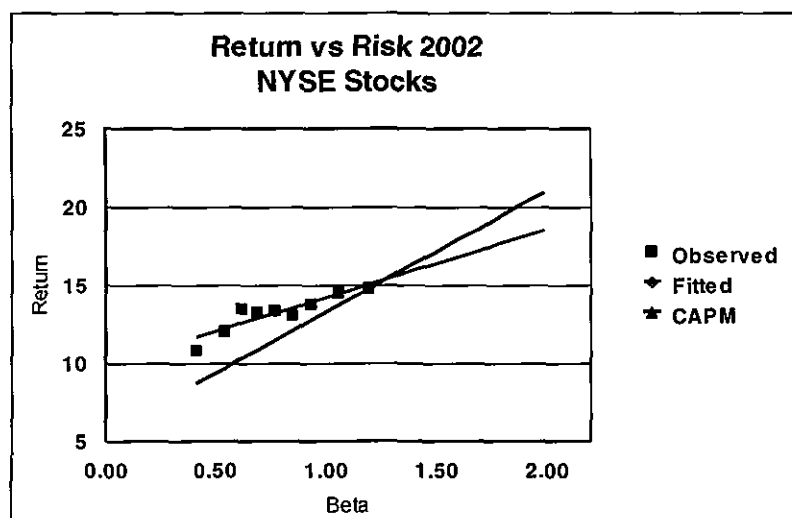
In an article published in Financial Management, Harris, Marston, Mishra, and O'Brien ("HMMO") estimate ex ante expected returns for S&P 500 companies over the period 1983-1998[1]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from 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:
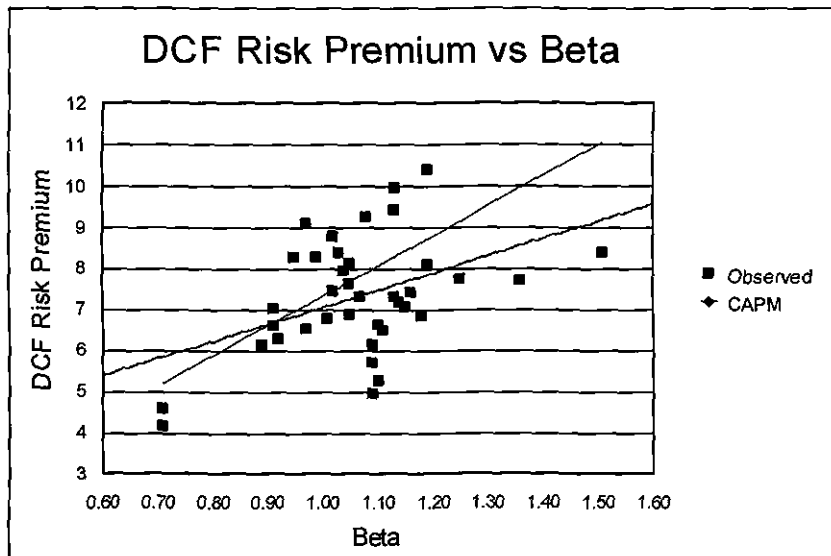
If the plain vanilla version of the CAPM is correct, then the intercept of the graph should be zero, recalling that the vertical axis represents returns in excess of the risk-free rate. Instead, the observed intercept is approximately 2 percent, that is approximately equal to 25 percent of the expected 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.

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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:

$$K = R_F + \alpha + \beta (MRP - \alpha) \tag{5}$$

or, alternatively by the following equivalent relationship:

$$K = R_F + a\,MRP + (1-a)\,\beta\,MRP \tag{6}$$

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:

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

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:

$$K = D_1/P_0 + g$$

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

$$r = D_1/B_0 + g$$

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

$$P - fP = B_0$$

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

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

$$r = D_1/P(1-f) + g$$

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

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 $ROE = D/P(1-f) + g = .09/.95 + .05 = 14.47\%$.

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 =	**14.00%**
(D/P + g)	
ALLOWED RETURN ON EQUITY =	**14.47%**
(D/P(1-f) + g)	

					MARKET			
					/			
	COMMON	RETAINED	TOTAL	STOCK	BOOK			
	STOCK	EARNINGS	EQUITY	PRICE	RATIO	EPS	DPS	PAYOUT
Yr	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(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. 15-1830-EL-AIR
CASE NO. 15-1831-EL-AAM
CASE NO. 15-1832-EL-ATA

DIRECT TESTIMONY
OF PAUL M. NORMAND

☐ 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

PAUL M. NORMAND

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

TABLE OF CONTENTS

1   **I.**   **INTRODUCTION**

2   **Q.**   **Would you please state your name, address and business affiliation?**

3   A.   My name is Paul M. Normand. I am a Principal with Management Applications

4   Consulting, Inc. ("MAC"), 1103 Rocky Drive, Suite 201, Reading, Pennsylvania 19609.

5   **Q.**   **Please describe MAC.**

6   A.   MAC is a management consulting firm which provides rate and regulatory assistance

7   including depreciation services for electric, gas and water utilities.

8   **Q.**   **Would you please summarize your education and business experience?**

9   A.   This information is contained in the attached Exhibit PMN-1. Pertinent to this testimony,

10   I have extensive experience in performing depreciation studies.

11   **II.**   **PURPOSE OF TESTIMONY**

12   **Q.**   **Please discuss the purpose of your testimony.**

13   A.   Our consulting firm was retained by counsel for The Dayton Power and Light Company

14   ("DP&L" or "Company") in 2014 to conduct a depreciation rate study for the Company's

15   Distribution and General Plant investments.

16   **Q.**   **Are you sponsoring any exhibits?**

17   A.   Yes, I am sponsoring the following exhibits:

18   • Exhibit PMN-1, which includes my qualifications

19   • Exhibit PNM-2, which is the Depreciation Study

20   **Q.**   **What are your responsibilities in connection with this filing?**

1   A.   I am responsible for planning the depreciation study, delineating and coordinating data

2   collection, ensuring the accuracy of the data and properly reflecting any accounting

3   adjustments for the study. Beyond data collection, I am also responsible for the

4   performance and interpretation of statistical analyses and the preparation of appropriate

5   schedules to reflect the results of the depreciation study as presented in Exhibit PMN-2.

6   Q.   **What property groups did you analyze in your study?**

7   A.   My analyses were based on the Company's Distribution and General Plant accounts as

8   identified in Schedule A of the attached "The Dayton Power and Light Company

9   Distribution and General Plant Depreciation Rate Study, Depreciation Accrual Rates

10   Based on Plant in Service at December 31, 2014" ("Depreciation Study") (Exhibit PMN-

11   2).

12   **III.**   **DEPRECIATION STUDY**

13   Q.   **Please explain the overall depreciation system (model) utilized in your Depreciation**

14   **Study.**

15   A.   The Depreciation Study used the overall straight line method, equal life group ("ELG"),

16   whole life technique in arriving at the recommended accrual rates for the Company based

17   on plant balances ending December 31, 2014. The whole life depreciation accrual

18   technique is the net sum of gross plant, plus or minus a net salvage, all divided by the

19   average remaining life.

20   Q.   **Are the contents of the Depreciation Study accurate and correct to the best of your**

21   **knowledge?**

1   A.   Yes. The depreciation accrual rates that I am proposing are the result of a detailed

2   *analysis of the Company's investment and retirements in plant and represent a fair and*

3   reasonable recovery.

4   Q.   **Is the depreciation model from your study consistent with the Company's last**

5   **study?**

6   A.   Yes, it is. Both the prior and current depreciation models consist of a straight line

7   method using an equal life group procedure with a whole life technique.

8   Q.   **Are the Company's current accrual rates based on the prior study?**

9   A.   Yes, they are.

10   Q.   **Are you familiar with the National Association of Regulatory Utility**

11   **Commissioners' definition of depreciation?**

12   A.   Yes. The definition of depreciation adopted by the National Association of Regulatory

13   Utility Commissioners ("NARUC") is:

14   "Depreciation," as applied to depreciable utility plant, means the loss in
15   service value not restored by current maintenance incurred in connection
16   with the consumption or prospective retirement of utility plant in the
17   course of service from causes which are known to be in current operation
18   and against which the utility is not protected by insurance. Among the
19   causes to be given consideration are wear and tear, decay, action of the
20   elements, inadequacy, obsolescence, changes in the art, changes in
21   demand and requirements of public authorities.

22   The Public Utilities Commission of Ohio is a member of NARUC. Another commonly

23   referenced definition of depreciation is that of the American Institute of Certified Public

24   Accounts (AICPA):

1   Depreciation accounting is a system of accounting which aims to
2   distribute the cost or other basic value of tangible capital assets, less
3   salvage (if any) over the estimated useful life of the unit (which may be a
4   group of assets) in a systematic and rational manner. It is a process of
5   allocation, not of valuation. Depreciation for the year is the portion of the
6   total charge under such a system that is allocated to the year. Although
7   the allocation may properly take into account occurrences during the year,
8   it is not intended to be a measurement of the effect of all such occurrences.

9   The two foregoing citations are found on pages 13 and 14, respectively, of "Public Utility

10   Depreciation Practices," August 1996, by the NARUC Staff Subcommittee on

11   Depreciation.

12   **Q.   What is the purpose of book depreciation rate studies, such as the one you**

13   **performed for the Company?**

14   A.   Consistent with the definitions above, the purpose of depreciation studies is to develop

15   depreciation accrual rates reflective of engineering judgment, current industry and

16   specific company experience, and current projections for the immediate future, relative to

17   the particular depreciable assets under study. The objective of depreciation as an element

18   of the cost of service is to provide for the appropriate and equitable recovery of the

19   investments in depreciable assets over an expected life term that assures the full recovery

20   of the investments less estimated net salvage. Net Salvage ("NS") is the gross salvage

21   less those costs relating to the removal or retirement of assets which must also be

22   recovered fairly over the same expected life.

23   **Q.   What process did you employ in compiling your depreciation studies?**

24   A.   The first was to create the depreciation study databases. The Company provided us with

25   the necessary property accounting history, additions, retirements, plant balances,

26   adjustments and transfers to create a complete database history for each account. The

1   Company also provided recent plant account level gross salvage and removal cost

2   history.

3 Q. **How did you proceed with your analysis of the Company's depreciable assets?**

4 A. I analyzed the historical data using computerized statistical routines and evaluated the

5   output by considering the indications from the statistical analyses, input from Company

6   personnel, the character of the depreciable assets, my experience with like assets, and

7   engineering knowledge and judgment. Once a determination was made as to the average

8   service life ("ASL") for each group (account) along with an appropriate Iowa curve, the

9   final calculations were then made to derive the recommended ELG whole life accrual

10   rates for each identified category of plant as shown on Schedule A of the Depreciation

11   Study (Exhibit PMN-2).

12 Q. **You referred to "statistical analyses." Please explain what is meant by this term.**

13 A. That term refers to the retirement rate method of actuarial life analysis, a well-known and

14   accepted analysis employed in depreciation studies. Whenever records of vintage

15   survivors and an adequate volume and frequency of vintaged (aged) retirements are

16   available, an actuarial analysis can be undertaken. The empirical survivor curves to

17   which we matched the Company-observed survivors are the Iowa curves.

18   The Iowa survivor curves used in our analyses were developed at Iowa State University;

19   they are empirical curves whose equations are published, along with tables of various

20   values, e.g. survivor factors at various ages. Iowa curves are widely accepted in the

21   industry as a common and convenient means of communicating and calculating technical

1   depreciation parameters. These survivor curves graphically depict the amount of

2   property existing at each age over the life of an asset class under review.

3   Our analyses of property history can sometimes provide us with an estimate of the

4   historical life of plant investments, possibly a starting point in the life estimation process;

5   however, it must be noted that life analysis is <u>not</u> life estimation. Life analysis can

6   provide only an indication as to what has happened in the past. Our need is to estimate

7   what will occur in the future; i.e., we must predict the future, not merely measure the

8   past.

9   **Q.   In preparing your life analyses, you stated that you also considered input from the**

10   **Company. What type of information did you consider?**

11 A.   I conferred with Company personnel to determine if there were any occurrences, changes

12   in policy, procedure, equipment, or practices that might impact upon service life, salvage,

13   or removal cost associated with depreciable assets. The major consideration here was to

14   determine whether indications of the past would likely be representative of the near-term

15   future.

16 **Q.   Your answers to previous questions indicate judgment and experience are elements**

17   **in life estimation and in the interpretation of statistical analyses. Do other**

18   **depreciation experts and authoritative sources concur?**

19 A.   Yes, the literature is unambiguous on this point. For example, page I.1 of the New York

20   State Department of Public Service publication, "Computer Supported Property Mortality

21   Studies," a reference work in this field which is an accurate summary of generally

22   accepted principles, published in 1971, states:

1   The purpose of an actuarial mortality study of public utility property is to
2   make a statistical determination of a representative life table and average
3   service life. The method used to derive these quantities in this report is
4   that of smoothing and extending the retirement ratios.
5
6   It must be clearly understood that the computer procedure explained in
7   Section II accomplishes electronically only those computations which
8   have had to be done manually, and nothing else. Because of the
9   computer's large storage capacity and extremely fast running time, it is
10   able to calculate a great deal more than has ever been obtained manually
11   in the past.
12
13   The computer exercises no judgment, reflects no opinions or company
14   policies and does not forecast the future. The computer programs are
15   merely the results of applying certain mathematical formulae to a set of
16   statistics obtained from accounting records – and, based on these data and
17   formulae give an indication of what has been the retirement experience of
18   the past and what would be the future life pattern if the same experience
19   were constant over the entire life of the surviving property under study.
20
21   Under no circumstances should it be construed that a specific indicated
22   service life and life table developed by this computer process must
23   necessarily be used as the life table and average service life in arriving at a
24   final estimate of annual and accrued depreciation. Stress is placed on the
25   fact that the selected life table and average service life finally used,
26   whether or not developed by program PSU-2 or PSU-2A must be the
27   engineer's best estimate for the property under study.
28
29 In summary, life estimation considers the blending of many factors, including informed

30 judgment. We are predicting the expected remaining lives of the Company's various

31 asset categories. The exercise of informed judgment is especially important as forecasts

32 for utilities continue to emphasize accelerated infrastructure improvements which are

33 greatly encouraged by regulators.

34 **Q.**   **Do regulatory commissions recognize that the use of judgment is part of any**

35   **depreciation study?**

36 **A.**   Yes, they do. Most commissions have long recognized that judgment is an important

37   aspect of determining proper accrual rates in any depreciation study. The NARUC

1   manual of Public Utility Depreciation Practices presents a brief discussion at page 126,

2   which includes the following principles:

3   Informed judgment is a term used to define the subjective portion of the
4   depreciation study process. It is based on a combination of general
5   experience, knowledge of the properties and a physical inspection,
6   information gathered throughout the industry, and other factors which
7   assist the analyst in making a knowledgeable estimate....
8
9   The analyst's role in performing the study is to review the results and
10   determine if they represent the mortality characteristics of the property.
11   Using judgment, the analyst considers such things as personal experience,
12   maintenance policies, past company studies, and other company owned
13   equipment to determine if the stub curve represents this class of property.

14   **Q.   What are the most prevalent approaches used in developing accrual rates?**

15   A.   The depreciation process consists of selecting one of the more prevalent categories from

16   each of the following three areas in order to develop a complete system in a study of

17   utility plant:

Method	Procedure	Technique
Straight Line	Broad Group	Remaining Life ("RL")
Life Span	Vintage (aged)	Whole Life ("WL")
	Equal Life Group ("ELG")	

18   **Q.   What system or method did you use in developing your proposed accrual rates?**

19   A.   The accrual rates were derived by using a straight line whole life depreciation method

20   with the equal life group procedure for each plant account as follows:

$$\text{Whole Life Accrual Rate} \ = \ \frac{100\% - \text{Net Salvage (NS\%)}}{\text{Average Service Life}}$$

21   **Q.   Please describe the equal life group procedure used in your study.**

1   A.   In the equal life procedure, the property group is subdivided according to subgroups

2   where the expected life is the same within a subgroup. The actual subgroup itself is a

3   function of the Iowa curve used in the account analysis. This approach recognizes the

4   full costs of short-lived assets versus simply using an overall average service life for all

5   units within an account. In other words, most properties do not experience identical

6   service lives. The equal life group will more closely reflect the actual consumptions of a

7   Company's assets within a particular investment group over time.

8   Q.   **Did your depreciation study also conduct an analysis of the Company's booked**

9   **reserves?**

10   A.   Yes, it did. Schedule C of Exhibit PMN-2 provides a table showing a comparison of each

11   account's booked reserve and estimated theoretical reserve based on the proposed

12   depreciation parameters of this study.

13   Q.   **Do your theoretical reserve calculations differ from the Company's actual booked**

14   **reserve?**

15   A.   In comparing the Company's total Distribution and General Plant accounts, there is not a

16   significant difference.

17   Q.   **Do you expect that a depreciation study will produce variance in reserve levels**

18   **based on Company booked and theoretical calculations?**

19   A.   Yes, I do; such a variance is not unusual. This variance is primarily a result of two

20   factors: length of time since last study, and redefining updated depreciation parameters.

21   Q.   **What are the Net Salvage values used in determining your proposed accrual rates?**

1   A.   Net Salvage is one of several factors used in the derivation of each of the proposed

2   accrual rates presented in the Depreciation Study, Exhibit PMN-2. Net salvage is the

3   resulting difference between the gross salvage of an asset when it is disposed less its

4   associated cost of removal from service. These factors vary somewhat between each

5   asset class, such as Poles or Services.

6   **Q.**   **Is Net Salvage important to establishing reasonable and equitable depreciation**

7   **accrual rates?**

8   A.   Yes it is. Net salvage is an important cost that must be recovered in an equitable manner

9   over the useful life of an asset from those customers who benefit from the use and service

10   of an asset. To defer the proper recovery of these costs until retirement would subsidize

11   existing customers by the recovery of those costs only from future customers.

12   **Q.**   **What is the total Company composite annual accrual rate that results from your**

13   **Depreciation Study?**

14   A.   The composite results of the proposed straight line, equal life individual account rates

15   discussed in the Depreciation Study as detailed for each account on Schedule A, column

16   8, of the report are 3.31% for 2014 and 3.46% for the prior 1991 study accrual rates

17   (Schedule B, column 2). These composite rates reflect a dollar-weighted average of the

18   individual balances as of December 31, 2014.

19   **Q.**   **Do the depreciation accrual rates that you propose result in a higher depreciation**

20   **expense than that derived using the existing authorized depreciation accrual rates?**

21   A.   No. The proposed accrual rates result in a depreciation expense that is lower than that

22   currently being recognized. On page 12 of the Depreciation Study and on Schedules A

1 and B, the proposed annual depreciation accrual expense rate for the Company is 3.31%

2 which results in a $2,162,906 (Schedule B, column 6) reduction to the annual

3 depreciation expense based on plant balances ended December 31, 2014.

4 Q. **Have you presented the net salvage impact in your depreciation study?**

5 A. Yes. The net salvage percent has been detailed for each account and subaccount in

6 columns 6 and 7 for the Company in Schedule A. In addition, a separate calculation has

7 also been provided in column 14 for the cost of removal ("COR") component contained

8 in each proposed accrual rate shown in column 8 of Schedule A. Column 16 of Schedule

9 A presents the plant-only accrual rates and excludes the net salvage amounts shown in

10 column 14.

11 Q. **Are the depreciation results presented in your study reasonable and applicable to**

12 **the Company's plant balances as of the date certain of September 30, 2015?**

13 A. Yes, they are. Our life analyses consisted of gathering and analyzing several decades of

14 data to derive accrual rates that are entirely appropriate for use several years beyond the

15 actual date of this study. The proposed accrual rates presented on Schedule A are

16 appropriate and reasonable for calculating annual depreciation expense for the respective

17 plant balances on a going-forward basis.

18 IV. <u>CONCLUSION</u>

19 Q. **Does this complete your testimony?**

20 A. Yes.

<u>**Exhibit PMN-1**</u>

**Qualifications of
Paul M. Normand**

PAUL M. NORMAND
Principal

Experience in the electric, gas, and water industry includes project management of various cost analyses, engineering system planning and design functions, and detailed electric power loss analyses. Also, experienced in the analysis and preparation of economic and plant data, revenue requirements and presentation before state and federal regulatory agencies. Presented expert testimony on behalf of utilities in over 30 applications before regulatory commissions.

EXPERIENCE:

1984 - Present **MANAGEMENT APPLICATIONS CONSULTING, INC.**
Principal consultant providing consulting services to industry in planning, pricing, and regulation. Extensive experience in analyzing power systems for power loss studies and regulatory issues.

Assist in gathering and updating property accounting data for depreciation studies. Review and analyze life analyses relating to simulated plant balances and actuarial data.
Perform property inspections to aid in service life estimation and salvage and removal cost estimations.

1983 - 1984 **P. M. NORMAND ASSOCIATES**
Independent consultant providing services to the utility industry in cost analyses, regulatory services and expert testimony.

1976 - 1983 **GILBERT/COMMONWEALTH**, Reading, Pa.
Director, Rate Regulatory Services - Administrative and fiscal responsibility for rate and regulatory services nationally for electric, gas, and water utilities. Additional responsibilities included all marketing, research and development efforts, and contract negotiations for all studies performed by the Regulatory Service Department. Provided consulting service to utilities in project management, personnel staffing, and future development efforts.

Manager, Austin, Texas Office - Responsibility for the overall administrative and business aspects for the department in the Southwest.

Senior Management Consultant - Responsibilities included project management of various electric and gas cost-of-service studies.

Consulting Engineer - Prepared class and time-differentiated cost-of- service studies, revenue requirements exhibits, and expert testimony for formal rate proceedings before regulatory agencies. Performed forecasted ten-year cost-of-service studies by customer classes. Analyzed and prepared transmission (wheeling) rates based on cost-of-service.

Engineer - Derived system demand and energy loss factors and customer load characteristics required for cost-of-service results and related rate schedules.

1975 - 1976   **WESTINGHOUSE ELECTRIC CORPORATION**, Pittsburgh, PA
Responsible for the procurement of electrical/electronic control equipment and power cables for the nuclear reactor control system. Assisted in the development of procedures for the seismic testing of various electronic equipment related to reactor control.

1971 - 1974   **NEW ENGLAND ELECTRIC SYSTEM**, Westborough, Massachusetts
Experience from various system assignments in conjunction with formal education. Assigned to the Transmission and Distribution Department with responsibilities in several voltage conversion efforts and system planning. Development of network modeling techniques, load flow, and fault study analyses for the system planning department.

1966 - 1970   **U.S. NAVY**
Aviation electronic technician with responsibilities for maintenance and trouble-shooting of electronic communication equipment.

EDUCATION:

B.S.E.E., Electrical Engineering, Northeastern University, 1975
M.S.E.E., Electrical Power Systems, Northeastern University, 1975

Graduate Studies - MBA Program, Lehigh University and Albright College, 1977 to 1980

SOCIETIES:

Institute of Electrical and Electronic Engineers
Society of Depreciation Professionals

APPEARANCES AS EXPERT WITNESS:

Federal Energy Regulatory Commission
Arkansas Public Service Commission
Delaware Public Service Commission
Indiana Utility Regulatory Commission
Illinois Commerce Commission
Kansas Corporation Commission
Kentucky Public Service Commission
Louisiana Public Service Commission
Maine Public Utilities Commission
Maryland Public Service Commission
Massachusetts Department of Public Utilities
Missouri Public Service Commission
New Hampshire Public Utilities Commission
New Jersey Board of Public Utilities
New York Public Service Commission
North Carolina Utilities Commission
Ohio Public Utilities Commission
Pennsylvania Public Utility Commission
Rhode Island Public Utilities Commission
Texas Public Utilities Commission

PAPERS AND PRESENTATIONS:

"Probability of Dispatch Costing Method for Electric Utility Cost-of-Service Analysis."
Co-authored with P. S. Hurley, presented to Edison Electric Institute Rate Research
Committee May 4, 1982.
"Costing Strategies under Changing Marketing Goals and Long Term Investment
Growth." Presented to Missouri Valley Electric Association (MVEA), Kansas City,
MO, November 13, 1991.

DEPRECIATION STUDIES PARTICIPATION:

Central Maine Power
Chesapeake Utilities Corporation
Corning Natural Gas Corporation
Dairyland Power Cooperative
Dayton Power & Light Company
EnergyNorth Natural Gas
Fitchburg Gas and Electric Light Company
Great River Energy
Green Mountain Power
KeySpan Energy Delivery – New York
KeySpan Gas East Corporation/LILCO
Midwest Energy Inc.
Minnkota Power Cooperative

National Grid – Boston, Essex and
    Colonial Gas Companies
New England Gas Co./Fall River
Northern Utilities – Maine and
    New Hampshire Divisions
Public Service of New Mexico –
Southern New Mexico Division
St. Lawrence Gas Company, Inc.
Texas-New Mexico Power Company –
Texas Division & General Office
Vectren Corporation
Vermont Gas Systems, Inc.
Unitil Energy Systems, Inc.

Exhibit PMN-2

Depreciation Study

THE DAYTON POWER AND LIGHT COMPANY

DISTRIBUTION AND GENERAL PLANT
DEPRECIATION RATE STUDY

Depreciation Accrual Rates
Based on Plant in Service
at December 31, 2014

MANAGEMENT APPLICATIONS CONSULTING, INC.
1103 Rocky Drive, Suite 201
Reading, PA 19609-1157

(610) 670-9199
fax (610) 670-9190
www.manapp.com

The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

LETTER OF TRANSMITTAL

MANAGEMENT APPLICATIONS CONSULTING, INC.

1103 Rocky Drive • Suite 201 • Reading, PA 19609-1157 • 610/670-9199 • fax 610/670-9190 •www.manapp.com

October 8, 2015

Mr. Randy Jones
Director, Accounting Services
The Dayton Power and Light Company
1065 Woodman Drive
Dayton, OH   45432

Dear Mr. Jones:

In accordance with the authorization of your organization, Management Applications Consulting, Inc. (MAC) has completed a depreciation rate study of certain depreciable electric distribution and general utility property of The Dayton Power and Light Company's plant in service as of December 31, 2014. The results of this study are presented in the attached report.

The study was accomplished by our organization, with the assistance of your staff, and others within your organization. The methods utilized in our study include those generally recognized in the industry.

We appreciate the opportunity to have been of service.

Respectfully,

MANAGEMENT APPLICATIONS CONSULTING, INC.

Paul M. Normand

PMN/rjp

Enclosures

The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

FOREWORD

The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

FOREWORD

This report presents the results of a detailed study of the relevant characteristics of the depreciable electric distribution and general plant in service of The Dayton Power and Light Company. The recommendations regarding annual depreciation accrual calculations have been developed on plant in service at December 31, 2014 and are applicable until subsequent studies indicate the need for revision. In our opinion, based on our analyses, experience and judgment, the straight line, equal life group procedure, whole life depreciation accrual rates developed herein will provide for the proper and timely recovery of capital invested in the depreciable electric distribution and general plant properties of the Company.

The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

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The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

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The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

SUMMARY

The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

EXECUTIVE SUMMARY

A.   Introduction

Management Applications Consulting, Inc. (MAC) was authorized by The Dayton Power and Light Company (DP&L or the Company) to prepare a depreciation accrual rate study of their distribution and general plant depreciable properties. The study was to develop Equal Life Group (ELG) whole life accrual rates consistent with its last depreciation study,[1] net salvage estimates for each depreciable plant account and certain subaccounts.

This report presents the results of the study together with MAC's recommendations for the recovery of DP&L's depreciable distribution and general plant investments.

B.   Definition of Depreciation

The purpose of depreciation accounting is the full recovery of the capital invested in certain property over the useful life of that property in a timely and equitable manner.

The National Association of Regulatory Utility Commissioners defines depreciation, as applied to depreciable utility plant, as:

> ...*the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.*

This study was prepared with this definition in mind.

C.   General Approach to Conducting Depreciation Studies

The MAC depreciation study analyses are consistent with the generally accepted approaches employed in the industry to determine annual depreciation accrual rates. In addition to reviewing and analyzing historical accounting records, engineering judgment is used in assessing historical experience as a possible factor to consider into the future. To this end, MAC becomes familiar with the property and its operations via site inspections and discussions with appropriate management personnel as to past practices and experience, as well as future plans and expectations, which could have had or may

---

[1] February 26, 1991 based on 12/31/89 plant in service.

2

The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

yet affect mortality patterns, average service lives, cost of removal or salvage. These approaches to preparing a depreciation study are typical of the industry.

D.   Depreciation Process

The depreciation process consists of selecting one of the more prevalent categories from each of the following three areas in order to develop a complete system in a study of utility plant:

Method	Procedure	Technique
Straight Line	Broad Group	Remaining Life (RL)
Life Span	Vintage (aged)	Whole Life (WL)
	Equal Life Group (ELG)	

E.   Depreciation System (Model)

Our depreciation model for this study consisted of using a straight line, Equal Life Group (ELG) procedure with a whole life technique for the depreciation model which uses the same accrual factor each year over the service life of the various plant accounts and subaccounts being analyzed. This approach is consistent with the Company's last study prepared on February 26, 1991 using a property plant balance as of December 31, 1989.

Depreciable plant must be recovered over a defined period of time, and our depreciation model uses the whole life technique for calculating the annual accrual rates proposed. These accrual rates are derived by using an estimated service life for each plant account as follows:

$$\text{Whole Life Accrual Rate} \quad = \quad \frac{100\% - \text{Net Salvage (NS\%)}}{\text{Average Service Life (ASL)}}$$

The plant account Average Service Life (ASL) here means the expected life of all units within a subgroup when new based on ELG calculations. The account-by-account whole life accrual rate results are presented in the attached Schedule A of Depreciation Accrual Rates in column (8) with net salvage and column (16) excluding net salvage (plant only).

F.   Curve Types

The most commonly recognized retirement curve type or frequency distribution is the "bell curve." Our depreciation study used a group of well recognized distributions known as the Iowa curves which were developed in the 1920s and 1930s at Iowa State University and are the most widely used and accepted curves in the industry for establishing survivor curves to assist in estimating average service life.

The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

G. Net Salvage (Salvage less Cost of Removal)

The overall objective of depreciation is to recover the original cost investment less any salvage values plus the removal cost according to the various Uniform Systems of Accounts. The accrual rates developed in this study reflect net salvage values based upon the most recent actual historical experience of the Company, modified by our judgment and experience.

A complete list of the Net Salvage (NS) factors and associated Cost of Removal (COR) level included in each factor has been detailed by account in columns 6, 7 and 14 of the Accrual Rate Schedule A. Appendix A presents the derivation of each COR component included in the proposed accrual rates by account shown in column 14 of Schedule A.

H. Summary Results

The summary results from our study (Schedules A and C) are functional composite ELG average service life estimates (whole life) and corresponding accrual rates, as shown below, which include net salvage (column 8).

	Average Service Life	Proposed Accrual Rate
Distribution Plant	39.2	3.31
General Plant[2]	34.8	2.87

A similar comparison by functional categories was also made with respect to annual accrual amounts ($) using current and proposed accrual rates (Schedule B):

	Current		Proposed		Change ( ) Reduction
	Rate	$	Rate	$	$
Distribution Plant	3.46	50,321,160	3.31	48,158,254	(2,162,906)
General Plant[2]	2.90	500,948	2.87	495,795	(5,183)

These composite rates are based on the use of the proposed plant account level accrual rates upon plant in service at December 31, 2014, and include a net salvage component in these cost estimates.

The following Table 1 presents a comparison of the proposed ASL (ALG) and NS parameters from this study along with those from the last study supporting the current accrual rates being used by the Company.

---

[2] Excludes accounts being amortized (393, 394, 395 and 398)

The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

TABLE 1
PROPOSED AND EXISTING ASL AND NS PARAMETERS

Plant Account	Proposed Average Service Life	Proposed Net Salvage	Existing Average Service Life	Existing Net Salvage
Distribution Plant				
361.00	45.0	(25)	45.0	(10)
361.40	33.0	(25)	40.0	(10)
362.00	55.0	(10)	50.0	(5)
362.10	25.0	10	N/A	N/A
362.10 (2010)	8.0	0	N/A	N/A
362.10 (2011)	8.0	0	N/A	N/A
362.10 (2012)	8.0	0	N/A	N/A
362.10 (2013)	8.0	0	N/A	N/A
362.70	20.0	0	N/A	N/A
364.00	50.0	(60)	38.0	(40)
365.00	50.0	(30)	40.0	(15)
366.00	75.0	(10)	55.0	(5)
367.00	50.0	(15)	38.0	(15)
368.00	46.0	(40)	44.0	0
369.10	45.0	(75)	33.0	(50)
369.20	45.0	(50)	35.0	(25)
370.00	30.0	0	32.0	0
371.10	30.0	(20)	20.0	(20)
371.20	45.0	0	50.0	0
General Plant				
390.02	30.0	0	40.0	0
393.00	26.0	0	30.0	0
394.00	26.0	5	30.0	5
395.00	25.0	0	35.0	0
398.00	16.0	0	25.0	5

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The Dayton Power and Light Company
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RECOMMENDATIONS

Based on our results of analyzing the Company's depreciable electric distribution and general plant property, we recommend the following:

1. The accrual rates shown in column (8) of the accrual rate Schedule A included in this report should be implemented. The level of reserve variance shown in Schedule A is $9,482,579 (excluding amortized general plant). Reserve variance is the difference between the theoretical reserve developed in this study and the actual booked Accumulated Provision for Depreciation. This variance is approximately 1.4% of the theoretical reserves ($691,565,765, Schedule A, page 2, column 11), and we do not recommend any amortization at this time as a result of this small difference.

2. Future reviews of these accrual rates should be undertaken on a periodic basis of at least every five to seven years in order to minimize changes in accrual rates and reserve variance.

3. Keep maintaining annual cost of removal and salvage history by plant account.

4. For the following fully depreciated accounts, we recommend using the following whole life accrual rates for any plant additions to these accounts until DPL's next depreciation study based on our review and analysis:

Account	Description	ASL	Accrual (1 / ASL)
362.70	Distr – Station Equipment – Fiber Cable	26.0	3.85%
372.00	Distr. – Leased Property on Customer Premises	40.0	2.50%

5. We recommend that DPL continues to amortize the General Plant (Accounts 393, 394, 395 and 398) as the most appropriate method of recovery.

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DEPRECIATION STUDY

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INTERPRETATION OF FINDINGS

A. Background

The development of appropriate book depreciation accrual rates is a subjective process in which the primary task is life estimation. Many believe that life analysis is the primary point; certainly one should collect property history and analyze this information to identify whatever "evidence" can be gleaned therefrom, but life estimation is not life analysis.

One must also recognize weaknesses and peculiarities in the life analysis employed, be generally aware of the equipment in the group being analyzed, be aware of the industry estimates for like equipment, and make every effort to obtain qualitative, first hand input relative to the particular company and equipment under study.

B. Application of Capital Recovery

The whole life technique for calculating the Company's accrual rate is a function of two variables: the average service life of the group and the estimated net salvage (salvage less cost to retire). The continued use of accrual rates properly developed at one point in time as a function of all circumstances known and projected at that time can be assumed to be appropriate for a limited number of years; however, if the estimated lives and net salvage are not re-estimated periodically, the resulting accrual rates may not provide the appropriate and timely recovery of capital. Changes will occur in equipment, technology, life expectations, mortality characteristics, salvage and removal costs, and demands of the public.

Obviously, when a change in life expectations or net salvage is forecasted, the book depreciation reserve compared to the computed or theoretical reserve immediately appears as either over or under accrued. Such changes would be recognized and addressed in the next depreciation rate study. The results of our depreciation study show that this variance is $10,664,769 or about 1.4% of the Company's theoretical reserve calculation of $698,788,068 as shown in Schedule A, page 2, column 13 for Total Depreciable Plant and General Plant amortization combined.

In general, this variance in the reserve is simply the difference between the theoretical reserve based on an updated set of depreciation parameters as developed in a depreciation study and the existing book reserves which reflect the historical reserve adjustments previously adopted. The theoretical reserve calculation, however, is based on a new set of accrual rates, and applying these results to the current plant balances as if they were constant historical factors will result in a variance. Obviously, there will usually be changes in depreciation rates followed by changes in theoretical reserves with resulting variances.

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For some categories of property, particularly mass properties, statistical mortality studies of past retirement experience may provide historical indications of the dispersion of retirements and of average service life, if there has been sufficient retirement activity over a reasonable period of time. Such indications can possibly provide a guide as to what to expect in the future, but it should not be taken for granted that the future will mirror the past, especially when present policies, plans, or external circumstances which are different dictate otherwise. In such instances, as well as when reliable retirement experience is lacking, reliance must be placed upon informed judgment in the establishment of expected average service lives and accrual rates.

Industry studies show that the majority of utility plant retirements are not due to the property/equipment being physically worn out; the retirements are mostly due to technological and physical obsolescence, inadequacy due to growth, exposure to the elements, requirements of others--typically public agencies. The latter relates to public works such as highway and street projects, urban renewal, sewer and/or water projects, airport construction, harbor/riverfront projects, etc.

C. Theoretical Depreciation Reserve

The objective of depreciation is complete and timely recovery of depreciable plant investment less net salvage. Periodic reviews and revisions to accrual rates help to minimize the magnitude of the revisions which may be necessary to keep the recovery process in tune. Obviously, when a change in either life expectations or net salvage is made, the book depreciation reserve immediately appears either over or under accrued. Changes to either the life or net salvage cannot generally be discerned on an annual basis; therefore, if such changes began to occur immediately upon completion of one depreciation rate study, it might be five years later (in another study) before the effect of the change is observed and the accrual rates properly adjusted to reflect it.

The theoretical depreciation reserve is a calculated level of reserve requirement based on a new set of depreciation parameters chosen in a study. In other words, the theoretical reserve is the future amounts of depreciation expense to be charged if the future retirements follow the recommended mortality characteristics in this study. The theoretical reserve is therefore the best estimate of reserve levels from the study if all future retirements occur as proposed by the recommended parameters for each account.

**The Dayton Power and Light Company
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<u>ACCOUNT-BY-ACCOUNT ANALYSIS AND RECOMMENDATIONS</u>

Appendix B contains the depreciation accrual schedule from the Company's last study (1991) based on 12/31/1989 plant in service which is referenced in the following discussion of each primary account for the Company:

NOTES:
- 1 — *Current Values* from Schedule A
- 2 — *Plant balances* do not include any net salvage in the amount to be recovered
- 3 — *Prior Plant $* (12/31/1989) from Appendix B
- 4 — *Booked* and *Theoretical Reserves* from Schedule A
- 5 — *Ratio %* referenced to account 2014 Plant Balance
- 6 — *Percent* that each account is to Total Depreciable Plant (Schedule A)
- 7 — *Average Service Life* is based on ALG for comparison purposes. Reference Schedule C for ALG and ELG ASL.

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A. DISTRIBUTION PLANT

Account: 361 Structures and Improvements

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	9,914,383	0.7	4,817,629
Booked Reserve:	4,765,854	48.1	
Theoretical Reserve:	5,153,794	52.0	
Earliest Vintage:	1915		

Recommendations	Prior	Proposed
Average Service Life:	45	46
Retirement Curve:	R 3.0	S 1.0
Future Net Salvage:	-10%	-25%
Accrual Rates:		
With Net Salvage	2.48%	2.85%
Without Net Salvage	2.25%	2.28%

Account Description

This account consists of various structures used to assist in energy delivery at the distribution level.

Service Life Analysis

Our review and analysis of this account indicates that a slight change is warranted from the 45-year ASL to a 46-year ASL. We propose a change in the curve type from the existing R 3.0 to an S 1.0.

Net Salvage

Our review of the data indicates that the existing (10)% net salvage should be increased to (25)%.

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Account: 361.40 Structures and Improvements – Other

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	40,910,512	2.8	47,576,241
Booked Reserve:	17,528,167	42.9	
Theoretical Reserve:	20,493,560	50.1	
Earliest Vintage:	1937		

Recommendations		
	Prior	Proposed
Average Service Life:	40	33
Retirement Curve:	R 2.5	L 0.0
Future Net Salvage:	0%	-25%
Accrual Rates:		
With Net Salvage	2.90%	4.41%
Without Net Salvage	2.90%	3.53%

Account Description

This account consists of various structures and plant-related items (rugs, doors, A/C units, pumps, etc.).

Service Life Analysis

Our analysis indicates that an ASL of 33 years with an L 0.0 Iowa curve would be appropriate.

Net Salvage

Our review of the historical NS indicates that a (25)% level would be reasonable.

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Account: **362 Station Equipment**

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	139,605,698	9.6	59,963,633
Booked Reserve:	50,570,578	36.2	
Theoretical Reserve:	55,051,272	39.4	
Earliest Vintage:	1915		

Recommendations		
	Prior	Proposed
Average Service Life:	50	55
Retirement Curve:	R 2.0	R 1.5
Future Net Salvage:	-5%	-10%
Accrual Rates:		
With Net Salvage	2.25%	2.23%
Without Net Salvage	2.14%	2.03%

Account Description

This account contains numerous substations which contain distribution transformers and switches utilized to transmit and transform high voltage energy to lower distribution primary voltages.

Service Life Analysis

Our review and analysis of this account indicates that the existing 50-year ASL should be increased to 55 years and that the current R 2.0 retirement curve be adjusted to an R 1.5.

Net Salvage

The existing (5)% net salvage should be increased to (10)% based on a review of the data.

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Account: **362.10 Station Equipment – Office Furniture**

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	20,157,048	1.4	9,553,918
Booked Reserve:	13,916,758	69.0	
Theoretical Reserve:	8,768,381	43.5	
Earliest Vintage:	1967		

Recommendations	Prior	Proposed
Average Service Life:	22.0	25
Retirement Curve:	S 0.0	R 1.5
Future Net Salvage:	5%	10%
Accrual Rates:		
With Net Salvage	5.31%	3.67%
Without Net Salvage	5.59%	4.08%

Account Description

The account contains various office furniture equipment.

Service Life Analysis

Our analysis of this account indicates that the parameters for this subaccount be set at a 25-year R 1.5 curve.

Net Salvage

We propose that the net salvage be set at 10% until the next study.

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The Dayton Power and Light Company
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Account: 362.10 Station Equipment – Computers

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	16,168,298	1.1	N/A
Booked Reserve:	6,644,820	41.1	
Theoretical Reserve:	5,862,341	36.3	
Earliest Vintage:	2009		

Recommendations	Prior	Proposed
Average Service Life:	N/A	8
Retirement Curve:	N/A	L 2.0
Future Net Salvage:	N/A	0.0%
Accrual Rates:		
With Net Salvage	(see below)	
Without Net Salvage		

Account Description

This account contains five years (2010 – 2014) of various computer-related equipment additions located at various substation locations.

Service Life Analysis

These additions occurred recently (2010 – 2014), and no analyses were performed with no retirement historically available. We recommend that an 8-year L 2.0 curve be used.

Net Salvage

We recommend no salvage value for this equipment based on the recommended 8-year ASL and technological changes over this same period.

Note
Recommended accrual rates:

2010	12.82
2011	13.89
2012	14.29
2013	14.93
2014	15.63

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The Dayton Power and Light Company
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Account: 362.70 Station Equipment – Communication Equipment – Other

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	42,722,771	2.9	6,898,451
Booked Reserve:	10,612,697	24.8	
Theoretical Reserve:	11,342,715	26.6	
Earliest Vintage:	1957		

Recommendations		
	Prior	Proposed
Average Service Life:	25.0	20
Retirement Curve:	L 1.5	S 1.5
Future Net Salvage:	-2%	0%
Accrual Rates:		
With Net Salvage	4.68%	5.52%
Without Net Salvage	4.59%	5.52%

Account Description

This account includes various communication equipment.

Service Life Analysis

Our analysis and experience indicates that a lower ASL is warranted, and we recommend a 20-year ASL with an S 1.5 curve.

Net Salvage

No salvage value is recommended for this account due to length of ASL and technical improvements.

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The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
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Account: 364 Poles, Towers and Fixtures

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	265,780,992	18.3	56,944,444
Booked Reserve:	147,547,298	55.5	
Theoretical Reserve:	142,157,094	53.5	
Earliest Vintage:	1935		

Recommendations	Prior	Proposed
Average Service Life:	38	50
Retirement Curve:	R 1.0	R 2.0
Future Net Salvage:	-40%	-60%
Accrual Rates:		
With Net Salvage	4.02%	3.54%
Without Net Salvage	2.87%	2.21%

Account Description

This account contains various types and sizes of poles to support the Company's distribution conductors and equipment.

Service Life Analysis

Our analysis of this account indicates that the existing 38-year R 1.0 parameters need to be increased, and we recommend a change to a 50-year R 2.0 curve.

Net Salvage

We propose to increase the net salvage from the existing (40)% to a (60)% level based on a review of the historical data.

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The Dayton Power and Light Company
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Account: **365 Overhead Conductors and Devices**

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	159,687,889	11.0	42,599,162
Booked Reserve:	77,466,231	48.5	
Theoretical Reserve:	84,321,013	52.8	
Earliest Vintage:	1926		

Recommendations	Prior	Proposed
Average Service Life:	40	50
Retirement Curve:	R 1.0	R 2.0
Future Net Salvage:	-15%	-30%
Accrual Rates:		
With Net Salvage	2.92%	2.76%
Without Net Salvage	2.54%	2.12%

Account Description

This account consists of various sizes and types of conductors used in the delivery of electricity across the Company's service territory.

Service Life Analysis

Our analysis of this account is inconclusive, but our experience with this type of equipment suggests that an increase in the ASL should be made. We recommend a change from the existing 40-year R 1.0 curve to a 50-year R 2.0 curve.

Net Salvage

Our review of the historical data indicates that an increase in the (15)% net salvage to a higher (30)% is appropriate.

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The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
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Account: 366 Underground Conduit

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	10,525,273	0.7	4,256,346
Booked Reserve:	5,396,972	51.3	
Theoretical Reserve:	4,359,324	41.4	
Earliest Vintage:	1923		

Recommendations		
	Prior	Proposed
Average Service Life:	55	75
Retirement Curve:	R 3.0	R 4.0
Future Net Salvage:	-5%	-10%
Accrual Rates:		
With Net Salvage	1.95%	1.51%
Without Net Salvage	1.86%	1.37%

Account Description

This account includes various sizes and lengths of conduit used to carry conductors from Account 367 to various locations and customers.

Service Life Analysis

Our experience and results from our analyses indicate that an increase in the existing parameters is appropriate, and we recommend increasing the existing 55-year ASL R 3.0 curve to a more reasonable 75-year R 4.0 curve.

Net Salvage

Our review of the historical NS data indicates that the existing (5)% be increased to (10)%.

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Account: 367 Underground Conductors and Devices

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	205,103,974	14.1	47,484,071
Booked Reserve:	95,297,579	46.5	
Theoretical Reserve:	75,694,677	36.9	
Earliest Vintage:	1948		

Recommendations		
	Prior	Proposed
Average Service Life:	38	50
Retirement Curve:	S 0.0	S 1.5
Future Net Salvage:	-15%	-15%
Accrual Rates:		
With Net Salvage	3.55%	2.55%
Without Net Salvage	3.09%	2.22%

Account Description

This account consists of various sizes, types, and length of conductors and switches used to transmit power at the distribution voltages.

Service Life Analysis

Our review and analysis of this account indicates that an increase to the depreciation parameters is warranted. We are recommending an increase from the existing 38-year ASL S 0.0 curve to a 50-year S 1.5 curve.

Net Salvage

We recommend maintaining the existing (15)% net salvage level based on our review of the data.

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Account: __368 Line Transformers__

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	272,576,395	18.8	107,312,239
Booked Reserve:	93,928,474	34.5	
Theoretical Reserve:	132,850,333	48.7	
Earliest Vintage:	1909		

Recommendations		
	Prior	Proposed
Average Service Life:	44	46
Retirement Curve:	S 1.0	S 2.0
Future Net Salvage:	0%	-40%
Accrual Rates:		
With Net Salvage	2.51%	3.22%
Without Net Salvage	2.51%	2.30%

Account Description

This account contains mostly smaller transformers that connect primary voltages to a secondary level for service to customers along with related switches, etc. It is the largest depreciable plant balance in Distribution representing 18.8% of total $.

Service Life Analysis

This is the Company's largest account in this study, and our analysis indicates a slight increase from the existing 44-year S 1.0 curve to a 46-year S 2.0 retirement curve.

Net Salvage

Our review of the cost of removal history indicates that an increase in the net salvage from the existing 0% to a higher (40)% is warranted.

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The Dayton Power and Light Company
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Account: 369.10 Overhead Services

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	48,406,213	3.3	16,779,264
Booked Reserve:	36,885,487	76.2	
Theoretical Reserve:	33,735,004	69.7	
Earliest Vintage:	1946		

Recommendations		
	Prior	Proposed
Average Service Life:	33	45
Retirement Curve:	R 3.0	R 2.5
Future Net Salvage:	-50%	-75%
Accrual Rates:		
With Net Salvage	4.47%	4.08%
Without Net Salvage	2.98%	2.33%

Account Description

This account contains mostly conductors and cables connecting secondary customers to the Company's secondary network.

Service Life Analysis

Our review and analysis of this account is inconclusive, but we are recommending based on our experience an increase in the ASL from the existing 33-year R 3.0 to a 45-year R 2.5.

Net Salvage

We are recommending an increase in the net salvage from the existing (50)% to (75)%.

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Account: 369.20 Undeground Services

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	157,453,368	10.8	26,182,421
Booked Reserve:	81,446,642	51.7	
Theoretical Reserve:	70,577,121	44.8	
Earliest Vintage:	1938		

Recommendations	Prior	Proposed
Average Service Life:	35	45
Retirement Curve:	R 2.0	S 4.0
Future Net Salvage:	-25%	-50%
Accrual Rates:		
With Net Salvage	4.09%	3.42%
Without Net Salvage	3.27%	2.28%

Account Description

This account consists of various types of conductors and cables connecting secondary customers to the network through underground conduit.

Service Life Analysis

Our analyses proved inconclusive, but we are recommending an increase based on experience from the existing 35-year to a higher 45-year ASL using an S 4.0 curve.

Net Salvage

Our review of the historical data indicates that an increase in net salvage from the existing (25)% to (50)% is warranted.

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Account: 370 Meters

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	48,023,242	3.3	26,570,116
Booked Reserve:	13,707,659	28.5	
Theoretical Reserve:	19,553,579	39.2	
Earliest Vintage:	1936		

Recommendations		
	Prior	Proposed
Average Service Life:	32	30
Retirement Curve:	S 1.0	S 1.0
Future Net Salvage:	0%	0%
Accrual Rates:		
With Net Salvage	3.26%	3.50%
Without Net Salvage	3.26%	3.50%

Account Description

This account includes various types of meters with a significant portion of these meters retrofitted with ERTS electronic components.

Service Life Analysis

Our review of this account indicates a slight change in this account's ASL from the existing 32-year to a 30-year. This recommendation is supported by the rather large recent investment in ERTS modules to existing meters with a much shorter life of approximately 15 years.

Net Salvage

Our recommendation is that this type of equipment along with the ASL and electronics will have little value with a net salvage of 0% to be conservative when considering any cost of removal.

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Account: 371.10 Installation on Customer Premise

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	15,680,586	1.1	7,540,147
Booked Reserve:	15,153,181	96.6	
Theoretical Reserve:	10,815,719	69.0	
Earliest Vintage:	1952		

Recommendations	Prior	Proposed
Average Service Life:	20	30
Retirement Curve:	R 0.5	R 1.0
Future Net Salvage:	-20%	-20%
Accrual Rates:		
With Net Salvage	5.77%	3.61%
Without Net Salvage	4.81%	3.01%

Account Description

Various plant items installed by Company at customer location.

Service Life Analysis

Our review and analysis of this account indicates that the ASL should be increased from the existing 20-year R 0.5 curve to a larger 30-year R 1.0 curve.

Net Salvage

Our review of the data indicates that the existing (20)% should be maintained at the current level.

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Account: 371.20 Installation on Customer Premises – Other

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	227,694	-	395,272
Booked Reserve:	157,484	69.2	
Theoretical Reserve:	170,256	74.8	
Earliest Vintage:	1929		

Recommendations	Prior	Proposed
Average Service Life:	50	45
Retirement Curve:	R 5.0	L 2.0
Future Net Salvage:	0%	0%
Accrual Rates:		
With Net Salvage	2.04%	1.67%
Without Net Salvage	2.04%	1.67%

Account Description

This account contains specific plant items to certain customer locations.

Service Life Analysis

Our analysis of this account indicates that a change in the depreciation parameters is required. We are proposing that the existing 50-year ASL be lowered to 45 years and the existing R 5.0 curve be changed to an L 2.0.

Net Salvage

We propose no change to the current 0% net salvage level due to the long ASL.

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B. GENERAL PLANT

Account : 390.02 Structures and Improvements

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	17,274,054		47,576,241
Booked Reserve:	11,057,305	64.0	
Theoretical Reserve:	10,659,582	61.7	
Earliest Vintage:	1987		

Recommendations		
	Prior	Proposed
Average Service Life:	40	30
Retirement Curve:	R 2.5	L 1.5
Future Net Salvage:	0%	0%
Accrual Rates:		
With Net Salvage	2.90%	2.87%
Without Net Salvage	2.90%	2.87%

Account Description

This account includes various buildings and related plant investments (carpets, pumps, A/C, plumbing, etc.) made by the Company at various locations.

Service Life Analysis

Our analysis indicates that a lower life from the existing 40-year ASL is warranted. We are recommending a 30-year ASL using and L 1.5 Iowa curve.

Net Salvage

We are estimating the continued level of 0% net salvage for this account.

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Account: 393 Stores Equipment

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	357,953	-	342,392
Booked Reserve:	274,882	76.8	
Theoretical Reserve:	292,211	81.6	
Earliest Vintage:	1990		

Recommendations	Prior	Proposed
Average Service Life:	30	26
Retirement Curve:	L 2.0	SQ
Future Net Salvage:	0%	0%
Accrual Rates:		
With Net Salvage	3.79%	3.85%
Without Net Salvage	3.79%	3.85%

Account Description

These general plant accounts include hundreds of items used to maintain and support the Company's other plant accounts. We are recommending that this account be amortized.

Service Life Analysis

Our analyses indicate that a shorter life is warranted, and we recommend changing the existing 30-year ASL to a 26-year ASL using an SQ retirement curve.

Net Salvage

We propose no change to the existing 0% net salvage level.

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Account: **394 Tools, Shop & Garage Equipment**

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	7,818,717		2,282,922
Booked Reserve:	4,324,923	55.3	
Theoretical Reserve:	4,852,149	62.1	
Earliest Vintage:	1987		

Recommendations		
	Prior	Proposed
Average Service Life:	30	26
Retirement Curve:	L 2.0	
	S 2.0	SQ
Future Net Salvage:	5%	5%
Accrual Rates:		
With Net Salvage	3.52%	3.66%
Without Net Salvage	3.70%	3.85%

Account Description

These general plant accounts include hundreds of items used to maintain and support the Company's other plant accounts. We are recommending that this account be amortized. Our total for the prior balance is 394.10 and 394.20 combined.

Service Life Analysis

Our analysis of this account indicates that a shorter ASL is warranted, and we recommend reducing the existing 30-year ASL to 26 years using an SQ retirement curve.

Net Salvage

We propose maintaining the current 5% net salvage level.

The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

Account: 395 Laboratory Equipment

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	4,734,172		1,075,893
Booked Reserve:	764,251	16.1	
Theoretical Reserve:	1,100,070	23.2	
Earliest Vintage:	1990		

Recommendations	Prior	Proposed
Average Service Life:	35	25
Retirement Curve:	L 0.0	SQ
Future Net Salvage:	0%	0%
Accrual Rates:		
With Net Salvage	3.70%	4.00%
Without Net Salvage	3.70%	4.00%

Account Description

These general plant accounts include hundreds of meter items used to maintain and support the Company's other plant accounts. We are recommending that this account be amortized.

Service Life Analysis

Our analysis for this account indicates that a 25-year ASL is a more representative level of recovery instead of the current 35-year ASL.

Net Salvage

We propose to maintain the current 0% net salvage.

The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

Account: 398 Miscellaneous Equipment

	Current Value	Ratio %	Prior Plant
Test Year:	2014		1989
Plant Balance:	1,067,205		1,056,427
Booked Reserve:	676,057	63.4	
Theoretical Reserve:	977,873	91.6	
Earliest Vintage:	1996		

Recommendations		
	Prior	Proposed
Average Service Life:	25	16
Retirement Curve:	L 0.0	SQ
Future Net Salvage:	5%	0%
Accrual Rates:		
With Net Salvage	4.91%	6.25%
Without Net Salvage	5.17%	6.25%

Account Description

These general plant accounts include hundreds of meter items used to maintain and support the Company's other plant accounts. We are recommending that this account be amortized.

Service Life Analysis

Our analysis of this account indicates that the current 25-year ASL should be lowered to 16 years which we are recommending. We are also recommending a change to the Iowa curve from the current L 0.0 to an SQ.

Net Salvage

We propose a change from the current 5% net salvage to 0%.

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The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

ACCRUAL RATE
SCHEDULES

The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

Schedule A

Distribution and General Plant

THE DAYTON POWER & LIGHT COMPANY
WHOLLY OWNED OWNED PROPERTY
SCHEDULE OF DEPRECIATION ACCRUAL RATES @12/31/2014
ELG WHOLE LIFE SCHEDULE WITH RESERVE VARIANCE

SCHEDULE A

ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/14	DISP TYPE	ASL	ACCRUAL RATE W/O NET SALV. (%)	ACCRUAL W/THOUT NET SALV.	NET SALV. %	SALV. FACTOR	ACCRUAL RATE W/ NET SALV. (%)	ACCRUAL W/TH NET SALV.	THEO. RSV. W/THOUT NET SALV.	THEO. RSV. W/TH NET SALV.	BOOK RSV. @12/31/14	RESERVE VARIANCE	COR RATE	SALVAGE RATE	ACCRUAL RATE W/O NET SALVAGE (16) = (8)-(14)+(15)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	DISTRIBUTION PLANT																
361.00	STRUCTURES & IMPROVEMENTS	9,914,383	S 1.0	46.0	2.28	226,048	-25	1.25	2.85	282,560	4,123,035	5,153,794	4,765,854	387,940	0.57%	0.00%	2.28%
361.40	STRUCTURES & IMPROVEMENTS-OTHER	40,910,512	L 0.0	33.0	3.53	1,444,141	-25	1.25	4.41	1,804,154	16,394,848	20,493,560	17,528,167	2,965,393	0.88%	0.00%	3.53%
362.00	STATION EQUIPMENT	139,605,698	R 1.5	55.0	2.03	2,833,996	-10	1.10	2.23	3,113,207	50,046,611	55,051,272	50,570,578	4,480,694	0.20%	0.00%	2.03%
362.10	STATION EQUIPMENT-OFFICE FURNITURE	20,157,048	R 1.5	25.0	4.08	822,408	-10	0.90	3.67	739,764	9,742,646	8,768,381	13,916,758	-5,148,377	0.00%	0.41%	4.08%
362.10	STATION EQUIPMENT-COMPUTERS (2010)	4,221,344	L 2.0	8.0	12.82	541,176	0	1.00	12.82	541,176	2,221,160	2,221,160	3,277,369	-1,056,209	0.00%	0.00%	12.82%
362.10	STATION EQUIPMENT-COMPUTERS (2011)	3,957,088	L 2.0	8.0	13.89	549,640	0	1.00	13.89	549,640	1,583,077	1,583,077	1,519,045	64,032	0.00%	0.00%	13.89%
362.10	STATION EQUIPMENT-COMPUTERS (2012)	2,868,178	L 2.0	8.0	14.29	409,863	0	1.00	14.29	409,863	973,643	973,643	906,987	66,656	0.00%	0.00%	14.29%
362.10	STATION EQUIPMENT-COMPUTERS (2013)	4,794,981	L 2.0	8.0	14.93	715,891	0	1.00	14.93	715,891	1,058,674	1,058,674	926,288	132,386	0.00%	0.00%	14.93%
362.10	STATION EQUIPMENT-COMPUTERS (2014)	326,707	L 2.0	8.0	15.63	51,064	0	1.00	15.63	51,064	25,787	25,787	15,131	10,656	0.00%	0.00%	15.63%
362.70	STATION EQUIPMENT-COMMUNICATION EQP.	42,722,771	S 1.5	20.0	5.52	2,358,297	0	1.00	5.52	2,358,297	11,342,715	11,342,715	10,612,697	730,018	0.00%	0.00%	5.52%
364.00	POLES, TOWERS & FIXTURES	265,780,992	R 2.0	50.0	2.21	5,873,760	-60	1.60	3.54	9,408,647	88,848,184	142,157,094	147,547,298	-5,390,204	1.33%	0.00%	2.21%
365.00	OVERHEAD CONDUCTORS & DEVICES	159,687,889	R 2.0	50.0	2.12	3,385,383	-30	1.30	2.76	4,407,386	64,862,318	84,321,013	77,466,231	6,854,782	0.64%	0.00%	2.12%
366.00	UNDERGROUND CONDUIT	10,525,273	R 4.0	75.0	1.37	144,196	-10	1.10	1.51	158,932	3,963,022	4,359,324	5,396,972	-1,037,648	0.14%	0.00%	1.37%
367.00	UNDERGROUND CONDUCTORS & DEVICES	205,103,974	S 1.5	50.0	2.22	4,553,308	-15	1.15	2.55	5,230,151	65,821,458	75,694,677	95,297,579	-19,602,902	0.33%	0.00%	2.22%
368.00	LINE TRANSFORMERS	272,576,395	S 2.0	46.0	2.30	6,269,257	-40	1.40	3.22	8,776,960	94,893,095	132,850,333	93,928,474	38,921,859	0.92%	0.00%	2.30%
369.10	OVERHEAD SERVICES	48,406,213	R 2.5	45.0	2.33	1,127,865	-75	1.75	4.08	1,974,973	19,277,145	33,735,004	36,885,487	-3,150,483	1.75%	0.00%	2.33%
369.20	UNDERGROUND SERVICES	157,453,368	S 4.0	45.0	2.28	3,589,937	-50	1.50	3.42	5,384,905	47,051,414	70,577,121	81,446,642	-10,869,521	1.14%	0.00%	2.28%
370.00	METERS	48,023,242	S 1.0	30.0	3.50	1,680,813	0	1.00	3.50	1,680,813	19,553,579	19,553,579	13,707,659	5,845,920	0.00%	0.00%	3.50%
371.10	INSTALL. ON CUSTOMER PREM.-PRIVATE OUT	15,680,586	R 1.0	30.0	3.01	471,986	-20	1.20	3.61	566,069	9,013,099	10,815,719	15,153,181	-4,337,462	0.60%	0.00%	3.01%
371.20	INSTALL ON CUSTOMER PREM.-OTHER	227,694	L 2.0	45.0	1.67	3,802	0	1.00	1.67	3,802	170,256	170,256	157,484	12,772	0.00%	0.00%	1.67%
	TOTAL DEPREC. WHOLLY OWNED DISTRIBUTION PLANT	1,452,944,336		42.3	2.55	37,052,831		1.30	3.31	48,158,254	510,965,766	680,906,183	671,025,881	9,880,302			2.55%
	GENERAL PLANT																
390.02	STRUCTURES AND IMPROVEMENTS	17,274,054	L 1.5	30.0	2.87	495,765	0	1.00	2.87	495,765	10,659,582	10,659,582	11,057,305	-397,723	0.00%	0.00%	2.87%
	TOTAL DEPREC. WHOLLY OWNED DISTR. & GNL. PLANT	1,470,218,390		42.1	2.55	37,548,596		1.30	3.31	48,654,019	521,625,348	691,565,765	682,083,186	9,482,579		0.00%	2.55%

The Dayton Power & Light 14 COL Dist. & Gnl (ELG) with Amort. (Sched A) @ 12-31-14 .XLS

10/15/2015

THE DAYTON POWER & LIGHT COMPANY
WHOLLY OWNED OWNED PROPERTY
SCHEDULE OF DEPRECIATION ACCRUAL RATES @12/31/2014
ELG WHOLE LIFE SCHEDULE WITH RESERVE VARIANCE

SCHEDULE A

ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/14 (1)	DISP TYPE (2)	ASL (3)	ACCRUAL RATE W/O NET SALV. (%) (4)	ACCRUAL WITHOUT NET SALV. (5)	NET SALV. % (6)	SALV. FACTOR (7)	ACCRUAL RATE W/ NET SALV. (%) (8)	ACCRUAL WITH NET SALV. (9)	THEO. RSV. WITHOUT NET SALV. (10)	THEO. RSV. WITH NET SALV. (11)	BOOK RSV. @12/31/14 (12)	RESERVE VARIANCE (13)	COR RATE (14)	SALVAGE RATE (15)	ACCRUAL RATE W/O NET SALVAGE (16) = (8)-(14)+(15)
	GENERAL PLANT AMORTIZED																
393.00	STORES EQUIPMENT	357,953	SQ	26.0	3.85	13,781	0	1.00	3.85	13,781	292,211	292,211	274,882	17,329	0.00%	0.00%	3.85%
394.00	TOOLS, SHOP & GARAGE EQUIPMENT	7,818,717	SQ	26.0	3.85	301,021	5	0.95	3.66	286,165	5,107,525	4,852,149	4,324,923	527,226	0.00%	0.19%	3.85%
395.00	LABORATORY EQUIPMENT	4,734,172	SQ	25.0	4.00	189,367	0	1.00	4.00	189,367	1,100,070	1,100,070	764,251	335,819	0.00%	0.00%	4.00%
398.00	MISCELLANEOUS EQUIPMENT	1,067,205	SQ	16.0	6.25	66,700	0	1.00	6.25	66,700	977,873	977,873	676,057	301,816	0.00%	0.00%	6.25%
	TOTAL AMORTIZED GENERAL PLANT	13,978,047		24.5	4.08	570,869		0.98	3.98	556,013	7,477,679	7,222,303	6,040,113	1,182,190	0.00%		4.08%
	SUBTOTAL WHOLLY OWNED **DISTR., GNL & AMORTIZED GNL PLANT**	1,484,196,437		41.8	2.57	38,119,465		1.29	3.32	49,210,032	529,103,027	698,788,068	688,123,299	10,664,769			2.57%
360.10	SUBSTATION LAND	1,829,253															
360.20	LAND-OTHER	53,054															
360.30	LAND RIGHTS	22,804,785											70,315				
360.40	DISTRIBUTION LAND	1,384,082															
361.00	STRUCTURES & IMPROVEMENTS-WPAFB31	108,613															
362.00	STATION EQUIPMENT-WPAFB	630,864															
362.00	STATION EQUIPMENT-WPAFB31	16,946,452															
362.10	STATION EQUIPMENT-COMPUTERS*	29,545,325											29,545,325				
362.20	STATION EQUIPMENT-GENERAL PLANT-TRANS.	38,107,988											35,470,964				
362.60	STATION EQUIPMENT-EDS*	625,742											625,742				
362.70	STATION EQUIPMENT-FIBER CABLE*	366,567											366,567				
362.70	STATION EQUIPMENT-MULTIPLEX*	1,750,695											1,750,695				
364.00	POLES, TOWERS & FIXTURES-WPAFB	31,903															
364.00	POLES, TOWERS & FIXTURES-WPAFB31	569,385															
365.00	OVERHEAD CONDUCTORS & DEVICES-WPAFB	132,171															
365.00	OVERHEAD CONDUCTORS & DEVICES-WPAFB31	494,974															
366.00	UNDERGROUND CONDUIT-WPAFB	87,103															
366.00	UNDERGROUND CONDUIT-WPAFB31	5,536,919															
367.00	UG CONDUCTORS & DEVICES-WPAFB	1,632,136															
367.00	UG CONDUCTORS & DEVICES-WPAFB31	4,556,673															
368.00	LINE TRANSFORMERS-WPAFB	682,533															
368.00	LINE TRANSFORMERS-WPAFB31	6,772,217															
372.00	LEASED PROPERTY ON CUSTOMER PREM.*	47,450											47,450				
389.20	LAND & LAND RIGHTS	1,608,881															
393.00	STORES EQUIPMENT	78,568															
395.00	WRIGHT PATTERSON	70,550															
396.00	POWER OPERATED EQUIPMENT	2,229,175											2,229,175				
	WRIGHT PATTERSON AIR FORCE BASE 106 ALLOCATION (DISTR.)	5,102,058															
	TOTAL WHOLLY OWNED **DISTR., GNL & AMORTIZED GNL PLANT**	1,627,982,533											758,229,532				

* Note: Account is fully depreciated.

WHOLE LIFE SCHEDULE WITH RESERVE VARIANCE

EXPLANATORY NOTES

The Schedule includes indicated (theoretical) reserves both with and without net salvage, the book reserve, and the reserve variance.

The following is an explanation of each column of the Schedule:

1. Column (1) presents the book balance for each account or sub-account at the indicated date.

2. Column (2) labeled "DISP TYPE" is designated as either Forecast or some selected Iowa curve type as discussed in the text.

3. Column (3) indicates the direct weighted average dollar service life in years for each investment group, except where Column (3) shows "Forecast", in which instance the life is a harmonically weighted average dollar service life. Another exception is any life which is a composite of two or more locations and/or two or more accounts (or sub-accounts), in which case the composite life is a harmonically weighted composite life derived by dividing the sum of accruals for the group into the depreciable balance of Column (1).

4. Column (4) is the unadjusted whole life accrual rate developed by dividing unity by Column (3), and expressing the quotient as a percentage.

5. Column (5) is the whole life accrual with no salvage adjustment, based upon the average service life associated with each investment group. These accruals are developed by multiplying Column (1) by Column (4).

6. Column (6) is the percent net salvage expectation; net salvage equals gross salvage minus removal cost.

7. Column (7) is the salvage factor, derived by subtracting the (signed) net salvage ratio from unity; e.g., a salvage factor of 1.10 is the result of 1.00 minus an expected net salvage ratio of minus 0.10; i.e., 1.00 - (-0.10) = 1.10.

8. Column (8) is the whole life accrual rate, reflecting adjustment for net salvage expectations; it is developed by multiplying Column (4) by Column (7), and expressing the product as a percentage.

9. Column (9) is the whole life accrual, adjusted for net salvage expectations. It is developed by multiplying Column (8) by Column (1).

WHOLE LIFE SCHEDULE WITH RESERVE VARIANCE

EXPLANATORY NOTES

10. Column (10) shows indicated depreciation reserves, unadjusted for net salvage expectations, calculated on the basis of the average service life and dispersion characteristics (or forecasts) associated with each investment group.

11. Column (11) is the indicated depreciation reserve, adjusted for net salvage expectations by multiplying Column (10) by Column (7).

12. Column (12) "BOOK RSV. @12/31/14" contains the Company's book reserves by account or sub-accounts.

13. Column (13) shows the difference between adjusted indicated reserves (Column 11) and book reserves (Column 12); i.e., Column (11) minus Column (12).

14. The column labeled "COR RATE" is the cost of removal percent that is included in the accrual rate with net salvage.

15. The column labeled "SALVAGE RATE" is the salvage percent that is included in the accrual rate with net salvage.

16. The column labeled "ACCRUAL RATE W/O NET SALVAGE" is the annual depreciation accrual without net salvage. Column (14) minus column (15) plus column (16) expressed as a percentage.

**The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014**

Schedule B

Comparison of Current and Proposed

THE DAYTON POWER & LIGHT COMPANY
WHOLLY OWNED PROPERTY
DEPRECIATION STUDY @12/31/2014
COMPARISON OF CURRENT AND PROPOSED DEPRECIATION ACCRUAL RATES
ELG METHOD

SCHEDULE B

ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/14	CURRENT ANNUAL DEPREC. ACCURAL RATE	CURRENT ANNUAL DEPREC. ACCRUAL	PROPOSED ANNUAL DEPREC. ACCRUAL RATE	PROPOSED ANNUAL DEPREC. ACCRUAL	DIFFERENCE BETWEEN PROPOSED & CURRENT ANNUAL ACCRUAL
		(1)	(2)	(3)	(4)	(5)	(6)
WHOLLY OWNED							
DISTRIBUTION PLANT							
361.00	STRUCTURES & IMPROVEMENTS	9,914,383	0.0248	245,877	0.0285	282,560	36,683
361.40	STRUCTURES & IMPROVEMENTS-OTHER	40,910,512	0.0290	1,186,405	0.0441	1,804,154	617,749
362.00	STATION EQUIPMENT	139,605,698	0.0225	3,141,128	0.0223	3,113,207	-27,921
362.10	STATION EQUIPMENT-OFFICE FURNITURE	20,157,048	0.0531	1,070,339	0.0367	739,764	-330,575
362.10	STATION EQUIPMENT-COMPUTERS (2010)	4,221,344	0.1190	502,340	0.1282	541,176	38,836
362.10	STATION EQUIPMENT-COMPUTERS (2011)	3,957,088	0.1190	470,893	0.1389	549,640	78,747
362.10	STATION EQUIPMENT-COMPUTERS (2012)	2,868,178	0.1190	341,313	0.1429	409,863	68,550
362.10	STATION EQUIPMENT-COMPUTERS (2013)	4,794,981	0.1190	570,603	0.1493	715,891	145,288
362.10	STATION EQUIPMENT-COMPUTERS (2014)	326,707	0.1190	38,878	0.1563	51,064	12,186
362.70	STATION EQUIPMENT-COMMUNICATION EQP.	42,722,771	0.0468	1,999,426	0.0552	2,358,297	358,871
364.00	POLES, TOWERS & FIXTURES	265,780,992	0.0402	10,684,396	0.0354	9,408,647	-1,275,749
365.00	OVERHEAD CONDUCTORS & DEVICES	159,687,889	0.0292	4,662,886	0.0276	4,407,386	-255,500
366.00	UNDERGROUND CONDUIT	10,525,273	0.0195	205,243	0.0151	158,932	-46,311
367.00	UNDERGROUND CONDUCTORS & DEVICES	205,103,974	0.0355	7,281,191	0.0255	5,230,151	-2,051,040
368.00	LINE TRANSFORMERS	272,576,395	0.0251	6,841,668	0.0322	8,776,960	1,935,292
369.10	OVERHEAD SERVICES	48,406,213	0.0447	2,163,758	0.0408	1,974,973	-188,785
369.20	UNDERGROUND SERVICES	157,453,368	0.0409	6,439,843	0.0342	5,384,905	-1,054,938
370.00	METERS	48,023,242	0.0326	1,565,558	0.0350	1,680,813	115,255
371.10	INSTALL. ON CUSTOMER PREM.-PRIVATE OUT	15,680,586	0.0577	904,770	0.0361	566,069	-338,701
371.20	INSTALL. ON CUSTOMER PREM.-OTHER	227,694	0.0204	4,645	0.0167	3,802	-843
	TOTAL DEPREC. WHOLLY OWNED DISTRIBUTION PLANT	1,452,944,336	0.0346	50,321,160	0.0331	48,158,254	-2,162,906
GENERAL PLANT							
390.02	STRUCTURES AND IMPROVEMENTS	17,274,054	0.0290	500,948	0.0287	495,765	-5,183
	TOTAL DEPREC. WHOLLY OWNED DISTR. & GNL. PLANT	1,470,218,390	0.0346	50,822,108	0.0331	48,654,019	-2,168,089
GENERAL PLANT AMORTIZED							
393.00	STORES EQUIPMENT	357,953	0.0379	13,566	0.0385	13,781	215
394.00	TOOLS, SHOP & GARAGE EQUIPMENT	7,818,717	0.0353	276,001	0.0366	286,165	10,164
395.00	LABORATORY EQUIPMENT	4,734,172	0.0370	175,164	0.0400	189,367	14,203
398.00	MISCELLANEOUS EQUIPMENT	1,067,205	0.0495	52,827	0.0625	66,700	13,873
	TOTAL AMORTIZED GENERAL PLANT	13,978,047	0.0370	517,558	0.0398	556,013	38,455
	TOTAL WHOLLY OWNED DISTR., GNL & AMORTIZED GNL. PLANT	1,484,196,437	0.0346	51,339,666	0.0332	49,210,032	-2,129,634

The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

Schedule C

Comparison of ASL using ALG and ELG

THE DAYTON POWER & LIGHT COMPANY
WHOLLY OWNED OWNED PROPERTY
SCHEDULE OF DEPRECIATION ACCRUAL RATES @12/31/2014
ELG WHOLE LIFE SCHEDULE

SCHEDULE C

ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/2014	% of Total Plant	DISP TYPE	ALG ASL	ELG ASL
		(1)	(3)	(3)	(4)	(5)
	DISTRIBUTION PLANT					
361.00	STRUCTURES & IMPROVEMENTS	9,914,383	0.68%	S 1.0	46.0	43.9
361.40	STRUCTURES & IMPROVEMENTS-OTHER	40,910,512	2.82%	L 0.0	33.0	28.3
362.00	STATION EQUIPMENT	139,605,698	9.61%	R 1.5	55.0	49.2
362.10	STATION EQUIPMENT-OFFICE FURNITURE	20,157,048	1.39%	R 1.5	25.0	24.5
362.10	STATION EQUIPMENT-COMPUTERS (2010)	4,221,344	0.29%	L 2.0	8.0	7.8
362.10	STATION EQUIPMENT-COMPUTERS (2011)	3,957,088	0.27%	L 2.0	8.0	7.2
362.10	STATION EQUIPMENT-COMPUTERS (2012)	2,868,178	0.20%	L 2.0	8.0	7.0
362.10	STATION EQUIPMENT-COMPUTERS (2013)	4,794,981	0.33%	L 2.0	8.0	6.7
362.10	STATION EQUIPMENT-COMPUTERS (2014)	326,707	0.02%	L 2.0	8.0	6.4
362.70	STATION EQUIPMENT-COMMUNICATION EQP.	42,722,771	2.94%	S 1.5	20.0	18.1
364.00	POLES, TOWERS & FIXTURES	265,780,992	18.29%	R 2.0	50.0	45.3
365.00	OVERHEAD CONDUCTORS & DEVICES	159,687,889	10.99%	R 2.0	50.0	47.2
366.00	UNDERGROUND CONDUIT	10,525,273	0.72%	R 4.0	75.0	72.9
367.00	UNDERGROUND CONDUCTORS & DEVICES	205,103,974	14.12%	S 1.5	50.0	45.1
368.00	LINE TRANSFORMERS	272,576,395	18.76%	S 2.0	46.0	43.4
369.10	OVERHEAD SERVICES	48,406,213	3.33%	R 2.5	45.0	43.0
369.20	UNDERGROUND SERVICES	157,453,368	10.84%	S 4.0	45.0	43.9
370.00	METERS	48,023,242	3.31%	S 1.0	30.0	28.6
371.10	INSTALL. ON CUSTOMER PREM.-PRIVATE OUT	15,680,586	1.08%	R 1.0	30.0	33.2
371.20	INSTALL. ON CUSTOMER PREM.-OTHER	227,694	0.02%	L 2.0	45.0	59.8
	TOTAL DEPREC. WHOLLY OWNED **DISTRIBUTION PLANT**	1,452,944,336			42.3	39.2
390.02	STRUCTURES AND IMPROVEMENTS	17,274,054		L 1.5	30.0	34.8
	TOTAL DEPREC. WHOLLY OWNED **DISTRIBUTION & GENERAL PLANT**	1,470,218,390			42.1	39.2
	GENERAL PLANT - AMORTIZED					
393.00	STORES EQUIPMENT	357,953		SQ	26.0	26.0
394.00	TOOLS, SHOP & GARAGE EQUIPMENT	7,818,717		SQ	26.0	26.0
395.00	LABORATORY EQUIPMENT	4,734,172		SQ	25.0	25.0
398.00	MISCELLANEOUS EQUIPMENT	1,067,205		SQ	16.0	16.0
	TOTAL AMORTIZED GENERAL PLANT	13,978,047			24.5	24.5
	SUBTOTAL WHOLLY OWNED **DISTR., GNL & AMORTIZED GNL. PLANT**	1,484,196,437			41.8	38.9

The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

APPENDIX A

Net Salvage Schedules

The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

Cost of Removal (COR)

THE DAYTON POWER & LIGHT COMPANY
WHOLLY OWNED PROPERTY
CALCULATION OF COR RATES
12/31/2014

A. Proposed COR = x%
B. W.L. Rate w/o COR= 100/ASL
C. W.L. Rate w/ COR = w.l. Rate * COR
D. COR Rate = W.L. Rate w/COR - W.L. Rate w/o COR

DISTRIBUTION PLANT

361.00   ASL= 43.9   N.S.=   -25

A. Proposed COR	25
B. W.L. Rate w/o COR	2.28
C. W.L. Rate w/ COR	2.85
D. COR Rate =	0.57

361.40   ASL= 28.3   N.S.=   -25

A. Proposed COR	25
B. W.L. Rate w/o COR	3.53
C. W.L. Rate w/ COR	4.41
D. COR Rate =	0.88

362.00   ASL= 49.2   N.S.=   -10

A. Proposed COR	10
B. W.L. Rate w/o COR	2.03
C. W.L. Rate w/ COR	2.23
D. COR Rate =	0.20

362.10   ASL= 24.5   N.S.=   10
(OFF. FURN.)

A. Proposed COR	0
B. W.L. Rate w/o COR	4.08
C. W.L. Rate w/ COR	4.08
D. COR Rate =	0.00

THE DAYTON POWER & LIGHT COMPANY
WHOLLY OWNED PROPERTY
CALCULATION OF COR RATES
12/31/2014

A. Proposed COR = x%
B. W.L. Rate w/o COR= 100/ASL
C. W.L. Rate w/ COR = w.l. Rate * COR
D. COR Rate = W.L. Rate w/COR - W.L. Rate w/o COR

362.10   ASL= 7.8   N.S.=   0
(COMPUTERS 2010)
    A. Proposed COR   0
    B. W.L. Rate w/o COR   12.82
    C. W.L. Rate w/ COR   12.82
    D. COR Rate =   0.00

362.10   ASL= 7.2   N.S.=   0
(COMPUTERS 2011)
    A. Proposed COR   0
    B. W.L. Rate w/o COR   13.89
    C. W.L. Rate w/ COR   13.89
    D. COR Rate =   0.00

362.10   ASL= 7.0   N.S.=   0
(COMPUTERS 2012)
    A. Proposed COR   0
    B. W.L. Rate w/o COR   14.29
    C. W.L. Rate w/ COR   14.29
    D. COR Rate =   0.00

362.10   ASL= 6.7   N.S.=   0
(COMPUTERS 2013)
    A. Proposed COR   0
    B. W.L. Rate w/o COR   14.93
    C. W.L. Rate w/ COR   14.93
    D. COR Rate =   0.00

362.10   ASL= 6.4   N.S.=   0
(COMPUTERS 2014)
    A. Proposed COR   0
    B. W.L. Rate w/o COR   15.63
    C. W.L. Rate w/ COR   15.63
    D. COR Rate =   0.00

THE DAYTON POWER & LIGHT COMPANY
WHOLLY OWNED PROPERTY
CALCULATION OF COR RATES
12/31/2014

A. Proposed COR = x%
B. W.L. Rate w/o COR= 100/ASL
C. W.L. Rate w/ COR = w.l. Rate * COR
D. *COR Rate = W.L. Rate w/COR – W.L. Rate w/o COR*

362.70	ASL= 18.1	N.S.=	0
(COMM.EQUIP.)			

A. Proposed COR   0
B. W.L. Rate w/o COR   5.52
C. W.L. Rate w/ COR   5.52
D. COR Rate =   0.00

364.00	ASL= 45.3	N.S.=	-60

A. Proposed COR   60
B. W.L. Rate w/o COR   2.21
C. W.L. Rate w/ COR   3.54
D. COR Rate =   1.33

365.00	ASL= 47.2	N.S.=	-30

A. Proposed COR   30
B. W.L. Rate w/o COR   2.12
C. W.L. Rate w/ COR   2.76
D. COR Rate =   0.64

366.00	ASL= 72.9	N.S.=	-10

A. Proposed COR   10
B. W.L. Rate w/o COR   1.37
C. W.L. Rate w/ COR   1.51
D. COR Rate =   0.14

367.00	ASL= 45.1	N.S.=	-15

A. Proposed COR   15
B. W.L. Rate w/o COR   2.22
C. W.L. Rate w/ COR   2.55
D. COR Rate =   0.33

368.00	ASL= 43.4	N.S.=	-40

A. Proposed COR   40
B. W.L. Rate w/o COR   2.30
C. W.L. Rate w/ COR   3.22
D. COR Rate =   0.92

THE DAYTON POWER & LIGHT COMPANY
WHOLLY OWNED PROPERTY
CALCULATION OF COR RATES
12/31/2014

A. Proposed COR = x%
B. W.L. Rate w/o COR= 100/ASL
C. W.L. Rate w/ COR = w.l. Rate * COR
D. COR Rate = W.L. Rate w/COR - W.L. Rate w/o COR

369.10	ASL= 43.0	N.S.=	-75
(OH SVCS.)			
A. Proposed COR		75	
B. W.L. Rate w/o COR		2.33	
C. W.L. Rate w/ COR		4.08	
D. COR Rate =		1.75	

369.20	ASL= 43.9	N.S.=	-50
(UG SVCS.)			
A. Proposed COR		50	
B. W.L. Rate w/o COR		2.28	
C. W.L. Rate w/ COR		3.42	
D. COR Rate =		1.14	

370.00	ASL= 28.6	N.S.=	0
A. Proposed COR		0	
B. W.L. Rate w/o COR		3.50	
C. W.L. Rate w/ COR		3.50	
D. COR Rate =		0.00	

371.10	ASL= 33.2	N.S.=	-20
(Private out.)			
A. Proposed COR		20	
B. W.L. Rate w/o COR		3.01	
C. W.L. Rate w/ COR		3.61	
D. COR Rate =		0.60	

371.20	ASL= 59.8	N.S.=	0
(Other)			
A. Proposed COR		0	
B. W.L. Rate w/o COR		1.67	
C. W.L. Rate w/ COR		1.67	
D. COR Rate =		0.00	

THE DAYTON POWER & LIGHT COMPANY
WHOLLY OWNED PROPERTY
CALCULATION OF COR RATES
12/31/2014

A. Proposed COR = x%
B. W.L. Rate w/o COR= 100/ASL
C. W.L. Rate w/ COR = w.l. Rate * COR
D. COR Rate = W.L. Rate w/COR - W.L. Rate w/o COR

GENERAL PLANT

390.02   ASL= 34.8   N.S.=   0

A. Proposed COR   0
B. W.L. Rate w/o COR   2.87
C. W.L. Rate w/ COR   2.87
D. COR Rate =   0.00

393.00   ASL= 26   N.S.=   0

A. Proposed COR   0
B. W.L. Rate w/o COR   3.85
C. W.L. Rate w/ COR   3.85
D. COR Rate =   0.00

394.00   ASL= 26   N.S.=   5

A. Proposed COR   0
B. W.L. Rate w/o COR   3.85
C. W.L. Rate w/ COR   3.85
D. COR Rate =   0.00

395.00   ASL= 25   N.S.=   0

A. Proposed COR   0
B. W.L. Rate w/o COR   4.00
C. W.L. Rate w/ COR   4.00
D. COR Rate =   0.00

398.00   ASL= 16   N.S.=   0

A. Proposed COR   0
B. W.L. Rate w/o COR   6.25
C. W.L. Rate w/ COR   6.25
D. COR Rate =   0.00

The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

Salvage

THE DAYTON POWER & LIGHT COMPANY
WHOLLY OWNED PROPERTY
CALCULATION OF SALVAGE RATES
12/31/2014

A. Proposed SALV = x%
B. W.L. Rate w/o Salvage = 100/ASL
C. W.L. Rate w/Salvage = w.l. Rate * SALV
D. Salvage Rate = W.L. Rate w/SALV - W.L. Rate w/o SALV

DISTRIBUTION PLANT

361.00	ASL= 43.9	N.S.=	-25

A. Proposed Salvage	0
B. W.L. Rate w/o Salvage	2.28
C. W.L. Rate w/ Salvage	2.28
D. Salvage Rate =	0.00

361.40	ASL= 28.3	N.S.=	-25

A. Proposed Salvage	0
B. W.L. Rate w/o Salvage	3.53
C. W.L. Rate w/ Salvage	3.53
D. Salvage Rate =	0.00

362.00	ASL= 49.2	N.S.=	-10

A. Proposed Salvage	0
B. W.L. Rate w/o Salvage	2.03
C. W.L. Rate w/ Salvage	2.03
D. Salvage Rate =	0.00

362.10	ASL= 24.5	N.S.=	10

(Office Furn.)

A. Proposed Salvage	10
B. W.L. Rate w/o Salvage	4.08
C. W.L. Rate w/ Salvage	3.67
D. Salvage Rate =	-0.41

THE DAYTON POWER & LIGHT COMPANY
WHOLLY OWNED PROPERTY
CALCULATION OF SALVAGE RATES
12/31/2014

A. Proposed SALV = x%
B. W.L. Rate w/o Salvage = 100/ASL
C. W.L. Rate w/Salvage = w.l. Rate * SALV
D. Salvage Rate = W.L. Rate w/SALV - W.L. Rate w/o SALV

362.10   ASL=   7.8   N.S.=   0
(COMPUTERS 2010)
   A. Proposed Salvage   0
   B. W.L. Rate w/o Salvage   12.82
   C. W.L. Rate w/ Salvage   12.82
   D. Salvage Rate =   0.00

362.10   ASL=   7.2   N.S.=   0
(COMPUTERS 2011)
   A. Proposed Salvage   0
   B. W.L. Rate w/o Salvage   13.89
   C. W.L. Rate w/ Salvage   13.89
   D. Salvage Rate =   0.00

362.10   ASL=   7.0   N.S.=   0
(COMPUTERS 2012)
   A. Proposed Salvage   0
   B. W.L. Rate w/o Salvage   14.29
   C. W.L. Rate w/ Salvage   14.29
   D. Salvage Rate =   0.00

362.10   ASL=   6.7   N.S.=   0
(COMPUTERS 2013)
   A. Proposed Salvage   0
   B. W.L. Rate w/o Salvage   14.93
   C. W.L. Rate w/ Salvage   14.93
   D. Salvage Rate =   0.00

362.10   ASL=   6.4   N.S.=   0
(COMPUTERS 2014)
   A. Proposed Salvage   0
   B. W.L. Rate w/o Salvage   15.63
   C. W.L. Rate w/ Salvage   15.63
   D. Salvage Rate =   0.00

THE DAYTON POWER & LIGHT COMPANY
WHOLLY OWNED PROPERTY
CALCULATION OF SALVAGE RATES
12/31/2014

A. Proposed SALV = x%
B. W.L. Rate w/o Salvage = 100/ASL
C. W.L. Rate w/Salvage = w.l. Rate * SALV
D. Salvage Rate = W.L. Rate w/SALV - W.L. Rate w/o SALV

362.70   ASL= 18.1   N.S.=   0
(Comm. Equip.)
   A. Proposed Salvage   0
   B. W.L. Rate w/o Salvage   5.52
   C. W.L. Rate w/ Salvage   5.52
   D. Salvage Rate =   0.00

364.00   ASL= 45.3   N.S.=   -60

   A. Proposed Salvage   0
   B. W.L. Rate w/o Salvage   2.21
   C. W.L. Rate w/ Salvage   2.21
   D. Salvage Rate =   0.00

365.00   ASL= 47.2   N.S.=   -30

   A. Proposed Salvage   0
   B. W.L. Rate w/o Salvage   2.12
   C. W.L. Rate w/ Salvage   2.12
   D. Salvage Rate =   0.00

366.00   ASL= 72.9   N.S.=   -10

   A. Proposed Salvage   0
   B. W.L. Rate w/o Salvage   1.37
   C. W.L. Rate w/ Salvage   1.37
   D. Salvage Rate =   0.00

367.00   ASL= 45.1   N.S.=   -15

   A. Proposed Salvage   0
   B. W.L. Rate w/o Salvage   2.22
   C. W.L. Rate w/ Salvage   2.22
   D. Salvage Rate =   0.00

368.00   ASL= 43.4   N.S.=   -40

   A. Proposed Salvage   0
   B. W.L. Rate w/o Salvage   2.30
   C. W.L. Rate w/ Salvage   2.30
   D. Salvage Rate =   0.00

THE DAYTON POWER & LIGHT COMPANY
WHOLLY OWNED PROPERTY
CALCULATION OF SALVAGE RATES
12/31/2014

A. Proposed SALV = x%
B. W.L. Rate w/o Salvage = 100/ASL
C. W.L. Rate w/Salvage = w.l. Rate * SALV
D. Salvage Rate = W.L. Rate w/SALV - W.L. Rate w/o SALV

369.10	ASL=	43.0	N.S.=	-75
A. Proposed Salvage			0	
B. W.L. Rate w/o Salvage			2.33	
C. W.L. Rate w/ Salvage			2.33	
D. Salvage Rate =			0.00	

369.20	ASL=	43.9	N.S.=	-50
A. Proposed Salvage			0	
B. W.L. Rate w/o Salvage			2.28	
C. W.L. Rate w/ Salvage			2.28	
D. Salvage Rate =			0.00	

370.00	ASL=	28.6	N.S.=	0
A. Proposed Salvage			0	
B. W.L. Rate w/o Salvage			3.50	
C. W.L. Rate w/ Salvage			3.50	
D. Salvage Rate =			0.00	

371.10	ASL=	33.2	N.S.=	-20
(Private out.)				
A. Proposed Salvage			0	
B. W.L. Rate w/o Salvage			3.01	
C. W.L. Rate w/ Salvage			3.01	
D. Salvage Rate =			0.00	

371.20	ASL=	59.8	N.S.=	0
(Other)				
A. Proposed Salvage			0	
B. W.L. Rate w/o Salvage			1.67	
C. W.L. Rate w/ Salvage			1.67	
D. Salvage Rate =			0.00	

THE DAYTON POWER & LIGHT COMPANY
WHOLLY OWNED PROPERTY
CALCULATION OF SALVAGE RATES
12/31/2014

A. Proposed SALV = x%
B. W.L. Rate w/o Salvage = 100/ASL
C. W.L. Rate w/Salvage = w.l. Rate * SALV
D. Salvage Rate = W.L. Rate w/SALV - W.L. Rate w/o SALV

GENERAL PLANT

390.20 ASL= 34.8 N.S.= 0

A. Proposed Salvage   0
B. W.L. Rate w/o Salvage 2.87
C. W.L. Rate w/ Salvage   2.87
D. Salvage Rate =   0.00

393.00 ASL= 26 N.S.= 0

A. Proposed Salvage   0
B. W.L. Rate w/o Salvage 3.85
C. W.L. Rate w/ Salvage   3.85
D. Salvage Rate =   0.00

394.00 ASL= 26 N.S.= 5

A. Proposed Salvage   5
B. W.L. Rate w/o Salvage 3.85
C. W.L. Rate w/ Salvage   3.66
D. Salvage Rate =   -0.19

395.00 ASL= 25 N.S.= 0

A. Proposed Salvage   0
B. W.L. Rate w/o Salvage 4.00
C. W.L. Rate w/ Salvage   4.00
D. Salvage Rate =   0.00

398.00 ASL= 16 N.S.= 0

A. Proposed Salvage   0
B. W.L. Rate w/o Salvage 6.25
C. W.L. Rate w/ Salvage   6.25
D. Salvage Rate =   0.00

The Dayton Power and Light Company
Distribution and General Plant Depreciation Accrual Rate Study
Based on Plant in Service at December 31, 2014

APPENDIX B

The Dayton Power and Light Company
1991 Depreciation Study
Based on
12/31/1989 Plant in Service

DAYTON POWER & LIGHT COMPANY

SCHEDULE OF DEPRECIATION ACCRUAL RATES AT DECEMBER 31, 1989

DISTRIBUTION PLANT

PLANT ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE a12/31/89 (1)	DISPERSION TYPE (2)	AVERAGE DOLLAR SERVICE LIFE (3)	ANNUAL ACCRUAL RATE WITHOUT NET SALVAGE (4)	ANNUAL ACCRUAL WITHOUT NET SALVAGE (5)	NET SALVAGE % (6)	SALVAGE FACTOR (7)	ANNUAL ACCRUAL RATE WITH NET SALVAGE (8)
361.00	STRUCTURES AND IMPROVEMENTS	4,817,629	R 3.0	45.0	2.25	108,397	-10	1.10	2.48
362.00	STATION EQUIPMENT-NORMAL	59,963,633	R 2.0	50.0	2.14	1,283,222	-5	1.05	2.25
362.60	STATION EQUIPMENT-EDS	1,047,274	R 3.0	11.0	8.93	93,522	0	1.00	8.93
364.00	POLES, TOWERS, & FIXTURES	56,944,444	R 1.0	38.0	2.87	1,634,306	-40	1.40	4.02
365.00	OH CONDUCTORS AND DEVICES	42,599,162	R 1.0	40.0	2.54	1,082,019	-15	1.15	2.92
366.00	UG CONDUIT	4,256,346	R 3.0	55.0	1.86	79,168	-5	1.05	1.95
367.00	UG CONDUCTORS AND DEVICES	47,484,071	S 1.0	38.0	3.09	1,467,258	-15	1.15	3.55
368.00	LINE TRANSFORMERS	107,312,239	S 1.0	44.0	2.51	2,693,537	0	1.00	2.51
369.10	OH SERVICES	16,779,264	R 3.0	33.0	2.98	500,022	-50	1.50	4.47
369.20	UG SERVICES	26,182,421	R 2.0	35.0	3.27	856,165	-25	1.25	4.09
370.00	METERS	26,570,116	S 1.0	32.0	3.26	866,186	0	1.00	3.26
371.10	INST ON CUST PREM-POL	7,540,147	R 0.5	20.0	4.81	362,681	-20	1.20	5.77
371.20	INST ON CUST PREM-OTHER	395,272	R 5.0	50.0	2.04	8,064	0	1.00	2.04
372.00	LEASED PROP ON CUST PREM	56,865	SQ	40.0	2.50	1,422	0	1.00	2.50
	TOTAL DEPREC DISTR PLANT	401,948,883		39.4	2.75	11,035,969	-15	1.15	3.16

DAYTON POWER & LIGHT COMPANY

SCHEDULE OF DEPRECIATION ACCRUAL RATES AT DECEMBER 31, 1989

PLANT ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/89 (1)	DISPERSION TYPE (2)	AVERAGE DOLLAR SERVICE LIFE (3)	ANNUAL ACCRUAL RATE WITHOUT NET SALVAGE (4)	ANNUAL ACCRUAL WITHOUT NET SALVAGE (5)	NET SALVAGE % (6)	SALVAGE FACTOR (7)	ANNUAL ACCRUAL RATE WITH NET SALVAGE (8)
	GENERAL PLANT								
390.10	STRUCT AND IMPROVS-NORMAL	47,576,241	R 2.5	40.0	2.90	1,379,711	0	1.00	2.90
390.60	STRUCT AND IMPROVS-EDS	49,793	R 3.0	11.0	8.62	4,292	0	1.00	8.62
391.20	OFFICE FURNITURE & EQUIPMENT	9,555,918	S 0.0	22.0	5.59	534,064	5	0.95	5.31
391.60	COMPUTER AND PERIPHERALS	1,189,457	R 2.0	8.0	11.90	141,545	0	1.00	11.90
393.20	STORES EQUIPMENT	342,392	L 2.0	30.0	3.79	12,977	0	1.00	3.79
394.10	TOOLS,SHOP,&GARAGE EQUIPMENT	930,182	S 2.0	30.0	3.68	34,231	5	0.95	3.50
394.20	GARAGE EQUIPMENT	1,352,740	L	30.0	3.72	50,322	5	0.95	3.53
395.00	LABORATORY EQUIPMENT	1,075,893	L 1.5	35.0	3.70	39,808	-2	1.02	3.70
397.00	COMMUNICATION EQUIP	6,898,451	R 3.0	25.0	4.59	316,639	0	1.00	4.68
397.20	COMMUNICATION EQUIP-EDS	861,608	L 0.0	11.0	8.70	74,942	0	1.00	8.70
397.60	MISCELLANEOUS EQUIP	35,904		25.0	3.94	1,415	5	0.95	3.74
398.10	MISCELLANEOUS EQUIP	1,020,523	L 0.0	25.0	5.21	53,169	5	0.95	4.95
398.20	MISCELLANEOUS EQUIP-EDS	55,258	R 3.0	11.0	8.93	4,935	0	1.00	8.93
398.60	MISCELLANEOUS EQUIP-EDS								
	TOTAL DEPREC. GENERAL PLANT	70,942,160		30.9	3.73	2,648,050	1	0.99	3.69
	TOTAL DEPREC ELECTRIC PLANT	724,105,754		38.0	2.83	20,509,567	-10	1.10	3.13