

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-2013-2372129

**Duquesne Light Company
Statement No. 9**

Direct Testimony of Paul R. Moul

Dated: August 2, 2013

Duquesne Light Company
Direct Testimony of Paul R. Moul
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GLOSSARY OF ACRONYMS AND DEFINED TERMS

ACRONYM	DEFINED TERM
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
CE	Comparable Earnings
CWIP	Construction Work in Progress
DCF	Discounted Cash Flow
DLH	Duquense Light Holdings, Inc.
EPACT	National Energy Policy Act
FERC	Federal Energy Regulatory Commission
FOMC	Federal Open Market Committee
IGF	Internally Generated Funds
LT	Long Term
MPL	Minimum pension liability
OCI	Other Comprehensive Income
POLR	Provider of last resort
PPUC	Pennsylvania Public Utility Commission
r	represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Return on the market
RP	Risk Premium
RTO	Regional Transmission Organizations
s	Represents the new common shares expected to be issued by a firm

s x v	Represents external growth
S&P	Standard & Poor's
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value
ytm	Yield to maturity

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INTRODUCTION AND SUMMARY OF RECOMMENDATION

1
2 **Q. Please state your name, occupation and business address.**

3 A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road,
4 Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P.
5 Moul & Associates, an independent financial and regulatory consulting firm. My
6 educational background, business experience and qualifications are provided in
7 Appendix A, which follows my direct testimony.

8
9 **Q. What is the purpose of your testimony?**

10 A. My testimony presents evidence, analysis and a recommendation concerning the
11 appropriate rate of return that the Pennsylvania Public Utility Commission
12 (“PPUC” or the “Commission”) should recognize in the determination of the
13 revenues that Duquesne Light Company (“Duquesne Light” or the “Company”) should
14 realize as a result of this proceeding. My analysis and recommendation are
15 supported by the detailed financial data contained in Exhibit PRM-1, which is a
16 multi-page document divided into fifteen (15) schedules.

17
18 **Q. Based upon your analysis, what is your conclusion concerning the appropriate
19 cost of common equity and rate of return for the Company?**

20 A. My conclusion is that the Company’s rate of return on common equity is 11.25%.
21 In determining the rate of return on common equity, the Commission should
22 consider the Company’s reliability and its high quality of customer service. With
23 this return, I have presented on page 1 of Schedule 1 the weighted average cost of

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1 capital, which is 8.36%. The resulting overall cost of capital, which is the product
2 of weighting the individual capital costs by the proportion of each respective type of
3 capital, should, if adopted by the Commission, establish a compensatory level of
4 return for the use of capital and provide the Company with the ability to attract
5 capital on reasonable terms.

6
7 **Q. What background information have you considered in reaching a conclusion**
8 **concerning the Company's cost of capital?**

9 A. Duquesne Light is wholly-owned subsidiary of Duquesne Light Holdings, Inc.
10 ("DLH" or the "Parent Company"). The Company provides electric delivery
11 service and provider of last resort ("POLR") service to 588,676 customers in
12 Allegheny and Beaver counties. In 2012, electric sales in Mwh for Duquesne Light
13 were comprised of approximately 29% to residential, 46% to commercial, 24% to
14 industrial customers, and 1% to street lighting and sales for resale customers.

15
16 **Q. How have you determined the cost of common equity in this case?**

17 A. The cost of common equity is established using capital market and financial data
18 relied upon by investors to assess the relative risk, and hence the cost of equity, for
19 an electric utility, such as Duquesne Light. In this regard, I relied on four well-
20 recognized measures of the cost of equity: The Discounted Cash Flow ("DCF")
21 model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model
22 ("CAPM"), and the Comparable Earnings ("CE") approach. The results of a variety
23 of approaches indicate that the Company's rate of return on common equity is

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1 11.25%.

2

3 **Q. In your opinion, what factors should the Commission consider when**
4 **determining the Company's cost of capital in this proceeding?**

5 A. The Commission's rate of return allowance must be set to cover the Company's
6 interest and dividend payments, provide a reasonable level of earnings retention,
7 produce an adequate level of internally generated funds to meet capital
8 requirements, be commensurate with the risk to which the Company's capital is
9 exposed, assure confidence in the financial integrity of the Company, support
10 reasonable credit quality, and allow the Company to raise capital on reasonable
11 terms. The return that I propose fulfills these established standards of a fair rate of
12 return set forth by the landmark Bluefield and Hope cases.¹ That is to say, my
13 proposed rate of return is commensurate with returns available on investments
14 having corresponding risks.

15

16 **Q. What factors have you considered in measuring the cost of equity in this case?**

17 A. The models that I used to measure the cost of common equity for the Company
18 were applied with market and financial data developed from my proxy group of ten
19 (10) electric companies. The criteria that I used to assemble the proxy group will
20 be described later in my testimony. The companies in the electric proxy group are
21 identified on page 2 of Schedule 3. I will refer to these companies as the "Electric

¹Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

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1 Group” throughout my testimony.

2

3 **Q. How have you performed your cost of equity analysis with the market data for**
4 **the Electric Group?**

5 A. I have applied the models/methods for estimating the cost of equity using the
6 average data for the Electric Group. I have not measured separately the cost of
7 equity for the individual companies within the Electric Group. By employing group
8 average data, rather than individual Company’s analysis, I have helped to minimize
9 the effect of extraneous influences on the market data for an individual company.

10

11 **Q. Please summarize your cost of equity analysis.**

12 A. My cost of equity determination was derived from the results of the
13 methods/models identified above, and revealed on page 2 of Schedule 1. In
14 general, the use of more than one method provides a superior foundation to arrive at
15 the cost of equity. At any point in time, reliance on a single method can provide an
16 incomplete measure of the cost of equity. The specific application of these
17 methods/models will be described later in my testimony. The following table,
18 derived from the model results presented on page 2 of Schedule 1, provides a
19 summary of the indicated costs of equity using each of these approaches.

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	<u>Electric Group</u>
DCF	10.78%
RP	12.25%
CAPM	11.36%
Comparable Earnings	12.15%
Average	11.64%
Median	11.76%
Mid-point	11.52%

1 The average of the market-determined measures (i.e., DCF, RP and CAPM) of the
2 cost of equity is 11.46% ($10.78\% + 12.25\% + 11.36\% = 34.39\% \div 3$). From these
3 measures of the cost of equity, I recommend that the Company's rate of return on
4 common equity be set at 11.25%. Although I have made no specific adjustment for
5 the Company's service quality, the Commission should give consideration to the
6 Company's high levels of service. The testimony of Mr. David Bordo summarizes
7 the many initiatives that the Company has undertaken, which have produced high
8 quality service. In particular, Mr. Bordo has shown that the Company ranks high in
9 customer service and its reliability has been exceptional. The Company should be
10 granted an opportunity to earn a rate of return on common equity of at least 11.25%.
11 I also believe my recommended cost of equity is appropriate in this case because it
12 makes no provision for the prospect that the rate of return may not be achieved due
13 to unforeseen events that could occur during the rate effective period and the large
14 construction projects underway.

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ELECTRIC UTILITY RISK FACTORS

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Q. Please identify some of the factors that make the electric utility industry generally different today than it was in the past.

A. Today, electric utilities generally are faced with meaningful changes in the fundamentals that affect their operations, while cost of service pricing continues to dominate much of their business profile. On the national level, the passage of the National Energy Policy Act (“EPACT”) and the issuance of FERC Order Nos. 888 and 889 and Order No. 2000 initiated sweeping changes that fundamentally altered the structure of the electric utility business. Order No. 2000 encouraged the formation of Regional Transmission Organizations (“RTO”) that offer non-discriminatory transmission service. Duquesne Light is part of the PJM Interconnection, LLC.

Q. Have these changes brought about increases in the risks facing electric utilities generally?

A. Yes. Aside from its traditional responsibility to maintain reliability and comply with the mandates of PJM, a different set of risks now exist for the electric delivery business in Pennsylvania. The risk of distributed generation will continue to be a concern, and could have an increasing influence on the business of electric delivery utilities. With technological advances in micro-turbines, potential commercialization of fuel cells, development of wind and solar power, and the creation of micro-grids, utilities face the potential for bypass and the resulting declines in transmission and distribution revenues. At the same time, an electric utility retains

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1 the obligation to provide reliable delivery service, it must continue to invest in its
2 rate base, and it must comply with mandates to promote conservation, without the
3 recovery of lost margins on reduced consumption, except on a prospective basis in
4 future rate cases. The Company is obligated to comply with the conservation
5 requirements of Act 129, which creates significant risks for Duquesne Light.
6 Without the ability to recover lost margins on reduced consumption between rate
7 cases, the Company faces a significant barrier to achieving its authorized return.
8 Even with the availability of the fully forecast test year, lost margins due to
9 successful conservation cannot be recovered beyond the fully forecast test year used
10 to set rates.

11 The obligation to serve also represents a key risk factor for the local
12 delivery of electricity. The risks facing the electric utilities are clearly different
13 from those that existed in the past. Investors generally are risk-averse, and with
14 increased uncertainty will require compensation for higher risk.

15
16 **Q. Please discuss further the risks for electric utilities.**

17 A. In the new environment, competitive issues have or will develop due to the
18 convergence of energy sources and bypass arising from self-generation or
19 distributed-generation. Regulatory risks include the overall framework of
20 ratesetting, cost allocation, and rate design issues, and the level of return that will be
21 allowed. With increased emphasis on market-determined prices and open access of
22 the transmission network, a new dimension exists in the electric utility business. A
23 pricing structure restricted by regulation diminishes management's ability to adjust

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1 its business strategy quickly to changing market conditions to respond to
2 broadening competition.

3

4 **Q. Are there other specific risk issues facing the Company?**

5 A. Yes. Energy deliveries to commercial and industrial customers, which represent
6 70% of the Company's energy deliveries, are usually thought to be of higher risk
7 than to residential customers. Success in this segment of the Company's market is
8 subject to the business cycle and pressures from alternative providers. Moreover,
9 external factors also can influence deliveries to these customers, which face
10 competitive pressure on their own operations from other facilities outside the
11 utility's service territory.

12 In addition, significant efforts to encourage conservation pursuant to the
13 requirements of Act 129 create a risk that Duquesne Light's distribution revenues
14 will likely decline between base rate cases.

15

16 **Q. Please indicate how the Company's risk profile is affected by its construction
17 program.**

18 A. The Company is faced with the requirement to undertake investment to maintain
19 and upgrade existing facilities in its service territory and to meet growth. Over the
20 next three years (i.e., 2013 through 2015), the Company's total capital expenditures
21 are expected to be approximately \$636 million. These expenditures will represent
22 approximately 27% ($\$636 \text{ million} \div \$2,328.5 \text{ million}$) of the net utility plant at
23 December 31, 2012. During 2012, 2013 and 2014, the internally generated funds as

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1 a percent of its capital expenditures have and will be 83.7%, 41.8%, and 49.0%, or
2 an average of 58.2%. The remainder will require attracting new capital from
3 investors. A fair rate of return for the Company represents a key to a financial
4 profile that will provide the Company with the ability to raise the capital, in all
5 market conditions to meet its needs, and to satisfy investor requirements. In the
6 situation where additional capital is required, as shown by the construction
7 expenditures indicated above, the regulatory process must establish a return on
8 equity that provides a reasonable opportunity for the Company to actually achieve
9 its cost of capital. This is especially important for Duquesne Light due to its
10 smaller size and the magnitude of its construction program.

FUNDAMENTAL RISK ANALYSIS

11
12
13 **Q. Is it necessary to conduct a fundamental risk analysis to provide a framework**
14 **for a determination of a utility's cost of equity?**

15 A. Yes. It is necessary to establish a company's relative risk position within its
16 industry through a fundamental analysis of various quantitative and qualitative
17 factors that bear upon investors' assessment of overall risk. The qualitative factors
18 that bear upon the Company's risk have already been discussed. The quantitative
19 risk analysis follows. The items that influence investors' evaluation of risk and
20 their required returns were described above. For this purpose, I compared
21 Duquesne Light to the S&P Public Utilities, an industry-wide proxy consisting of
22 various regulated businesses, and to the Electric Group.

23

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1 **Q. What are the components of the S&P Public Utilities?**

2 A. The S&P Public Utilities is a widely recognized index that is comprised of electric
3 power and natural gas companies. These companies are identified on page 3 of
4 Schedule 4.

5
6 **Q. What criteria did you employ to assemble the Electric Group?**

7 A. The Electric Group companies have the following common characteristics: (i) their
8 stock is traded on the New York Stock Exchange, (ii) they are listed in the “Electric
9 Utility (East)” section of The Value Line Investment Survey, and (iii) they are not
10 currently the target of a publicly-announced merger or acquisition. It would be
11 inappropriate to include a company that is a target of a takeover in a proxy group
12 because the stock price of that company usually does not reflect its underlying
13 fundamentals.

14
15 **Q. Why have you included integrated companies in your Electric Group that have
16 generating assets?**

17 A. Because there are an insufficient number of delivery only electric companies. For
18 the most part, the integrated companies that are members of the Electric Group have
19 generation that is subject to cost of service regulation. When analyzing the business
20 segments for the electric utilities, generation assets should be treated the same as
21 other regulated assets in the case where cost of service regulation applies in
22 jurisdictions that have not restructured their electric business. This treatment is
23 distinct from non-regulated merchant generation that would be classified as part of

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1 non-regulated, competitive investments. For the purpose of narrowing the proxy
2 group to a manageable number and to align the relative business risks, the proxy
3 group candidates have more than 60% of their identifiable assets devoted to
4 regulated utility operations. The companies that are included in the proxy group
5 consist of: Consolidated Edison, Inc., Dominion Resources, Inc., Duke Energy
6 Corp., FirstEnergy Corp., Northeast Utilities, Pepco Holdings Inc., SCANA Corp.,
7 Southern Company, TECO Energy, Inc. and UIL Holdings.

8
9 **Q. Is knowledge of a utility's bond rating an important factor in assessing its risk**
10 **and cost of capital?**

11 A. Yes. Knowledge of a company's credit quality rating is important because the cost
12 of each type of capital is directly related to the associated risk of the firm. So while
13 a company's credit quality risk is shown directly by the rating and yield on its
14 bonds, these relative risk assessments also bear upon the cost of equity. This is
15 because a firm's cost of equity is represented by its borrowing cost plus
16 compensation to recognize the higher risk of an equity investment compared to
17 debt.

18
19 **Q. How do the bond ratings compare for Duquesne Light, the Electric Group, and**
20 **the S&P Public Utilities?**

21 A. For Duquesne Light, its Long Term ("LT") issuer rating is Baa1 from Moody's
22 Investors Service ("Moody's") and the corporate credit rating ("CCR") is BBB-
23 from Standard & Poor's Corporation ("S&P"). The LT issuer rating by Moody's

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1 and the CCR designation by S&P focuses upon the credit quality of the issuer of the
2 debt, rather than upon the debt obligation itself. The testimony of Mr. James
3 Milligan, the Company's Manager of Treasury Operations, provides further detail
4 on the Company's credit ratings, and in particular the upgrade of the Company's
5 rating by Moody's on March 5, 2013. For the Electric Group, the average LT issuer
6 rating is Baa1 from Moody's and the average CCR is BBB+ from S&P. For the
7 S&P Public Utilities, the average composite rating is Baa1 by Moody's and BBB+
8 by S&P. Many of the financial indicators that I will subsequently discuss are
9 considered during the rating process. In this regard, the Company's credit quality is
10 weaker in comparison with the Electric Group.

11
12 **Q. How do the financial data compare for Duquesne Light, the Electric Group,
13 and the S&P Public Utilities?**

14 A. The broad categories of financial data that I will discuss are shown on Schedules 2,
15 3, and 4. The data cover the five-year period 2008-2012. The important categories
16 of relative risk may be summarized as follows:

17 Size. In terms of capitalization, Duquesne Light is smaller than the average
18 size of the Electric Group and the S&P Public Utilities. All other things being
19 equal, a smaller company is riskier than a larger company because a given change
20 in revenue and expense has a proportionately greater impact on a small firm. In
21 addition, Duquesne Light serves a concentrated geographic area, and in particular,
22 an urban area that is often more costly to service. As I will demonstrate later, the
23 size of a firm can impact its cost of equity. This is the case for Duquesne Light.

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1 Market Ratios. Market-based financial ratios provide a partial indication of
2 the investor-required cost of equity. If all other factors are equal, investors will
3 require a higher rate of return on equity for companies that exhibit greater risk, in
4 order to compensate for that risk. That is to say, a firm that investors perceive to
5 have higher risks will experience a lower price per share in relation to expected
6 earnings.²

7 There are no market ratios available for Duquesne Light because the
8 Company's stock is not traded. The five-year average price-earnings multiple for
9 the Electric Group was similar to that of the S&P Public Utilities. The five-year
10 average dividend yield was higher for the Electric Group, as compared to the S&P
11 Public Utilities. The average market-to-book ratio for the Electric Group was
12 similar to the S&P Public Utilities.

13 Common Equity Ratio. The level of financial risk is measured by the
14 proportion of long-term debt and other senior capital that is contained in a
15 company's capitalization. Financial risk is also analyzed by comparing common
16 equity ratios (the complement of the ratio of debt and other senior capital). That is
17 to say, a firm with a high common equity ratio has lower financial risk, while a firm
18 with a low common equity ratio has higher financial risk. The five-year average
19 common equity ratios, based on permanent capital, were 61.4% for Duquesne Light,
20 45.1% for the Electric Group, and 45.0% for the S&P Public Utilities. The average
21 common equity ratio in 2012 was 46.0% for the Electric Group and reflected a

²For example, two otherwise similarly situated firms each reporting \$1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

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1 range of common equity ratios from 37.1% to 53.2%. The common equity ratio
2 proposed by Duquesne Light in this case of 51.94%, is clearly within the range of
3 common equity ratios for the Electric Group.

4 Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's
5 earned returns signifies relatively greater levels of risk, as shown by the coefficient
6 of variation (standard deviation ÷ mean) of the rate of return on book common
7 equity. The higher the coefficients of variation, the greater degree of variability.
8 For the five-year period, the coefficients of variation were 0.371 (3.6% ÷ 9.7%) for
9 Duquesne Light, 0.104 (1.0% ÷ 9.6%) for the Electric Group, and 0.104 (1.1% ÷
10 10.6%) for the S&P Public Utilities. The earnings variability for Duquesne Light
11 was significantly higher than the Electric Group and the S&P Public Utilities,
12 indicating that the Company has higher risk.

13 Operating Ratios. I have also compared operating ratios (the percentage of
14 revenues consumed by operating expense, depreciation and taxes other than income
15 taxes).³ The complement of the operating ratio is the operating margin which
16 provides a measure of profitability. The higher the operating ratio, the lower the
17 operating margin. The five-year average operating ratios were 76.6% for Duquesne
18 Light, 82.8% for the Electric Group, and 82.3% for the S&P Public Utilities. The
19 operating risk for Duquesne Light is below that for to the Electric Group, and the
20 S&P Public Utilities, thus indicating lower risk.

21 Coverage. The level of fixed charge coverage (i.e., the multiple by which

³The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

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1 available earnings cover fixed charges, such as interest expense) provides an
2 indication of the earnings protection for creditors. Higher levels of coverage, and
3 hence earnings protection for fixed charges, are usually associated with superior
4 grades of creditworthiness. The five-year average interest coverage (excluding
5 Allowance for Funds Used During Construction (“AFUDC”)) was 6.25 times for
6 Duquesne Light, 3.06 times for the Electric Group, and 3.12 times for the S&P
7 Public Utilities. The higher interest coverage for Duquesne Light can be traced to
8 its lower proportion of debt in its capital structure.

9 Quality of Earnings. Measures of earnings quality usually are revealed by
10 the percentage of AFUDC related to income available for common equity, the
11 effective income tax rate, and other cost deferrals. These measures of earnings
12 quality usually influence a firm’s internally generated funds because poor quality of
13 earnings would not generate high levels of cash flow. Quality of earnings has not
14 been a significant concern for Duquesne Light, the Electric Group, and the S&P
15 Public Utilities.

16 Internally Generated Funds. Internally generated funds (“IGF”) provide an
17 important source of new investment capital for a utility and represent a key measure
18 of credit strength. Historically, the five-year average percentage of IGF to capital
19 expenditures was 64.1% for Duquesne Light, 77.6% for the Electric Group, and
20 91.1% for the S&P Public Utilities. The IGF to construction for Duquesne Light
21 points to higher risk for the Company. This situation is expected to persist because
22 the Company’s IGF to construction expenditures are expected to be just 54.5% as
23 an average for the next three years, as noted above.

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1 Betas. The financial data that I have been discussing relate primarily to
2 company-specific risks. Market risk for firms with publicly-traded stock is
3 measured by beta coefficients. Beta coefficients attempt to identify systematic risk,
4 i.e., the risk associated with changes in the overall market for common
5 equities.⁴Value Line publishes such a statistical measure of a stock's relative
6 historical volatility to the rest of the market. A comparison of market risk is shown
7 by the Value Line beta of .68 as the average for the Electric Group (see page 2 of
8 Schedule 3), and .75 as the average for the S&P Public Utilities (see page 3 of
9 Schedule 4).

10

11 **Q. Please summarize your risk evaluation of the Company and the Electric**
12 **Group.**

13 A. The risk of Duquesne Light parallels that of the Electric Group in certain respects.
14 However, Duquesne Light is much smaller than the average size of the Electric
15 Group, its earnings are much more variable, and its IGF to construction has been
16 lower. The Company's higher common equity ratio provides a partial offset to the
17 other high risk factors for the Company. On balance, the risk factors average out,
18 indicating that the cost of equity for the Electric Group would provide a reasonable
19 basis for measuring the Company's cost of equity, provided that the rate of return

⁴Beta is a relative measure of the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index. The "Beta coefficient" is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. The betas are adjusted for their long-term tendency to converge toward 1.00. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

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1 determination reflects the Companies' common equity ratio. As such, the results
2 from the Electric Group provide a reasonable measure of the Company's cost of
3 equity.

CAPITAL STRUCTURE RATIOS

4
5
6 **Q. Please explain the selection of capital structure ratios for Duquesne Light.**

7 A. In the situation where the operating public utility raises its own long-term debt and
8 preferred stock directly in the capital markets, as is the case for Duquesne Light, it
9 is proper to employ the capital structure ratios and senior capital cost rates of the
10 regulated public utility for rate of return purposes. Furthermore, consistency
11 requires that the embedded cost rate of the Company's senior securities also be
12 employed. This procedure is consistent with the procedures used by the
13 Commission in prior rate cases.

14
15 **Q. Does Schedule 5 provide the capitalization and capital structure ratios you
16 have considered?**

17 A. Yes. Schedule 5 presents Duquesne Light's capitalization and related capital
18 structure at March 31, 2013, the end of the historic test year. Also shown on
19 Schedule 5 is the Duquesne Light's estimated capital structure at March 31, 2014,
20 which is the end of the future test year, and at April 30, 2015, which is the end of
21 the fully forecast test year. During the future test year, the changes in the
22 Company's capital structure are projected to include: (i) the maturity of two issues
23 of debt in the aggregate amount of \$150,000,000; (ii) the issuance of new long-term

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1 debt in the amount of \$275,000,000, (iii) the issuance of \$50,000,000 of
2 intercompany loans; and (iv) the Company's projection of retained earnings growth.

3 Also reflected on Schedule 5 are several adjustments to the capital structure.
4 The first adjustment is related to the call premiums on the early redemption or
5 refunding of high cost long-term debt. The second adjustment relates to
6 accumulated Other Comprehensive Income ("OCI").

7
8 **Q. Please describe the first adjustment.**

9 A. I have adjusted the principal amounts of long-term debt to exclude the amounts
10 used to finance premiums on the early redemption of high cost long-term debt. To
11 do otherwise would deny Duquesne Light the full return on the premiums paid to
12 redeem this high cost capital since additional amounts of capital were issued to pay
13 the call premiums. The amounts issued to finance the call premiums do not increase
14 the Company's rate base. That is to say, no additional rate base was created through
15 additional debt that was necessary to finance these transactions, and therefore an
16 adjustment is required to provide the return necessary to service the additional
17 capital. Hence, Duquesne Light's long-term debt amounts must be adjusted for this
18 disparity in order that the return necessary to service the capitalization is produced
19 from rate base investment times the overall rate of return.

20 This adjustment is equitable since customers receive the cost savings
21 resulting from these refinancing in the form of a lower overall rate of return, and
22 Duquesne Light recovers all costs incurred in providing these benefits to the
23 customers. To accomplish these savings, the Company paid the debt holders a

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1 premium for surrendering its securities prior to maturity. These premiums
2 represented an investment made by Duquesne Light to reduce its overall cost of
3 capital. Since the reduced interest costs are reflected in the lower cost of capital to
4 ratepayers, it is appropriate that the Company recover the costs incurred to produce
5 these savings. This includes both a return of and return on the unamortized
6 premiums. Adjusting the principal amounts in the capital structure provides a
7 return on the premium as a part of the embedded cost rates of capital.

8
9 **Q. Please explain the second adjustment.**

10 A. The accumulated OCI must be eliminated from the capital structure for ratesetting
11 purposes. OCI arises from a variety of sources, including: minimum pension
12 liability (“MPL”), foreign currency hedges, unrealized gains and losses on
13 securities available for sale, interest rate swaps, and other cash flow hedges. The
14 accumulated OCI must be excluded from the common equity because it does not
15 represent funds that the Company has used to finance its rate base.

16
17 **Q. What capital structure ratios do you recommend be adopted for rate of return
18 purposes in this proceeding?**

19 A. Since ratemaking is prospective, the rate of return should reflect known changes
20 that will occur during the course of the future test year, at a minimum, and should
21 consider conditions that will exist during the period of time the proposed rates will
22 be effective. As a result, I will adopt the Company's fully forecast test year-end
23 capital structure ratios of 42.95% long-term debt, 5.11% preferred stock, and

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1 51.94% common equity. These capital structure ratios are the best approximation
 2 of the mix of capital the Company will employ to finance its rate base during the
 3 period new rates are in effect. Short-term debt has been excluded from these ratios
 4 because the Commission's approved practice is to assign short-term debt to CWIP
 5 in the calculation of AFUDC. Hence, the cost of short-term debt is capitalized
 6 through AFUDC and plays no role in setting base rates. In each instance, the short-
 7 term debt shown on Schedule 5 is less than the associated CWIP balances, e.g. \$168
 8 million at March 31, 2013, \$222 million at March 31, 2014, and \$149 million at
 9 April 30, 2015. This means that all short-term debt is being used by the Company
 10 to finance CWIP.

11 As shown by the forecasts of the common equity ratios for the Electric
 12 Group, the Company's future test year common equity ratio is within the range
 13 expected by investors. This is revealed by the Value Line forecasts shown below.

Company	2013	2014	2016-18
Consolidated Edison	52.5%	53.0%	53.0%
Dominion Resources	39.5%	40.5%	42.0%
Duke Energy	51.5%	50.5%	48.0%
First Energy	45.5%	45.0%	44.0%
Northeast Utilities	53.0%	52.5%	52.0%
PEPCO Holdings	50.0%	50.0%	50.0%
SCANA	47.0%	46.5%	47.5%
Southern Company	45.5%	44.0%	43.5%
TECO Energy	44.0%	46.0%	45.0%
UIL Holdings	43.0%	44.0%	45.5%
Average	<u>47.2%</u>	<u>47.2%</u>	<u>47.1%</u>

The Value Line Investment Survey, February 22, 2013

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We can see that the Company's 51.94% common equity ratio for the fully forecast test year is well within the range indicated above, where common equity ratios up to 53.0% are indicated.

COST OF SENIOR CAPITAL

1

2 **Q. What cost rate have you assigned to the debt portion of Duquesne Light's**
3 **capital structure?**

4 A. Consistency with the capital structure ratios for the Company requires that the
5 embedded cost rates of Duquesne Light's senior securities must also be employed.
6 This procedure is consistent with the ratesetting procedures used by the
7 Commission in prior Duquesne Light rate cases. The determination of the cost of
8 debt is essentially an arithmetic exercise. This is due to the fact that the Company
9 has contracted for the use of this capital for a specific period of time at a specified
10 cost rate. As shown on page 1 of Schedule 6, the actual embedded cost rate of long-
11 term debt was 5.50% at March 31, 2013. By March 31, 2014, the embedded debt
12 cost rate is estimated to be 5.29%, as shown on page 2 of Schedule 6. Finally, the
13 embedded cost of debt is projected to be 5.18% at the end of the fully forecast test
14 year end April 30, 2015. The cost of long-term debt that is scheduled to be issued
15 on November 1, 2013 is estimated to be 5.10%, with an effective cost of 5.20%
16 after issuance expenses. The new intercompany loans are expected to have an
17 interest rate of 4.15%. The interest rate on the intercompany loans was developed
18 based on the terms of the affiliated interest agreement approved by the Commission.

19 The Company received three indicative rates from three separate investment banks

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1 and used the lowest of the three rates to arrive at the 4.15% rate on the
2 intercompany loans. The details leading to the development of the individual
3 effective cost rates for each series of long-term debt, using the cost rate to maturity
4 technique, are shown on page 4 of Schedule 6. The cost rate, or yield to maturity
5 (“ytm”), used on page 4 of Schedule 6 is the rate of discount that equates the
6 present value of all future interest and principal payments with the net proceeds of
7 the bond.

8 I will adopt the 5.18% embedded cost of long-term debt at April 30, 2015,
9 as shown on page 3 of Schedule 6. This rate is related to the amount of long-term
10 debt shown on Schedule 5 which provides the basis for the 42.95% long-term debt
11 ratio. In my calculation of the embedded cost of long-term debt, I have recognized
12 the costs associated with the Company's early redemption of high cost debt. As
13 previously explained, it is necessary to compensate Duquesne Light for the costs
14 incurred to lower the embedded debt cost rate which reduces the cost of capital
15 charged to ratepayers. The amortization of gains on long-term debt has also been
16 reflected as part of these costs during the historic test year. Subsequent thereto, the
17 amortization of the gains ended.

18
19 **Q. What preferred stock cost rate have you calculated for the Company?**

20 A. For the future test year, I have calculated a 5.89% embedded cost of preferred stock
21 as shown on page 3 of Schedule 7. I will adopt the 5.89% embedded cost of
22 preferred stock, which is related to the 5.11% preferred stock ratio shown on
23 Schedule 5. The details regarding the individual cost rates for each series of

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1 preferred stock are provided on page 4 of Schedule 7.

2

3

COST OF EQUITY – GENERAL APPROACH

4 **Q. Please describe the process you employed to determine the cost of equity for**
5 **the Company.**

6 A. Although my fundamental financial analysis provides the required framework to
7 establish the risk relationships among the Company, the Electric Group, and the
8 S&P Public Utilities, the cost of equity must be measured by standard financial
9 models that I identified above. Differences in risk traits, such as size, business
10 diversification, geographical diversity, regulatory policy, financial leverage, and
11 bond ratings must be considered when analyzing the cost of equity.

12 It is also important to reiterate that no one method or model of the cost of
13 equity can be applied in an isolated manner. Rather, informed judgment must be
14 used to take into consideration the relative risk traits of the firm. It is for this reason
15 that I have used more than one method to measure the Company's cost of equity.
16 As I describe below, each of the methods used to measure the cost of equity
17 contains certain incomplete and/or overly restrictive assumptions and constraints
18 that are not optimal. Therefore, I favor considering the results from a variety of
19 methods. In this regard, I applied each of the methods with data taken from the
20 Electric Group and took into account the exemplary performance of the Company's
21 management to arrive at a cost of equity of 11.25%.

22

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DISCOUNTED CASH FLOW

1

2 **Q. Please describe your use of the Discounted Cash Flow approach to determine**
3 **the cost of equity.**

4 A. The DCF model seeks to explain the value of an asset as the present value of future
5 expected cash flows discounted at the appropriate risk-adjusted rate of return. In its
6 simplest form, the DCF return on common stock consists of a current cash
7 (dividend) yield and future price appreciation (growth) of the investment. The
8 dividend discount equation is the familiar DCF valuation model and assumes future
9 dividends are systematically related to one another by a constant growth rate. The
10 DCF formula is derived from the standard valuation model: $P = D/(k-g)$, where $P =$
11 price, $D =$ dividend, $k =$ the cost of equity, and $g =$ growth in cash flows. By
12 rearranging the terms, we obtain the familiar DCF equation: $k = D/P + g$. All of the
13 terms in the DCF equation represent investors' assessment of expected future cash
14 flows that they will receive in relation to the value that they set for a share of stock
15 (P). The DCF equation is sometimes referred to as the "Gordon" model.⁵ My DCF
16 results are provided on page 2 of Schedule 1 for the Electric Group. The DCF
17 return is 10.78%.

18 Among other limitations of the model, there is a certain element of
19 circularity in the DCF method when applied in rate cases. This is because
20 investors' expectations for the future depend upon regulatory decisions. In turn,
21 when regulators depend upon the DCF model to set the cost of equity, they rely

⁵ Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950's, J. B. Williams explicated the DCF model in its present form nearly two decades earlier.

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1 upon investor expectations that include an assessment of how regulators will decide
2 rate cases. Due to this circularity, the DCF model may not fully reflect the true risk
3 of a utility.

4
5 **Q. Please explain the dividend yield component of a DCF analysis.**

6 A. The DCF methodology requires the use of an expected dividend yield to establish
7 the investor-required cost of equity. The monthly dividend yields for the twelve
8 months ended April 2013 are shown on Schedule 8 and reflect an adjustment to the
9 month-end prices to capture the buildup of the dividend in the price that has
10 occurred since the last ex-dividend date (i.e., the date by which a shareholder must
11 own the shares to be entitled to the dividend payment – usually about two to three
12 weeks prior to the actual payment).

13 For the twelve months ended April 2013, the average dividend yield was
14 4.49% for the Electric Group based upon a calculation using annualized dividend
15 payments and adjusted month-end stock prices. The dividend yields for the more
16 recent six- and three-month periods were 4.49% and 4.34%, respectively. I have
17 used, for the purpose of the DCF model, the six-month average dividend yield of
18 4.49% for the Electric Group. The use of this dividend yield will reflect current
19 capital costs, while avoiding spot yields. For the purpose of a DCF calculation, the
20 average dividend yield must be adjusted to reflect the prospective nature of the
21 dividend payments, i.e., the higher expected dividends for the future. Recall that
22 the DCF is an expectational model that must reflect investor anticipated cash flows
23 for the Electric Group. I have adjusted the six-month average dividend yield in

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1 three different, but generally accepted, manners and used the average of the three
2 adjusted values as calculated in the lower panel of data presented on Schedule 8.
3 That adjusted dividend yield is 4.63% for the Electric Group.
4

5 **Q. Please explain the underlying factors that influence investors' growth**
6 **expectations.**

7 A. As noted previously, investors are interested principally in the future growth of their
8 investment (i.e., the price per share of the stock). Future earnings per share growth
9 represent the DCF model's primary focus because under the constant price-earnings
10 multiple assumption of the model, the price per share of stock will grow at the same
11 rate as earnings per share. In conducting a growth rate analysis, a wide variety of
12 variables can be considered when reaching a consensus of prospective growth,
13 including: earnings, dividends, book value, and cash flow stated on a per share
14 basis. Historical values for these variables can be considered, as well as analysts'
15 forecasts that are widely available to investors. A fundamental growth rate analysis
16 is sometimes represented by the internal growth ("b x r"), where "r" represents the
17 expected rate of return on common equity and "b" is the retention rate that consists
18 of the fraction of earnings that are not paid out as dividends. To be complete, the
19 internal growth rate should be modified to account for sales of new common stock -
20 - this is called external growth ("s x v"), where "s" represents the new common
21 shares expected to be issued by a firm and "v" represents the value that accrues to
22 existing shareholders from selling stock at a price different from book value.

23 Fundamental growth, which combines internal and external growth, provides an

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1 explanation of the factors that cause book value per share to grow over time.

2 Growth also can be expressed in multiple stages. This expression of growth
3 consists of an initial “growth” stage where a firm enjoys rapidly expanding markets,
4 high profit margins, and abnormally high growth in earnings per share. Thereafter,
5 a firm enters a “transition” stage where fewer technological advances and increased
6 product saturation begin to reduce the growth rate and profit margins come under
7 pressure. During the “transition” phase, investment opportunities begin to mature,
8 capital requirements decline, and a firm begins to pay out a larger percentage of
9 earnings to shareholders. Finally, the mature or “steady-state” stage is reached
10 when a firm’s earnings growth, payout ratio, and return on equity stabilizes at levels
11 where they remain for the life of a firm. The three stages of growth assume a step-
12 down of high initial growth to lower sustainable growth. Even if these three stages
13 of growth can be envisioned for a firm, the third “steady-state” growth stage, which
14 is assumed to remain fixed in perpetuity, represents an unrealistic expectation
15 because the three stages of growth can be repeated. That is to say, the stages can be
16 repeated where growth for a firm ramps-up and ramps-down in cycles over time.

17
18 **Q. What investor-expected growth rate is appropriate in a DCF calculation?**

19 A. Investors consider both company-specific variables and overall market sentiment
20 (i.e., level of inflation rates, interest rates, economic conditions, etc.) when
21 balancing their capital gains expectations with their dividend yield requirements. I
22 follow an approach that is not rigidly formatted because investors are not influenced
23 by a single set of company-specific variables weighted in a formulaic manner.

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1 Therefore, in my opinion, all relevant growth rate indicators using a variety of
2 techniques must be evaluated when formulating a judgment of investor-expected
3 growth.

4
5 **Q. What data for the proxy group did you review in your growth rate analysis?**

6 A. I considered the growth in the financial variables shown on Schedules 9 and 10.
7 The historical growth rates were taken from the Value Line publication that
8 provides these data. As shown on Schedule 9, the historical growth of earnings per
9 share was in the range of 1.35% to 5.00% for the Electric Group.

10 Schedule 10 provides projected earnings per share growth rates taken from
11 analysts' forecasts compiled by IBES/First Call, Zacks, Morningstar and Value
12 Line. IBES/First Call, Zacks and Morningstar represent reliable authorities of
13 projected growth upon which investors rely. The IBES/First Call, Zacks and
14 Morningstar growth rates are consensus forecasts taken from a survey of analysts
15 that make projections of growth for these companies. The IBES/First Call, Zacks
16 and Morningstar estimates are obtained from the Internet and are widely available
17 to investors. First Call probably is quoted most frequently in the financial press
18 when reporting on earnings forecasts. The Value Line forecasts also are widely
19 available to investors and can be obtained by subscription or free-of-charge at most
20 public and collegiate libraries. The IBES/First Call and Zacks forecasts are limited
21 to earnings per share growth, while Value Line makes projections of other financial
22 variables. The Value Line forecasts of dividends per share, book value per share,
23 and cash flow per share have also been included on Schedule 10 for the Electric

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1 Group.

2

3 **Q. What specific evidence have you considered in the DCF growth analysis?**

4 A. As to the five-year forecast growth rates, Schedule 10 indicates that the projected
5 earnings per share growth rates for the Electric Group are 5.01% by IBES/First Call
6 4.21% by Zacks, 5.65% by Morningstar, and 4.45% by Value Line. The Value
7 Line projections indicate that earnings per share for the Electric Group will grow
8 prospectively at a more rapid rate (i.e., 4.45%) than the dividends per share (i.e.,
9 3.38%), which translates into a declining dividend payout ratio for the future. As
10 noted earlier, with the constant price-earnings multiple assumption of the DCF
11 model, growth for these companies will occur at the higher earnings per share
12 growth rate, thus producing the capital gains yield expected by investors.

13

14 **Q. What conclusion have you drawn from these data regarding the applicable**
15 **growth rate to be used in the DCF model?**

16 A. A variety of factors should be examined to reach a conclusion on the DCF growth
17 rate. However, certain growth rate variables should be emphasized when reaching a
18 conclusion on an appropriate growth rate. First, historical and projected earnings
19 per share, dividends per share, book value per share, cash flow per share, and
20 retention growth represent indicators that could be used to provide an assessment of
21 investor growth expectations for a firm. However, although history cannot be
22 ignored, it cannot receive primary emphasis. This is because an analyst, when
23 developing a forecast of future earnings growth, would first apprise himself/herself

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1 of the historical performance of a company. Hence, there is no need to count
2 historical growth rates separately, because historical performance already is
3 reflected in analysts' forecasts. Second, from the various alternative measures of
4 growth identified above, earnings per share should receive greatest emphasis.
5 Earnings per share growth is the primary determinant of investors' expectations
6 regarding their total returns in the stock market. This is because the capital gains
7 yield (i.e., price appreciation) will track earnings growth with a constant price
8 earnings multiple (a key assumption of the DCF model). Moreover, earnings per
9 share (derived from net income) are the source of dividend payments, and are the
10 primary driver of retention growth and its surrogate, i.e., book value per share
11 growth. As such, under these circumstances, greater emphasis must be placed upon
12 projected earnings per share growth. In this regard, it is worthwhile to note that
13 Professor Myron Gordon, the foremost proponent of the DCF model in rate cases,
14 concluded that the best measure of growth in the DCF model is a forecast of
15 earnings per share growth.⁶ Hence, to follow Professor Gordon's findings,
16 projections of earnings per share growth, such as those published by IBES/First
17 Call, Zacks, Morningstar and Value Line, represent a reasonable assessment of
18 investor expectations.

19 The forecasts of earnings per share growth, as shown on Schedule 10,
20 provide a range of growth rates of 4.21% to 5.65%. Although the DCF growth rates
21 cannot be established solely with a mathematical formulation, it is my opinion that

⁶ Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

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1 an investor-expected growth rate of 5.50% is within the array of earnings per share
2 growth rates shown by the analysts' forecasts. The growth rate that I determined
3 for the DCF analysis is reflective of growth that is associated with improving
4 business conditions. The stellar performance of the stock market in 2013 points to
5 an improving economy, as it is one of the leading economic indicators compiled by
6 The Conference Board. In fact, the Leading Economic Index, whose financial
7 components include the stock market, has increased in five of the last six months.
8 In addition, "the strengths among the leading indicators have become more
9 widespread in recent months," said The Conference Board.⁷ The Value Line
10 forecast of dividend per share growth is inadequate in this regard due to the
11 forecasted decline in the dividend payout ratio.

12
13 **Q. Are the dividend yield and growth components of the DCF adequate to explain**
14 **the rate of return on common equity when it is used in the calculation of the**
15 **weighted average cost of capital?**

16 A. Only if the capital structure ratios are measured with the market value of debt and
17 equity. In the case of the Electric Group, those capital structure ratios are 47.28%
18 long-term debt, 0.31% preferred stock, and 52.42% common equity, as shown on
19 Schedule 11. If book values are used to compute the capital structure ratios, as is
20 the customary ratemaking practice in Pennsylvania, then an adjustment is required.

21

⁷ The Conference Board U.S. Business Cycle Indicators -The Conference Board Leading Economic Index (LEI) for the U.S. and Related Composite Economic Indexes for February 2013 [Press Release]. Retrieved from <http://www.conference-board.org/data/bci.cfm> dated March 21, 2013

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1 **Q. Please explain why.**

2 A. If regulators use the results of the DCF (which are based on the market price of the
3 stock of the companies analyzed) to compute the weighted average cost of capital
4 based on a book value capital structure used for ratesetting purposes, the utility will
5 not, by definition, recover its risk-adjusted capital cost. This is because market
6 valuations of equity are based on market value capital structures, which in general
7 have more equity and less debt and therefore reflect less risk than book value
8 capital structures (see Schedule 11 for the comparison). The utility's risk-adjusted
9 cost of equity will necessarily be lower with the less risky market value capital
10 structure than with the book value capital structure. The difference represents that
11 portion of the utility's cost of equity that it will not recover unless either the market
12 value cost of equity is applied to the utility's market value capital structure or it is
13 adjusted to reflect the higher risk associated with the book value capital structure.
14 By the same token, if the utility's market value capital structure is less than its book
15 value structure, then the utility's market cost of equity should be adjusted
16 downward to reflect the lower risk associated with the book value capital structure,
17 or else the utility will over-recover its total cost of equity.

18 This shortcoming of the DCF has persuaded the Pennsylvania Public Utility
19 Commission to adjust the DCF determined cost of equity upward to make the return
20 consistent with the book value capital structure. Specific adjustments to recognize
21 this risk difference were made in the following cases:

- 22 • January 10, 2002 for Pennsylvania-American Water Company in Docket No.
23 R-00016339 -- 60 basis points adjustment.
24 • August 1, 2002 for Philadelphia Suburban Water Company in Docket No.

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- 1 R-00016750 -- 80 basis points adjustment.
2 • January 29, 2004 for Pennsylvania-American Water Company in Docket No.
3 R-00038304 (affirmed by the Commonwealth Court on November 8, 2004) --
4 60 basis points adjustment.
5 • August 5, 2004 for Aqua Pennsylvania, Inc. in Docket No. R-00038805 -- 60
6 basis points adjustment.
7 • December 22, 2004 for PPL Electric Utilities Corporation in Docket No. R-
8 00049255 -- 45 basis points adjustment.
9 • February 8, 2007 for PPL Gas Utilities Corporation in Docket No. R-00061398
10 -- 70 basis points adjustment.

11
12 In order to make the DCF results relevant to the capitalization measured at book
13 value (as is done for rate setting purposes), the market-derived cost rate cannot be
14 used without modification.

15

16 **Q. Is your leverage adjustment dependent upon the market valuation or book**
17 **valuation from an investor's perspective?**

18 A. The only perspective that is important to investors is the return that they can realize
19 on the market value of their investment. As I have measured the DCF, the simple
20 yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that
21 an investor is willing to pay for a share of stock. The need for the leverage
22 adjustment arises when the results of the DCF model (k) are to be applied to a
23 capital structure that is different than indicated by the market price (P). From the
24 market perspective, the financial risk of the Electric Group is accurately measured
25 by the capital structure ratios calculated from the market capitalization of a firm. If
26 the ratesetting process utilized the market capitalization ratios, then no additional
27 analysis or adjustment would be required, and the simple yield (D/P) plus growth
28 (g) components of the DCF would satisfy the financial risk associated with the

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1 market value of the equity capitalization. Because the ratesetting process uses a
2 different set of ratios calculated from the book value capitalization, then further
3 analysis is required to synchronize the financial risk of the book capitalization with
4 the required return on the book value of the equity. This adjustment is developed
5 through precise mathematical calculations, using well recognized analytical
6 procedures that are widely accepted in the financial literature. To arrive at that
7 return, the rate of return on common equity is the unleveraged cost of capital (or
8 equity return at 100% equity) plus one or more terms reflecting the increase in
9 financial risk resulting from the use of leverage in the capital structure. The
10 calculations presented in the lower panel of data shown on Schedule 11, under the
11 heading "M&M," provides a return of 7.88% when applicable to a capital structure
12 with 100% common equity.

13

14 **Q. How is the DCF-determined cost of equity adjusted for the financial risk**
15 **associated with the book value of the capitalization?**

16 A. In pioneering work, Nobel laureates Modigliani and Miller developed several
17 theories about the role of leverage in a firm's capital structure. As part of that work,
18 Modigliani and Miller established that, as the borrowing of a firm increases, the
19 expected return on stockholders' equity also increases. This principle is
20 incorporated into my leverage adjustment, which recognizes that the expected
21 return on equity increases to reflect the increased risk associated with the higher
22 financial leverage shown by the book value capital structure, as compared to the
23 market value capital structure that contains lower financial risk. Modigliani and

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1 Miller proposed several approaches to quantify the equity return associated with
2 various degrees of debt leverage in a firm's capital structure. These formulas point
3 toward an increase in the equity return associated with the higher financial risk of
4 the book value capital structure. Simply stated, the leverage adjustment contains no
5 factor for a particular market-to-book ratio. It merely expresses the cost of equity
6 as the unleveraged return plus compensation for the additional risk of introducing
7 debt and/or preferred stock into the capital structure. There can be no dispute that a
8 firm's financial risk varies with the relative amount of leverage contained in its
9 capital structure.

10

11 **Q. Is the leverage adjustment that you propose designed to transform the market**
12 **return into one that is designed to produce a particular market-to-book ratio?**

13 A. No, it is not. The adjustment that I label as a "leverage adjustment" is merely a
14 convenient way of showing the amount that must be added to (or subtracted from)
15 the result of the simple DCF model (i.e., $D/P + g$), in the context of a return that
16 applies to the capital structure used in ratemaking, which is computed with book
17 value weights rather than market value weights, in order to arrive at the utility's
18 total cost of equity. I specify a separate factor, which I call the leverage adjustment,
19 but there is no need to do so other than providing identification for this factor. If I
20 expressed my return solely in the context of the book value weights that we use to
21 calculate the weighted average cost of capital, and ignore the familiar $D/P + g$
22 expression entirely, then there would be no separate element to reflect the financial
23 leverage change from market value to book value capitalization. As shown in the

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1 bottom panel of data on Schedule 11, the equity return applicable to the book value
2 common equity ratio is equal to 7.88%, which is the return for the Electric Group
3 applicable to its equity with no debt in its capital structure (i.e., the cost of capital is
4 equal to the cost of equity with a 100% equity ratio) plus 2.88% compensation for
5 having a 53.46% debt ratio, plus 0.02% for having a 0.45% preferred stock ratio.
6 The sum of the parts is 10.78% (7.88% + 2.88% + 0.02%) and there is no need to
7 even address the cost of equity in terms of $D/P + g$. To express this same return in
8 the context of the familiar DCF model, I summed the 4.63% dividend yield, the
9 5.50% growth rate, and the 0.65% leverage adjustment in order to arrive at the same
10 10.78% (4.63% + 5.50% + 0.65%) return. I know of no means to mathematically
11 solve for the 0.65% leverage adjustment by expressing it in the terms of any
12 particular relationship of market price to book value. The 0.65% adjustment is
13 merely a convenient way to compare the 10.78% return computed directly with the
14 Modigliani & Miller formulas to the 10.13% return generated by the DCF model
15 based on a market value capital structure. My point is that when we use a market-
16 determined cost of equity developed from the DCF model, it reflects a level of
17 financial risk that is different (in this case, lower) from the capital structure stated at
18 book value. This process has nothing to do with targeting any particular market-to-
19 book ratio.

20
21 **Q. Please provide the DCF return based upon your preceding discussion of**
22 **dividend yield, growth, and leverage.**

23 A. As explained previously, I have utilized a six-month average dividend yield

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1 ("D₁/P₀") adjusted in a forward-looking manner for my DCF calculation. This
2 dividend yield is used in conjunction with the growth rate ("g ") previously
3 developed. The DCF also includes the leverage modification ("lev.") required when
4 the book value equity ratio is used in determining the weighted average cost of
5 capital in the ratesetting process rather than the market value equity ratio related to
6 the price of stock.

	D_1/P_0	+	g	+	$lev.$	=	k
Electric Group	4.63%	+	5.50%	+	0.65%	=	10.78%

7 The DCF result shown above represents the simplified (i.e., Gordon) form of the
8 model that contains a constant growth assumption. I should reiterate, however, that
9 the DCF indicated cost rate provides an explanation of the rate of return on
10 common stock market prices without regard to the prospect of a change in the price-
11 earnings multiple. An assumption that there will be no change in the price-earnings
12 multiple is not supported by the realities of the equity market, because price-
13 earnings multiples do not remain constant. This is one of the constraints of this
14 model that makes it important to consider other model results when determining a
15 company's cost of equity.

RISK PREMIUM ANALYSIS

18 **Q. Please describe your use of the risk premium approach to determine the cost of**
19 **equity.**

20 **A. With the Risk Premium approach, the cost of equity capital is determined by**

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1 corporate bond yields plus a premium to account for the fact that common equity is
2 exposed to greater investment risk than debt capital. The result of my Risk
3 Premium study is shown on page 2 of Schedule 1. That result is 12.25%. As with
4 other models used to determine the cost of equity, the Risk Premium approach has
5 its limitations, including potential imprecision in the assessment of the future cost
6 of corporate debt and the measurement of the risk-adjusted common equity
7 premium.

8
9 **Q. What long-term public utility debt cost rate did you use in your risk premium**
10 **analysis?**

11 A. In my opinion, a 5.25% yield represents a reasonable estimate of the prospective
12 yield on long-term A-rated public utility bonds.

13
14 **Q. What forecasts of interest rates have you considered in your analysis?**

15 A. I have determined the prospective yield on A-rated public utility debt by using the
16 Blue Chip Financial Forecasts (“Blue Chip”) along with the spread in the yields that
17 I describe below. The Blue Chip is a reliable authority and contains consensus
18 forecasts of a variety of interest rates compiled from a panel of banking, brokerage,
19 and investment advisory services. In early 1999, Blue Chip stopped publishing
20 forecasts of yields on A-rated public utility bonds because the Federal Reserve
21 deleted these yields from its Statistical Release H.15. To independently project a
22 forecast of the yields on A-rated public utility bonds, I have combined the forecast
23 yields on long-term Treasury bonds published on May 1, 2013, and a yield spread

DIRECT TESTIMONY OF PAUL R. MOUL

1 of 1.50%, derived from historical data.

2

3 **Q. What historical data have you analyzed?**

4 A. I have analyzed the historical yields on the Moody's index of long-term public
5 utility debt and are shown on page 1 of Schedule 12. For the twelve months ended
6 April 2013, the average monthly yield on Moody's index of A-rated public utility
7 bonds was 4.04%. For the six and three-month periods ended April 2013, the yields
8 were 4.06% and 4.13%, respectively. During the twelve-months ended April 2013,
9 the range of the yields on A-rated public utility bonds was 3.84% to 4.20%. Page 2
10 of Schedule 12 shows the long-run spread in yields between A-rated public utility
11 bonds and long-term Treasury bonds. As shown on page 3 of Schedule 12, the
12 yields on A-rated public utility bonds have exceeded those on Treasury bonds by
13 1.53% on a twelve-month average basis, 1.45% on a six-month average basis, and
14 1.42% on a the three-month average basis. From these averages, 1.50% represents
15 a reasonable spread for the yield on A-rated public utility bonds over Treasury
16 bonds.

17

18 **Q. How have you used these data to project the yield on A-rated public utility**
19 **bonds for the purpose of your Risk Premium analysis?**

20 A. Shown below is my calculation of the prospective yield on A-rated public utility
21 bonds using the building blocks discussed above, i.e., the Blue Chip forecast of
22 Treasury bond yields and the public utility bond yield spread. For comparative
23 purposes, I also have shown the Blue Chip forecasts of Aaa-rated and Baa-rated

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1 corporate bonds. These forecasts are:

Year	Quarter	Blue Chip Financial Forecasts			A-rated Public Utility	
		Corporate		30-Year	Spread	Yield
		Aaa-rated	Baa-rated	Treasury		
2013	Second	3.8%	4.7%	3.0%	1.50%	4.50%
2013	Third	3.9%	4.8%	3.2%	1.50%	4.70%
2013	Fourth	4.0%	4.9%	3.3%	1.50%	4.80%
2014	First	4.1%	5.0%	3.4%	1.50%	4.90%
2014	Second	4.2%	5.2%	3.5%	1.50%	5.00%
2014	Third	4.3%	5.3%	3.7%	1.50%	5.20%

2 **Q. Are there additional forecasts of interest rates that extend beyond those shown**
 3 **above?**

4 A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its
 5 December 1, 2012 publication, Blue Chip published longer-term forecasts of
 6 interest rates, which were reported to be:

Averages	Blue Chip Financial Forecasts		
	30-Year	Corporate	
	Treasury	Aaa-rated	Baa-rated
2014-18	4.7%	5.4%	6.4%
2019-23	5.5%	6.1%	7.1%

7 Given these forecasted interest rates, a 5.25% yield on A-rated public utility bonds
 8 represents a reasonable expectation.

9
 10 **Q. What equity risk premium have you determined for this case?**

11 A. To develop an appropriate equity risk premium, I analyzed the results from the
 12 2013 Classic Yearbook for Stocks, Bonds, Bills and Inflation (“SBBI”) published
 13 by Ibbotson Associates that is part of Morningstar. My investigation reveals that
 14 the equity risk premium varies according to the level of interest rates. That is to

DIRECT TESTIMONY OF PAUL R. MOUL

1 say, the equity risk premium increases as interest rates decline and it declines as
2 interest rates increase. This inverse relationship is revealed by the summary data
3 presented below and shown on page 1 of Schedule 13.

<u>Common Equity Risk Premiums</u>	
Low Interest Rates	7.00%
Average Across All Interest Rates	5.41%
High Interest Rates	3.77%

4
5 Based on my analysis of the historical data, the equity risk premium was
6 7.00% when the marginal cost of long-term government bonds was low (i.e.,
7 3.03%, which was the average yield during periods of low rates). Conversely, when
8 the yield on long-term government bonds was high (i.e., 7.35% on average during
9 periods of high interest rates) the spread narrowed to 3.77%. Over the entire
10 spectrum of interest rates, the equity risk premium was 5.41% when the average
11 government bond yield was 5.16%. With the current low interest rates, an equity
12 risk premium of 7.00% is indicated today.

13
14 **Q. What common equity cost rate did you determine based on your risk premium**
15 **analysis?**

16 A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for
17 long-term public utility debt (i.e., "i"), and the equity risk premium (i.e., "RP").

18 The Risk Premium approach provides a cost of equity of:

DIRECT TESTIMONY OF PAUL R. MOUL

	i	+	RP	=	k
Electric Group	5.25%	+	7.00%	=	12.25%

1

2

CAPITAL ASSET PRICING MODEL

3

Q. What are the features of the CAPM as you have used it?

4

A. The CAPM uses the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. The result of the CAPM is 11.36% as shown on page 2 of Schedule 1. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return (“Rf”), the beta measure of systematic risk (“β”), and the market risk premium (“Rm-Rf”) derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

13

14

Q. What betas have you considered in the CAPM?

15

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on Schedule 11, the average beta is 0.68 for the Electric Group.

17

18

Q. What betas have you used in the CAPM determined cost of equity?

19

A. The betas must be reflective of the financial risk associated with the ratesetting capital structure that is measured at book value. Therefore, Value Line betas cannot

20

DIRECT TESTIMONY OF PAUL R. MOUL

1 be used directly in the CAPM, unless the cost rate developed using those betas is
2 applied to a capital structure measured with market values. To develop a CAPM
3 cost rate applicable to a book-value capital structure, the Value Line (market value)
4 betas have been unleveraged and releveraged for the book value common equity
5 ratios using the Hamada formula,⁸ as follows:

$$\beta_l = \beta_u [1 + (1 - t) D/E + P/E]$$

6
7 where β_l = the leveraged beta, β_u = the unleveraged beta, t = income tax rate, D =
8 debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas
9 published by Value Line have been calculated with the market price of stock and,
10 therefore, are related to the market value capitalization. By using the formula
11 shown above and the capital structure ratios measured at market value, the beta
12 would become 0.43 for the Electric Group if it employed no leverage and was 100%
13 equity financed. Those calculations are shown on Schedule 11 under the category
14 "Hamada" who is credited with developing those formulas. With the unleveraged
15 beta as a base, I calculated the leveraged beta of 0.76 for the book value capital
16 structure of the Electric Group. The book value leveraged beta that I will employ in
17 the CAPM cost of equity is 0.76 for the Electric Group.

18
19 **Q. What risk-free rate have you used in the CAPM?**

20 **A.** As shown on page 1 of Schedule 14, I provided the historical yields on Treasury

⁸ Robert S. Hamada, "The Effects of the Firm's Capital Structure on the Systematic Risk of Common Stocks" *The Journal of Finance* Vol. 27, No. 2, Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, December 27-29, 1971. (May 1972), pp.435-452

DIRECT TESTIMONY OF PAUL R. MOUL

1 notes and bonds. For the twelve months ended April 2013, the average yield on 30-
2 year Treasury bonds was 2.90%. For the six- and three-months ended April 2013,
3 the yields on 30-year Treasury bonds were 3.00% and 3.09%, respectively. During
4 the twelve-months ended April 2013, the range of the yields on 30-year Treasury
5 bonds was 2.59% to 3.17%. The recent low yields on Treasury bonds can be traced
6 to events that have occurred during the past several years that included the financial
7 crisis and its aftermath. The resulting decline in the yields on Treasury obligations
8 can be attributed to a number of factors, including: the sovereign debt crisis in the
9 euro zone, concern over a possible double dip recession, the potential for deflation,
10 and the Federal Reserve's large balance sheet that has been expanded through the
11 purchase of Treasury obligations and mortgage-backed securities (also known as
12 QEI, QEII, and QEIII), and the reinvestment of the proceeds from maturing
13 obligations and the lengthening of the maturity of the Fed's bond portfolio through
14 the sale of short-term Treasuries and the purchase of long-term Treasury obligations
15 (also known as "operation twist"). Essentially, low interest rates are the product of
16 the policy of the FOMC in its attempt to deal with stagnant job growth, which is
17 part of its dual mandate. As shown on page 2 of Schedule 14, forecasts published
18 by Blue Chip on May 1, 2013 indicate that the yields on long-term Treasury bonds
19 are expected to be in the range of 3.0% to 3.7% during the next six quarters. The
20 longer term forecasts described previously show that the yields on 30-year Treasury
21 bonds will average 4.7% from 2014 through 2018 and 5.5% from 2019 to 2023.
22 For the reasons explained previously, forecasts of interest rates should be
23 emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I

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1 have used a 3.75% risk-free rate of return for CAPM purposes, which considers not
2 only the Blue Chip forecasts, but also the recent trend in the yields on long-term
3 Treasury bonds.

4
5 **Q. What market premium have you used in the CAPM?**

6 A. As shown in the lower panel of data presented on page 2 of Schedule 14, the market
7 premium is derived from historical data and the Value Line and S&P 500 returns.
8 For the historically based market premium, I have used the arithmetic mean
9 obtained from the data presented on page 1 of Schedule 13. On that schedule, the
10 market return on large stocks during periods of low interest rates was 11.72%.
11 During that time, the yield on long-term government bonds was 3.03%. The
12 resulting market premium is 8.69% (11.72% - 3.03%) based on historical data. For
13 the forecast returns, I calculated a 12.87% total market return from the Value Line
14 data and a DCF return of 11.41% for the S&P 500. With the average forecast return
15 of 12.14% ($12.87\% + 11.41\% = 24.28\% \div 2$), I calculated a market premium of
16 8.39% ($12.14\% - 3.75\%$) using forecast data. The market premium applicable to
17 the CAPM derived from these sources equals 8.54% ($8.39\% + 8.69\% = 17.08\% \div$
18 2).

19
20 **Q. Are there adjustments to the CAPM that are necessary to fully reflect the rate
21 of return on common equity?**

22 A. Yes. The technical literature supports an adjustment relating to the size of the
23 company or portfolio for which the calculation is performed. As the size of a firm

DIRECT TESTIMONY OF PAUL R. MOUL

1 decreases, its risk and, hence, its required return increases. Moreover, in his
 2 discussion of the cost of capital, Professor Brigham has indicated that smaller firms
 3 have higher capital costs than otherwise similar larger firms (see Fundamentals of
 4 Financial Management, fifth edition, page 623). Also, the Fama/French study (see
 5 "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June
 6 1992) established that the size of a firm helps explain stock returns. In an October
 7 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock
 8 Effect," it was demonstrated that the CAPM could understate the cost of equity
 9 significantly according to a company's size. Indeed, it was demonstrated in the
 10 SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had
 11 returns in excess of those shown by the simple CAPM. In this regard, the common
 12 equity capitalization for Duquesne Light is \$1,093 million at the end of the fully
 13 forecast test year, as shown on Schedule 5. For my CAPM analysis, I have adopted
 14 the mid-cap adjustment of 1.12%, as revealed on page 3 of Schedule 14.

15
 16 **Q. What CAPM result have you determined?**

17 **A.** I derived the following CAPM-indicated cost of equity:

	R_f	+	(β	x	($R_m - R_f$))	+	size	=	k
Electric Group	3.75%	+	(0.76	x	(8.54%))	+	1.12%	=	11.36%

18
 19

DIRECT TESTIMONY OF PAUL R. MOUL

COMPARABLE EARNINGS

1

2 **Q. How have you applied the Comparable Earnings approach in this case?**

3 A. The Comparable Earnings approach determines the equity return based upon results
4 from non-regulated companies. It is the oldest of all rate of return methods, having
5 been around for about one century. Because regulation is a substitute for
6 competitively determined prices, the returns realized by non-regulated firms with
7 comparable risks to a public utility provide useful insight into a fair rate of return.
8 In order to identify the appropriate return, it is necessary to analyze returns earned
9 (or realized) by other firms within the context of the Comparable Earnings standard.
10 The firms selected for the Comparable Earnings approach should be companies
11 whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms)
12 so that circularity is avoided.

13 There are two avenues available to implement the Comparable Earnings
14 approach. One method involves the selection of another industry (or industries)
15 with comparable risks to the public utility in question, and the results for all
16 companies within that industry serve as a benchmark. The second approach
17 requires the selection of parameters that represent similar risk traits for the public
18 utility and the comparable risk companies. Using this approach, the business lines
19 of the comparable companies become unimportant. The latter approach is
20 preferable with the further qualification that the comparable risk companies exclude
21 regulated firms in order to avoid the circular reasoning implicit in the use of the
22 achieved earnings/book ratios of other regulated firms. The United States Supreme
23 Court has held that:

DIRECT TESTIMONY OF PAUL R. MOUL

1 A public utility is entitled to such rates as will permit it
2 to earn a return on the value of the property which it
3 employs for the convenience of the public equal to that
4 generally being made at the same time and in the same
5 general part of the country on investments in other
6 business undertakings which are attended by
7 corresponding risks and uncertainties.... The return
8 should be reasonably sufficient to assure confidence in
9 the financial soundness of the utility and should be
10 adequate, under efficient and economical management,
11 to maintain and support its credit and enable it to raise
12 the money necessary for the proper discharge of its
13 public duties. *Bluefield Water Works vs. Public Service*
14 *Commission, 262 U.S. 668 (1923).*

15
16 Therefore, it is important to identify the returns earned by firms that compete for
17 capital with a public utility. This can be accomplished by analyzing the returns of
18 non-regulated firms that are subject to the competitive forces of the marketplace.

19
20 **Q. How have you implemented the Comparable Earnings approach?**

21 A. In order to implement the Comparable Earnings approach, non-regulated companies
22 were selected from The Value Line Investment Survey for Windows that have six
23 categories of comparability designed to reflect the risk of the Electric Group. These
24 screening criteria were based upon the range as defined by the rankings of the
25 companies in the Electric Group. The items considered were: Timeliness Rank,
26 Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical
27 Rank. The identities of the companies comprising the Comparable Earnings group
28 and their associated rankings within the ranges are identified on page 1 of Schedule
29 15.

30 Value Line data was relied upon because it provides a comprehensive basis

DIRECT TESTIMONY OF PAUL R. MOUL

1 for evaluating the risks of the comparable firms. As to the returns calculated by
2 Value Line for these companies, there is some downward bias in the figures shown
3 on page 2 of Schedule 15, because Value Line computes the returns on year-end
4 rather than average book value. If average book values had been employed, the
5 rates of return would have been slightly higher. Nevertheless, these are the returns
6 considered by investors when taking positions in these stocks. Because many of the
7 comparability factors, as well as the published returns, are used by investors in
8 selecting stocks, and the fact that investors rely on the Value Line service to gauge
9 returns, it is, therefore, an appropriate database for measuring comparable return
10 opportunities.

11

12 **Q. What data have you used in your Comparable Earnings analysis?**

13 A. I have used both historical realized returns and forecasted returns for non-utility
14 companies. As noted previously, I have not used returns for utility companies in
15 order to avoid the circularity that arises from using regulatory-influenced returns to
16 determine a regulated return. It is appropriate to consider a relatively long
17 measurement period in the Comparable Earnings approach in order to cover
18 conditions over an entire business cycle. A ten-year period (five historical years
19 and five projected years) is sufficient to cover an average business cycle. Unlike
20 the DCF and CAPM, the results of the Comparable Earnings method can be applied
21 directly to the book value capitalization. In other words, the Comparable Earnings
22 approach does not contain the potential misspecification contained in market
23 models when the market capitalization and book value capitalization diverge

DIRECT TESTIMONY OF PAUL R. MOUL

1 significantly. The historical rate of return on book common equity was 12.4%
2 using only the returns that were less than 20% and greater than 8% as shown on
3 page 2 of Schedule 15. Points of demarcation were chosen to eliminate the results
4 of highly profitable enterprises, which the Bluefield case stated were not the type of
5 returns that a utility was entitled to earn. For this purpose, I used 20% as the point
6 where those returns could be viewed as highly profitable and should be excluded
7 from the Comparable Earnings approach. And to minimize the effect of a skewed
8 distribution, I removed from the average the returns that were less than 8%. The
9 forecast rates of return as published by Value Line are shown by the 11.9% using
10 the same parameters, as provided on page 2 of Schedule 15. Using these data my
11 Comparable Earnings result is 12.15%, as shown on page 2 of Schedule 1.

CONCLUSION ON COST OF EQUITY

12
13
14 **Q. What is your conclusion regarding the Company's cost of common equity?**

15 A. Based upon the application of a variety of methods and models described
16 previously, it is my opinion that a reasonable cost of common equity for the
17 Company is 11.25%. My cost of equity recommendation is obtained from a range
18 of results and should be considered in the context of the Company's risk
19 characteristics, giving consideration to the Company's high level of service. It is
20 essential that the Commission employ a variety of techniques to measure the
21 Company's cost of equity because of the limitations/infirmities that are inherent in
22 each method.

23

DIRECT TESTIMONY OF PAUL R. MOUL

1 **Q. Does this complete your direct testimony?**

2 A. Yes. However, I reserve the right to supplement my testimony, if necessary, and to
3 respond to witnesses presented by other parties.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

**EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE
AND QUALIFICATIONS**

1
2
3 I was awarded a degree of Bachelor of Science in Business Administration by
4 Drexel University in 1971. While at Drexel, I participated in the Cooperative Education
5 Program which included employment, for one year, with American Water Works Service
6 Company, Inc., as an internal auditor, where I was involved in the audits of several
7 operating water companies of the American Water Works System and participated in the
8 preparation of annual reports to regulatory agencies and assisted in other general
9 accounting matters.

10 Upon graduation from Drexel University, I was employed by American Water
11 Works Service Company, Inc., in the Eastern Regional Treasury Department where my
12 duties included preparation of rate case exhibits for submission to regulatory agencies, as
13 well as responsibility for various treasury functions of the thirteen New England
14 operating subsidiaries.

15 In 1973, I joined the Municipal Financial Services Department of Betz
16 Environmental Engineers, a consulting engineering firm, where I specialized in financial
17 studies for municipal water and wastewater systems.

18 In 1974, I joined Associated Utility Services, Inc., now known as AUS
19 Consultants. I held various positions with the Utility Services Group of AUS
20 Consultants, concluding my employment there as a Senior Vice President.

21 In 1994, I formed P. Moul & Associates, an independent financial and regulatory
22 consulting firm. In my capacity as Managing Consultant and for the past twenty-nine
23 years, I have continuously studied the rate of return requirements for cost of service-

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

1 regulated firms. In this regard, I have supervised the preparation of rate of return studies,
2 which were employed, in connection with my testimony and in the past for other
3 individuals. I have presented direct testimony on the subject of fair rate of return,
4 evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

5 My studies and prepared direct testimony have been presented before thirty-seven
6 (37) federal, state and municipal regulatory commissions, consisting of: the Federal
7 Energy Regulatory Commission; state public utility commissions in Alabama, Alaska,
8 California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana,
9 Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota,
10 Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma,
11 Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia,
12 Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on
13 Environmental Quality. My testimony has been offered in over 200 rate cases involving
14 electric power, natural gas distribution and transmission, resource recovery, solid waste
15 collection and disposal, telephone, wastewater, and water service utility companies.
16 While my testimony has involved principally fair rate of return and financial matters, I
17 have also testified on capital allocations, capital recovery, cash working capital, income
18 taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony
19 has been offered on behalf of municipal and investor-owned public utilities and for the
20 staff of a regulatory commission. I have also testified at an Executive Session of the
21 State of New Jersey Commission of Investigation concerning the BPU regulation of solid
22 waste collection and disposal.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

1 I was a co-author of a verified statement submitted to the Interstate Commerce
2 Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was
3 also co-author of comments submitted to the Federal Energy Regulatory Commission
4 regarding the Generic Determination of Rate of Return on Common Equity for Public
5 Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-
6 000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of
7 the National Association of Water Companies, which represented the water utility group
8 in the Proceeding on Motion of the Commission to Consider Financial Regulatory
9 Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to
10 the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking
11 (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on
12 behalf of the Edison Electric Institute in its intervention in the case of Southern California
13 Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of
14 participants at the Technical Conference in Docket No. PL07-2 on the Composition of
15 Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

16 In late 1978, I arranged for the private placement of bonds on behalf of an
17 investor-owned public utility. I have assisted in the preparation of a report to the
18 Delaware Public Service Commission relative to the operations of the Lincoln and
19 Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and
20 report on the proposed financing and disposition of certain assets of Sussex Shores Water
21 Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on
22 Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County
23 Commissioners of Collier County, Florida.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

1 I have been a consultant to the Bucks County Water and Sewer Authority
2 concerning rates and charges for wholesale contract service with the City of Philadelphia.
3 My municipal consulting experience also included an assignment for Baltimore County,
4 Maryland, regarding the City/County Water Agreement for Metropolitan District
5 customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

DUQUESNE LIGHT COMPANY

EXHIBIT

TO ACCOMPANY

THE DIRECT TESTIMONY

OF

PAUL R. MOUL

CONCERNING
RATE OF RETURN

Duquesne Light Company
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Duquesne Light Company
Proposed Rate of Return
Estimated at April 30, 2015

<u>Type of Capital</u>	<u>Ratios</u>	<u>Cost Rate</u>	<u>Weighted Cost Rate</u>
Long-Term Debt	42.95%	5.18%	2.23%
Preferred Stock	5.11%	5.89%	0.30%
Common Equity	<u>51.94%</u>	11.25%	<u>5.83%</u>
Total	<u>100.00%</u>		<u>8.36%</u>

Indicated levels of fixed charge coverage assuming that the Company could actually achieve its proposed rate of return:

Pre-tax coverage of interest expense based upon a 41.4935% composite federal and state income tax rate (12.71% ÷ 2.23%)	5.70 x
Post-tax coverage of interest expense (8.36% ÷ 2.23%)	3.75 x
Post-tax coverage of interest expense and preferred stock dividends (8.36% ÷ 2.53%)	3.30 x

Duquesne Light Company

Cost of Equity
as of April 30, 2013

Discounted Cash Flow (DCF)	D_1/P_0	+	g	+	$lev.$	=	k		
Electric Group	4.63%	+	5.50%	+	0.65%	=	10.78%		
Risk Premium (RP)	I	+	RP	=	k				
Electric Group	5.25%	+	7.00%	=	12.25%				
Capital Asset Pricing Model (CAPM)	Rf	+	β	x ($Rm-Rf$) +	$size$	=	k
Electric Group	3.75%	+	0.76	x (8.54%) +	1.12%	=	11.36%
Comparable Earnings (CE)	Historical		Forecast		Average				
Comparable Earnings Group	12.4%		11.9%		12.15%				

- References
- (1) Schedule 08 page 1
 - (2) Schedule 10 page 1
 - (3) Schedule 11 page 1
 - (4) A-rated public utility bond yield comprised of a 3.75% risk-free rate of return (Schedule 14 page 2) and a yield spread of 1.50% (Schedule 12 page 3)
 - (5) Schedule 13 page 1
 - (6) Schedule 14 pages 1 & 2
 - (7) Schedule 11 page 1
 - (8) Schedule 14 page 2
 - (9) Schedule 14 page 3
 - (10) Schedule 15 page 2

Duquesne Light Company
Capitalization and Financial Statistics
2008-2012, Inclusive

	<u>2012</u>	<u>2011</u>	<u>2010</u>	<u>2009</u>	<u>2008</u>	
	(Millions of Dollars)					
Amount of Capital Employed						
Permanent Capital	\$ 1,940.1	\$ 1,933.4	\$ 1,753.3	\$ 1,633.3	\$ 1,517.3	
Short-Term Debt	\$ 20.0	\$ -	\$ 75.0	\$ 45.0	\$ 75.0	
Total Capital	<u>\$ 1,960.1</u>	<u>\$ 1,933.4</u>	<u>\$ 1,828.3</u>	<u>\$ 1,678.3</u>	<u>\$ 1,592.3</u>	
						<u>Average</u>
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	39.2%	39.3%	33.8%	27.1%	22.5%	32.4%
Preferred Stock	5.6%	5.6%	6.2%	6.6%	7.1%	6.2%
Common Equity	<u>55.3%</u>	<u>55.1%</u>	<u>60.1%</u>	<u>66.3%</u>	<u>70.3%</u>	<u>61.4%</u>
	<u>100.1%</u>	<u>100.0%</u>	<u>100.1%</u>	<u>100.0%</u>	<u>99.9%</u>	<u>100.0%</u>
Based on Total Capital:						
Total Debt, incl. Short Term	39.8%	39.3%	36.5%	29.0%	26.2%	34.2%
Preferred Stock	5.5%	5.6%	5.9%	6.4%	6.8%	6.0%
Common Equity	<u>54.7%</u>	<u>55.1%</u>	<u>57.6%</u>	<u>64.5%</u>	<u>67.0%</u>	<u>59.8%</u>
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>99.9%</u>	<u>100.0%</u>	<u>100.0%</u>
Rate of Return on Book Common Equity	13.8%	13.4%	7.1%	6.9%	7.1%	9.7%
Operating Ratio (1)	65.7%	69.8%	84.8%	81.2%	81.7%	76.6%
Coverage incl. AFUDC (2)						
Pre-tax: All Interest Charges	7.21 x	6.55 x	4.16 x	5.79 x	7.54 x	6.25 x
Post-tax: All Interest Charges	4.69 x	4.45 x	3.38 x	3.79 x	4.59 x	4.18 x
Overall Coverage: All Int. & Pfd. Div.	4.08 x	3.89 x	2.87 x	3.12 x	3.62 x	3.52 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	7.21 x	6.55 x	4.16 x	5.79 x	7.54 x	6.25 x
Post-tax: All Interest Charges	4.69 x	4.45 x	3.38 x	3.79 x	4.59 x	4.18 x
Overall Coverage: All Int. & Pfd. Div.	4.08 x	3.89 x	2.87 x	3.12 x	3.62 x	3.52 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Effective Income Tax Rate	40.7%	37.8%	24.7%	41.9%	45.0%	38.0%
Internal Cash Generation/Construction (4)	83.7%	61.5%	49.7%	74.4%	51.1%	64.1%
Gross Cash Flow/ Avg. Total Debt(5)	44.3%	36.7%	41.7%	43.7%	48.6%	43.0%
Gross Cash Flow Interest Coverage(6)	9.15 x	7.03 x	7.78 x	7.62 x	8.88 x	8.09 x
Common Dividend Coverage (7)	1.95 x	2.56 x	2.21 x	3.24 x	1.65 x	2.32 x

See Page 2 for Notes.

Duquesne Light Company.
Capitalization and Financial Statistics
2008-2012, Inclusive

Notes:

- (1) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.
- (2) Coverage calculations represent the number of times available earnings including AFUDC (allowance for funds used during construction), as reported in its entirety, cover fixed charges.
- (3) Coverage calculations represent the number of times available earnings excluding AFUDC (allowance for funds used during construction), as reported in its entirety, cover fixed charges.
- (4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally generated funds from operations after payment of all cash dividends.
- (5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFUDC) as a percentage of average total debt.
- (6) Gross Cash Flow plus interest charges divided by interest charges.
- (7) Common dividend coverage is the relationship of internally generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Company provided data

Electric Group
Capitalization and Financial Statistics ⁽¹⁾
2008-2012, Inclusive

	<u>2012</u>	<u>2011</u>	<u>2010</u>	<u>2009</u>	<u>2008</u>	
	(Millions of Dollars)					
Amount of Capital Employed						
Permanent Capital	\$ 24,931.4	\$ 20,153.1	\$ 18,657.4	\$ 18,108.5	\$ 16,668.3	
Short-Term Debt	\$ 984.7	\$ 476.4	\$ 462.3	\$ 413.5	\$ 769.1	
Total Capital	<u>\$ 25,916.1</u>	<u>\$ 20,629.5</u>	<u>\$ 19,119.7</u>	<u>\$ 18,522.0</u>	<u>\$ 17,437.4</u>	
Market-Based Financial Ratios						<u>Average</u>
Price-Earnings Multiple	18 x	16 x	16 x	14 x	15 x	16 x
Market/Book Ratio	163.1%	154.7%	142.4%	129.7%	161.6%	150.3%
Dividend Yield	4.5%	4.7%	5.2%	5.9%	4.7%	5.0%
Dividend Payout Ratio	81.9%	76.7%	83.2%	79.0%	72.6%	78.7%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	53.5%	53.9%	54.0%	55.1%	54.7%	54.2%
Preferred Stock	0.5%	0.6%	0.6%	0.7%	0.9%	0.7%
Common Equity ⁽²⁾	<u>46.0%</u>	<u>45.5%</u>	<u>45.4%</u>	<u>44.3%</u>	<u>44.4%</u>	<u>45.1%</u>
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>
Based on Total Capital:						
Total Debt incl. Short Term	55.7%	55.4%	55.1%	56.0%	56.9%	55.8%
Preferred Stock	0.5%	0.6%	0.6%	0.7%	0.9%	0.6%
Common Equity ⁽²⁾	<u>43.9%</u>	<u>43.9%</u>	<u>44.3%</u>	<u>43.3%</u>	<u>42.2%</u>	<u>43.5%</u>
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>
Rate of Return on Book Common Equity ⁽²⁾	8.1%	9.6%	10.2%	9.4%	10.7%	9.6%
Operating Ratio ⁽³⁾	80.6%	82.1%	82.2%	84.3%	84.9%	82.8%
Coverage incl. AFUDC ⁽⁴⁾						
Pre-tax: All Interest Charges	3.07 x	3.23 x	3.33 x	2.90 x	3.23 x	3.15 x
Post-tax: All Interest Charges	2.35 x	2.46 x	2.47 x	2.26 x	2.45 x	2.40 x
Overall Coverage: All Int. & Pfd. Div.	2.32 x	2.43 x	2.45 x	2.22 x	2.41 x	2.37 x
Coverage excl. AFUDC ⁽⁴⁾						
Pre-tax: All Interest Charges	2.99 x	3.13 x	3.21 x	2.81 x	3.14 x	3.06 x
Post-tax: All Interest Charges	2.26 x	2.36 x	2.36 x	2.17 x	2.36 x	2.30 x
Overall Coverage: All Int. & Pfd. Div.	2.23 x	2.33 x	2.33 x	2.13 x	2.32 x	2.27 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	7.0%	7.9%	10.5%	7.3%	6.8%	7.9%
Effective Income Tax Rate	35.0%	34.7%	34.1%	32.9%	35.6%	34.5%
Internal Cash Generation/Construction ⁽⁵⁾	73.5%	82.6%	90.5%	74.5%	67.0%	77.6%
Gross Cash Flow/ Avg. Total Debt ⁽⁶⁾	19.3%	20.5%	21.3%	19.3%	20.2%	20.1%
Gross Cash Flow Interest Coverage ⁽⁷⁾	5.65 x	4.78 x	4.85 x	4.32 x	4.43 x	4.81 x
Common Dividend Coverage ⁽⁸⁾	3.43 x	3.67 x	4.15 x	3.76 x	3.88 x	3.78 x

See Page 2 for Notes.

Electric Group
Capitalization and Financial Statistics
2005-2009, Inclusive

Notes:

- (1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
- (2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.
- (3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
- (4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
- (5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
- (6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
- (7) Gross Cash Flow plus interest charges divided by interest charges.
- (8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection

The Electric Group includes companies that (i) their stock is traded on the New York Stock Exchange, (ii) they are listed in the "Electric Utility (East)" section of The Value Line Investment Survey, (iii) and they are not currently the target of a publicly-announced merger or acquisition.

Ticker	Company	Corporate Credit Ratings		Stock Traded	S&P Stock Ranking	Value Line Beta
		Moody's	S&P			
ED	Consolidated Edison, Inc.	A3	A-	NYSE	B+	0.60
D	Dominion Resources, Inc.	A3	A-	NYSE	B+	0.65
DUK	Duke Energy Corp.	A3	BBB+	NYSE	B	0.60
FE	FirstEnergy Corp.	Baa2	BBB-	NYSE	B+	0.75
NU	Northeast Utilities	Baa2	A-	NYSE	B	0.70
POM	Pepco Holdings Inc.	Baa2	BBB+	NYSE	B	0.75
SCG	SCANA Corp.	Baa2	BBB+	NYSE	A-	0.65
SO	Southern Company	A3	A	NYSE	A-	0.55
TE	TECO Energy, Inc.	A3	BBB+	NYSE	B	0.85
UIL	UIL Holdings	Baa2	BBB	NYSE	B	0.70
	Average	<u>Baa1</u>	<u>BBB+</u>		<u>B+</u>	<u>0.68</u>

Source of Information: Utility COMPUSTAT

Standard & Poor's Public Utilities
Capitalization and Financial Statistics ⁽¹⁾
2008-2012, Inclusive

	<u>2012</u>	<u>2011</u>	<u>2010</u>	<u>2009</u>	<u>2008</u>	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	\$ 21,620.0	\$ 18,840.8	\$ 17,587.3	\$ 16,618.6	\$ 15,620.1	
Short-Term Debt	\$ 648.9	\$ 531.4	\$ 435.4	\$ 415.0	\$ 803.5	
Total Capital	<u>\$ 22,268.9</u>	<u>\$ 19,372.2</u>	<u>\$ 18,022.7</u>	<u>\$ 17,033.6</u>	<u>\$ 16,423.6</u>	
Market-Based Financial Ratios						<u>Average</u>
Price-Earnings Multiple	18 x	15 x	15 x	14 x	14 x	15 x
Market/Book Ratio	164.0%	155.2%	142.8%	137.1%	174.9%	154.8%
Dividend Yield	4.1%	4.4%	4.8%	5.2%	4.3%	4.6%
Dividend Payout Ratio	70.3%	64.7%	72.0%	72.2%	61.9%	68.2%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	52.9%	52.9%	53.4%	54.2%	54.3%	53.5%
Preferred Stock	1.6%	1.3%	1.3%	1.5%	1.7%	1.5%
Common Equity ⁽²⁾	<u>45.5%</u>	<u>45.8%</u>	<u>45.3%</u>	<u>44.3%</u>	<u>44.0%</u>	<u>45.0%</u>
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>
Based on Total Capital:						
Total Debt incl. Short Term	54.5%	54.5%	54.7%	55.6%	57.1%	55.3%
Preferred Stock	1.6%	1.3%	1.3%	1.4%	1.6%	1.4%
Common Equity ⁽²⁾	<u>44.0%</u>	<u>44.3%</u>	<u>44.0%</u>	<u>43.0%</u>	<u>41.3%</u>	<u>43.3%</u>
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>
Rate of Return on Book Common Equity ⁽²⁾	9.2%	10.5%	10.8%	10.1%	12.2%	10.6%
Operating Ratio ⁽³⁾	81.3%	81.4%	81.6%	83.0%	84.1%	82.3%
Coverage incl. AFUDC ⁽⁴⁾						
Pre-tax: All Interest Charges	2.94 x	3.35 x	3.34 x	3.06 x	3.39 x	3.22 x
Post-tax: All Interest Charges	2.35 x	2.59 x	2.52 x	2.36 x	2.57 x	2.48 x
Overall Coverage: All Int. & Pfd. Div.	2.32 x	2.57 x	2.50 x	2.33 x	2.53 x	2.45 x
Coverage excl. AFUDC ⁽⁴⁾						
Pre-tax: All Interest Charges	2.85 x	3.25 x	3.25 x	2.96 x	3.28 x	3.12 x
Post-tax: All Interest Charges	2.25 x	2.49 x	2.43 x	2.26 x	2.46 x	2.38 x
Overall Coverage: All Int. & Pfd. Div.	2.22 x	2.47 x	2.41 x	2.22 x	2.42 x	2.35 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	7.1%	5.7%	6.6%	7.8%	7.7%	7.0%
Effective Income Tax Rate	26.2%	36.8%	34.3%	31.8%	33.8%	32.6%
Internal Cash Generation/Construction ⁽⁵⁾	75.0%	89.4%	108.0%	100.0%	83.1%	91.1%
Gross Cash Flow/ Avg. Total Debt ⁽⁶⁾	21.9%	23.2%	23.9%	22.5%	22.6%	22.8%
Gross Cash Flow Interest Coverage ⁽⁷⁾	5.37 x	5.12 x	5.09 x	4.85 x	4.75 x	5.04 x
Common Dividend Coverage ⁽⁸⁾	4.31 x	4.58 x	4.88 x	4.73 x	4.95 x	4.69 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2008-2012, Inclusive

Notes:

- (1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
- (2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account
- (3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
- (4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
- (5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
- (6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
- (7) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
- (8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities
Company Identities

	Ticker	Credit Rating ⁽¹⁾		Common Stock Traded	S&P Stock Ranking	Value Line Beta
		Moody's	S&P			
AGL Resources Inc.	GAS	A3	BBB+	NYSE	A	0.75
Ameren Corporation	AEE	Baa2	BBB	NYSE	B	0.80
American Electric Power	AEP	Baa2	BBB	NYSE	B	0.70
CMS Energy	CMS	Baa1	BBB	NYSE	B	0.75
CenterPoint Energy	CNP	Baa2	BBB+	NYSE	B	0.80
Consolidated Edison	ED	A3	A-	NYSE	B+	0.60
DTE Energy Co.	DTE	A3	BBB+	NYSE	B+	0.75
Dominion Resources	D	A3	A-	NYSE	B+	0.65
Duke Energy	DUK	A3	BBB+	NYSE	B	0.60
Edison Int'l	EIX	A3	BBB+	NYSE	B	0.75
Entergy Corp.	ETR	Baa2	BBB	NYSE	A+	0.70
EQT Corp.	EQT	Baa3	BBB	NYSE	B+	1.15
Exelon Corp.	EXC	A3	BBB	NYSE	B+	0.80
FirstEnergy Corp.	FE	Baa2	BBB-	NYSE	A-	0.80
Integrus Energy Group	TEG	A2	A-	NYSE	B	0.90
NextEra Energy Inc.	NEE	A2	A-	NYSE	A	0.75
NiSource Inc.	NI	Baa2	BBB-	NYSE	B	0.85
Northeast Utilities	NU	Baa2	A-	NYSE	B	0.70
NRG Energy Inc.	NRG	Ba3	BB-	NYSE	NR	1.10
ONEOK, Inc.	OKE	Baa2	BBB	NYSE	NR	0.95
PEPCO Holdings, Inc.	POM	Baa2	BBB+	NYSE	B	0.75
PG&E Corp.	PCG	A3	BBB	NYSE	B	0.55
PPL Corp.	PPL	Baa2	BBB	NYSE	B+	0.65
Pinnacle West Capital	PNW	Baa1	BBB+	NYSE	B	0.70
Public Serv. Enterprise Inc.	PEG	A3	BBB	NYSE	B+	0.75
SCANA Corp.	SCG	Baa2	BBB+	NYSE	A-	0.65
Sempra Energy	SRE	A2	A	NYSE	A-	0.80
Southern Co.	SO	A3	A	NYSE	A-	0.55
TECO Energy	TE	A3	BBB+	NYSE	B	0.85
Wisconsin Energy Corp.	WEC	A2	A-	NYSE	A	0.65
Xcel Energy Inc	XEL	A3	A-	NYSE	B+	0.65
Average for S&P Utilities		<u>Baa1</u>	<u>BBB+</u>		<u>A</u>	<u>0.75</u>

Note: ⁽¹⁾ Ratings are those of utility subsidiaries

Source of Information: Moody's Investors Service
Standard & Poor's Corporation
Standard & Poor's Stock Guide
Value Line Investment Survey for Windows

Duquesne Light Company
Capitalization and Related Capital Structure Ratios
Actual at March 31, 2013 and Estimated at March 31, 2014 and April 30, 2015

	Actual at March 31, 2013			Estimated at March 31, 2014			Estimated at April 30, 2015		
	Amount Outstanding	Ratios		Amount Outstanding	Ratios		Amount Outstanding	Ratios	
		Excl. S-T Debt	Incl. S-T Debt		Excl. S-T Debt	Incl. S-T Debt		Excl. S-T Debt	Incl. S-T Debt
Long-Term Debt	\$ 726,551,578	38.06%	37.56%	\$ 853,973,134 ⁽²⁾	41.07%	40.87%	\$ 906,301,361 ⁽²⁾	42.95%	42.05%
Preferred Stock	107,935,500	5.65%	5.58%	107,935,500	5.19%	5.17%	107,935,500	5.11%	5.01%
Common Equity									
Common Stock	10			10			10		
Capital Surplus	986,264,247			986,264,247			986,264,247		
Retained earnings ⁽¹⁾	88,454,714			131,395,446 ⁽³⁾			109,747,255 ⁽³⁾		
Total Common Equity	1,074,718,971	56.29%	55.56%	1,117,659,703	53.74%	53.49%	1,096,011,512	51.94%	50.85%
Total Permanent Capital	1,909,206,049	100.00%	98.71%	2,079,568,337	100.00%	99.52%	2,110,248,373	100.00%	97.91%
Short-term Debt ⁽⁴⁾	25,000,000		1.29%	10,000,000		0.48%	45,000,000		2.09%
Total Capital Employed	\$ 1,934,206,049		100.00%	\$ 2,089,568,337		100.00%	\$ 2,155,248,373		100.00%

Notes:

⁽¹⁾ Excluding Accumulated Other Comprehensive Income ("OCI") of:
\$ (12,644,420)

\$ (8,738,867)

\$ (8,242,998)

⁽²⁾ Reflects changes in the principal amount of long-term debt of:
6.57% Ser.R due 02/15/14
5.10% Ser.T due 11/01/43
Allegheny County 1999 Series A due 12/01/13
Intercompany Loans
Amortization of Loss on Reacquired Debt

\$ (100,000,000)
275,000,000
(50,000,000)
50,000,000
2,328,227

\$ 50,000,000
2,328,227

⁽³⁾ Projection of retained earnings.

⁽⁴⁾ Short-term debt components
Revolver borrowings \$ 20,000,000
I/C Short-term debt 5,000,000

\$ 10,000,000
-

\$ 45,000,000
-

Source of Information: Company provided data

Duquesne Light Company
Calculation of the Embedded Cost of Long-Term Debt
Estimated at March 31, 2013

<u>Series</u>	<u>Principal Amount Outstanding</u> ⁽¹⁾	<u>Percent to Total</u>	<u>Effective Cost Rate</u>	<u>Weighted Cost Rate</u> ⁽²⁾
<u>First Collateral Trust Bonds</u>				
6.57% Ser.R due 02/15/14	\$ 100,000,000	13.16%	6.79%	0.89%
4.76% Ser.S due 02/03/42	200,000,000	26.32%	4.81%	1.27%
<u>Pollution Control Revenue Bonds</u>				
Allegheny County 1999				
Series A due 12/01/13	50,000,000	6.58%	4.39%	0.29%
Ohio Water Development				
Authority 1999 Series C				
due 3/01/31	33,955,000	4.47%	4.79%	0.21%
Beaver County 1999				
Series B due 3/01/31	13,700,000	1.80%	4.81%	0.09%
Beaver County 1999				
Series C due 8/01/33	18,000,000	2.37%	4.80%	0.11%
Beaver County 1999				
Series D due 4/01/31	44,250,000	5.82%	4.55%	0.26%
<u>Intercompany Loans</u>				
Loan A	100,000,000	13.16%	4.71%	0.62%
Loan B	50,000,000	6.58%	4.25%	0.28%
Loan C	150,000,000	19.74%	4.53%	0.89%
Total Long -Term Debt	759,905,000	<u>100.00%</u>		<u>4.92%</u>
Unamortized Call Premium	<u>(33,353,422)</u>			
Long Term- Debt	<u>\$ 726,551,578</u>			
Annualized Cost	\$ 37,398,212			
Amortization of Loss on Reacquired Debt	<u>2,567,977</u>			
Total Cost	<u>\$ 39,966,189</u>			<u>5.50%</u>

Notes: ⁽¹⁾ Includes current portion of long-term debt.
⁽²⁾ As calculated on page 4 of this schedule.

Source of Information: Company provided data

Duquesne Light Company
Calculation of the Embedded Cost of Long-Term Debt
Estimated at March 31, 2014

<u>Series</u>	<u>Principal Amount Outstanding</u> ⁽¹⁾	<u>Percent to Total</u>	<u>Effective Cost Rate</u>	<u>Weighted Cost Rate</u> ⁽²⁾
<u>First Collateral Trust Bonds</u>				
4.76% Ser.S due 02/03/42	\$ 200,000,000	22.60%	4.81%	1.09%
5.10% Ser.T due 11/01/43	275,000,000	31.08%	5.20%	1.62%
<u>Pollution Control Revenue Bonds</u>				
Ohio Water Development Authority 1999 Series C due 3/01/31				
	33,955,000	3.84%	4.79%	0.18%
Beaver County 1999 Series B due 3/01/31				
	13,700,000	1.55%	4.81%	0.07%
Beaver County 1999 Series C due 8/01/33				
	18,000,000	2.03%	4.80%	0.10%
Beaver County 1999 Series D due 4/01/31				
	44,250,000	5.00%	4.55%	0.23%
<u>Intercompany Loans</u>				
Loan A	100,000,000	11.30%	4.71%	0.53%
Loan B	50,000,000	5.65%	4.25%	0.24%
Loan C	150,000,000	16.95%	4.53%	0.77%
Total Long -Term Debt	884,905,000	<u>100.00%</u>		<u>4.83%</u>
Unamortized Call Premium	<u>(30,931,866)</u>			
Long Term- Debt	<u>\$ 853,973,134</u>			
Annualized Cost	\$ 42,712,790			
Amortization of Loss on Reacquired Debt	<u>2,421,556</u>			
Total Cost	<u>\$ 45,134,346</u>			<u>5.29%</u>

Notes: ⁽¹⁾ Includes current portion of long-term debt.
⁽²⁾ As calculated on page 4 of this schedule.

Source of Information: Company provided data

Duquesne Light Company
Calculation of the Embedded Cost of Long-Term Debt
Estimated at April 30, 2015

<u>Series</u>	<u>Principal Amount Outstanding</u> ⁽¹⁾	<u>Percent to Total</u>	<u>Effective Cost Rate</u>	<u>Weighted Cost Rate</u> ⁽²⁾
<u>First Collateral Trust Bonds</u>				
4.76% Ser.S due 02/03/42	\$ 200,000,000	21.39%	4.81%	1.03%
5.10% Ser.T due 11/01/43	275,000,000	29.42%	5.20%	1.53%
<u>Pollution Control Revenue Bonds</u>				
Ohio Water Development Authority 1999 Series C due 3/01/31				
	33,955,000	3.63%	4.79%	0.17%
Beaver County 1999 Series B due 3/01/31				
	13,700,000	1.47%	4.81%	0.07%
Beaver County 1999 Series C due 8/01/33				
	18,000,000	1.93%	4.80%	0.09%
Beaver County 1999 Series D due 4/01/31				
	44,250,000	4.73%	4.55%	0.22%
<u>Intercompany Loans</u>				
Loan A	100,000,000	10.70%	4.71%	0.50%
Loan B	50,000,000	5.35%	4.25%	0.23%
Loan C	150,000,000	16.04%	4.53%	0.73%
Loan D	50,000,000	5.35%	4.15%	0.22%
Total Long -Term Debt	934,905,000	<u>100.00%</u>		<u>4.79%</u>
Unamortized Call Premium	<u>(28,603,639)</u>			
Long Term- Debt	<u>\$ 906,301,361</u>			
Annualized Cost	\$ 44,787,790			
Amortization of Loss on Reacquired Debt	<u>2,149,134</u>			
Total Cost	<u>\$ 46,936,924</u>			<u>5.18%</u>

Notes: ⁽¹⁾ Includes current portion of long-term debt.
⁽²⁾ As calculated on page 4 of this schedule.

Source of Information: Company provided data

Duquesne Light Company
Calculation of the Effective Cost of Long-Term Debt by Series

Series	Coupon Rate	Date of Issue	Date of Maturity	Average Term in Years ⁽¹⁾	Principal Amount Outstanding	Premium/Discount & Expense	Net Proceeds	Net Proceeds Ratio	Effective Cost Rate ⁽²⁾
First Collateral Trust Bonds									
6.57% Ser.R due 02/15/14	6.57%	03/03/09	02/15/14	5.0	\$ 100,000,000	\$ 901,436	\$ 99,098,564	99.10%	6.79%
4.76% Ser.S due 02/03/42	4.76%	02/01/12	02/03/42	30.0	200,000,000	1,685,878	198,314,122	99.16%	4.81%
5.10% Ser.T due 11/01/43	5.10%	11/01/13	11/01/43	30.0	275,000,000	4,125,000	270,875,000	98.50%	5.20%
Pollution Control Revenue Bonds									
Allegheny County 1999 Series A due 12/01/13 Ohio Water Development Authority	4.35%	11/18/99	12/01/13	14.0	50,000,000	210,987	49,789,013	99.58%	4.39%
1999 Series C due Beaver County 1999 Series B due 3/01/31	4.75%	11/18/99	03/01/31	31.3	33,955,000	205,000	33,750,000	99.40%	4.79%
Beaver County 1999 Series C due 8/01/33	4.75%	11/18/99	08/01/20	20.7	13,700,000	115,718	13,584,282	99.16%	4.81%
Beaver County 1999 Series D due 4/01/31	4.75%	11/18/99	08/01/33	33.7	18,000,000	150,884	17,849,116	99.16%	4.80%
Beaver County 1999 Series D due 4/01/31	4.50%	11/18/99	11/01/29	30.0	44,250,000	376,475	43,873,525	99.15%	4.55%
Intercompany Loans									
Loan A	4.71%	07/01/10	07/01/20	10.0	100,000,000	-	100,000,000	100.00%	4.71%
Loan B	4.25%	09/29/10	09/29/20	10.0	50,000,000	-	50,000,000	100.00%	4.25%
Loan C	4.53%	06/30/11	06/30/21	10.0	150,000,000	-	150,000,000	100.00%	4.53%
Loan D	4.15%	11/01/14	11/01/24	10.0	50,000,000	-	50,000,000	100.00%	4.15%

Notes: ⁽¹⁾ Determined by taking into account the effect the annual sinking fund requirements which are met by the retirement of bonds which reduce the term of each issue.

⁽²⁾ The effective cost for each issue is the yield to maturity using as inputs the average term of issue, coupon rate, and net proceeds ratio.

Source of Information: Company provided data

Duquense Light Company
Calculation of the Embedded Cost of Preferred Stock
Actual at March 31, 2013

<u>Series</u>	<u>Principal Amount Outstanding</u>	<u>Percent to Total</u>	<u>Effective Cost Rate</u>	<u>Weighted Cost Rate</u> ⁽¹⁾
3.75% Series	\$ 7,400,000	6.86%	3.77%	0.26%
4.10% Series	5,993,000	5.55%	4.12%	0.23%
4.15% Series	6,622,500	6.14%	4.16%	0.26%
4.20% Series	5,000,000	4.63%	4.23%	0.20%
6.50% Series	74,950,000	69.44%	6.67%	4.63%
\$2.10 Series	<u>7,970,000</u>	<u>7.38%</u>	4.19%	<u>0.31%</u>
	<u>\$ 107,935,500</u>	<u>100.00%</u>		<u>5.89%</u>

Notes: ⁽¹⁾ As calculated on page 4 of this schedule.

Source of Information: Company provided data

Duquense Light Company
Calculation of the Embedded Cost of Preferred Stock
Estimated at March 31, 2014

<u>Series</u>	<u>Principal Amount Outstanding</u>	<u>Percent to Total</u>	<u>Effective Cost Rate</u>	<u>Weighted Cost Rate</u> ⁽¹⁾
3.75% Series	\$ 7,400,000	6.86%	3.77%	0.26%
4.10% Series	5,993,000	5.55%	4.12%	0.23%
4.15% Series	6,622,500	6.14%	4.16%	0.26%
4.20% Series	5,000,000	4.63%	4.23%	0.20%
6.50% Series	74,950,000	69.44%	6.67%	4.63%
\$2.10 Series	7,970,000	7.38%	4.19%	0.31%
	<u>\$ 107,935,500</u>	<u>100.00%</u>		<u>5.89%</u>

Notes: ⁽¹⁾ As calculated on page 4 of this schedule.

Source of Information: Company provided data

Duquense Light Company
Calculation of the Embedded Cost of Preferred Stock
Estimated at April 30, 2015

<u>Series</u>	<u>Principal Amount Outstanding</u>	<u>Percent to Total</u>	<u>Effective Cost Rate</u>	<u>Weighted Cost Rate</u> ⁽¹⁾
3.75% Series	\$ 7,400,000	6.86%	3.77%	0.26%
4.10% Series	5,993,000	5.55%	4.12%	0.23%
4.15% Series	6,622,500	6.14%	4.16%	0.26%
4.20% Series	5,000,000	4.63%	4.23%	0.20%
6.50% Series	74,950,000	69.44%	6.67%	4.63%
\$2.10 Series	7,970,000	7.38%	4.19%	0.31%
	<u>\$ 107,935,500</u>	<u>100.00%</u>		<u>5.89%</u>

Notes: ⁽¹⁾ As calculated on page 4 of this schedule.

Source of Information: Company provided data

Duquense Light Company
Calculation of the Effective Cost of Preferred Stock by Series

<u>Series</u>	<u>Dividend Rate</u>	<u>Date of Issue</u>	<u>Original Principal Amount</u>	<u>Premium/Discount and Expense</u>	<u>Net Proceeds</u>	<u>Net Proceeds Ratio</u>	<u>Effective Cost Rate ⁽¹⁾</u>
3.75% Series	3.75%	09/19/50	\$ 7,500,000	\$ 47,010	\$ 7,452,990	99.37%	3.77%
4.10% Series	4.10%	07/01/54	6,000,000	31,828	5,968,172	99.47%	4.12%
4.15% Series	4.15%	09/24/52	7,000,000	25,540	6,974,460	99.64%	4.16%
4.20% Series	4.20%	12/14/53	5,000,000	31,915	4,968,085	99.36%	4.23%
6.50% Series	6.50%	04/16/04	75,000,000	1,899,354	73,100,646	97.47%	6.67%
\$2.10 Series	4.20%	01/25/55	8,000,000	(10,544)	8,010,544	100.13%	4.19%

Notes: ⁽¹⁾ For series without sinking fund requirements, the effective cost rate is the nominal dividend rate divided by the net proceeds ratio.

Source of Information: Company provided data

**Monthly Dividend Yields for
Electric Group
for the Twelve Months Ending April 2013**

<u>Company</u>	<u>May-12</u>	<u>Jun-12</u>	<u>Jul-12</u>	<u>Aug-12</u>	<u>Sep-12</u>	<u>Oct-12</u>	<u>Nov-12</u>	<u>Dec-12</u>	<u>Jan-13</u>	<u>Feb-13</u>	<u>Mar-13</u>	<u>Apr-13</u>	<u>12-Month Average</u>	<u>6-Month Average</u>	<u>3-Month Average</u>
Consolidated Edison Inc. (ED)-NY	4.02%	3.91%	3.78%	4.00%	4.06%	4.04%	4.35%	4.38%	4.37%	4.18%	4.05%	3.90%			
Dominion Resources, Inc. (D)-NY	4.05%	3.92%	3.91%	4.02%	4.00%	4.03%	4.13%	4.09%	4.19%	4.02%	3.88%	3.67%			
Duke Energy Corporation (DUK)-I	4.56%	4.36%	4.56%	4.73%	4.75%	4.70%	4.80%	4.83%	4.49%	4.43%	4.24%	4.10%			
FirstEnergy Corp. (FE)-NYSE	4.72%	4.50%	4.43%	5.05%	5.03%	4.87%	5.20%	5.31%	5.50%	5.59%	5.25%	4.77%			
Northeast Utilities (NU)-NYSE	3.81%	3.55%	3.46%	3.64%	3.60%	3.51%	3.54%	3.52%	3.63%	3.54%	3.39%	3.26%			
Pepco Holdings, Inc. (POM)-NYSI	5.74%	5.54%	5.45%	5.67%	5.74%	5.48%	5.54%	5.53%	5.58%	5.39%	5.06%	4.81%			
SCANA Corp. (SCG)-NYSE	4.26%	4.15%	4.05%	4.22%	4.11%	4.06%	4.32%	4.35%	4.37%	4.20%	3.98%	3.77%			
Southern Company (SO)-NYSE	4.28%	4.26%	4.11%	4.34%	4.28%	4.23%	4.52%	4.61%	4.48%	4.37%	4.21%	4.25%			
TECO Energy, Inc. (TE)-NYSE	5.07%	4.91%	4.89%	5.08%	5.00%	4.98%	5.25%	5.29%	5.01%	5.11%	4.97%	4.64%			
UIL Holdings Corporation (UIL)-N'	5.17%	4.83%	4.69%	4.96%	4.83%	4.81%	4.87%	4.83%	4.67%	4.45%	4.38%	4.18%			
Average	4.57%	4.39%	4.33%	4.57%	4.54%	4.47%	4.65%	4.67%	4.63%	4.53%	4.34%	4.14%	4.49%	4.49%	4.34%

Note:

Source of Information:

Forward-looking Dividend Yield	1/2 Growth	D_0/P_0 4.49%	(.5g) 1.027500	D_1/P_0 4.62%	$K = \frac{D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^2 + D_0(1+g)^3}{P_0} + g$
	Discrete	D_0/P_0 4.49%	Adj. 1.034145	D_1/P_0 4.65%	$K = \frac{D_0(1+g)^{25} + D_0(1+g)^{26} + D_0(1+g)^{27} + D_0(1+g)^{28}}{P_0} + g$
	Quarterly	D_0/P_0 1.12333%	Adj. 1.013475	D_1/P_0 4.63%	$K = \left[\left(1 + \frac{D_0(1+g)^{25}}{P_0} \right)^4 - 1 \right] + g$
	Average			4.63%	
	Growth rate			<u>5.50%</u>	
	K			<u>10.13%</u>	

Historical Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

Electric Group	Earnings per Share		Dividends per Share		Book Value per Share		Cash Flow per Share	
	Value Line		Value Line		Value Line		Value Line	
	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year
Consolidated Edison, Inc.	4.50%	1.00%	1.00%	1.00%	4.50%	4.00%	4.50%	1.00%
Dominion Resources, Inc.	6.50%	7.00%	6.50%	3.50%	3.50%	3.50%	3.00%	3.00%
Duke Energy Corp.	7.00%	-	-	-	-4.00%	-	1.00%	-
FirstEnergy Corp.	-2.00%	0.50%	4.00%	4.00%	1.50%	3.00%	0.50%	1.50%
Northeast Utilities	18.00%	-	8.50%	12.50%	3.50%	3.00%	2.00%	-2.50%
Pepco Holdings Inc.	-4.50%	-4.50%	1.50%	-	0.50%	0.50%	-4.00%	-4.50%
PPL Corp.	-	3.00%	7.50%	10.50%	7.00%	10.50%	-	2.00%
Public Service Enterprises Grp.	12.50%	6.00%	4.00%	2.50%	8.50%	7.00%	8.50%	6.00%
SCANA Corp.	2.00%	4.50%	4.00%	4.50%	4.50%	3.50%	-1.00%	4.00%
Southern Company	3.00%	3.00%	4.00%	3.00%	6.00%	3.50%	3.50%	2.00%
TECO Energy, Inc.	3.50%	-5.00%	1.50%	-4.50%	6.50%	-2.00%	2.00%	-4.00%
UIL Holdings	4.50%	-2.00%	-	-	-0.50%	-	1.50%	-2.00%
Average	<u>5.00%</u>	<u>1.35%</u>	<u>4.25%</u>	<u>4.11%</u>	<u>3.46%</u>	<u>3.65%</u>	<u>1.95%</u>	<u>0.59%</u>

Source of Information: Value Line Investment Survey, February 22, 2013

Analysts' Five-Year Projected Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

Exhibit PRM-1
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Schedule 10 [1 of 1]

<u>Electric Group</u>	<u>Yahoo First Call</u>	<u>Zacks</u>	<u>Morningstar</u>	<u>Value Line</u>				
				<u>Earnings Per Share</u>	<u>Dividends Per Share</u>	<u>Book Value Per Share</u>	<u>Cash Flow Per Share</u>	<u>Percent Retained to Common Equity</u>
Consolidated Edison, Inc.	2.03%	3.30%	2.90%	3.50%	1.50%	3.50%	5.00%	3.50%
Dominion Resources, Inc.	7.27%	4.60%	8.30%	5.50%	6.00%	3.50%	5.50%	5.00%
Duke Energy Corp.	4.17%	4.20%	5.10%	4.50%	2.00%	3.50%	3.00%	3.00%
FirstEnergy Corp.	4.60%	0.60%	5.60%	2.00%	Nil	3.50%	Nil	3.00%
Northeast Utilities	8.04%	7.60%	12.50%	6.50%	8.50%	7.50%	3.50%	4.00%
Pepco Holdings Inc.	3.63%	5.30%	4.10%	6.00%	1.00%	1.50%	3.50%	2.50%
SCANA Corp.	4.53%	4.30%	5.20%	4.50%	2.00%	5.00%	3.00%	4.50%
Southern Company	4.84%	4.80%	3.90%	4.50%	4.00%	4.50%	4.50%	3.50%
TECO Energy, Inc.	2.94%	3.40%	4.90%	3.50%	2.00%	2.50%	4.50%	4.00%
UIL Holdings	8.07%	4.00%	4.00%	4.00%	Nil	4.50%	3.00%	3.00%
Average	5.01%	4.21%	5.65%	4.45%	3.38%	3.95%	3.94%	3.60%

Source of Information :

Yahoo First Call, May 3, 2013
Zacks, May 3, 2013
Reuters, May 3, 2013
Value Line Investment Survey, February 22, 2013

Electric Group
Financial Risk Adjustment

Exhibit PRM-1
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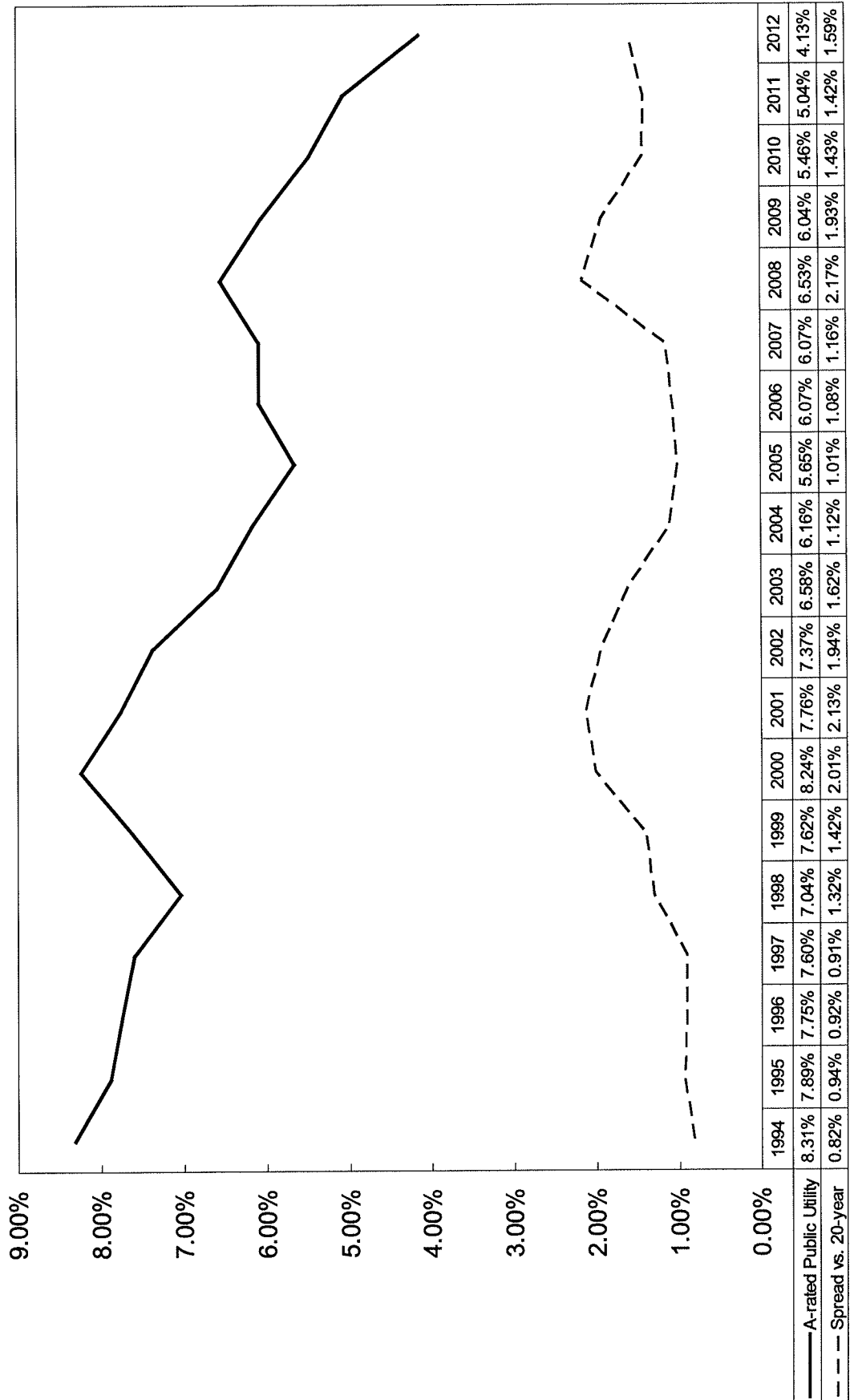
Fiscal Year	Consolidated	Dominion	Duke Energy	FirstEnergy	Northeast	Pepco Holdings,	SCANA	The Southern	TECO Energy,	UIL Holdings	Average									
	Edison Inc. (NYSE:ED)	Resources, Inc (NYSE:D)	Corporation (NYSE:DUK)	Corporation (NYSE:NU)	Utilities (NYSE:NU)	Inc. (NYSE:POM)	Corporation (NYSE:SCG)	Company (NYSE:SO)	Inc. (NYSE:TE)	Corp. (NYSE:UIL)										
	12/31/12	12/31/12	12/31/12	12/31/12	12/31/12	12/31/12	12/31/12	12/31/12	12/31/12	12/31/12										
Capitalization at Fair Values																				
Debt(D)	12,935,000	22,192,000	44,001,000	19,460,000	8,640,700	5,004,000	6,115,000	23,480,000	3,439,400	1,900,000	14,716,710									
Preferred(P)	0	255,000	93,000	0	152,200	0	0	1,082,000	0	340	158,254									
Equity(E)	14,976,983	29,836,800	44,915,200	17,464,718	12,273,216	4,510,603	6,024,480	37,159,080	3,630,216	1,813,615	17,260,491									
Total	27,911,983	52,283,800	89,009,200	36,924,718	21,066,116	9,514,603	12,139,480	61,721,080	7,069,616	3,713,955	32,135,455									
Capital Structure Ratios																				
Debt(D)	46.34%	42.45%	49.43%	52.70%	41.02%	52.59%	50.37%	38.04%	48.65%	51.16%	47.28%									
Preferred(P)	0.00%	0.49%	0.10%	0.00%	0.72%	0.00%	0.00%	1.75%	0.00%	0.01%	0.31%									
Equity(E)	53.66%	57.07%	50.46%	47.30%	58.26%	47.41%	49.63%	60.20%	51.35%	48.83%	52.42%									
Total	100.00%	100.01%	99.98%	100.00%	100.00%	100.00%	100.00%	99.99%	100.00%	100.00%	100.01%									
Common Stock																				
Issued	292,871,896	576,000,000	704,000,000	418,216,437	230,015,427	132,000,000	878,000,000	216,600,000	50,645,490	50,645,490										
Treasury	23,210,700	0.000	0.000	0.000	0.000	0.000	10,000,000	0.000	0.000	0.000										
Outstanding	269,661,196	576,000,000	704,000,000	418,216,437	314,053,634	230,015,427	132,000,000	868,000,000	216,600,000	50,645,490										
Market Price	\$55.54	\$51.80	\$63.80	\$41.76	\$39.08	\$19.61	\$45.64	\$42.81	\$16.76	\$35.81										
Capitalization at Carrying Amounts																				
Debt(D)	10,768,000	19,074,000	39,461,000	16,957,000	7,963,500	4,177,000	5,121,000	21,530,000	2,972,700	1,610,550	12,963,475									
Preferred(P)	0	257,000	93,000	0	155,600	0	0	1,082,000	0	340	158,794									
Equity(E)	11,869,000	10,568,000	40,863,000	13,084,000	9,237,050	4,446,000	4,154,000	18,297,000	2,291,800	1,116,553	11,592,640									
Total	22,637,000	29,899,000	80,417,000	30,041,000	17,356,150	8,623,000	9,275,000	40,909,000	5,264,500	2,727,443	24,714,909									
Capital Structure Ratios																				
Debt(D)	47.57%	63.79%	49.07%	56.45%	45.88%	48.44%	55.21%	52.63%	56.47%	59.05%	53.46%									
Preferred(P)	0.00%	0.86%	0.12%	0.00%	0.90%	0.00%	0.00%	2.64%	0.00%	0.01%	0.45%									
Equity(E)	52.43%	35.35%	50.81%	43.55%	53.22%	51.56%	44.79%	44.73%	43.53%	40.94%	46.09%									
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%									
Betas	Value Line	0.60	0.65	0.60	0.75	0.70	0.75	0.65	0.55	0.85	0.70	0.68								
Hamada	BI =	Bu	[1+ (1 - t)	D/E	+	P/E]													
	0.68 =	Bu	[1+ (1-0.35)	0.9019	+	0.0059]													
	0.68 =	Bu	[1+ 0.65	0.9019	+	0.0059]													
	0.43 =	Bu	1.5921																	
Hamada	BI =	0.43	[1+ (1 - t)	D/E	+	P/E]													
	BI =	0.43	[1+ 0.65	1.1598	+	0.0098]													
	BI =	0.43	1.7637																	
	BI =	0.76																		
M&M	ku =	ke	- (((ku	-	i)	1-t)	D	/	E)-(ku	-	d)	P	/	E
	7.88% =	10.13%	- (((7.88%	-	4.06%)	0.65)	47.28%	/	52.42%)-(7.88%	-	5.68%)	0.31%	/	52.42%
	7.88% =	10.13%	- (((3.82%	-)	0.65)	0.9019	/)-(2.20%	-)	0.0059	/	
	7.88% =	10.13%	- ((2.48%	-))	0.9019	/)-(2.20%	-)	0.0059	/	
	7.88% =	10.13%	-	2.24%	-						/		-	0.01%	-			/		
M&M	ke =	ku	+ (((ku	-	i)	1-t)	D	/	E)+(ku	-	d)	P	/	E
	10.78% =	7.88%	+ (((7.88%	-	4.06%)	0.65)	53.46%	/	46.09%)+(7.88%	-	5.68%)	0.45%	/	46.09%
	10.78% =	7.88%	+ (((3.82%	-)	0.65)	1.1598	/)+(2.20%	-)	0.0098	/	
	10.78% =	7.88%	+ ((2.48%	-))	1.1598	/)+(2.20%	-)	0.0098	/	
	10.78% =	7.88%	+	2.88%	-						/		+	0.02%	-			/		

**Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2008-2012
and the Twelve Months Ended April 2013**

<u>Years</u>	<u>Aa Rated</u>	<u>A Rated</u>	<u>Baa Rated</u>	<u>Average</u>
2008	6.18%	6.53%	7.24%	6.65%
2009	5.75%	6.04%	7.06%	6.28%
2010	5.24%	5.46%	5.96%	5.55%
2011	4.78%	5.04%	5.57%	5.13%
2012	3.83%	4.13%	4.86%	4.27%
Five-Year Average	<u>5.16%</u>	<u>5.44%</u>	<u>6.14%</u>	<u>5.58%</u>
<u>Months</u>				
May-12	3.92%	4.20%	4.97%	4.36%
Jun-12	3.79%	4.08%	4.91%	4.26%
Jul-12	3.58%	3.93%	4.85%	4.12%
Aug-12	3.65%	4.00%	4.88%	4.18%
Sep-12	3.69%	4.02%	4.81%	4.17%
Oct-12	3.68%	3.91%	4.54%	4.05%
Nov-12	3.60%	3.84%	4.42%	3.95%
Dec-12	3.75%	4.00%	4.56%	4.10%
Jan-13	3.90%	4.15%	4.66%	4.24%
Feb-13	3.95%	4.18%	4.74%	4.29%
Mar-13	3.95%	4.20%	4.72%	4.29%
Apr-13	3.74%	4.00%	4.49%	4.08%
Twelve-Month Average	<u>3.77%</u>	<u>4.04%</u>	<u>4.71%</u>	<u>4.17%</u>
Six-Month Average	<u>3.82%</u>	<u>4.06%</u>	<u>4.60%</u>	<u>4.16%</u>
Three-Month Average	<u>3.88%</u>	<u>4.13%</u>	<u>4.65%</u>	<u>4.22%</u>

Source: Mergent Bond Record

Yields on A-rated Public Utility Bonds and Spreads over 20-Year Treasuries



A rated Public Utility Bonds over 20-Year Treasuries

Year	A-rated	20-Year Treasuries		Year	A-rated	20-Year Treasuries		Year	A-rated	20-Year Treasuries	
	Public Utility	Yield	Spread		Public Utility	Yield	Spread		Public Utility	Yield	Spread
Dec-98	6.91%	5.36%	1.55%								
Jan-99	6.97%	5.45%	1.52%	Jan-04	6.15%	5.01%	1.14%	Jan-09	6.39%	3.46%	2.93%
Feb-99	7.09%	5.66%	1.43%	Feb-04	6.15%	4.94%	1.21%	Feb-09	6.30%	3.83%	2.47%
Mar-99	7.26%	5.87%	1.39%	Mar-04	5.97%	4.72%	1.25%	Mar-09	6.42%	3.78%	2.64%
Apr-99	7.22%	5.82%	1.40%	Apr-04	6.35%	5.16%	1.19%	Apr-09	6.48%	3.84%	2.64%
May-99	7.47%	6.08%	1.39%	May-04	6.62%	5.46%	1.16%	May-09	6.49%	4.22%	2.27%
Jun-99	7.74%	6.36%	1.38%	Jun-04	6.46%	5.45%	1.01%	Jun-09	6.20%	4.51%	1.69%
Jul-99	7.71%	6.28%	1.43%	Jul-04	6.27%	5.24%	1.03%	Jul-09	5.97%	4.38%	1.59%
Aug-99	7.91%	6.43%	1.48%	Aug-04	6.14%	5.07%	1.07%	Aug-09	5.71%	4.33%	1.38%
Sep-99	7.93%	6.50%	1.43%	Sep-04	5.98%	4.89%	1.09%	Sep-09	5.53%	4.14%	1.39%
Oct-99	8.06%	6.66%	1.40%	Oct-04	5.94%	4.85%	1.09%	Oct-09	5.55%	4.16%	1.39%
Nov-99	7.94%	6.48%	1.46%	Nov-04	5.97%	4.89%	1.08%	Nov-09	5.64%	4.24%	1.40%
Dec-99	8.14%	6.69%	1.45%	Dec-04	5.92%	4.88%	1.04%	Dec-09	5.79%	4.40%	1.39%
Jan-00	8.35%	6.86%	1.49%	Jan-05	5.78%	4.77%	1.01%	Jan-10	5.77%	4.50%	1.27%
Feb-00	8.25%	6.54%	1.71%	Feb-05	5.61%	4.61%	1.00%	Feb-10	5.87%	4.48%	1.39%
Mar-00	8.28%	6.38%	1.90%	Mar-05	5.83%	4.89%	0.94%	Mar-10	5.84%	4.49%	1.35%
Apr-00	8.29%	6.18%	2.11%	Apr-05	5.64%	4.75%	0.89%	Apr-10	5.81%	4.53%	1.28%
May-00	8.70%	6.55%	2.15%	May-05	5.53%	4.56%	0.97%	May-10	5.50%	4.11%	1.39%
Jun-00	8.36%	6.28%	2.08%	Jun-05	5.40%	4.35%	1.05%	Jun-10	5.46%	3.95%	1.51%
Jul-00	8.25%	6.20%	2.05%	Jul-05	5.51%	4.48%	1.03%	Jul-10	5.26%	3.80%	1.46%
Aug-00	8.13%	6.02%	2.11%	Aug-05	5.50%	4.53%	0.97%	Aug-10	5.01%	3.52%	1.49%
Sep-00	8.23%	6.09%	2.14%	Sep-05	5.52%	4.51%	1.01%	Sep-10	5.01%	3.47%	1.54%
Oct-00	8.14%	6.04%	2.10%	Oct-05	5.79%	4.74%	1.05%	Oct-10	5.10%	3.52%	1.58%
Nov-00	8.11%	5.98%	2.13%	Nov-05	5.88%	4.83%	1.05%	Nov-10	5.37%	3.82%	1.55%
Dec-00	7.84%	5.64%	2.20%	Dec-05	5.80%	4.73%	1.07%	Dec-10	5.56%	4.17%	1.39%
Jan-01	7.80%	5.65%	2.15%	Jan-06	5.75%	4.65%	1.10%	Jan-11	5.57%	4.28%	1.29%
Feb-01	7.74%	5.62%	2.12%	Feb-06	5.82%	4.73%	1.09%	Feb-11	5.68%	4.42%	1.26%
Mar-01	7.68%	5.49%	2.19%	Mar-06	5.98%	4.91%	1.07%	Mar-11	5.56%	4.27%	1.29%
Apr-01	7.94%	5.78%	2.16%	Apr-06	6.29%	5.22%	1.07%	Apr-11	5.55%	4.28%	1.27%
May-01	7.99%	5.92%	2.07%	May-06	6.42%	5.35%	1.07%	May-11	5.32%	4.02%	1.30%
Jun-01	7.85%	5.82%	2.03%	Jun-06	6.40%	5.29%	1.11%	Jun-11	5.26%	3.91%	1.35%
Jul-01	7.78%	5.75%	2.03%	Jul-06	6.37%	5.25%	1.12%	Jul-11	5.27%	3.95%	1.32%
Aug-01	7.59%	5.58%	2.01%	Aug-06	6.20%	5.08%	1.12%	Aug-11	4.69%	3.24%	1.45%
Sep-01	7.75%	5.53%	2.22%	Sep-06	6.00%	4.93%	1.07%	Sep-11	4.48%	2.83%	1.65%
Oct-01	7.63%	5.34%	2.29%	Oct-06	5.98%	4.94%	1.04%	Oct-11	4.52%	2.87%	1.65%
Nov-01	7.57%	5.33%	2.24%	Nov-06	5.80%	4.78%	1.02%	Nov-11	4.25%	2.72%	1.53%
Dec-01	7.83%	5.76%	2.07%	Dec-06	5.81%	4.78%	1.03%	Dec-11	4.33%	2.67%	1.66%
Jan-02	7.66%	5.69%	1.97%	Jan-07	5.96%	4.95%	1.01%	Jan-12	4.34%	2.70%	1.64%
Feb-02	7.54%	5.61%	1.93%	Feb-07	5.90%	4.93%	0.97%	Feb-12	4.36%	2.75%	1.61%
Mar-02	7.76%	5.93%	1.83%	Mar-07	5.85%	4.81%	1.04%	Mar-12	4.48%	2.94%	1.54%
Apr-02	7.57%	5.85%	1.72%	Apr-07	5.97%	4.95%	1.02%	Apr-12	4.40%	2.82%	1.58%
May-02	7.52%	5.81%	1.71%	May-07	5.99%	4.98%	1.01%	May-12	4.20%	2.53%	1.67%
Jun-02	7.42%	5.65%	1.77%	Jun-07	6.30%	5.29%	1.01%	Jun-12	4.08%	2.31%	1.77%
Jul-02	7.31%	5.51%	1.80%	Jul-07	6.25%	5.19%	1.06%	Jul-12	3.93%	2.22%	1.71%
Aug-02	7.17%	5.19%	1.98%	Aug-07	6.24%	5.00%	1.24%	Aug-12	4.00%	2.40%	1.60%
Sep-02	7.08%	4.87%	2.21%	Sep-07	6.18%	4.84%	1.34%	Sep-12	4.02%	2.49%	1.53%
Oct-02	7.23%	5.00%	2.23%	Oct-07	6.11%	4.83%	1.28%	Oct-12	3.91%	2.51%	1.40%
Nov-02	7.14%	5.04%	2.10%	Nov-07	5.97%	4.56%	1.41%	Nov-12	3.84%	2.39%	1.45%
Dec-02	7.07%	5.01%	2.06%	Dec-07	6.16%	4.57%	1.59%	Dec-12	4.00%	2.47%	1.53%
Jan-03	7.07%	5.02%	2.05%	Jan-08	6.02%	4.35%	1.67%	Jan-13	4.15%	2.68%	1.47%
Feb-03	6.93%	4.87%	2.06%	Feb-08	6.21%	4.49%	1.72%	Feb-13	4.18%	2.78%	1.40%
Mar-03	6.79%	4.82%	1.97%	Mar-08	6.21%	4.36%	1.85%	Mar-13	4.20%	2.78%	1.42%
Apr-03	6.64%	4.91%	1.73%	Apr-08	6.29%	4.44%	1.85%	Apr-13	4.00%	2.55%	1.45%
May-03	6.36%	4.52%	1.84%	May-08	6.28%	4.60%	1.68%				
Jun-03	6.21%	4.34%	1.87%	Jun-08	6.38%	4.74%	1.64%				
Jul-03	6.57%	4.92%	1.65%	Jul-08	6.40%	4.62%	1.78%				
Aug-03	6.78%	5.39%	1.39%	Aug-08	6.37%	4.53%	1.84%	Average:			
Sep-03	6.56%	5.21%	1.35%	Sep-08	6.49%	4.32%	2.17%	12-months			1.53%
Oct-03	6.43%	5.21%	1.22%	Oct-08	7.56%	4.45%	3.11%	6-months			1.45%
Nov-03	6.37%	5.17%	1.20%	Nov-08	7.60%	4.27%	3.33%	3-months			1.42%
Dec-03	6.27%	5.11%	1.16%	Dec-08	6.52%	3.18%	3.34%				

Common Equity Risk Premiums
Years 1926-2012

	<u>Large Common Stocks</u>	<u>Long- Term Corp. Bonds</u>	<u>Equity Risk Premium</u>	<u>Long-Term Govt. Bonds Yields</u>
Low Interest Rates	11.72%	4.72%	7.00%	3.03%
Average Across All Interest Rates	11.82%	6.41%	5.41%	5.16%
High Interest Rates	11.92%	8.15%	3.77%	7.35%

Source of Information: 2013 Stocks, Bonds, Bills, and Inflation (S&P) Classis Yearbook

Basic Series				
Annual Total Returns (except yields)				
Year	Large Common Stocks	Long- Term Corp. Bonds	Stocks vs. Corp. Bonds	Long- Term Govt. Bonds Yields
1940	-9.78%	3.39%	-13.17%	1.94%
1945	36.44%	4.08%	32.36%	1.99%
1941	-11.59%	2.73%	-14.32%	2.04%
1949	18.79%	3.31%	15.48%	2.09%
1946	-8.07%	1.72%	-9.79%	2.12%
1950	31.71%	2.12%	29.59%	2.24%
1939	-0.41%	3.97%	-4.38%	2.26%
1948	5.50%	4.14%	1.36%	2.37%
2012	16.00%	10.68%	5.32%	2.41%
1947	5.71%	-2.34%	8.05%	2.43%
1942	20.34%	2.60%	17.74%	2.46%
1944	19.75%	4.73%	15.02%	2.46%
1943	25.90%	2.83%	23.07%	2.48%
2011	2.11%	17.95%	-15.84%	2.48%
1938	31.12%	6.13%	24.99%	2.52%
1936	33.92%	6.74%	27.18%	2.55%
1951	24.02%	-2.69%	26.71%	2.69%
1954	52.62%	5.39%	47.23%	2.72%
1937	-35.03%	2.75%	-37.78%	2.73%
1953	-0.99%	3.41%	-4.40%	2.74%
1935	47.67%	9.61%	38.06%	2.76%
1952	18.37%	3.52%	14.85%	2.79%
1934	-1.44%	13.84%	-15.28%	2.93%
1955	31.56%	0.48%	31.08%	2.95%
2008	-37.00%	8.78%	-45.78%	3.03%
1932	-8.19%	10.82%	-19.01%	3.15%
1927	37.49%	7.44%	30.05%	3.16%
1957	-10.78%	8.71%	-19.49%	3.23%
1930	-24.90%	7.98%	-32.88%	3.30%
1933	53.99%	10.38%	43.61%	3.36%
1928	43.61%	2.84%	40.77%	3.40%
1929	-8.42%	3.27%	-11.69%	3.40%
1956	6.56%	-6.81%	13.37%	3.45%
1926	11.62%	7.37%	4.25%	3.54%
1960	0.47%	9.07%	-8.60%	3.80%
1958	43.36%	-2.22%	45.58%	3.82%
1962	-8.73%	7.95%	-16.68%	3.95%
1931	-43.34%	-1.85%	-41.49%	4.07%
2010	15.06%	12.44%	2.62%	4.14%
1961	26.89%	4.82%	22.07%	4.15%
1963	22.80%	2.19%	20.61%	4.17%
1964	16.48%	4.77%	11.71%	4.23%
1959	11.96%	-0.97%	12.93%	4.47%
1965	12.45%	-0.46%	12.91%	4.50%
2007	5.49%	2.60%	2.89%	4.50%
1966	-10.06%	0.20%	-10.26%	4.55%
2009	26.46%	3.02%	23.44%	4.58%
2005	4.91%	5.87%	-0.96%	4.61%
2002	-22.10%	16.33%	-38.43%	4.84%
2004	10.88%	8.72%	2.16%	4.84%
2006	15.79%	3.24%	12.55%	4.91%
2003	28.68%	5.27%	23.41%	5.11%
1998	28.58%	10.76%	17.82%	5.42%
1967	23.98%	-4.95%	28.93%	5.56%
2000	-9.10%	12.87%	-21.97%	5.58%
2001	-11.89%	10.65%	-22.54%	5.75%
1971	14.30%	11.01%	3.29%	5.97%
1968	11.06%	2.57%	8.49%	5.98%
1972	18.99%	7.26%	11.73%	5.99%
1997	33.36%	12.95%	20.41%	6.02%
1995	37.58%	27.20%	10.38%	6.03%
1970	3.86%	18.37%	-14.51%	6.48%
1993	10.08%	13.19%	-3.11%	6.54%
1996	22.96%	1.40%	21.56%	6.73%
1999	21.04%	-7.45%	28.49%	6.82%
1969	-8.50%	-8.09%	-0.41%	6.87%
1976	23.93%	18.65%	5.28%	7.21%
1973	-14.69%	1.14%	-15.83%	7.26%
1992	7.62%	9.39%	-1.77%	7.26%
1991	30.47%	19.89%	10.58%	7.30%
1974	-26.47%	-3.06%	-23.41%	7.60%
1986	18.67%	19.85%	-1.18%	7.89%
1994	1.32%	-5.76%	7.08%	7.99%
1977	-7.16%	1.71%	-8.87%	8.03%
1975	37.23%	14.64%	22.59%	8.05%
1989	31.69%	16.23%	15.46%	8.16%
1990	-3.10%	6.78%	-9.88%	8.44%
1978	6.57%	-0.07%	6.64%	8.98%
1988	16.61%	10.70%	5.91%	9.18%
1987	5.25%	-0.27%	5.52%	9.20%
1985	31.73%	30.09%	1.64%	9.56%
1979	18.61%	-4.18%	22.79%	10.12%
1982	21.55%	42.56%	-21.01%	10.95%
1984	6.27%	16.86%	-10.59%	11.70%
1983	22.56%	6.26%	16.30%	11.97%
1980	32.50%	-2.76%	35.26%	11.99%
1981	-4.92%	-1.24%	-3.68%	13.34%

**Yields for Treasury Constant Maturities
Yearly for 2008-2012
and the Twelve Months Ended April 2013**

<u>Years</u>	<u>1-Year</u>	<u>2-Year</u>	<u>3-Year</u>	<u>5-Year</u>	<u>7-Year</u>	<u>10-Year</u>	<u>20-Year</u>	<u>30-Year</u>
2008	1.82%	2.00%	2.24%	2.80%	3.17%	3.67%	4.36%	4.28%
2009	0.47%	0.96%	1.43%	2.19%	2.81%	3.26%	4.11%	4.08%
2010	0.32%	0.70%	1.11%	1.93%	2.62%	3.21%	4.03%	4.25%
2011	0.18%	0.45%	0.75%	1.52%	2.16%	2.79%	3.62%	3.91%
2012	0.18%	0.28%	0.38%	0.76%	1.22%	1.80%	2.54%	2.92%
Five-Year Average	<u>0.59%</u>	<u>0.88%</u>	<u>1.18%</u>	<u>1.84%</u>	<u>2.40%</u>	<u>2.95%</u>	<u>3.73%</u>	<u>3.89%</u>
<u>Months</u>								
May-12	0.19%	0.29%	0.39%	0.76%	1.21%	1.80%	2.53%	2.93%
Jun-12	0.19%	0.29%	0.39%	0.71%	1.08%	1.62%	2.31%	2.70%
Jul-12	0.19%	0.25%	0.33%	0.62%	0.98%	1.53%	2.22%	2.59%
Aug-12	0.18%	0.27%	0.37%	0.71%	1.14%	1.68%	2.40%	2.77%
Sep-12	0.18%	0.26%	0.34%	0.67%	1.12%	1.72%	2.49%	2.88%
Oct-12	0.18%	0.28%	0.37%	0.71%	1.15%	1.75%	2.51%	2.90%
Nov-12	0.18%	0.27%	0.36%	0.67%	1.08%	1.65%	2.39%	2.80%
Dec-12	0.16%	0.26%	0.35%	0.70%	1.13%	1.72%	2.47%	2.88%
Jan-13	0.15%	0.27%	0.39%	0.81%	1.30%	1.91%	2.68%	3.08%
Feb-13	0.16%	0.27%	0.40%	0.85%	1.35%	1.98%	2.78%	3.17%
Mar-13	0.15%	0.26%	0.39%	0.82%	1.32%	1.96%	2.78%	3.16%
Apr-13	0.12%	0.23%	0.34%	0.71%	1.15%	1.76%	2.55%	2.93%
Twelve-Month Average	<u>0.17%</u>	<u>0.27%</u>	<u>0.37%</u>	<u>0.73%</u>	<u>1.17%</u>	<u>1.76%</u>	<u>2.51%</u>	<u>2.90%</u>
Six-Month Average	<u>0.15%</u>	<u>0.26%</u>	<u>0.37%</u>	<u>0.76%</u>	<u>1.22%</u>	<u>1.83%</u>	<u>2.61%</u>	<u>3.00%</u>
Three-Month Average	<u>0.14%</u>	<u>0.25%</u>	<u>0.38%</u>	<u>0.79%</u>	<u>1.27%</u>	<u>1.90%</u>	<u>2.70%</u>	<u>3.09%</u>

Source: Federal Reserve statistical release H.15

Measures of the Risk-Free Rate & Corporate Bond Yields

The forecast of Treasury and Corporate yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated May 1, 2013

Year	Quarter	Treasury					Corporate	
		1-Year Bill	2-Year Note	5-Year Note	10-Year Note	30-Year Bond	Aaa Bond	Baa Bond
2013	Second	0.2%	0.3%	0.8%	1.9%	3.0%	3.8%	4.7%
2013	Third	0.2%	0.3%	0.9%	2.0%	3.2%	3.9%	4.8%
2013	Fourth	0.2%	0.4%	1.0%	2.1%	3.3%	4.0%	4.9%
2014	First	0.2%	0.4%	1.2%	2.3%	3.4%	4.1%	5.0%
2014	Second	0.3%	0.6%	1.3%	2.4%	3.5%	4.2%	5.2%
2014	Third	0.4%	0.7%	1.5%	2.5%	3.7%	4.3%	5.3%

Measures of the Market Premium

Value Line Return

As of:	Dividend Yield	+	Median Appreciation Potential	=	Median Total Return
April 26, 2013	2.2%		10.67%		12.87%

DCF Result for the S&P 500 Composite

D/P	(1+5g)	+	g	=	k
1.99%	(1.0467)		9.33%		11.41%

where:	Price (P)	at	30-Apr-13	=	1597.57
	Dividend (D)	for	1st Qtr. '13	=	7.95
	Dividend (D)		annualized	=	31.80
	Growth (g)	by	First Call	=	9.33%

Summary

Value Line		12.87%
S&P 500		11.41%
Average		12.14%
Risk-free Rate of Return (Rf)		3.75%
Forecast Market Premium		8.39%
Historical Market Premium (Rm)	(Rf)	
1926-2012 Arith. mean	11.72%	3.03%
		8.69%
Average - Forecast/Historical		8.54%

Table 7-6: Size-Decile Portfolios of the NYSE/AMEX/NASDAQ
Long-Term Returns in Excess of CAPM

Decile	Beta*	Arith- metic Mean Return (%)	Actual Return in Excess of Riskless Rate** (%)	CAPM Return in Excess of Riskless Rate† (%)	Size Premium (Return in Excess of CAPM) (%)
Mid-Cap, 3-5	1.12	13.73	8.61	7.50	1.12
Low-Cap, 6-8	1.23	15.19	10.07	8.23	1.85
Micro-Cap, 9-10	1.36	18.03	12.91	9.10	3.81

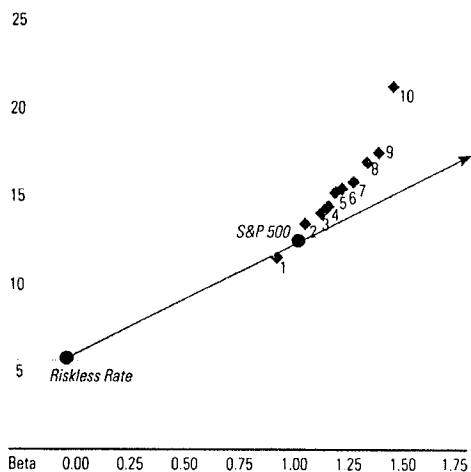
Data from 1926–2012.

*Betas are estimated from monthly returns in excess of the 30-day U.S. Treasury bill total return, January 1926–December 2012.

**Historical riskless rate measured by the 87-year arithmetic mean income return component of 20-year government bonds (5.12 percent).

†Calculated in the context of the CAPM by multiplying the equity risk premium by beta. The equity risk premium is estimated by the arithmetic mean total return of the S&P 500 (11.82 percent) minus the arithmetic mean income return component of 20-year government bonds (5.12 percent) from 1926–2012.

Graph 7-2: Security Market Line Versus Size-Decile Portfolios of the NYSE/AMEX/NASDAQ



Data from 1926–2012.

Serial Correlation in Small Company Stock Returns

The serial correlation, or first-order autocorrelation, of returns on large capitalization stocks is near zero. [See Table 7-1.] If stock returns are serially correlated, then one can gain some information about future performance based on past returns. For the smallest stocks, the serial correlation is near or above 0.1. This observation bears further examination.

Table 7-7: Size-Decile Portfolios of the NYSE/AMEX/NASDAQ
Serial Correlations of Annual Returns in Excess of Decile 1 Returns

Decile	Serial Correlations of Annual Returns in Excess of Decile 1 Return
2	0.22
3	0.27
4	0.25
5	0.25
6	0.33
7	0.27
8	0.34
9	0.29
10	0.38

Data from 1926–2012. Source: Morningstar and CRSP. Calculated (or Derived) based on data from CRSP US Stock Database and CRSP US Indices Database ©2013 Center for Research in Security Prices (CRSP®), The University of Chicago Booth School of Business. Used with permission.

To remove the randomizing effect of the market as a whole, the returns for decile 1 are geometrically subtracted from the returns for deciles 2 through 10. The result illustrates that these series differences exhibit greater serial correlation than the decile series themselves. Table 7-7 above presents the serial correlations of the excess returns for deciles 2 through 10. These serial correlations suggest some predictability of smaller company excess returns. However, caution is necessary. The serial correlation of small company excess returns for non-calendar years (February through January, etc.) do not always confirm the results shown here for calendar (January through December) years. The results for the non-calendar years (not shown in this book) suggest that predicting small company excess returns may not be easy.

Comparable Earnings Approach

Using Non-Utility Companies with

Timeliness of 3 & 4; Safety Rank of 1, 2 & 3; Financial Strength of B, B+, B++ & A;

Price Stability of 90 to 100; Betas of .55 to .85; and Technical Rank of 3, 4 & 5

<u>Company</u>	<u>Industry</u>	<u>Timeliness Rank</u>	<u>Safety Rank</u>	<u>Financial Strength</u>	<u>Price Stability</u>	<u>Beta</u>	<u>Technical Rank</u>
AutoZone Inc.	RETAUTO	3	3	B	90	0.70	3
Bemis Co.	PACKAGE	3	2	A	90	0.85	3
Capitol Fed. Fin'l	THRIFT	3	3	B+	95	0.65	3
CareFusion Corp.	MEDICINV	3	3	B++	90	0.75	3
Cullen/Frost Bankers	BANK	3	1	A	90	0.85	3
Dun & Bradstreet	INFOSER	3	3	B	95	0.75	4
Forest Labs.	DRUG	3	3	A	90	0.80	3
Haemonetics Corp.	MEDICNON	3	2	B++	95	0.65	3
Hanover Insurance	INSPRPTY	3	2	B++	90	0.80	3
Hormel Foods	FOODPROC	3	1	A	100	0.65	3
Kellogg	FOODPROC	3	1	A	100	0.55	3
Kroger Co.	GROCERY	3	2	B++	95	0.60	3
Laboratory Corp.	MEDSERV	3	1	A	100	0.65	3
Marsh & McLennan	FINSERV	3	3	B	95	0.75	3
Mercury General	INSPRPTY	4	2	B++	95	0.70	3
Molson Coors Brewing	BEVERAGE	3	2	B++	90	0.65	3
Northwest Bancshares	THRIFT	3	3	B+	90	0.75	3
Owens & Minor	MEDICNON	3	2	A	90	0.70	3
Paychex Inc.	ITSERV	3	1	A	95	0.85	3
People's United Fin'l	THRIFT	3	3	B+	95	0.70	3
Philip Morris Int'l	TOBACCO	3	2	B++	95	0.75	3
Quest Diagnostics	MEDSERV	3	2	B++	95	0.75	3
RLI Corp.	INSPRPTY	3	2	B++	90	0.80	3
Safeway Inc.	GROCERY	3	3	B+	90	0.70	3
SAIC Inc.	INDUSRV	3	2	B++	100	0.65	4
Schein (Henry)	MEDICNON	3	3	B+	95	0.80	3
Silgan Holdings	PACKAGE	3	3	B+	95	0.75	3
Synopsys Inc.	SOFTWARE	3	1	A	95	0.80	3
United Parcel Serv.	AIRTRANS	3	1	A	95	0.85	3
Waste Management	ENVIRONM	3	2	A	95	0.80	3
Weis Markets	GROCERY	3	1	A	95	0.65	3
Average		<u>3</u>	<u>2</u>	<u>B++</u>	<u>94</u>	<u>0.73</u>	<u>3</u>
Electric Group	Average	<u>3</u>	<u>2</u>	<u>B++</u>	<u>97</u>	<u>0.68</u>	<u>4</u>

Source of Information: Value Line Investment Survey for Windows, April 2013

Comparable Earnings Approach

Five -Year Average Historical Earned Returns
for Years 2008-2012 and
Projected 3-5 Year Returns

<u>Company</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>Average</u>	<u>Projected 2016-18</u>
AutoZone Inc.	NMF	-	-	NMF	NMF	-	NMF
Bemis Co.	12.3%	8.2%	10.5%	11.6%	10.6%	10.6%	15.5%
Capitol Fed. Fin'l	5.8%	7.0%	7.1%	3.3%	4.1%	5.5%	4.5%
CareFusion Corp.	-	5.8%	6.7%	7.3%	6.9%	6.7%	8.5%
Cullen/Frost Bankers	11.8%	9.5%	10.1%	9.5%	9.8%	10.1%	9.5%
Dun & Bradstreet	-	-	-	-	-	-	NMF
Forest Labs.	25.6%	21.8%	23.3%	18.0%	0.5%	17.8%	7.5%
Haemonetics Corp.	11.9%	12.5%	12.2%	10.7%	11.0%	11.7%	12.0%
Hanover Insurance	9.7%	8.0%	6.2%	1.3%	1.9%	5.4%	9.5%
Hormel Foods	14.2%	16.1%	17.0%	17.8%	17.7%	16.6%	16.5%
Kellogg	79.3%	53.3%	57.8%	69.9%	53.6%	62.8%	32.5%
Kroger Co.	24.1%	23.2%	21.1%	30.0%	33.8%	26.4%	23.0%
Laboratory Corp.	30.4%	25.3%	23.7%	25.8%	24.4%	25.9%	20.0%
Marsh & McLennan	NMF	9.2%	8.6%	16.2%	17.8%	13.0%	20.0%
Mercury General	7.7%	10.0%	6.4%	8.2%	4.0%	7.3%	10.0%
Molson Coors Brewing	8.6%	10.0%	8.6%	8.8%	5.5%	8.3%	9.0%
Northwest Bancshares	7.8%	2.5%	4.4%	5.6%	5.6%	5.2%	7.5%
Owens & Minor	14.7%	14.3%	14.4%	13.4%	11.1%	13.6%	15.5%
Paychex Inc.	48.1%	39.8%	34.0%	34.4%	34.2%	38.1%	38.5%
People's United Fin'l	2.7%	2.0%	1.6%	3.8%	4.9%	3.0%	8.0%
Philip Morris Int'l	91.9%	111.0%	207.0%	NMF	NMF	136.6%	NMF
Quest Diagnostics	17.8%	18.3%	17.9%	19.7%	17.0%	18.1%	14.5%
RLI Corp.	15.3%	12.2%	13.9%	14.7%	10.8%	13.4%	8.5%
Safeway Inc.	14.2%	14.6%	11.8%	16.7%	18.3%	15.1%	24.0%
SAIC Inc.	21.4%	21.8%	22.8%	21.8%	18.5%	21.3%	14.5%
Schein (Henry)	14.0%	13.3%	13.9%	15.1%	14.8%	14.2%	12.0%
Silgan Holdings	25.1%	23.2%	26.1%	29.4%	20.1%	24.8%	18.5%
Synopsys Inc.	13.1%	10.8%	9.1%	10.2%	9.8%	10.6%	9.0%
United Parcel Serv.	52.8%	30.4%	44.7%	59.6%	57.0%	48.9%	30.0%
Waste Management	18.4%	15.7%	16.2%	16.6%	15.2%	16.4%	20.0%
Weis Markets	7.1%	9.1%	9.4%	10.1%	10.4%	9.2%	9.0%
Average						<u>21.3%</u>	<u>15.3%</u>
Median						<u>13.6%</u>	<u>13.3%</u>
Average (excluding values <8% and >20%)						<u>12.4%</u>	<u>11.9%</u>

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-2013-2372129

Duquesne Light Company

Statement No. 10

Direct Testimony of James Milligan

Dated: August 2, 2013

1 **Q. Please state your full name and business address.**

2 A. James H. Milligan, 411 Seventh Avenue MD 7-3, Pittsburgh PA 15219.

3

4 **Q. On whose behalf are you testifying?**

5 A. Duquesne Light Company (“Duquesne Light” or “Company”).

6

7 **Q. What is your position at Duquesne Light?**

8 A. I am the Manager of Treasury Operations.

9

10 **Q. What are your current responsibilities?**

11 A. I oversee cash management, interest rate risk management, debt covenant compliance,
12 corporate insurance, capital markets transactions, pension administration, wholesale
13 counterparty credit risk and bank and rating agency relationship management.

14

15 **Q. Please describe your professional experience and educational background.**

16 A. I received a B.S. in Marketing and Economics from Indiana University of Pennsylvania
17 and an M.B.A. from the University of Pittsburgh. I have been employed at Duquesne
18 Light since 2007 and in my current role since 2011. Prior to joining Duquesne Light, I
19 served in various finance positions at Strategic Energy LLC and FirstEnergy Corp.

20

21 **Q. Have you previously testified before the Commission or other regulatory agencies?**

22 A. No.

23

1 **Q. What is the purpose of your testimony?**

2 A. I will explain the Company's current and future capital structure, cost of long-term debt,
3 current credit ratings and the importance of maintaining Duquesne Light's ratings. In
4 addition, I will discuss the Company's decision to implement a Liability Driven
5 Investment ("LDI") strategy for the Company's pension assets.

6

7 **Q. Are you sponsoring any data filing requirements as part of your testimony?**

8 A. Yes, I am sponsoring Duquesne Light's capitalization and cost of capital schedules.
9 Please see Exhibit JHM-1 to see a list of data filing requirements that I am sponsoring.

10

11 **Q. Please review Duquesne Light's current and future capital structure.**

12 A. The capital structure as of March 31, 2013 was approximately 38.1% debt, 5.5%
13 preferred stock and 56.4% equity. The Company plans to issue incremental long-term
14 debt in the FTY and FPFTY to fund a portion of the planned capital expenditures,
15 pension contributions and other general corporate purposes. As a result of the
16 incremental debt, the Company will decrease its equity as a percentage of total
17 capitalization to 51.9% by the end of the FPFTY.

18

19 **Q. What is the cost of long-term debt for Duquesne Light?**

20 A. The total adjusted long-term cost of debt at March 31, 2013 for Duquesne Light is 5.50%.
21 Given current market rates and planned issuances of debt during the FTY and FPFTY,
22 the total adjusted long-term cost of debt is expected to decrease to approximately 5.18%
23 by the end of the FPFTY.

1

2 **Q. Please describe Duquesne Light's credit ratings.**

3 A. Duquesne Light's current issuer or corporate credit rating is Baa1 and BBB- as rated by
4 Moody's and Standard & Poor's, respectively. Moody's upgraded Duquesne Light's
5 rating on March 5, 2013 from Baa2 to Baa1. In its Credit Opinion released on March 7,
6 2013, Moody's noted that Duquesne Light's Baa1 rating reflects the Company's strong
7 credit metrics and stable, regulated business model. On June 13, 2013, Standard &
8 Poor's affirmed the BBB- issuer credit rating and revised the outlook from stable to
9 positive noting the Company's excellent business risk profile and improved credit
10 metrics. Please see Attachment DFR III-F-4c - Rating Agency Reports for a table
11 illustrating Duquesne Light's credit ratings relative to the entire ratings table of Moody's
12 and Standard & Poor's. Despite the recent ratings upgrades and outlook revisions,
13 Duquesne Light's current issuer credit ratings from Moody's and Standard & Poor's are
14 at the lower end of the investment grade spectrum. Baa1 is three notches above non-
15 investment grade and BBB- is the lowest investment rating. As indicated in Attachment
16 DFR III-F-4c - Rating Agency Reports, ratings below Baa3 for Moody's and BBB- for
17 Standard & Poor's are considered "non-investment" grade and certain investors are not
18 permitted or are limited in the amount they may invest in bonds with non-investment
19 grade ratings.

20

21 **Q. Why is it important for the Company to maintain its creditworthiness?**

22 A. Duquesne Light's creditworthiness is used to determine whether and at what cost capital
23 should be lent to the Company. The Company's credit ratings are an accepted indication

1 of creditworthiness used by the capital markets. A low credit rating reduces the
2 availability of capital and makes capital more expensive. As noted previously, a
3 company with a non-investment grade rating may have a smaller universe of buyers for
4 its bonds, which increases the execution risk of issuing debt and increases the interest
5 rate. Duquesne Light has ongoing needs to access the capital markets to refinance
6 upcoming debt maturities, fund growth capital expenditures, and to meet its significant
7 pension obligations required under the Pension Protection Act. The Company must be
8 able to attract this needed capital at reasonable terms in order to fund these requirements.

9

10 **Q. Do you believe that Duquesne Light's current credit ratings provide the Company**
11 **with the financial flexibility it requires to meet customer needs at reasonable rates?**

12 A. Yes, Duquesne's current investment grade ratings are minimally adequate to allow the
13 Company to efficiently access the capital markets and do so at reasonable cost. However,
14 the Company must be able to continue to show cash flows sufficient to recover costs and
15 earn a reasonable return in the future to maintain these ratings. Any downward pressure
16 on the ratings could result in a downgrade to the issuer rating to non-investment grade by
17 one or both of the agencies, which, in turn, could result in higher financing costs and
18 greater execution risk when accessing the capital markets. A one notch downgrade in
19 credit ratings by both agencies could cost the Company an interest rate increase of
20 approximately 25 basis points under the terms of its current Credit Agreement and 50 to
21 100 basis points on new debt issued, depending on the tenor and other relevant factors.
22 Maintaining current credit ratings ensures lower borrowing costs for Duquesne Light.
23 Lower borrowing costs for Duquesne Light benefits ratepayers in the form of lower rates.

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Q. Are the results of this rate proceeding important to the Company’s ability to maintain its current credit ratings?

A. Yes, the ability to recover costs and earn a reasonable return is an important criteria used by the rating agencies in determining the Company’s creditworthiness. In addition, the rating agencies assess the supportiveness of the regulatory framework in which the Company is operating, the Company’s market position, and its overall financial strength. Using these criteria, Duquesne Light’s small size and lack of geographic and market diversification require it to have stronger financial metrics and lower overall business risk in order to attain a similar rating as a larger, more geographically diverse utility. Stronger financial metrics would include having a capital structure with higher equity capitalization and stronger cash flows compared to interest and debt levels. In general, the rating agencies view Pennsylvania as a supportive regulatory jurisdiction.

Q. Has the Company executed any debt issuances over the last three years?

A. Yes, in January 2011 Duquesne Light remarketed \$65.7 million of 4.75% tax-exempt pollution control revenue refunding bonds (“PCRRB”) to fund capital expenditures and other general corporate purposes. In February 2012, Duquesne Light issued \$200 million of 4.76% first mortgage bonds (“FMB”) through a private placement. The proceeds were used to refinance a 6.7% \$200 million DLC FMB due on April 15, 2012.

1 **Q. What are the Company's financing needs during the next several years?**

2 A. Duquesne Light's financing needs from the fourth quarter of 2013 through the end of the
3 fully projected future test year, April 30, 2015, total approximately \$325 million.
4 Duquesne Light must refinance \$50 million of PCRRBs in December 2013 and a \$100
5 million of FMBs in February 2014. In addition, Duquesne Light has additional funding
6 requirements of approximately \$175 million related to capital expenditures, pension
7 contribution requirements and other general corporate purposes that must be funded
8 externally.

9
10 To satisfy these funding needs, Duquesne Light plans to issue \$275,000,000 of secured
11 debt in late 2013 and early 2014 through a deferred draw private placement. Draws of
12 \$150,000,000 and \$125,000,000 are currently expected to occur in the November 2013
13 and January 2014, respectively. During the 4th quarter of 2014, Duquesne Light plans to
14 utilize an intercompany loan facility under an affiliated interest agreement that is
15 currently pending approval before the Pennsylvania Public Utility Commission (Docket
16 #G-2010-2162823) to borrow the remaining \$50,000,000 of needed capital.

17
18 **Q. What capital structure ratios do you recommend be adopted for rate of return
19 purposes in this proceeding?**

20 A. The Company recommends a capital structure ratio of 43.1% debt, 5% preferred stock
21 and 51.9% equity. The equity capitalization is lower than the actual equity capitalization
22 of 56.4% as of March 31, 2013. The equity capitalization will be decreased and the debt
23 ratio will increase in conjunction with the aforementioned financing plans which will

1 increase total debt outstanding for Duquesne Light by \$175 million. The recommended
2 capital structure is consistent with Duquesne Light's capital structure in the FPFTY and,
3 as described by Mr. Paul Moul, is within a reasonable range compared to Duquesne
4 Light's peers. This capital structure is also supportive of maintaining Company's
5 investment grade credit ratings.

6

7 **Q. Has Duquesne Light faced any challenges related to pension funding requirements**
8 **as a result of market volatility and the economy in general over that past several**
9 **years?**

10 A. Yes, Duquesne Light's pension plan was more than fully funded at year-end 2007, but
11 by year-end 2008 the funded status had deteriorated due to the sharp decline in the equity
12 markets during that time period. The deterioration in the funded status resulted in higher
13 required contributions to be made to the plan, as prescribed by The Pension Protection
14 Act of 2006 ("PPA").

15

16 **Q. Has the Company taken any steps to manage the funding risks presented by the**
17 **pension plan?**

18 A. Yes, the Company closed entry into its defined benefit plan for new management hires in
19 2007 and new union hires in 2010. The tangible benefits of closing the plan will take a
20 number of years to realize because the majority of participants in the pension plan that
21 were active when the plan was closed remain active and continue to accrue benefits. The
22 risks associated with the pension liability related to active membership will only decrease
23 as these members retire or are no longer employed by Duquesne Light.

1

2 **Q. Are there any additional strategies for managing the volatility of the pension's**
3 **funded status and, thereby, manage the volatility of the pension funding**
4 **requirements, that the Company is pursuing?**

5 A. Yes, the Company is implementing a Liability Driven Investing (“LDI”) strategy to
6 mitigate the volatility associated with pension plan funding. LDI is an investment
7 strategy that focuses on managing pension assets in relation to pension liabilities. This
8 investment strategy is not new, as insurance companies have been using it for years under
9 the name of Asset Liability Management. The strategy is increasingly being adopted by
10 pension plan sponsors with a significant motivation to manage volatility of the pension
11 funded status. Reduced volatility in pension plan funded status and pension plan funding
12 can provide greater predictability to the Company’s cash management and capital
13 planning and ultimately provide for more stable rates for customers.

14

15 **Q. How does LDI mitigate funded status and funding requirement risks of the pension**
16 **plan?**

17 A. LDI is a risk and volatility mitigation strategy, but it does not eliminate risk and
18 volatility. The overall goal of LDI is to minimize the volatility of Plan funded status, and
19 thus contribution volatility, by investing in long duration fixed income strategies that
20 attempt to better match the duration of the Plan’s liabilities. To see how the volatility of
21 the funding status is reduced by LDI, consider the following example. Assume interest
22 rates decline. The discount rate used to calculate the present value of the pension plan
23 liabilities declines, which results in the present value of the pension plan liabilities

1 increasing due to the discounting of future benefit payments at lower rates.
2 Simultaneously, as interest rates decline the market value of the pension plan fixed
3 income assets increases due to the discounting of future coupon payments at lower rates.
4 With perfect correlation, which is unattainable, the changes in the pension plan liability
5 would move dollar for dollar with a change in the pension plan assets and vice versa.
6

7 **Q. How does LDI differ from how Duquesne Light has historically managed its pension**
8 **plan assets?**

9 A. Historically, the Company has sought to maximize the return on its pension assets while
10 managing the volatility of those returns through diversification of investments. The
11 Company has not sought to minimize funding status volatility by aligning the volatility
12 due to interest rates of assets and liabilities.
13

14 **Q. Are there any negative aspects of an LDI strategy?**

15 A. An underfunded plan that switches to an LDI strategy could have higher funding
16 contributions to return the plan to a fully funded status due to the plan's investments
17 earning less. To offset this need for higher contributions, Duquesne Light plans to
18 transition from the former return seeking strategy to an LDI strategy as funded status of
19 the pension improves. This implementation plan balances the near-term need for assets
20 with higher expected returns with a longer-term recognition that lower funded status
21 volatility strategies are more suitable for a pension plan. As funded status improves, the
22 plan will increasingly be invested in LDI mandate investments which will help to
23 preserve the improved funded status. Another negative aspect of LDI is that even after

1 LDI has been fully implemented by the Company, the pension plan will still not be
2 perfectly hedged from movement in its liabilities, as interest-rate movements do not
3 compose all variables that impact liabilities. In addition, it is never possible to perfectly
4 match the liability discount rate with returns from fixed income of the same duration, so
5 all of the risks associated with funding status will never be totally eliminated.

6

7 **Q. Is LDI a common investment strategy for pension plans?**

8 A. Yes, and it is increasing in popularity, especially with companies that are seeking to
9 manage funded status volatility in order to avoid a recurrence of the large pension
10 funding status deteriorations that occurred over the last several years.

11

12 **Q. Does that conclude your testimony?**

13 A. Yes, it does.

53.53-II PRIMARY STATEMENTS OF RATE BASE AND OPERATING INCOME

53.53-II-B Rate Base Schedules

53.53-II-B-4 Cash working capital

53.53-II-B-5 Bank balances

53.53-III RATE OF RETURN

53.53-III-A Claimed Rate of Return

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**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-2013-2372129

Duquesne Light Company

Statement No. 11

Direct Testimony of Howard S. Gorman

Dated: August 2, 2013

1 **SECTION I- INTRODUCTION AND PURPOSE OF TESTIMONY**

2 **Q. Please state your name and occupation.**

3 A. My name is Howard Gorman. I am the President of HSG Group, Inc., a
4 consulting firm that I started in 2010.

5 **Q. Please summarize your educational background and professional experience.**

6 A. My educational background, professional experience and summary of testimony
7 are outlined in Attachment A.

8 **Q. On whose behalf are you testifying in this proceeding?**

9 A. I am testifying on behalf of Duquesne Light Company (“Duquesne Light” or
10 “Company”) in this proceeding before the Pennsylvania Public Utility
11 Commission (“Commission”).

12 **Q. What is the scope of your testimony in this proceeding?**

13 A. My testimony describes the jurisdictional separation studies (each a “JSS”) and
14 the unbundled, allocated cost of service study (“ACOS”) I have prepared for
15 Duquesne Light to comply with the Commission’s Data Filing Requirements
16 (“DFR”), specifically DFR IV-E-1.

17 The purpose of the JSS is to separate Duquesne Light’s total annual revenue
18 requirement, after first eliminating revenues and costs attributed to providing
19 supply service, between the portion subject to the jurisdiction of the Federal
20 Energy Regulatory Commission (“FERC”), i.e., the transmission revenue
21 requirement, on the one hand, and the portion subject to the jurisdiction of the
22 Commission, i.e., the distribution revenue requirement, on the other hand.

1 The purpose of the ACOS is to assign, on a cost-causation basis, Duquesne
2 Light's distribution revenue requirement among the rate classes in its Tariff.

3 The studies were prepared for the following periods:

- 4 • Year ended March 31, 2013, the Historic Test Year ("HTY")- JSS,
- 5 • and
- 6 • Year ended April 30, 2015, the Fully Projected Future Test Year
7 ("FPFTY")- JSS and ACOS

8 The FPFTY is the year being used by the Company in this proceeding for
9 determining the revenue requirement. In the FPFTY ACOS, the revenue
10 requirement resulting from the ACOS for each rate class was compared to the
11 revenue produced by the present Tariff rates, and this information was used for
12 guidance by Duquesne Light in designing the rates it is proposing in this
13 proceeding.

14 The HTY JSS was not used in determining the distribution portion of the total
15 revenue requirement.

16 In my testimony, "jurisdiction" means jurisdiction, or regulation, only as to rates.

17 **Q. How is your testimony organized?**

18 A. My testimony is organized as follows:

19 Section I (this section)- Introduction and purpose of testimony

20 Section II- Overview of JSS and ACOS

21 Section III- Identification and discussion of exhibits included with my testimony

22 Section IV- Presentation of FPFTY JSS and HTY JSS

23 Section V- Presentation of FPFTY Class ACOS Study

1 Section VI- Development of Allocators for FPPTY ACOS

2 **SECTION II- OVERVIEW OF JURISDICTIONAL SEPARATION STUDIES**

3 **AND CLASS COST OF SERVICE STUDIES**

4 **Q. Please describe what a JSS is and how it is prepared.**

5 A. The Company's filing is based on its investments and costs incurred to provide
6 distribution delivery service to its Pennsylvania jurisdictional customers.
7 Company witness Mr. O'Brien has determined the Company's total revenue
8 requirement for the FPPTY (Duquesne Light Exhibit No. 2). The purpose of the
9 JSS is to separate the total revenue requirement, after first eliminating revenues
10 and costs to provide supply service, between the portion subject to the jurisdiction
11 of the FERC, i.e., transmission revenue requirement, and the portion subject to the
12 jurisdiction of the Commission, i.e., the distribution revenue requirement.

13 In addition, a portion of the total revenue requirement is assigned or allocated to
14 the Borough of Pitcairn, which I discuss below.

15 In performing the JSS, each component of the total annual revenue requirement,
16 including plant and other rate base items, operating expenses, depreciation and
17 taxes, is analyzed, in order to directly assign or to allocate that item between
18 transmission and distribution. The distribution revenue requirement amount
19 determined in the JSS, is then allocated among the rate classes in the ACOS.

20 **Q. Please discuss how distribution service provided to the Borough of Pitcairn is**
21 **reflected in the JSS.**

22 A. The Borough of Pitcairn was historically a "sales for resale" customer of the
23 Company and subject to the jurisdiction of the FERC. Subsequent to electric
24 restructuring in Pennsylvania, Pitcairn now purchases its energy requirements

1 from a wholesale provider, receives transmission service under the PJM Open
2 Access Transmission Tariff and uses delivery service provided by the Company at
3 23 kV. The Company's distribution Tariff does not provide for this service (to a
4 wholesale customer), therefore the costs associated with providing the service are
5 removed in determining the distribution revenue requirement. To accomplish
6 this, Pitcairn is represented as a separate column in the JSS.

7 **Q. Please describe what a ACOS is and how it is prepared.**

8 A. The Company's filing is based on its investments and costs incurred to provide
9 distribution delivery service to its Pennsylvania jurisdictional customers. The
10 purpose of the ACOS is to directly assign or allocate among the rate classes each
11 component of the distribution revenue requirement, including plant and other rate
12 base items, operating expenses, depreciation and taxes, in order to determine the
13 cost of providing service to each rate class. Each component of the total revenue
14 requirement must be analyzed and assigned or allocated among the rate classes, so
15 that the utility can establish rates that, based on assumptions such as sales
16 volumes and the number of customers, provide it with a fair opportunity to
17 recover its costs and to earn an appropriate return.

18 A three-step process is traditionally used to analyze each component of the
19 revenue requirement. The first step is Functionalization of each component; for
20 Duquesne Light these functions are Primary Distribution, Secondary Distribution
21 and Billing.

22 The second step is Classification of each functionalized component as Demand,
23 Energy or Customer.

1 The final step, Class allocation, is the allocation of each functionalized, classified
2 component among the rate classes.

3 The results of the ACOS, that is, the distribution revenue requirement determined
4 for each rate class, are compared to the revenue produced by the present Tariff
5 rates; this information was used by Duquesne Light for guidance in designing the
6 rates it is proposing in this proceeding.

7 **Q. Please explain what is meant by "direct assignment."**

8 A. The term "direct assignment" means identifying plant investments or costs
9 incurred exclusively to serve a specific customer or group of customers. Direct
10 assignments best reflect the cost causation of serving particular customers or rate
11 classes. Therefore, direct assignments should be used whenever possible.

12 **Q. Please define External allocators and Internal allocators.**

13 A. Two types of allocators are used in performing a JSS or ACOS: external
14 allocators and internal allocators. *External allocators* are based on special studies
15 derived from the utility's accounting, operating and other records. For example,
16 the allocator "NCP-Primary" measures each class' peak, not necessarily
17 coincident with the system peak, and is used to allocate certain demand costs.

18 Other examples of external allocators are the number of customers in each rate
19 class, meter costs for each rate class and historical bad debt experience for each
20 rate class.

21 *Internal allocators* are based on some combination of external allocators,
22 previously directly assigned costs and other internal allocators. For example, the
23 allocators for property insurance costs are based on plant investments; it is
24 necessary to allocate plant investments before property insurance costs can be

1 allocated. Both external and internal allocators are used in each of the
2 functionalization, classification and allocation steps.

3 **Q. How did you determine the FPFTY total revenue requirement?**

4 A. The FPFTY total revenue requirement was determined by Duquesne Light
5 witness O'Brien to be \$756.8 million. The exhibits that I am sponsoring show, by
6 FERC account, the composition of the total revenue requirement for the JSS, and
7 the composition of the distribution revenue requirement for the ACOS.

8 **Q. How did you determine the revenue at present rates in the FTY and the**
9 **FPFTY?**

10 A. The supply, transmission and distribution revenue at present rates for the FTY and
11 the FPFTY was computed by Duquesne Light witness Mr. Pfrommer, as shown
12 on Attachment DFR IV-A Fully Projected Future (page 2, columns E, F and G).
13 This information was used in the JSS and the ACOS; the distribution revenue at
14 present rates was also used in the ACOS.

15 **Q. What rate classes are represented in the ACOS?**

16 A. The ACOS includes the following rate classes:

17 Residential (RS)
18 Residential Heating (RH)
19 Residential Add-on Heat (RA)
20 General Service (GS No demand)
21 General Medium<25 (GM<25)
22 General Medium>25 (GM>25)
23 General Medium Heating<25 (GMH<25)
24 General Medium Heating>25 (GMH>25)
25 General Large (GL)
26 General Large Heating (GLH)
27 Large (L)
28 High-Voltage Power Service (HVPS)
29 Street Lighting Energy (SLE)
30 Street Lighting (SLM)
31 Unmetered Service (UMS)

1 **Q. Are these the rate classes that are currently in the Tariff?**

2 A. Yes, with the following explanations and exceptions:

3 1. The current Tariff class GSGM includes a separate set of rates for each of
4 the following customer load profiles: a) GS No Demand; b) GM Demand
5 under 25 kW (GM<25) and c) GM Demand 25 kW and greater (GM>25).

6 Because there is a different set of rates for each customer load profile, they
7 are represented separately in the ACOS.

8 2. The current Tariff class GMH was split into two groups in the ACOS,
9 because they are represented as separate customer load profiles in the
10 Company's supply tariff: a) GMH Demand under 25 kW (GMH<25) and
11 b) GMH Demand 25 kW and greater (GMH>25).

12 3. The ACOS rate class Street Lighting (SLM) includes four Tariff rate
13 classes: Street Lighting Municipal (SLM), Street Lighting Highway
14 (SLH), Private Area Lighting (PAL) and Architectural Lighting (AL).
15 SLM, SLH and PAL have the same load and usage profiles. AL is very
16 small and was included for convenience in performing the ACOS. The
17 current Lighting classes will remain separate classes in the Tariff.

18 **Q. Please describe the functions that you analyzed in the ACOS.**

19 A. The functions analyzed are Primary Distribution, Secondary Distribution and
20 Billing. The distribution system, which comprises Primary Distribution and
21 Secondary Distribution, moves power from distribution substations to the
22 Company's customers. The distribution system includes operating facilities rated
23 below 69kV; *Primary Distribution* includes assets rated 4kV through 23kV and
24 *Secondary Distribution* includes all other distribution assets related to moving

1 power to customers, including service drops and excluding meters. *Billing*
2 includes metering, billing and customer accounting and service.

3 **Q. Did you review or prepare the Company's jurisdictional separation study**
4 **and class cost of service study in its most recent rate case before this**
5 **Commission, Docket R-2179522?**

6 A. Yes, I reviewed the Company's jurisdictional separation study in that proceeding,
7 and I prepared the Company's class cost of service in that proceeding.

8 **Q. Were the same methodologies used to prepare the JSS and the ACOS that**
9 **you are presenting today, compared to the methodologies used in Docket R-**
10 **2179522?**

11 A. Yes, I used the same methodologies to prepare the JSS and ACOS presented
12 today, as were used to prepare the JSS and ACOS in Docket R-2179522. In some
13 cases, the method of computing allocators was updated based on more current
14 information.

15 **SECTION III- IDENTIFICATION AND DISCUSSION OF EXHIBITS**

16 **Q. Please identify the exhibits that are included with your testimony.**

17 A. My testimony includes the following Exhibits:

18	<u>Jurisdictional Separation Study (JSS)</u>	
19	Exhibit 6-1	JSS for Fully Projected Future Test Year
20	Exhibit 6-1A	Allocator values for JSS for FPFTY
21	Exhibit 6-1B	JSS for Historical Test Year
22		
23	<u>Allocated Cost of Service Study (ACOS)- Fully Projected Future Test</u>	
24		<u>Year-</u>
25	Exhibit 6-2	Summary of Revenue requirement by rate class
26	Exhibit 6-2A	Revenue requirement by rate class by account
27	Exhibit 6-2B	Revenue requirement by rate class- Functional
28		classification
29	Exhibit 6-2C	Customer charge costs- RS
30	Exhibit 6-2D	Customer charge costs- GS
31	Exhibit 6-2E	Customer charge costs- GM<25
32	Exhibit 6-2F	Customer charge costs- GM>25
33	Exhibit 6-2G	Customer charge costs- GMH

1	Exhibit 6-2H	Customer charge costs- L
2		
3	Exhibit 6-3	Functionalization
4	Exhibit 6-3A	Classification for Secondary Distribution function
5		
6	Exhibit 6-4A	Class allocation - Primary Distribution Demand
7	Exhibit 6-4B	Class allocation- Secondary Distribution Demand
8	Exhibit 6-4C	Class allocation - Secondary Distribution Customer
9	Exhibit 6-4D	Class allocation - Billing customer
10		
11	Exhibit 6-5A	Assignment or Allocator Used for Each Account
12	Exhibit 6-5B	Allocator values - Functionalization
13	Exhibit 6-5C	Allocator values- Classification
14	Exhibit 6-5D	Allocator values - Class allocation
15		
16	Exhibit 6-6	Development of external allocator values
17		
18	Exhibit 6-7	Distribution ROR at Proposed Revenue Allocation
19		

20 **Q. Please describe Exhibits 6-1, 6-1A and 6-1B.**

21 A. Exhibit 6-1 presents the jurisdictional separation study for the FPFTY. The
22 exhibit shows each item in the total revenue requirement, the direct assignment or
23 allocator selected for that item, and the result of the allocation (or assignment)
24 among supply, transmission, Pitcairn and distribution. The items in the revenue
25 requirement comprise: plant and other rate base (lines 1-76), operating expenses
26 (lines 77-135), depreciation expense (lines 137-157) and taxes (lines 159-175).
27 Revenues (lines 179-187) are compared to total expenses (line 177, also line 189)
28 to compute net income at present rates (line 190, also line 208) and return on rate
29 base (line 210). This information is summarized on lines 192-210.

30 The revenue requirement to produce a rate of return of 8.36% in the FPFTY is
31 computed on lines 212-228, and the revenue requirement compared to revenue at
32 present rates is shown on line 231. It should be noted that the 8.36% rate of
33 return target is the Company's requested return in this distribution proceeding;

1 that return is applied to the other functions only for computational purposes in
2 preparing the exhibit.

3 The distribution revenue requirement for the FPPTY is \$509.8 million, an
4 increase of \$76.3 million.

5 Exhibit 6-1A shows the development of the allocators used in the JSS.

6 Exhibit 6-1B presents the JSS for the HTY. The line references are the same as
7 for Exhibit 6-1.

8 **Q. Please describe Exhibits 6-2, 6-2A and 6-2B.**

9 A. Exhibit 6-2 summarizes the results of the ACOS for the FPPTY. The exhibit
10 presents, for each rate class, the return on rate base at present rates for the FPPTY,
11 and the FPPTY revenue requirement assuming each class provides the rate of
12 return on rate base requested by the Company in this proceeding, 8.36%.

13 The exhibit shows revenue at present rates (lines 1-4), expenses (line 6), net
14 income (line 7) and rate base (line 9) for each rate class, and computes return on
15 rate base at present rates (line 11). The revenue requirement for each rate class to
16 produce a rate of return of 8.36% is on line 13, and the corresponding net income
17 and rate of return for each rate class are computed on lines 15-25. The increase or
18 decrease in distribution revenue for each class to produce the 8.36% return is on
19 line 27, and the percent of present rate distribution revenue that the increase or
20 decrease represents is on line 28.

21 The exhibit demonstrates that to produce the return on rate base of 8.36% an
22 increase in distribution revenue of \$76.3 million, or 17.6%, is needed.

1 Exhibit 6-2A shows the FPFTY distribution revenue requirement by component
2 for each rate class, with a total distribution revenue requirement of \$509.8
3 million. The line references are the same as for Exhibit 6-1.

4 The revenue requirement for each class is computed on lines 213-228. The
5 revenue requirement is the sum of allocated operating expenses, depreciation
6 expense and general taxes, return on allocated rate base, related income tax
7 expense and gross receipts tax. The distribution revenue requirement for each
8 rate class is shown on line 228; these are the same as the amounts on Exhibit 6-2,
9 line 13, and include both Tariff revenues and other revenues attributed to each
10 class.

11 Exhibit 6-2B summarizes the Distribution revenue requirement by functional
12 classification and also shows unitized revenue requirements.

13 **Q. Please describe Exhibits 6-2C through 6-2H.**

14 A. Exhibits 6-2C through 6-2H compute the costs to be considered in determining
15 the customer charge, based on PUC precedent, for the following rate classes: RS
16 (Exhibit 6-2C); GS (Exhibit 6-2D), GM<25 (Exhibit 6-2E); GM>25 (Exhibit 6-
17 2F). GMH (Exhibit 6-2G); and L (Exhibit 6-2H). The amounts on these exhibits
18 are based on the results of the ACOS.

19 **Q. Please describe Exhibit 6-3.**

20 A. Exhibit 6-3 shows how each component of the FPFTY revenue requirement has
21 been allocated among the Functions: Primary Distribution, Secondary
22 Distribution and Billing. The schedule shows the allocator selected for each
23 component, and the result of the allocation. The line references are the same as
24 for Exhibit 6-1.

1 **Q. Please describe Exhibit 6-3A.**

2 A. Exhibit 6-3A shows how each component of the Secondary Distribution function
3 has been classified to either Demand or Customer. Classification schedules are
4 not needed for Primary Distribution because it is classified 100% to Demand or
5 for Billing because it is classified 100% to Customer. Exhibit 6-3A shows the
6 classification allocator selected for each component, and the result of the
7 allocation. The line references are the same as for Exhibit 6-1.

8 **Q. Please describe Exhibits HSG-4A through 4D.**

9 A. Exhibits HSG-4A through 4D shows how each component of the functionalized,
10 classified costs has been allocated among the rate classes. Exhibits HSG-4A
11 through 4D show Primary Distribution Demand, Secondary Distribution Demand,
12 Secondary Distribution Customer and Billing Customer, respectively. The totals
13 for Primary Distribution Demand and Billing Customer are from Exhibit 6-3
14 (Functionalization), and the totals for Secondary Distribution Demand and
15 Secondary Distribution Customer are from Exhibit 6-3A (Classification-
16 Secondary distribution). Each exhibit shows the allocation factor selected to
17 allocate each component among the rate classes, and the result of the allocation.
18 The line references are the same as for Exhibit 6-1.

19 **Q. Please describe Exhibits 6-5A through 6-5D.**

20 A. Exhibit 6-5A shows the allocator used for each account. The exhibit includes
21 Functionalization; Classification of Secondary Distribution; and Class Allocation
22 of Primary Distribution Demand; Secondary Distribution Demand; Secondary
23 Distribution Customer; and Billing Customer.

1 Exhibits HSG-5B through 5D show the allocator values for Functionalization,
2 Classification and Class Allocation, respectively.

3 **Q. Please describe Exhibit 6-6.**

4 A. Exhibit 6-6 shows the development of the external allocator values. I will discuss
5 each exhibit in detail later in my testimony.

6 **SECTION IV- JURISDICTIONAL SEPARATION STUDIES**

7 **Q. Referring to Exhibit 6-1, the JSS for the FPFTY, how did you determine the**
8 **appropriate direct assignment or allocator for the jurisdictional separation**
9 **of each item in the total revenue requirement?**

10 A. Selection of the appropriate direct assignment or allocator for the jurisdictional
11 separation of each component of the total revenue requirement was based on
12 careful consideration of cost causality, as well as prior Duquesne Light
13 methodology, Commission precedent and utility practice as stated in the Electric
14 Utility Cost Allocation Manual (January 1992) of the National Association Of
15 Regulatory Utility Commissioners (“NARUC Manual”). Cost causality means
16 the cause and effect relationships between customer requirements, load profiles
17 and usage characteristics on one hand, and the costs incurred to serve those
18 requirements on the other hand.

19 **Q. Did you use the same allocator for each account as was used in the JSS**
20 **presented in Docket R-2179522?**

21 A. In most cases, I used the same allocator for each account as in the JSS presented
22 in Docket R-2010-2179522 (“Prior JSS”). For a few accounts, detailed
23 information was available to allow a closer alignment with cost causation in this
24 JSS. I will cite these instances as I discuss the allocation of each component of
25 the revenue requirement, immediately below.

1 **Q. How did you directly assign or allocate the components of rate base for the**
2 **purpose of jurisdictional separation?**

3 A. *Intangible assets* is primarily software. Software was allocated based on its use
4 for plant-related activities, labor-related activities, retail billing and customer-
5 related activities, or Smart Meter or FOCUS software. Smart Meter and FOCUS
6 software were allocated based on their respective uses by the Company. In the
7 Prior JSS, Intangible assets followed the allocation of Plant.

8 *Transmission plant* and *distribution plant* were directly assigned to their
9 respective functions based on the FERC accounts, except for the distribution
10 assets that serve Pitcairn, which were directly assigned to it. The Company's
11 FERC accounts reflect the 7-factor test (separating Transmission and Distribution
12 assets) completed in connection with its filing in Docket R-00061346.

13 *General plant* was allocated based on the labor content of operating and
14 maintenance ("O&M") accounts.

15 *Depreciation reserve* followed the plant and asset accounts to which it related.

16 *Other rate base items* were provided by function (Accumulated deferred income
17 tax, Materials & supplies) or were directly assigned (Customer deposits) or
18 allocated (Cash working capital, Capitalized pension).

19 **Q. How did you directly assign or allocate costs for the purpose of jurisdictional**
20 **separation?**

21 A. *Supply costs* and *Transmission O&M* were directly assigned to their respective
22 functions. *Distribution O&M* was directly assigned to the distribution function,
23 except for a small portion that was allocated to Pitcairn based on its share of the
24 distribution assets that serve Pitcairn. Customer accounts and customer service

1 costs were directly assigned to Distribution, except for FOCUS-related costs
2 which were split between Transmission and Distribution.

3 *Administrative & general* costs related to customer accounts and customer service
4 (i.e., costs for bill printing, customer care, meters and regulatory commission)
5 were directly assigned to distribution; property insurance was allocated based on
6 plant cost; and other costs were allocated based on the labor content of O&M
7 accounts. In the Prior JSS, all Administrative & general costs were allocated
8 based on labor, except for property insurance.

9 *Depreciation expense* followed the plant or assets accounts to which it related.
10 *Taxes* were allocated based on labor (payroll taxes), plant cost (PURPA tax),
11 revenue subject Pennsylvania gross receipts tax; or taxable income on
12 Pennsylvania and Federal bases (income tax).

13 **Q. How did you directly assign or allocate revenue for the purpose of**
14 **jurisdictional separation?**

15 A. *Supply* and *Transmission revenue* were directly assigned to their respective
16 functions; these amounts include miscellaneous revenues directly identified to
17 those functions. *Distribution revenue*, including delivery revenue and other
18 revenues included in this proceeding, were directly assigned to distribution.

19 **Q. How did you compute the Pennsylvania jurisdictional distribution revenue**
20 **requirement?**

21 A. The Pennsylvania jurisdictional distribution revenue requirement is computed on
22 lines 213-228. It is the amount required to recover all jurisdictional costs, and to
23 provide an after-tax return on jurisdictional rate base of 8.36%.

24 It should be noted that the revenue requirements for supply, transmission and
25 Pitcairn shown on Exhibit 6-1 are for computational purposes in preparing the

1 exhibit (i.e., to tie to the total), and may differ from the amounts that would be
2 established in appropriate proceedings.

3 **Q. Does the JSS for the HTY, presented in Exhibit 6-1B, compute the HTY**
4 **jurisdictional revenue requirement in the same manner as the JSS for the**
5 **FPFTY?**

6 A. Yes.

7 **SECTION V- ALLOCATED COST OF SERVICE (ACOS) STUDY**

8 **Q. Referring to Exhibits 6-2 through 6-5D, the ACOS for the FPFTY, how did**
9 **you determine the appropriate allocators for functionalizing, classifying and**
10 **allocating the components of the distribution revenue requirement?**

11 A. Selection of the appropriate approach for functionalizing, classifying and
12 allocating each component of the revenue requirement was based on careful
13 consideration of cost causality, as well as prior Duquesne Light methodology,
14 Commission precedent and utility practice as stated in the NARUC Manual. Cost
15 causality means the cause and effect relationships between customer
16 requirements, load profiles and usage characteristics on one hand, and the costs
17 incurred to serve those requirements on the other hand.

18 **Q. Please describe the functionalization step of a ACOS.**

19 A. In the functionalization step, costs are separated by the utility's basic service
20 functions; for Duquesne Light, these are Primary Distribution, Secondary
21 Distribution and Billing. There are separate functions for Primary Distribution
22 and Secondary Distribution because some customers take service at Primary
23 voltages; therefore it is necessary to separate the assets so that only the customers
24 that use each portion of the system are allocated the costs attributed to that
25 portion. Billing refers to activities starting at the meter on the customer's

1 premises, and includes metering activities and customer care, as well as activities
2 intrinsic to the utility function.

3 **Q. Were any assets refunctionalized?**

4 A. For the most part, functionalization follows costs as recorded in the FERC
5 Uniform System of Accounts. The ACOS excludes assets and costs related to
6 Transmission (moving power at voltages 69kV and above), which were separated
7 from the total revenue requirement in the JSS.
8 However, some accounts were split into more than one cost component. For
9 example, a portion of Station Equipment (Account 362) representing assets used
10 to serve customers in the downtown network was split out, based on the
11 Company's accounting and operating records, in order to allocate the cost among
12 the appropriate rate classes.
13 Underground Conduits (Account 366) and Underground Conductors (Account
14 367) were split into separate components representing three different portions of
15 the underground system- Radial; Network; and Underground Residential
16 Development ("URD"), based on Company engineering estimates and judgments.
17 Exhibit 6-3 shows the amount for each FERC account and other component
18 included in the revenue requirement (in the column "Balance"), the functional
19 allocator used for each (in the column "Allocator"), and the amounts assigned to
20 each function (in the columns "Primary Distribution" and "Secondary
21 Distribution" and "Billing"). The revenue requirement for each function is shown
22 on line 228. Exhibit 6-5B shows the values for each functional allocator.

1 **Q. How were assets and costs assigned or allocated among the functions?**

2 A. Many assets and costs can be directly assigned to a function, and this was done
3 whenever possible. For example, Customer accounts and service (Accounts 901-
4 908) were assigned to the Billing function. Costs related directly to particular
5 assets, such as Maintenance of Station Equipment (Account 592), were allocated
6 in proportion to the assets. Certain items, such as general plant and administrative
7 and general expenses, are related to more than one function. Each cost was
8 analyzed and allocated among the functions, using an appropriate allocation basis.

9 **Q. How were assets functionalized between the Primary Distribution and**
10 **Secondary Distribution functions?**

11 A. Duquesne Light's Primary Distribution system operates at voltages of 4kV up to
12 23kV. In recent years, Duquesne Light has converted much of the 4kV system to
13 23kV, and has expanded the 23kV portion of the system.

14 Structures (Account 361) and Station Equipment (Account 362) are part of the
15 Primary Distribution system.

16 Overhead Conductors and Devices (Account 365) was functionalized between
17 Primary Distribution and Secondary Distribution based on a review of purchases
18 over the period 1999-2012.

19 Poles, Towers and Fixtures (Account 364) were allocated proportionately to the
20 Overhead Conductors and Devices they support.

21 Each component (Radial, Network, and URD) of Underground Conduits
22 (Account 366) and Underground Conductors (Account 367) was functionalized
23 between Primary Distribution and Secondary Distribution based on a review of
24 purchases over the period 1999-2012.

1 Line Transformers (Account 368) has subaccounts for Overhead, Radial, Network
2 and URD. Almost all transformers are part of the Secondary Distribution system,
3 except for some of the larger Overhead transformers which are part of the Primary
4 Distribution system.

5 Services (Account 369) are also part of the Secondary Distribution system, and
6 Meters (Account 370) and Meter Communications Equipment (Account 370.1)
7 are part of the Billing function. Street Lighting Equipment (Account 373) is part
8 of the Secondary Distribution system.

9 Exhibit 6-6B summarizes the results of the functionalization of distribution assets
10 (accounts 360-373 in the USA) between Primary Distribution and Secondary
11 distribution. Exhibit 6-6C shows the supporting calculations.

12 **Q. Please describe the classification step of a ACOS.**

13 A. In the classification step, the previously functionalized accounts are separated into
14 Customer, Energy or Demand, according to the system design or operating
15 characteristics that cause them to be incurred.

16 Customer-related costs are incurred to attach a customer to the distribution
17 system, to operate and maintain the Company's distribution plant, to meter usage,
18 and to maintain the customer's account. Customer-related costs are primarily a
19 function of the number of customers served and continue to be incurred whether
20 or not a particular customer uses any electricity, and typically do not vary with
21 usage or load profile. They include capital costs associated with the customer
22 portion of the distribution system, services and meters, and operating costs such
23 as customer service, field service, billing and accounting.

1 Energy-related costs would vary with the amount of electricity sold to or
2 delivered to customers. In the ACOS, only \$2.9 million of costs (related to
3 regulatory expenses) and \$9.8 million of rate base (related to Supply working
4 capital) were allocated on the basis of energy (MWh).

5 Demand-, or capacity-, related costs are associated with plant that is designed,
6 constructed and operated to meet system peak demand or non-coincident class
7 peak demand.

8 **Q. How were assets and costs classified?**

9 A. Most assets and costs fit into one of the three classifications, but some are split
10 between Demand and Customer based upon special studies or based on the
11 classification of related assets or other related costs.

12 On the Duquesne Light system, Primary Distribution plant is designed to meet
13 localized peak demands; these functions are classified 100% to Demand. The
14 Billing function is classified 100% to Customer.

15 Secondary Distribution plant has two purposes- to connect the customer in order
16 to carry electricity to the customer regardless of use, and to meet localized peak
17 demands. Most Secondary Distribution assets (i.e., Overhead Conductors;
18 Underground Conduits; Underground Conductor; and Line Transformers) were
19 classified as Demand or Customer using a Minimum System approach. In the
20 Minimum System approach, for each Secondary Distribution asset class, the
21 Minimum Size Ratio was computed, equal to the ratio of x) the cost of the
22 minimum size of that asset necessary to provide reliable distribution service to y)
23 the average cost of that asset. The utility must install the minimum size asset, and

1 incur the cost for that asset, simply to connect the customer, regardless of usage or
2 load profile, and the cost of the minimum size asset is not related to usage (kWh)
3 or peak demand. Therefore the portion of total asset cost represented by the
4 Minimum System Ratio is classified as Customer-related. The balance of each
5 Secondary Distribution asset account is classified as Demand-related.

6 Investments in Poles, Towers and Fixtures are classified as Customer
7 proportionately to Overhead Conductors. Services, Meters and Meter
8 Communications Equipment, and Street Lighting assets are classified as
9 Customer.

10 Secondary Distribution costs that are related to particular assets were classified in
11 proportion to those assets. For example, Maintenance of Overhead Lines
12 (Account 593) was classified using the same classification allocator as Overhead
13 Lines. Other costs, such as general plant and administrative and general
14 expenses, are related to more than one function. Therefore each other cost was
15 analyzed to determine the appropriate classification allocator.

16 Exhibit 6-3A shows the classification of each component in the Secondary
17 Distribution function by FERC account. Primary Distribution is classified 100%
18 to Demand and Billing is classified 100% to Customer, so there is no need to
19 show the classification by FERC account. Exhibit 6-5C shows the values for each
20 classification allocator.

21 **Q. Please describe the Minimum System approach used in the ACOS.**

22 A. The Minimum System approach was used for Secondary system Line
23 Transformers, Overhead Conductors and Underground Conductors.

1 For *Line Transformers*, Duquesne Light provided detailed historical records by
2 size and by cost for each of Overhead transformers (Account 368.1),
3 Underground Radial transformers (Account 368.3), Underground Network
4 transformers (Account 368.5) and URD transformers (Account 368.7). For each
5 of these accounts, the Minimum System Ratio, equal to the ratio of (x) the cost of
6 the minimum size transformer to (y) the average cost of all transformers, was
7 computed, using recent costs. The Minimum System Ratio represents the
8 Customer component of cost, and is mathematically equal to dividing (a) what the
9 account balance would be if all units in the account were equivalent to the
10 minimum size unit, by (b) the total account balance.

11 For *Overhead Conductors* and *Underground Conductors*, historical information
12 by size and by cost was not available. For each item, the ratio of (x) the estimated
13 current cost if the minimum size (voltage rated) unit would be installed to (y) the
14 estimated average current cost of all units, was computed; this ratio equals the
15 Customer component of cost. Separate minimum size computations were made
16 for Overhead Conductors and each component of Underground Conductors
17 (Radial, Network and URD).

18 Exhibit 6-6B summarizes the classification of distribution assets (Accounts 360-
19 373 in the FERC USA) based on the Minimum System Study, and Exhibit 6-6C
20 shows the supporting calculations.

21 The demand-classified portions of certain of these assets were adjusted to reflect
22 the ability of the minimum size system to carry a portion of peak load (Peak Load
23 Carrying Capacity, or "PLCC"). I will discuss the PLCC adjustment below.

1 **Q. Please describe the class allocation step of a ACOS.**

2 A. In the class allocation step, the functionalized, classified costs are allocated
3 among the rate classes, based on causal relationships. These relationships are
4 determined by analyzing the Company's system design and operations, its
5 accounting records and its system and customer load data. Based on those
6 analyses, direct assignments of costs, as well as cost allocators, can be chosen for
7 each asset and cost.

8 **Q. How were the components of the rate base in the Distribution revenue**
9 **requirement allocated among the rate classes in the ACOS?**

10 A. Demand-related assets, or the demand-related portions, were allocated based on
11 the appropriate class non-coincident peak ("NCP") allocator. Exhibit 6-6D
12 identifies the demand allocator selected for the demand component of each type
13 of asset (Distribution Substations; Poles, Tower and Fixtures and Overhead
14 Conductors; Underground Conduits and Underground Conductors; and Line
15 Transformers). Separate NCP allocators were developed for the different
16 configurations of the distribution system, as described in Exhibit 6-6D.

17 Customer-related assets, or the customer-related portions, were allocated based on
18 the number of customers that use the asset, or special studies for Services
19 (Account 369- based on the comparative costs of installing residential and
20 commercial services), Meters (Account 370-based on the number and types of
21 meters used by each rate class) and related assets.

1 General plant was allocated based on the labor content of O&M accounts.
2 Depreciation reserve and Accumulated deferred income tax followed the plant
3 and asset accounts to which they related.
4 Cash Working Capital, Materials & supplies and Capitalized pension were) or
5 allocated using internal allocators, and Customer deposits was directly assigned.

6
7 Each of Exhibits 6-4A though 6-4D shows the allocator used for each component
8 of the rate base functionally classified as Primary Demand, Secondary Demand,
9 Secondary Customer and Billing Customer, respectively.

10

11 **Q. How were costs in the Distribution revenue requirement allocated among the**
12 **rate classes in the ACOS?**

13 A. The demand-related and customer-related components of O&M costs followed
14 the allocation of the particular assets to which they related. For example,
15 Maintenance of Overhead Lines (Account 593) was allocated using the same
16 allocators as the plant asset Overhead Conductors, (Account 365) and
17 Maintenance of Underground Lines (Account 594) was allocated in proportion to
18 the total of the plant assets Underground Lines- Radial, Network and URD
19 (Account 367). Special studies were used to develop the allocators for Meter
20 Expenses (Account 586) and Maintenance of Meters (Account 597).

21 Miscellaneous Distribution Expenses (Account 588) and Maintenance of
22 Miscellaneous Plant (Account 599) were functionalized, classified and allocated
23 in proportion to distribution plant.

1 Customer accounts and service accounts (Accounts 901-908 were analyzed to
2 determine the activities charged to each account, and each activity was allocated
3 based on the appropriate causal relationship. Examples of some components are:

- 4 • Inbound calls (activity in Customer records and collections- Account 903)
5 was allocated based on types of inbound calls (e.g., Credit - Residential;
6 Credit- Commercial; Verify payment).
- 7 • Credit and collection (activity in Customer records and collections) was
8 allocated based on delinquencies by customer group and rate class.
- 9 • Customer care and customer service and Field service (activities in
10 Customer records and collections), as well as Customer assistance
11 (Account 908) were allocated based on number of customers.

12 Administrative and general expenses (Accounts 920-935) were allocated based on
13 the activities to which they relate, including the labor component of O&M, plant
14 cost, number of customers, number of meters, and revenue or MWh delivered.

15 Depreciation expense followed the plant accounts to which it related.

16 Taxes were allocated based on labor (payroll taxes), plant cost (PURPA tax),
17 revenue subject Pennsylvania gross receipts tax; or taxable income on
18 Pennsylvania and Federal bases (income tax).

19 Each of Exhibits 6-4A through 6-4D shows the allocator used for each component
20 of costs functionally classified as Primary Demand, Secondary Demand,
21 Secondary Customer and Billing Customer, respectively.

22

1 **Q. How was revenue at present rates applicable to the Distribution revenue**
2 **requirement allocated among the rate classes in the ACOS?**

3 A. Distribution delivery revenue was directly assigned based on Attachment DFR
4 IV-A Fully Projected Future (page 2, column E). Forfeited discounts were
5 allocated based on historical net write-offs. Rent from Electric Property was
6 allocated in the same manner as Overhead Conductors. Miscellaneous Service
7 Revenue and Other Revenue were allocated based on Distribution delivery
8 revenue.

9

10 **SECTION VI- DEVELOPMENT OF ALLOCATORS FOR CLASS ACOS STUDY**

11 **Q. How were the allocators used in the ACOS developed?**

12 A. Exhibit 6-6 shows the development of the external allocators used in the ACOS.
13 Exhibit 6-6 includes Exhibits 6-6A through 6-6L.

14 **Q. Please describe Exhibit 6-6A.**

15 A. Exhibit 6-6A shows the allocator values for each external class allocator. The
16 allocator values are developed in the remaining pages of Exhibit 6-6.

17 **Q. Please describe Exhibit 6-6B and Exhibit 6-6C.**

18 A. Exhibit 6-6B summarizes the results of the functionalization of distribution assets
19 (accounts 360-373 in the FERC USA) between Primary Distribution and
20 Secondary Distribution and the Minimum System Study.

21 Exhibit 6-6C shows the calculations for the functionalization of distribution assets
22 between Primary Distribution and Secondary Distribution and the Minimum
23 System Study.

1 **Q. Please describe Exhibit 6-6D, Exhibit 6-6E and Exhibit 6-6E-1.**

2 A. Exhibit 6-6D identifies the demand allocator selected for the demand component
3 of each type of asset (Distribution Substations; Poles, Tower and Fixtures and
4 Overhead Conductors; Underground Conduits and Underground Conductors; and
5 Line Transformers). Separate allocators were developed for the Radial, Network
6 and URD components of Underground Conduits and Underground Conductors
7 and Line Transformers. Exhibit 6-6D also discusses how each demand allocator
8 was developed.

9 Exhibit 6-6E presents the computation of the demand allocators, by applying the
10 approach discussed in Exhibit 6-6D. Exhibit 6-6E-1 presents the PLCC
11 adjustment.

12 **Q. Please discuss the PLCC adjustment.**

13 A. The minimum size components developed for the Secondary Distribution system
14 have the ability to carry a portion of peak load (Peak Load Carrying Capacity, or
15 "PLCC"). The PLCC of certain of these assets was removed in computing the
16 allocator for the Secondary-Demand classified portion of those assets.

17 For example, the minimum system for OH Transformers (based on the 25 kVA
18 minimum size component) have capacity equal to 3.174 kW per customer;
19 therefore in computing the allocator NCP-Secondary-Xfmr which is used for the
20 demand component of OH Transformers, peak demands above 3.174 kW per
21 customer are deducted from the for each class.

22 The PLCC adjustment was made for OH Transformers and Radial Transformers,
23 comprising 58.8% of Secondary Demand plant; the effect on the results of the

1 ACOS was insignificant. The PLCC adjustment was not made for other
2 Secondary Demand plant because the detailed information needed was not readily
3 available and effect on the results of the ACOS would not be justified.

4 **Q. Please describe Exhibit 6-6F.**

5 A. Exhibit 6-6F presents the values for revenue and physical (MWh) allocators, and
6 number of customers, as shown on Attachment DFR IV-A Fully Projected Future
7 (page 1, columns C and D).

8 **Q. Please describe Exhibit 6-6G.**

9 A. Exhibit 6-6G presents the calculation of service costs based on current installed
10 costs for typical residential and commercial services.

11 **Q. Please describe Exhibit 6-6H.**

12 A. Exhibit 6-6H presents the calculation of the meter cost allocator and related
13 allocators, based on the number of meters by meter type and by rate class and
14 information as to meter maintenance costs and related costs.

15 **Q. Please describe Exhibit 6-6I.**

16 A. Exhibit 6-6I presents the allocation of Customer Accounts and Service Expense,
17 based on the activities reflected in Supervision (account 901), Meter reading
18 (account 902) and Customer records and collections (account 903). It includes a
19 supporting analysis of Call Center activity.

20 **Q. Please describe Exhibit 6-6J, Exhibit 6-6K and Exhibit 6-6L.**

21 A. Exhibit 6-6J, Exhibit 6-6K and Exhibit 6-6L allocate among the rate classes,
22 Write-offs; Number of delinquencies and Delinquency amounts; and Customer
23 deposits, respectively, based on historical information.

1 **Q. How did you develop the revenue requirements for each class?**

2 A. The revenue requirements for each class are computed in the same manner as that
3 used by witness Mr. O'Brien to compute the overall revenue requirement for the
4 FPFTY, and that I used to calculate the jurisdictional revenue requirements. Class
5 revenue requirements are the sum of each class' allocated operating expenses,
6 depreciation expense, general taxes, required return and the income tax and gross
7 receipts tax. Distribution service revenue requirements for each rate class are
8 shown on line 228 for Functionalization (Exhibit 6-3), Classification (Secondary
9 Distribution- Exhibit 6-3A), Functionally Classified (Exhibits HSG-4A to 4D),
10 and in total (Exhibit 6-2A).

11 **Q. How did you determine the revenue deficiency for each rate class?**

12 A. The class revenue deficiency is computed by comparing the revenue requirements
13 for each class to the revenue that is forecast at present rates for that class.

14 **SECTION VII- RATES OF RETURN AT PROPOSED REVENUE ALLOCATION**

15 **Q. Please describe Exhibit 6-7.**

16 A. Exhibit 6-7 computes the Distribution Rates of Return for each rate class based on
17 the revenue allocation proposed by Mr. Pfrommer. The revenue that would be
18 produced under proposed rates for the FPFTY was computed by Mr. Pfrommer,
19 as shown on Attachment DFR IV-A Fully Projected Future (page 6).

20

21 **Q. Does this conclude your direct testimony at this time?**

22 A. Yes.

23

**RESUME OF
HOWARD S. GORMAN
PRESIDENT – HSG GROUP, INC.**

SUMMARY

Mr. Gorman has more than 25 years of experience in the energy industry, including 15 years in rate and regulatory proceedings, and more than 30 years experience overall in accounting, finance and rate and regulatory matters.

Mr. Gorman has testified as an expert witness regarding utility revenue requirements, class cost of service, revenue allocation and rate design. He has testified as an expert witness before the Massachusetts Department of Public Utilities, New Jersey Board of Public Utilities, New York State Public Service Commission, Ontario Energy Board, Pennsylvania Public Utility Commission and Rhode Island Public Utilities Commission.

Mr. Gorman has performed financial analyses of energy infrastructure projects for acquisitions and in support of due diligence for financing, and has negotiated and completed construction and term loans, tax-exempt and taxable bonds and subordinated debt. His experience includes financial modeling, financial analysis and forecasting.

Mr. Gorman also has experience in financial accounting, as Controller and Treasurer of Trigen Energy Corporation, where he built the finance function, managed subsidiary controllers and supported an IPO with NYSE listing.

PROFESSIONAL EMPLOYMENT

2010 - Present	HSG Group, Inc. <i>President</i>
1997 - 2010	Black & Veatch Corporation (R.J. Rudden Associates, Inc. before 2005) <i>Principal Consultant</i>
1995 - 1997	Independent Consultant
1987 – 1995	Trigen Energy Corporation 1987-1993: <i>Corporate Controller</i> ; Trigen was formed in 1987 1993-1995: <i>Treasurer</i> ; Trigen had IPO with NYSE listing in 1994
1982 - 1987	Coleco Industries, Inc. <i>Director, Treasury</i>
1976 - 1979	Touche Ross & Co. <i>Staff Accountant</i>

PROFESSIONAL EXPERIENCE

Rate and Regulatory Support for Utilities

Mr. Gorman has provided rate and regulatory support for numerous electric and gas utilities in several jurisdictions, including performing the following:

- Developing utility revenue requirements
- Performing class cost allocation studies and marginal cost studies
- Recommending class revenue allocation
- Analyzing and recommending rate design structures
- Reviewing interaffiliate cost allocation methodology

A list of rate case dockets in which Mr. Gorman has provided expert testimony is presented in the table ‘**Expert Testimony**’ at the end of this resume.

Energy Project Analysis

Mr. Gorman has performed financial analyses of energy-related assets, including electric and gas distribution companies, power plants and transmission operators. These analyses included developing cash flows and financial statements for both regulatory and accounting purposes, and included review of assumptions, analysis of data, modeling, sensitivity testing and stress testing.

Among these analyses are: valuations of power plants, financial projections for cogeneration heat and power plants and energy companies for the purpose of acquisition, valuation of waste-to-energy assets, valuation of a publicly traded multi-jurisdiction utility, and assessment of strategic fit and valuation for a utility considering diversifying into energy-related services.

Energy Project Financing

Mr. Gorman has sourced, structured, negotiated and completed transactions including construction and term loans, tax-exempt bonds, taxable bonds, subordinated debt and asset-backed (receivables and inventory) revolving credit facilities.

Mr. Gorman has supported energy projects in connection with due diligence for financing, including contract review, financial modeling, supply analysis, forward price projections, and economic valuation with cash flow forecasting, and the identification, assessment and mitigation of financial and operating risks for the project and its investors.

Financial Management

Mr. Gorman has extensive experience in financial accounting. As Controller and Treasurer of Trigen Energy Corporation, he built the finance and accounting function, developed reports, procedures and management tools, and managed subsidiary controllers across North America, including an IPO with NYSE listing (1994).

He managed the corporate insurance portfolios and the benefit plans for Trigen Energy Corporation and for Coleco Industries.

Computer Modeling and Decision Support

Mr. Gorman is an accomplished modeler with expertise in spreadsheet and database applications, as well as the use of programming tools. He has developed analytical tools to perform valuations, projections and simulations. These models have been applied to financial analysis, cost allocations, rate design and pricing, forecasting revenue requirements, numerous tax and accounting matters, supply modeling and optimizations. Several of these models have contained interactive modules for automated scenario testing and sensitivity analysis.

PUBLICATIONS AND PRESENTATIONS

“What Wall Street Needs From FERC,” published in R. J. Rudden Financial, LLC’s *Energy Capital Markets Report*, September 2002

“A Balanced Look at Balance Sheets,” published in R.J. Rudden Financial, LLC’s *Energy Capital Markets Report*, June 2002

“From Wires To Riches: Shareholder Value Creation In The T&D Business,” April 2002 (co-authored).

“Assessment of Retail Choice Programs,” presented at the American Gas Association Rate and Strategic Issues Committee Conference, March 2002

“Value Creation With Transmission Assets,” quoted in *Electrical World’s Special Edition Quarter 1, 2002*, March 2002

“The Remarkable Story on Enron,” published in Scudder’s *Annual End of Year Issue*, December 2001

EDUCATION

New York University, B.S., Accounting, 1976

Harvard Business School, MBA, 1981

Expert Testimony Submitted by Howard S. Gorman				
Jurisdiction	Docket	Client	Date	Subject Matter
New Hampshire	DE-13-063	Granite State Electric Company	2013	Electric class cost of service (marginal cost); revenue allocation; rate design
New York	12-E-0201	Niagara Mohawk Power Corporation	2012	Electric class cost of service; revenue allocation
Rhode Island	RIPUC 4323	Narragansett Electric	2012	Electric class cost of service
New York	11-E-0590	Village of Rockville Centre	2011	Electric revenue requirements; rate design; sales forecast
New York	11-G-0142	Chautauqua Utilities, Inc.	2011	Gas revenue requirements, rate design
Pennsylvania	R-2010-2179103	Kellogg Company (intervener)	2010	Water class cost of service; revenue allocation
Pennsylvania	R-2010-2179522	Duquesne Light Company	2010	Electric class cost of service; revenue allocation; rate design
Pennsylvania	R-2010-2172662	Wellsboro Electric Company	2010	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania	R-2010-2172665	Citizens' Electric Company of Lewisburg, PA	2010	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania	R-2010-2174470	Valley Energy, Inc.	2010	Gas revenue requirements, rate design
Pennsylvania	R-2010-2161592	PECO Energy (Gas)	2010	Gas class cost of service; revenue allocation; rate design
Pennsylvania	R-2010-2161575	PECO Energy (Electric)	2010	Electric class cost of service; revenue allocation; rate design
New York	10-E-0050	Niagara Mohawk Power Corporation	2010	Electric class cost of service

Expert Testimony Submitted by Howard S. Gorman				
Jurisdiction	Docket	Client	Date	Subject Matter
New York	09-E-0862	Jamestown Board of Public Utilities	2009	Electric revenue requirements
Pennsylvania	R-2009 2139884	Philadelphia Gas Works	2009	Gas class cost of service; revenue allocation
Rhode Island	RIPUC 4065	Narragansett Electric	2009	Electric class cost of service; revenue allocation; rate design
Massachusetts	DPU 09-39	Massachusetts Electric and Nantucket Electric	2009	Electric revenue requirements; adjustment mechanisms; class cost of service; revenue allocation; rate design
Pennsylvania	R-2008-2028394	PECO Energy (Gas)	2008	Gas class cost of service; revenue allocation; rate design
Pennsylvania	R-00072350	Wellsboro Electric Company	2007	Electric revenue requirements; rate design
Pennsylvania	R-00072348	Citizens' Electric Company of Lewisburg, PA	2007	Electric revenue requirements; rate design
Pennsylvania	R-00072349	Valley Energy, Inc.	2007	Gas revenue requirements; rate design
Pennsylvania	R-00061931	Philadelphia Gas Works	2006	Gas class cost of service; revenue allocation; rate design
New York	06-E-0911	Village of Freeport	2006	Electric revenue requirements; rate design
Ontario	EB-2007-0905 et al	Ontario Power Generation Inc.	2006, 2010	Electric Cost allocation methodology
Pennsylvania	R-00061346	Duquesne Light Company	2006	Electric class cost of service; revenue allocation; rate design
Ontario	EB-2005-0378 et al	Hydro One Networks Inc.	2005, 2006, 2008, 2009, 2010, 2012	Electric Transmission and Distribution Cost allocation; OH capitalization rates

Expert Testimony Submitted by Howard S. Gorman				
Jurisdiction	Docket	Client	Date	Subject Matter
New York	03-E-1568	Village of Rockville Centre	2003	Electric revenue requirements; rate design; sales forecast
New Jersey	ER020805 06 et al	Gerdau AmeriSteel aka Co-Steel (intervenor)	2002	Electric cost allocation and rate design; industrial rates
New Jersey	ER020503 03 et al	Gerdau AmeriSteel aka Co-Steel (intervenor)	2002	Electric cost allocation and rate design; industrial rates
Pennsylvania	M-00021612	Philadelphia Gas Works	2002	Gas rate unbundling
Pennsylvania	R-00017034	Philadelphia Gas Works	2002	Gas class cost of service
Pennsylvania	R-00006042	Philadelphia Gas Works	2001	Gas class cost of service; recovery of fixed costs

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-2013-2372129

**Duquesne Light Company
Statement No. 12**

Direct Testimony of William V. Pfrommer

Date: August 2, 2013

DIRECT TESTIMONY OF WILLIAM V. PFROMMER

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Q. Please state your full name and business address.

A. My name is William V. Pfrommer. My business address is Duquesne Light Company, 411 Seventh Avenue, Pittsburgh, PA 15219.

Q. What is your position at Duquesne Light Company?

A. I am employed by Duquesne Light Company (“Duquesne Light” or “Company”) as the Senior Manager, Rates and Tariff Services.

Q. How long have you worked at Duquesne Light?

A. I have been employed by Duquesne Light Company, Duquesne Holdings or its subsidiaries for 31 years.

Q. What are your current responsibilities?

A. I am responsible for overseeing the Company’s retail rates and wholesale transmission rates, which includes supervising the preparation, development and implementation of the distribution rates proposed in this proceeding. In addition, it is my responsibility to ensure the rates are properly applied to customer bills.

Q. What are your qualifications, work experience and educational background?

A. I received a Bachelor of Science Degree in Mechanical Engineering from Grove City College in 1978 and a Masters in Business Administration from the University of Pittsburgh in 1989. I was employed by Westinghouse Air Brake Company in 1978 and performed various duties as a staff engineer. I began my career at the Company in 1982 as a Project Engineer in the Engineering and Construction Division at the Beaver Valley Power Station. Over the last 31 years, I have held staff, supervisory and managerial positions in engineering, nuclear construction, customer technical services, marketing and rates. In the Rate Department at Duquesne Light, I was responsible for the calculations to unbundle the rates to support the implementation of electric utility restructuring and customer choice in Pennsylvania. As General Manager of Rates at AquaSource, the

1 previous water and wastewater subsidiary of DQE, Inc., I was responsible for providing
2 direction to regional controllers on all regulatory matters, and maintaining the tariffs in
3 the 12 states where AquaSource had utility operations. I have testified on rate design
4 matters before the Pennsylvania Public Utility Commission (“Commission”) and Federal
5 Energy Regulatory Commission (“FERC”). A list of proceedings in which I have
6 submitted testimony is provided in Appendix A. I am a licensed professional engineer in
7 the Commonwealth of Pennsylvania.

8
9 **Q. Are you sponsoring any exhibits, parts of exhibits or responses to the Commission’s**
10 **filing requirements as part of your direct testimony?**

11 A. Yes. I am sponsoring Exhibit WVP-1, which is the proposed tariff supplement to the
12 currently effective Tariff Electric Pa. P.U.C. No. 24 implementing the proposed rates,
13 riders and tariff revisions in this proceeding, Exhibit WVP-2 which is a redline version of
14 Exhibit No. 1, and Exhibit WVP-3 the Digest of Proposed Changes contained within
15 Duquesne’s proposed supplement. Exhibit WVP-4 contains the calculations supporting a
16 proposed new street lighting rate. Exhibit WVP-5 contains the calculations supporting
17 the Company’s proposed Pension Rate Adjustment rider.

18 I am sponsoring Schedule D-5D of Duquesne Light Exhibits 2, 3 and 4 and also
19 sponsoring the Company’s responses to the following filing requirements:

20
21 IV-A 1-4: Summary of Individual Rate Effects

22 IV-B: Description of Proposed Tariff Changes

23 IV-C: Revenue Effects and Billing Analysis for Changed Rates

24 IV-D 1 and 2: Monthly Billing Effects Charts and Data

25 IV-E 2: Comparisons Showing Cost and Proposed Base Rate Revenues for Residential
26 and Demand/Energy Rate Schedules

27
28 **Q. Please explain how these filing requirements were prepared.**

29 A. All filing requirements were prepared either by me or under my direct supervision. They
30 were prepared, to the best of my knowledge, in accordance with Commission
31 requirements and practice.

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Q. What is the purpose of your direct testimony regarding Duquesne Light’s request for increased rates?

- A. The purpose of my testimony is to address the following:
1. The allocation of the proposed revenue increase among the rate classes.
 2. The proposed rate design for distribution charges.
 3. The revenue impact by rate schedule.
 4. The proof of revenue at current and proposed rates.
 5. Proposed tariff changes.

Q. How is your testimony organized?

A. My testimony may be summarized as follows. First, I will explain the Company’s goals and objectives in allocating the proposed revenue increase. I will show how the proposed revenue increase was allocated among the rate classes and the resulting relative rate class returns. These items are discussed in the “Allocation of Proposed Revenue Increase” section.

Second, I will describe the rate design principles and how they were used to determine the proposed rates. I will then discuss how the proposed rates, when applied to forecast billing units, achieves the target allocated revenue for each rate class. These two items are discussed in the “Rate Design” section.

Third, I will address the proposed revenue impact by rate schedule and how a proof of revenue at current and proposed rates was developed to demonstrate that the proposed rates produce the target revenue for each class. These items are discussed in two sections, “Revenue Impact by Rate Schedule” and “Proof of Revenue,” respectively.

Finally, I will discuss the proposed changes to the Company’s retail tariff to implement these new rates, including the proposed street lighting rate and the proposed Pension Rate Adjustment Mechanism rider, under the heading “Proposed Retail Tariff Changes.”

Q. Were all of the proposed rate design changes and tariff changes also prepared under your direction or supervision?

1 A. Yes. All of the rate design work and tariff changes were prepared by me or under my
2 direct supervision.
3

4 **I. ALLOCATION OF PROPOSED REVENUE INCREASE**
5

6 **Q. What were the Company's goals and objectives in allocating the revenue increase?**

7 A. The Company proposes to continue the objectives it established in its 2006 and 2010
8 distribution rate case proceedings. The first objective was to move each rate class closer
9 to the full cost to provide service to each rate class, as determined in the class cost
10 allocation study prepared by Mr. Gorman. Whether the proposed revenue allocation
11 accurately reflects the costs can be evaluated by whether the rates for the customer class
12 fully recover the distribution costs allocated to that class, as measured by the class cost of
13 service study results at proposed rates. A unitized rate of return greater than 1.0 means
14 that the rate class is contributing a greater than average rate of return. A unitized rate of
15 return less than one means that the rate class is providing less than average returns. The
16 Company's goal in this rate case, as in its 2006 and 2010 rate case is to move each rate
17 class closer to 1.0.

18 The second overall objective is to mitigate the rate impacts both on rate classes
19 and on individual customer subgroups while continuing to progress to the rate class fully
20 allocated cost of service and reduce the subsidization among classes. In this proceeding,
21 the Company's goal was to limit the distribution revenue increase to any one rate class to
22 no more than 1.5 times the overall system average increase on a distribution bill basis.
23 This limitation balances the shift to cost of service with concerns regarding customer
24 impact.
25

26 **Q. Have the revenue impacts to each rate class been calculated using the fully allocated
27 class cost of service results?**

28 A. Yes. As described by Mr. Gorman, fundamental cost allocation principles were used to
29 functionalize, classify and allocate the revenue requirement among the rate classes in
30 order to determine the fully allocated cost of service, which set the base parameters for
31 revenue allocation and rate design. The rate class revenue requirements that reflect cost

1 causation and serve as the starting point for revenue allocation and rate design are shown
2 in Exhibit 6-2 and 6-2A. This Exhibit shows the revenue increases that would be
3 required if rates were set to recover each class' fully allocated cost of service (at the same
4 proposed rate of return for distribution).
5

6 **Q. Please explain how the revenue increase has been allocated across rate classes.**

7 A. In the 2010 base rate case, the Company was able to limit the increase to any one rate
8 class to no more than 1.8 times the system average rate increase on a distribution bill
9 basis. In this proceeding, the Company is proposing to limit the distribution revenue
10 increase to any one rate class to no more than 1.5 times the overall system average
11 increase on a distribution bill basis.

12 In addition, the Company is proposing to move each rate class' rate of return
13 relative to system average closer toward the system average rate of return or "unity,"
14 measured as class distribution rate of return divided by system average distribution rate
15 of return and also is proposing to move each class closer to cost of service by reducing
16 the subsidy received or provided by each class as measured on a dollar basis. The
17 Company has employed gradualism principles, on a distribution bill basis, and is moving
18 all classes closer to cost of service. Exhibit 6-7 provides the proposed revenue increase,
19 the calculation of the relative return for each rate class and the calculation of the subsidy
20 reduction for each rate class.

21
22 **Q. What is the proposed distribution revenue increase for each rate class in this
23 proceeding?**

24 A. Table No. 1 presents the proposed distribution revenue increase by rate class in this
25 proceeding. This resulted in increases to the residential and smaller commercial and
26 industrial ("C&I") classes being at toward the higher end of the revenue allocation while
27 two of the three lighting classes were held to no increase.

28 In this proceeding, the Company was able to limit the proposed increase to less
29 than 1.50 times the system average.
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Table No. 1 Proposed Distribution Increase by Rate Class

	System	Residential			Small and Medium C&I					Large C&I				Lighting		
		RS	RH	RA	GS	GM<25	GM>25	GMH <25	GMH >25	GL	GLH	L	HVPS	SE	SL	UMS
2013 at Full COS	17.6%	25.3%	25.5%	50.4%	76.1%	8.6%	8.2%	37.4%	5.5%	6.9%	18.9%	4.1%	-43.0%	-22.9%	-15.5%	-48.9%
2013 at Proposed Allocation	17.6%	22.9%	22.9%	26.3%	26.5%	12.6%	13.5%	22.9%	11.1%	12.1%	21.1%	9.9%	-26.4%	-18.1%	-12.4%	-26.4%
Relative Increase		1.30 x	1.30 x	1.50 x	1.50 x	0.71 x	0.77 x	1.30 x	0.63 x	0.69 x	1.20 x	0.56 x	(1.50) x	(1.03) x	(0.71) x	(1.50) x

I note that four of the rate classes are proposed to get a rate decrease in order to move these classes closer to full cost of service. Therefore the revenue decrease is appropriate for these rate classes.

Q. What are the rate class relative rates of return for the distribution business at the proposed distribution revenue increase in Table No. 1?

A. Table No. 2 compares the distribution rate class relative rates of return at the cost of service at present rates in Exhibit 6-7. Table No. 2 also presents information demonstrating progress toward unity at the proposed revenue allocation in this proceeding.

Table No. 2 Rate of Return at Proposed Revenue Allocation

	System	Residential			Small and Medium C&I					Large C&I				Lighting		
		RS	RH	RA	GS	GM<25	GM>25	GMH <25	GMH >25	GL	GLH	L	HVPS	SE	SL	UMS
2013 Before Allocation	5.67%	0.71 x	0.75 x	0.23 x	(0.15) x	1.26 x	1.32 x	0.56 x	1.39 x	1.36 x	1.09 x	1.44 x	5.88 x	2.48 x	2.49 x	5.27 x
2013 at Proposed Allocation	8.36%	7.9%	7.9%	4.9%	2.4%	9.1%	9.2%	6.3%	9.3%	9.2%	8.7%	9.3%	17.4%	9.4%	9.4%	17.5%
Relative Return	8.36%	0.95 x	0.94 x	0.59 x	0.28 x	1.09 x	1.10 x	0.75 x	1.11 x	1.10 x	1.04 x	1.11 x	2.08 x	1.12 x	1.12 x	2.10 x

Q. Does the proposed revenue allocation reduce the relative class subsidies on a dollar basis?

A. Yes. Table No. 3 compares the current class subsidies at current rates and at the proposed revenue allocation. The subsidy is improved on a dollar basis by 10% or better for all but one class.

Table No. 3 Rate Class Dollar Subsidies at Proposed Allocation (\$000's)

Subsidy Paid / (Received)	Residential			Small and Medium C&I					Large C&I				Lighting		
	RS	RH	RA	GS	GM<25	GM>25	GMH <25	GMH >25	GL	GLH	L	HVPS	SE	SL	UMS
Current Rates	(18,123)	(1,359)	(498)	(3,497)	1,814	6,092	(349)	828	7,581	319	3,113	365	569	2,463	680
At Proposed Allocation	(4,792)	(440)	(391)	(3,219)	896	2,882	(293)	331	2,952	188	1,146	119	70	294	258
Subsidy Better / (Worse)	13,331	919	107	278	918	3,210	56	497	4,629	131	1,967	246	499	2,169	422
Improvement	74%	68%	21%	8%	51%	53%	16%	60%	61%	41%	63%	67%	88%	88%	62%

Q. Was the Company able to achieve its desired goals?

A. Yes. Table No. 1 demonstrates that the proposed revenue allocation achieves a relatively narrow range of percentage distribution revenue increases for all rate classes that receive an increase and limits the increase to no more than 1.5 times the system average.

Table No. 2 demonstrates each rate class is moving closer to the desired goal of full cost of service on a relative basis to the proposed system average rate of return

Table No. 3 demonstrates the interclass subsidy is improved for all rate classes on a dollar subsidy basis.

Q. Was a schedule prepared showing the proposed targeted revenues for each rate class resulting from this revenue allocation?

A. Yes. The proposed targeted revenues for each rate class that result from application of the above principles are shown in DFR IV-A, Pages 1-3 and Schedule D-5D, Exhibit 2.

II. RATE DESIGN

Q. Please describe the goals and objectives used in designing the proposed distribution rates.

A. The primary goal was to design rates that, when applied to forecast billing determinants, produce the proposed revenue increase and the proposed targeted revenues for each rate class for the fully projected future test year. In addition, the Company continued its plan described in recent rate cases to migrate toward rates that reflect the services provided by a delivery company, and the way in which fixed costs are incurred. To achieve these goals, the Company proposes to maintain its goal of designing rates that emphasize fixed monthly charges and demand based charges, where appropriate, to recover costs. At the same time, the Company recognizes the potential impact on individual customers by

1 eliminating familiar rate structures, and the overall goal to keep rates simple and easy for
2 the customer to understand. Within these parameters, the Company developed rates for
3 each rate class that balances these objectives.
4

5 **Q. Please describe how the overall objectives were implemented for the distribution**
6 **rates for the residential rate classes.**

7 A. The Company proposes to continue to use a combination of fixed and energy-based rates
8 for all of the residential rate classes i.e. Residential Service rate RS, Residential Heating
9 Service rate RH and Residential Service Add-On Heat Pump rate RA. The Company
10 proposes to increase the fixed monthly customer charge to \$15.00 per month which is
11 supported by the fixed customer cost analysis of serving a residential customer identified
12 in Exhibit 6-2C. I also note that a higher customer charge provides some revenue
13 stability for the Company and cost stability for customers, and encourages the Company
14 to support conservation measures by reducing the benefit to the Company from higher
15 sales volumes.

16 Recovery of the remaining revenue (that is, target revenue less the amount
17 recovered through the fixed monthly charge) will be through an increased flat usage
18 charge per kWh.
19

20 **Q. Please describe the rate design for customers on Rate RH and RA.**

21 A. Rate RH and rate RA are the Company's residential space heating rates. The current rate
22 structures use a combination of fixed and energy-based variable charges similar to rate
23 RS, except that rates RH and RA have a lower rate for usage during the November to
24 April heating season. Currently, rates RH and RA have the same rate structure as rate RS
25 during the May through October non-heating season.

26 For rates RH and RA, the Company proposes the same fixed monthly customer
27 charge as for rate RS and the same usage charge as rate RS during the non-heating
28 months since there is not a material difference in average customer load or usage of these
29 rate classes during those months.

30 The Company recognizes space heating customers use considerably more
31 electricity during the heating season than customers on basic residential service rate RS.

1 The Company proposes to retain the lower kWh charge during the heating season. This
2 lower distribution energy rate achieves the target revenue, and mitigates significant bill
3 impacts during the heating season particularly for lower consumption customers.
4

5 **Q. Please describe how the rate design objectives were implemented for commercial
6 and industrial customers on General Service Small and Medium Rate GS/GM.**

7 A. This rate represents a diverse group of over 51,500 commercial and industrial (“C&I”)
8 customers. This group consists of approximately 22,800 non-demand metered customers
9 on rate GS, approximately 19,200 customers with monthly metered demand less than 25
10 kW and approximately 9,500 customers with monthly metered demand equal to or
11 greater than 25 kW. The categorization of customers at less than 25 kW and equal to or
12 greater than 25 kW was established and approved in the Company’s 2007 default service
13 filing and continued and approved for the distribution business in the Company’s 2010
14 base rate proceeding. The Company proposes to continue this separation point in this
15 proceeding.
16

17 **Q. What is the distribution rate design that is being proposed in this proceeding for
18 rate GS non-demand metered customers?**

19 A. For rate GS, the Company is proposing the same rate design as implemented in the
20 previous base rate proceeding. The Company is proposing to bill non-demand metered
21 customers the same fixed monthly charge as residential customers, which is supported by
22 Exhibit 6-2D, and a flat usage charge similar to how it bills these customers at present
23 rates, to recover the balance of the target revenues.
24

25 **Q. What is the distribution rate design that is being proposed in this proceeding for
26 rate GM demand metered customers?**

27 A. The Company is proposing to maintain the same distribution rate structure that exists
28 today. The Company first used the demand related and customer related costs identified
29 in Exhibit 6-2E and Exhibit 6-2F to establish the base customer charge and to recover the
30 same revenue proportionally from demand charges as it does today.

1 For all demand metered customers on rate GM (those with demand less than 25
2 kW and those with demand equal to or greater than 25 kW), the Company is proposing a
3 monthly customer charge based on the customer related costs in Exhibit 6-2E for the rate
4 class and 50% of the demand related costs for the first 5 kW of demand as it does today.
5 The variable demand charge is designed to recover 50% of the remaining target revenue
6 with the balance recovered through a flat usage charge per kilowatt-hour. This will retain
7 approximately the same proportion of revenue from fixed, demand and energy charges as
8 today.

9
10 **Q. What is the distribution rate design that is being proposed in this proceeding for**
11 **rate GMH?**

12 A. Rate GMH is the complementary electric space heating rate of rate schedule GS/GM and
13 applies to approximately 3,300 electric space heating commercial and industrial
14 customers. The Company is proposing to maintain the same distribution rate structure
15 that exists today. The Company proposes rate design principles similar to those used in
16 the last base rate proceeding and those used for rate GM in this proceeding. For the non-
17 heating season months (June to September), the monthly customer charge is based on the
18 same principles used for rate GM demand metered customers and the demand and energy
19 charges are the same charges as rate GM customers less than 25 kW.

20 For the heating months (October to May), customers will not be billed for demand
21 and only be billed for usage, the same as today's rate structure. The energy charge is
22 designed to recover the balance of the target revenue.

23
24 **Q. Is the Company proposing to separate rate GMH into separate classes at the 25 kW**
25 **level?**

26 A. No. The Company presented rate GMH separated at monthly metered demand less than
27 25 kW and equal to or greater than 25 kW to reflect the different rates for surcharges,
28 transmission and default service supply. Similar to the previous base rate proceeding, the
29 Company does not propose to separate this rate class for distribution rate purposes.

1 **Q. Please describe the current distribution rate design for large commercial and**
2 **industrial customers on rate GL.**

3 A. Rate GL is applicable to approximately 770 customers. Currently, the rate schedule
4 contains a minimum charge for the first 300 kW of demand and a demand charge for each
5 additional kW of demand. There are no distribution usage charges associated with these
6 rate schedules.

7
8 **Q. What is the distribution rate design that is being proposed for rate GL?**

9 A. The Company is proposing to continue the same rate structure for rate GL using a
10 minimum demand charge based on the customer's contract demand and recover the
11 remaining revenue through the variable demand charge. The monthly demand charges
12 for the first block of demand (300 kW) have been increased by the rate class revenue
13 percent increase in Table No. 1. The balance of the target revenues are recovered
14 through the additional demand charges.

15
16 **Q. What is the rate design that is being proposed in this proceeding for rate GLH?**

17 A. Rate GLH is the complementary electric space heating rate to rate GL and applies to
18 approximately 110 customers. The Company proposes to continue the existing rate
19 structure and proposes rate design principles similar in concept to those used for rate GM
20 and rate GMH in this proceeding. For the non-heating season months (June to
21 September), these customers will be billed the same charges as rate GL. For the heating
22 months (October to May), the Company is proposing to bill a flat usage charge per
23 kilowatt-hour.

24
25 **Q. Please describe the current distribution rate design for large commercial and**
26 **industrial customers on rate L.**

27 A. Rate L is applicable to approximately 28 customers. These customers represent some of
28 the largest customers served by the Company and are diverse in size (demand) as well as
29 service voltage. Currently, the rate schedule contains a minimum charge for the first
30 5,000 kW of demand and two declining block demand charges for each additional kW of
31 demand. There are no distribution usage charges associated with these rate schedules.

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Q. What is the distribution rate design that is being proposed for rate L?

A. The Company is proposing two changes to rate L. First, the Company is proposing to eliminate the declining block demand charge. While there is only a small differential in current rates, a declining block demand charge is inconsistent with energy conservation and demand response programs.

Second, the Company is proposing to offer a voltage-based rate as part of rate L. There are five customers on rate L served at the 138 kV transmission voltage level. These customers are not eligible for rate HVPS because their monthly billing demand is less than the 30,000 kW minimum billing demand requirement of rate HVPS.

With these two adjustments, the Company is proposing to continue the same rate structure for rate L using a minimum demand charge based on the customer’s contract demand and recover the remaining revenue through the variable demand charge. The monthly demand charges for the first block of demand (5,000 kW) have been increased by the rate class revenue percent increase in Table No. 1. The balance of the target revenues are recovered through the additional demand charges.

Q. Please explain the Company’s reasoning to add the voltage-based rate option to rate L.

A. The distribution rates reflect the level of service voltage and the system requirements to meet the load requirements of each rate class. The Company is proposing this change in the interest of designing rates that better reflect the level of distribution service necessary and costs incurred to serve these transmission voltage customers.

The current rate design is disadvantageous to the 138 kV customers that do not meet the 30,000 kW demand criteria of rate HVPS. One of these customers has expressed competitive concerns with the current rate design. The new rate design should address this customer’s concerns. However, if the new rate design is not adopted, Duquesne Light may address the customer’s competitive concerns through a Rule 4 contract under the Company’s tariff, which allows the Company to enter into separate contracts with larger customers to address competitive alternatives. If the Company

1 enters into a Rule 4 contract, the Company must be permitted to recover the difference in
2 rates that the Company would have otherwise received under Rate L.

3
4 **Q. What is the Company's basis for the proposed distribution rates at the 138 kV level.**

5 A. The Company did not prepare a separate cost study specifically to develop the proposed
6 rates at this voltage level. There are five customers on rate HVPS served at 138 kV
7 voltage level. Because the five rate L customers are served at the 138 kV level, and are
8 all industrial classification and similar load profile of rate HVPS industrial customers, the
9 Company proposes to use the same fixed charge rate of HVPS for customers less than
10 50,000 kW.

11
12 **Q. Please describe the current distribution rate design for industrial customers on rate
13 HVPS.**

14 A. There are currently five customers on rate HVPS each with a monthly metered demand
15 greater than 30,000 kW in accordance with the tariff¹. In the 2010 base rate proceeding,
16 the Company proposed, and the Commission approved, a monthly fixed distribution
17 charge based on the customer's monthly metered demand. There are no variable demand
18 distribution charges or variable usage distribution charges.

19
20 **Q. What is the distribution rate design that is being proposed for rate HVPS**

21 A. For rate HVPS, the Company is proposing to continue the same rate structure currently in
22 place using a monthly fixed charge based on the monthly metered billing demand of the
23 customer. Each of the fixed monthly charges have been adjusted by the rate class
24 percentage change in distribution revenue.

25
26 **Q. What changes are being proposed to the distribution rates of the lighting and
27 unmetered rate classes?**

¹ There are currently five customers on rate HVPS. One customer is known to be discontinuing operations at the end of 2013. The fully projected future test year revenue reflects four customers on this rate schedule.

1 A. The Company has aggregated rates AL, SM, SH and PAL for cost of service and revenue
2 allocation purposes. Rate SE and rate UMS (Unmetered Service) are treated individually.
3 The Company is proposing to retain the same rate structure for these rate classes.

4 For rates AL, SM, SH and PAL, the Company is proposing an across-the-board
5 reduction to the revenue for each rate class at the proposed decrease and alignment of
6 interclass rates to ensure consistency of charges.

7 For rate SE and rate UMS, the Company is proposing to reduce the current rates
8 by the percentage revenue reduction for each rate class.

9

10 **Q. Is the Company proposing any changes to its transmission rates in this proceeding?**

11 A. No, the Company is not proposing to change transmission rates in this proceeding. The
12 Company has adopted the FERC formula rate making process to establish an annual
13 revenue requirement and wholesale network integrated transmission service rate that
14 changes June 1 every year. The current wholesale rate is not affected by this proceeding.

15

16 **Q. Is the Transmission Service Charge (“TSC”) changing because of this filing?**

17 A. No. The Company submitted and the Commission approved the TSC in the Company’s
18 2006 distribution rate case. The Company’s retail transmission rates were redesigned to
19 reflect the FERC formula and the method of providing and paying for transmission
20 service through PJM. The TSC is updated June 1 every year in conjunction with the
21 update to the FERC formula. The TSC has worked successfully since it was
22 implemented, and the Company is not proposing changes to the TSC or changes to the
23 TSC retail rates in this proceeding. The DFR’s that I am sponsoring contain the current
24 TSC retail rates.

25

26 **III. REVENUE IMPACT BY RATE SCHEDULE**

27 **Q. Have the annual revenue effects of the new proposed rates been calculated?**

28 A. Yes. Schedule D-5D of Duquesne Light Exhibit No. 2 was prepared in accordance with
29 PA PUC Data Filing Requirement IV-A. The pages in this schedule provide the rate
30 class revenue impact and the overall revenue effect for the fully projected future test year
31 period.

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Q. Please explain Schedule D-5D for the fully projected future test year.

A. Schedule D-5D page 1 identifies the forecast customers, sales and retail revenue by rate class for distribution, transmission and generation. The customers, sales and revenues are based on the forecast billing determinants provided in Mr. Habberfield’s forecast. Also shown are the forecast revenues the Company plans to collect at current rates through tariff riders for the Consumer Education Surcharge (“CES”) Rider 1, the Universal Service Charge (“USC”) Rider 5, the Energy Efficiency and Conservation and Demand Response (“EECDR”) Surcharge Rider 15, the Smart Meter Charge (“SMC”) Rider 20, and the State Tax Adjustment (“STAS”) Rider 10. The Customer Assistance Program (“CAP”) revenue credit is the billing deficiency associated with CAP customers that is recovered through the USC charge.

Page 2 reflects the forecast revenue at current rates with the surcharge revenue removed and only the STAS revenue shown. The STAS is proposed to be set at 0% with the associated taxes recovered in the proposed distribution charges. The distribution revenue in Schedule D-5D, Column E, page 2 is the base distribution revenue from which the requested increase is measured. The total revenue on page 2 ties to the total revenue described by Mr. O’Brien with his revenue adjustments.

On July 1, 2013, Duquesne Light filed a revised CES with the Commission at Docket No. R-2013-2371825. In that filing, Duquesne Light is requesting Commission approval to recover education costs incurred in carrying out the Commission’s Retail Market Investigation (“RMI”) mandates and all other consumer education expenses incurred by the Company to conduct consumer education activities ordered by the Commission. Duquesne Light is no longer recovering any other consumer education costs through the CES. The Company distribution revenue for the rate classes affected by this request would be adjusted should the Company’s request to recover RMI and Commission ordered consumer education expenses through the CES be denied.

Page 3 of Schedule D-5D shows the distribution revenue and total revenue at the requested revenue increase and the respective increases on a percentage basis.

For illustrative purposes, pages 4-6 provide similar calculations assuming 100% default service supply load.

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IV. PROOF OF REVENUE

- Q. Was a bill frequency analysis or proof of revenue calculation prepared?**
- A. Yes. Attachment DFR IV-C-Proof was prepared in accordance with the Commission’s Data Filing Requirement IV-C and provides the calculation of revenues at current and proposed rates. Attachment DFR IV-C-Proof provides a calculation for each retail tariff rate schedule. For each rate schedule, the first column identifies the type of charge by business segment, i.e. customer charge, demand charge or energy charge for distribution, transmission and generation and for each rider if applicable to that rate schedule. The second column provides the annual billing determinants for each charge forecasted by Mr. Habberfield. The third column identifies the current and proposed rates for each block. The fourth column identifies the revenues derived by multiplying the billing determinants in the second column by the rates in the third column. The revenues computed on these pages produce the revenues shown on the respective pages of Schedule D-5D (Fully Projected Future).

- Q. Do the forecast revenues at current and proposed rates reflect reduced sales from the effects of Act 129?**
- A. Yes. Mr. Habberfield included an adjustment in developing the Company’s sales forecast for the reduced sales due to implementation of Act 129 projected through the end of the fully projected future test year. The proposed rates and fully projected future test year revenue were calculated based on his sales forecast .

V. PROPOSED RETAIL TARIFF CHANGES

- Q. Please describe the contents of Exhibit WVP-3.**
- A. This exhibit sets forth in detail the modifications being proposed to the Company’s tariff provided in Exhibit WVP-1, including the changes in rates and rate design I previously discussed, to recover the proposed distribution revenue requirement that is being requested. The proposed modifications are also shown in a redline version of the tariff supplement provided in Exhibit WVP-2.

1 **Q. Are you proposing changes to the Rules and Regulation section of the proposed**
2 **tariff supplement?**

3 A. Yes. The Company is proposing one change to the Rules and Regulation section of the
4 tariff. The Company is proposing to revise Rule 21.1, Payment of Bills for Residential
5 Service, to allow more flexibility for customer requests to change the payment due date
6 for certain customers with a demonstrated financial burden.

7
8 **Q. Are you proposing changes to the tariff rate schedules section of the proposed tariff**
9 **supplement?**

10 A. Yes. The distribution rates identified in each rate schedule in Exhibit WVP-1 have been
11 modified to achieve the allocated revenue increase previously described in my testimony.
12 Aside from the proposed change to rate L that I previously described, the Company is not
13 proposing changes to the distribution rate structure in this proceeding. In addition, the
14 Company is proposing to add an LED street lighting rate option to rate SM and rate PAL.

15
16 **Q. Please describe the proposed change to add an LED street light rate option to the**
17 **tariff.**

18 A. Rate SM, Street Lighting Municipal, and rate PAL, Private Area Lighting, offer street
19 lighting options to municipal and non-municipal customers respectively. The street light
20 options include mercury vapor and high pressure sodium (“HPS”) fixtures. Over the last
21 two years, customers have inquired about the availability of the LED street light option.
22 The Company proposes to add the LED street light option to these two rate schedules.

23
24 **Q. Please describe the proposed changes to the tariff to implement the LED street light**
25 **rate?**

26 A. Several changes are needed to the tariff to include the LED option. The applicable rates
27 for rate SM and rate PAL are the same since the same fixture and lamp are used for each
28 application.

29 Rate SM and rate PAL have been revised to add in tabular format the LED fixture
30 options and applicable distribution rates. These rates are a fixed charge per fixture per

1 month similar to the mercury vapor and HPS fixture options. These rates are based on
2 the calculations in Exhibit WVP-4 for each lamp size.

3 In addition, Rider 8, Default Service Supply, has been revised to show the LED
4 lamp options. The default service rates are monthly fixed charges based on the monthly
5 kWh for each lamp size and the current default service supply rates obtained in the
6 Company's March and April 2013 request for proposal.

7 Finally, Appendix A, Transmission Service Charge ("TSC"), has also been
8 modified to add the LED lamp options. Since this is a new rate, and is an off-peak load,
9 there are no TSC charges for these fixtures.

10
11 **Q. Are there any changes or additions to the rider section and riders in the tariff?**

12 A. Yes, there are four. First, the Company is updating Rider No. 5, Universal Service
13 Charge, to revise the number of Customer Assistance Program ("CAP") customers used
14 in the formula. Second, the Company is proposing to reset Rider No. 10 - State Tax
15 Adjustment to zero to reflect recovery of these charges in base rates. Third, the Company
16 is updating Rider No. 16, Service to Non-Utility Generating Facilities, to better define the
17 charges for back-up power. Finally, the Company is proposing to add a new Rider No.
18 22, Pension Rate Adjustment, to the tariff.

19
20 **Q. Please explain the change to Rider No. 5 – Universal Service Charge.**

21 A. Rider No. 5 was implemented in the Company's 2010 base rate proceeding. The rider
22 includes a provision to adjust the Universal Service Charge based on the number of CAP
23 customers enrolled in the program. The current enrollment number stated in the rider is
24 35,700 CAP customers which was established in the Company's previous base rate case.
25 The rider includes a provision to reset this participation level in each distribution rate
26 case. The Company proposes to update this figure to 41,650 customers which is the
27 projected number of customers to be enrolled in the CAP program at year end 2014. This
28 projected enrollment is defined in the Company's Universal Service and Energy
29 Conservation Plan for 2014-2016 filed with the Commission on February 28, 2013.

30
31 **Q. Please explain the change to Rider No. 10 – State Tax Adjustment.**

1 A. Rider No. 10 is a two-part surcharge to recover changes in taxes of the Commonwealth.
2 Part 1 of the STAS reflects changes in tax rates for the Capital Stock Tax, Corporate Net
3 Income Tax and Public Realty Tax, and is applicable only to the distribution charges of
4 customer bills. Part 2 of the STAS reflects changes in the Gross Receipts Tax and is
5 applicable to the distribution, transmission and generation charges for customers taking
6 service from the Company. For presentation purposes in this filing, both parts of the
7 STAS have been set at 0%. The Company will submit its annual STAS reconciliation
8 filing in December 2013, for any state tax changes not reflected in the base rate filing.
9

10 **Q. Please provide a brief summary of Rider No. 16 – Service to Non-Utility Generating**
11 **Facilities.**

12 A. Rider No. 16 defines the Company’s tariff requirements for back-up power service that
13 applies to customer-owned, non-utility generating facilities. Customers pay tariff rates for
14 supplementary power that is the energy and capacity supplied by the Company that is in
15 addition to the energy and capacity that the non-utility generating facility generates itself.
16 Customers pay Rider No. 16 charges for back-up power to replace energy and capacity
17 ordinarily provided by the non-utility generating facility (i.e. during an outage of the non-
18 utility generating facility). The rider is applicable to the general service rate schedules.
19 There is currently one customer on Rider No. 16.
20

21 **Q. Please explain the proposed changes to Rider No. 16.**

22 A. The current backup distribution charges were established in the last rate case and define a
23 minimum demand charge whether or not the non-utility generating facility is operating or
24 not. The Company is proposing changes to the back-up charges and to the language in
25 the rider to better-define the billing determinants associated with back-up power.
26

27 **Q. What is the back-up power distribution rate you are proposing for Rider No. 16.**

28 A. The Company is proposing a distribution rate of \$2.50 per kW. This is based on an
29 average of the primary demand costs per kW in Mr. Gorman’s Exhibit 6-2B and a load
30 factor of 30%. The load factor is an estimate based on the availability of the current

1 customer, a review of other utility tariffs, and the expectation of the need for the
2 Company to provide back-up power.

3
4 **Q. Please explain why the Company is proposing a Pension Rate Adjustment
5 Mechanism as a new rider in its tariff.**

6 A. Based on estimates provided by Mr. Ankrum, the Company's pension plan contributions
7 are projected to decline significantly by 2017 as the plan approaches fully funded status.
8 The Company is proposing the Pension Rate Adjustment Mechanism ("Pension Rate
9 Adjustment") to rates to align future distribution rates with future pension funding
10 requirements and to avoid a pension over-funding situation.

11
12 **Q. Please summarize how the Pension Rate Adjustment Mechanism will work.**

13 A. The Pension Rate Adjustment may be used to reduce distribution rates in the event that
14 the Company's pension funding is reduced below the amount that is used to establish
15 pension expense approved by the Commission in this base rate proceeding. If pension
16 costs increase after the Rider is implemented to reduce pension expense recovery, the
17 Pension Rate Adjustment may also be used to recover subsequent increases in expenses
18 up to the level of expense originally included in base rates.

19
20 **Q. Why not file a base rate case as the Company gets close to full funding of its pension
21 plan?**

22 A. The Company does not know when it's next base rate case will be filed. The Pension
23 Rate Adjustment may benefit all stakeholders by avoiding the time and costs associated
24 with preparing a base rate case and avoids overfunding of the pension trust if the
25 Company is required to fund the contribution used to set rates in this proceeding.

26
27 **Q. Please describe the process to determine when the Company would file the proposed
28 Pension Rate Adjustment Mechanism.**

29 A. Witness Ankrum (DLC St. No. 2) presents the proposed pension funding requirements in
30 this proceeding. The pension funding amount approved to be recovered in base rates in
31 this proceeding will serve as the basis for the Pension Rate Adjustment. The Company

1 will continue to recover pension costs through distribution and transmission rates at the
2 level determined in this proceeding. The Company will monitor and evaluate the pension
3 funding level and projected annual funding requirement. As the pension becomes closer
4 to fully funded, the Company will compare the funding used to establish rates with the
5 required annual contribution, and will initially submit the Pension Rate Adjustment in the
6 event the Company's projected pension funding requirements are lower than the funding
7 requirements used to establish rates in this case.

8
9 **Q. Could the Pension Rate Adjustment ever cause distribution rates to exceed those**
10 **established in this proceeding?**

11 A. No. The first Pension Rate Adjustment filing will be a reduction to distribution rates.
12 The Pension Rate Adjustment may be used to reduce distribution rates in the event that
13 the Company's pension funding requirement is reduced below the amount that is used to
14 establish pension expense approved by the Commission in this base rate proceeding. If
15 pension costs increase after the first rider is implemented to reduce pension expense
16 recovery, the Pension Rate Adjustment may also be used to recover subsequent increases
17 in expenses up to the level of expense originally included in base rates.

18
19 **Q. How frequently will the Company submit the Pension Rate Adjustment after the**
20 **initial filing?**

21 A. After the initial rider filing, the Company may update the Pension Rate Adjustment no
22 more frequently than annually.

23
24 **Q. Where will the pension funding level in base rates be defined?**

25 A. The Company proposes that the pension funding level be defined as a requirement of the
26 Commission's final order in this proceeding as it was in the 2010 rate case settlement
27 (paragraph 37) adopted by the Commission.

28
29 **Q. Please describe the content of the first Pension Rate Adjustment Mechanism filing.**

30 A. For the first Pension Rate Adjustment, , the Company would submit a filing to the
31 Commission seeking to reduce distribution rates. The filing would contain:

- 1
- 2 a) a statement by an officer of the Company that the Company is changing the pension
- 3 contribution and will implement the Pension Adjustment Mechanism
- 4 b) a five year projection of the annual pension funding requirements
- 5 c) calculations supporting the basis of the new (lower) funding expense level requested
- 6 by the Company
- 7 d) a calculation of the reduction to distribution rates at the lower expense level
- 8 e) the proposed tariff supplement requesting the adjustment within Rider No. 22 –
- 9 Pension Rate Adjustment Mechanism.

10

11 The new lower funding requirement would be the revised funding amount based on the

12 estimated funding requirement for the upcoming 12 month period. The reduction to

13 distribution rates will be the difference between the expense amount of pension

14 contributions determined in this proceeding and the expense component projected for the

15 upcoming 12 month period.

16

17 **Q. Please describe how the change in distribution rates will be determined as a result of**

18 **implementing the Pension Rate Adjustment?**

19 A. Rate class revenue requirements for pension expense as well as the pension expense

20 component in FERC account 926 are defined in Exhibit 6-2A. The allocation of pension

21 expense to each rate class under Exhibit 6-2A will be the basis from which to compute

22 the reduction to distribution rates for each rate class based on the projected pension

23 expense level.

24 The rate class share of pension funding from Exhibit 6-2A on a percentage basis

25 is defined in proposed Rider 22, Pension Adjustment Mechanism, in Exhibit WVP-1.

26 The difference between the pension expense determined in this proceeding and the

27 revised pension expense determined in a future Pension Rate Adjustment filing will be

28 allocated to each rate class using these percentages. The difference will be used to

29 compute a reduction to the applicable tariff distribution rates based on the applicable

30 billing units defined in the proposed rider. The adjustment defined in the rider would be

31 subtracted from the applicable base distribution rate. The rate class allocations defined in

1 the rider would remain in effect until the next base distribution rate case proceeding. In
2 no event will the rate adjustment determined through the Pension Rate Adjustment be a
3 positive number (i.e. in no event will distribution rates ever exceed those established in
4 this proceeding because of the Pension Rate Adjustment).

5 The revised expense component would be allocated to each rate class. This
6 difference would be divided by the forecast calendar year billing units defined in the
7 rider. The reduced distribution rates would take effect in 60 days from the date of the
8 filing. This rider would be non-bypassable and not be subject to reconciliation.

9
10 **Q. Do you have an example of the calculation?**

11 A. Yes. Exhibit WVP-5 provides an illustrative example of how the change in rates would
12 be determined. The figures are for illustrative purposes and not based on this proceeding
13 or pension funding projections.

14
15 **Q. How will rates be determined in subsequent Pension Rate Adjustment filings?**

16 A. The Company will repeat the same process used in the first Pension Rate Adjustment
17 filing. The annual funding will be based on the projection of pension funding the
18 upcoming 12 month period.

19 The adjustment to rates will be based on the expense component (50%) of the
20 funding level in this proceeding less the projection for the upcoming calendar year.

21 The adjustment to the applicable billing unit in the rider will be updated and
22 effective 60 days from the filing date.

23
24 **Q. How would the Pension Mechanism be reflected on the customer bill?**

25 A. It will not show up on the bill. It will be subtracted from the applicable base rate
26 (determined by the billing units described above).

27
28 **Q. Does this conclude your direct testimony?**

29 A. Yes, it does.

30

1 **Appendix A**

2 **William V. Pfrommer - Rate and Regulatory Proceedings**

3 **Pennsylvania Public Utility Commission:**

4 Docket No. M-2012-2334399 - Energy Efficiency and Conservation Phase II Plan

5 Docket No. P-2012-2301664 – Default Service Program and Procurement Plan for the Period
6 June 1, 2013 through May 31, 2015

7 Docket No. R-2010-2179522 – Distribution Base Rate Case Docket No. P-2000-2135500 -
8 Provider of Last Resort (POLR V)

9 Docket No. M-2009-2093217 - Act 129 Energy Efficiency and Conservation and Demand
10 Response Plan

11 Docket No. M-2009-2123948 - Act 129 Smart Meter Procurement and Installation Plan

12 Docket No. P-00072247 - Provider of Last Resort (POLR IV)

13 Docket No. R-00061346 – Distribution Base Rate Case

14 Docket No. P-00032071 - Provider of Last Resort (POLR III)

15
16 **Federal Energy Regulatory Commission:**

17 Docket No. ER13-1220-000 – Monthly Deferred Tax Adjustment Charge

18 Docket No. ER08-1309-000 – Changes to the MISO Open Access Transmission
19 Tariff to integrate the Company into the Midwest Independent System Operator, Inc.

20 Docket No. ER05-85-000 – Changes to the PJM Open Access Transmission Tariff
21 to integrate the Company into the PJM Interconnection, L.L.C.

22
23 **Other:**

24 Cause No. 42416, Filed April 14, 2003, Indiana Utility Regulatory Commission –
25 Petition of Utility Center, Inc., d/b/a AquaSource

26 Cause No. 41968, Filed March 30, 2001, Indiana Utility Regulatory Commission –
27 In the Matter of Utility Center, Inc., d/b/a AquaSource

28 Docket Nos. 2000-1074-UCR and 2000-1075-UCR, Filed June 15, 2000 – Texas
29 Natural Resource Conservation Commission, Applications of AquaSource
30 Utility, Inc. to Change its Water and Sewer Tariffs and Rates

Exhibit No. WVP-1

SUPPLEMENT NO. 81
TO ELECTRIC – PA. P.U.C. NO. 24



SCHEDULE OF RATES

For Electric Service in Allegheny and Beaver Counties

(For List of Communities Served, see Pages No. 4 and 5)

Issued By

DUQUESNE LIGHT COMPANY

411 Seventh Avenue
Pittsburgh, PA 15219

Richard Riazzi

President and Chief Executive Officer

ISSUED: August 2, 2013

EFFECTIVE: October 1, 2013

Filed at Docket No. R-2013-2372129

NOTICE

**THIS SUPPLEMENT MAKES CHANGES TO
THE TABLE OF CONTENTS, A RULE, RATE SCHEDULES AND RIDERS,
MAKES INCREASES AND DECREASES TO THE RATES AND ADDS A RIDER**

See Page Two

LIST OF MODIFICATIONS MADE BY THIS TARIFF**CHANGES****List of Modifications****Page No. 2**

Pages No. 2A through 2D were added to the Tariff.

Table of Contents**Twenty-Second Revised Page No. 3
Cancelling Twenty-First Revised Page No. 3**

Pages No. 2A through 2D were added to the Table of Contents.

Rider No. 22 – Pension Rate Adjustment Mechanism, Original Pages No. 112B, 112C and 112D, was added to the Table of Contents.

Due to repagination, Page No. 116A was added to the Table of Contents.

Rule No. 21.1 Payment of Bills for Residential Service**First Revised Page No. 23A
Cancelling Original Page No. 23A**

Language has been modified to reflect the current operations of the Company.

Rate L – Large Power Service**Fifth Revised Page No. 53
Cancelling Fourth Revised Page No. 53**

Language has been modified to reflect the addition of “Service Voltage Less than 138 Kv” and “Service Voltage 138 Kv and Greater.”

The “Next 10,000 kilowatts of Demand” block has been eliminated from the Rate Schedule.

A Fixed Monthly Charge has been added under “Service Voltage 138 Kv and Greater.”

Rate L – Large Power Service**Second Revised Page No. 54
Cancelling First Revised Page No. 54**

Language has been modified in the second paragraph under “Contract Provisions” to reflect the elimination of the 10,000, 25,000 and 750,000 kilowatt-hour blocks under the Energy Charge.

Language has been modified to replace the word “Capacity” with the word “Demand.”

Rate SM – Street Lighting Municipal**Sixth Revised Page No. 68
Cancelling Fifth Revised Page No. 68**

Language has been modified to include Light-Emitting Diode (LED) fixtures and pricing.

Currently approved language has been moved to accommodate the addition of the Light-Emitting Diode (LED) fixtures and pricing information.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)**Rate SM – Street Lighting Municipal**Sixth Revised Page No. 69
Cancelling Fifth Revised Page No. 69**Rate SM – Street Lighting Municipal**Second Revised Page No. 70
Cancelling First Revised Page No. 70

Currently approved language has been moved to accommodate the addition of the Light-Emitting Diode (LED) fixtures and pricing information.

Rate PAL – Private Area LightingSixth Revised Page No. 76
Cancelling Fifth Revised Page No. 76

Language has been modified to include Light-Emitting Diode (LED) fixtures and pricing.

Currently approved language has been moved to accommodate the addition of the Light-Emitting Diode (LED) fixtures and pricing information.

Rate PAL – Private Area LightingFifth Revised Page No. 77
Cancelling Fourth Revised Page No. 77**Rate PAL – Private Area Lighting**Third Revised Page No. 78
Cancelling Second Revised Page No. 78

Currently approved language has been moved to accommodate the addition of the Light-Emitting Diode (LED) fixtures and pricing information.

Rider MatrixThird Revised Page No. 79A
Cancelling Second Revised Page No. 79A

Rider No. 22 – Pension Rate Adjustment Mechanism has been added to the Rider Matrix.

Rider No. 8 – Default Service SupplyThird Revised Page No. 88A
Cancelling Second Revised Page No. 88A

The Table has been modified to include Light-Emitting Diode (LED) fixtures and pricing.

Currently approved language has been moved to accommodate the addition of the Light-Emitting Diode (LED) fixtures and pricing information.

Rider No. 8 – Default Service SupplyThird Revised Page No. 88B
Cancelling Second Revised Page No. 88B

Currently approved language has been moved to accommodate the addition of the Light-Emitting Diode (LED) fixtures and pricing information.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rider No. 10 – State Tax Adjustment

**Ninth Revised Page No. 94
Eighth Revised Page No. 94**

Rider No. 10 – State Tax Adjustment has been modified to reflect that Part 1 of the STAS has been set to zero.

Rider No. 16 – Service to Non-Utility Generating Facilities

**Fourth Revised Page No. 101
Cancelling Third Revised Page No. 101**

Language and definitions have been modified to reflect current operations of the Company.

Rider No. 16 – Service to Non-Utility Generating Facilities

**Fourth Revised Page No. 102
Cancelling Third Revised Page No. 102**

Language has been modified to remove the “Contract Demand” under B. Back-Up Power.

Language has been modified to add a distribution charge to be applied to the Back-Up Billing Determinants for Back-Up Power under B. Back-Up Power.

Rider No. 22 – Pension Rate Adjustment Mechanism

**Original Page No. 112B
Original Page No. 112C
Original Page No. 112D**

Rider No. 22 – Pension Rate Adjustment Mechanism has been added to the Tariff.

Appendix A – Transmission Service Charges

**Twelfth Revised Page No. 113
Cancelling Eleventh Revised Page No. 113**

**Fifth Revised Page No. 114
Cancelling Fourth Revised Page No. 114**

**Fifth Revised Page No. 115
Cancelling Fourth Revised Page No. 115**

**Seventh Revised Page No. 116
Cancelling Sixth Revised Page No. 116**

Original Page No. 116A

Currently approved language has been moved to accommodate the addition of the Light-Emitting Diode (LED) fixtures and pricing information.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)**Appendix A – Transmission Service Charges**Fifth Revised Page No. 114
Cancelling Fourth Revised Page No. 114

The table has been modified to include Light-Emitting Diode (LED) fixtures and pricing.

Appendix A – Transmission Service Charges

Original Page No. 116A

Original Page No. 116A has been added to the Tariff to accommodate the addition of the Light-Emitting Diode (LED) fixtures and pricing information.

INCREASES**Rate RS – Residential Service**Sixth Revised Page No. 32
Cancelling Fifth Revised Page No. 32**Rate RH – Residential Service Heating**Sixth Revised Page No. 34
Cancelling Fifth Revised Page No. 34**Rate RA – Residential Service Add-On Heat Pump**Sixth Revised Page No. 37
Cancelling Fifth Revised Page No. 37**Rate GS/GM – General Service Small and Medium**Fifth Revised Page No. 40
Cancelling Fourth Revised Page No. 40**Rate GMH – General Service Medium Heating**Fifth Revised Page No. 43
Cancelling Fourth Revised Page No. 43Eighth Revised Page No. 44
Cancelling Seventh Revised Page No. 44**Rate GL – General Service Large**Fifth Revised Page No. 47
Cancelling Fourth Revised Page No. 47**Rate GLH – General Service Large Heating**Fifth Revised Page No. 50
Cancelling Fourth Revised Page No. 50**Rate L – Large Power Service**Fifth Revised Page No. 53
Cancelling Fourth Revised Page No. 53**Rate PAL – Private Area Lighting**Fifth Revised Page No. 77
Cancelling Fourth Revised Page No. 77**Rate PAL – Private Area Lighting**Third Revised Page No. 78
Cancelling Second Revised Page No. 78

LIST OF MODIFICATIONS MADE BY THIS TARIFF

INCREASES – (Continued)

Rate UMS – Unmetered Service

Sixth Revised Page No.74
Cancelling Fifth Revised Page No. 74

Unit prices have changed resulting in increases.

Rider No. 5 – Universal Service Charge

Fourth Revised Page No. 85
Cancelling Third Revised Page No. 85

Rider No. 5 – Universal Service Charge has been updated as directed in the Rider to reflect the participation level of CAP customers.

DECREASES

Rate GS/GM – General Service Small and Medium

Fifth Revised Page No. 40
Cancelling Fourth Revised Page No. 40

Rate GMH – General Service Medium Heating

Fifth Revised Page No. 43
Cancelling Fourth Revised Page No. 43

Rate HVPS – High Voltage Power Service

Fifth Revised Page No. 57
Cancelling Fourth Revised Page No. 57

Rate AL – Architectural Lighting Service

Sixth Revised Page No. 61
Cancelling Fifth Revised Page No. 61

Rate SE – Street Lighting Energy

Sixth Revised Page No. 64
Cancelling Fifth Revised Page No. 64

Rate SM – Street Lighting Municipal

Sixth Revised Page No. 68
Cancelling Fifth Revised Page No. 68

Rate SM – Street Lighting Municipal

Second Revised Page No. 70
Cancelling First Revised Page No. 70

Rate SH – Street Lighting Highway

Sixth Revised Page No. 71
Cancelling Fifth Revised Page No. 71

Rate UMS – Unmetered Service

Sixth Revised Page No.74
Cancelling Fifth Revised Page No. 74

Rate PAL – Private Area Lighting

Sixth Revised Page No. 76
Cancelling Fifth Revised Page No. 76

Unit prices have changed resulting in decreases.

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(C) – Indicates Change

RULES AND REGULATIONS – (Continued)

BILLS AND NET PAYMENT PERIODS – (Continued)

21.1 PAYMENT OF BILLS FOR RESIDENTIAL SERVICE The Company will designate a due date on its bill which shall be a business day no less than 20 days from the date of transmittal of the bill. The Company may accommodate changes to due dates for residential customers upon written customer request and when a demonstrated financial burden for the current due date exists for ratepayers receiving Social Security or equivalent monthly checks. (C)
(C)
(C)

RATE RS - RESIDENTIAL SERVICE

AVAILABILITY

Available to residential or combined residential and farm customers using the Company's standard low voltage service for lighting, appliance operation, and general household purposes and for commercial or professional activity where associated consumption represents less than 25% of the total monthly usage at the premise.

Available only when supplied at 240 volt (or less) single phase service through a single meter directly by the Company to a single family dwelling or to an individual dwelling unit in a multiple dwelling structure. For the purposes of this rate, a dwelling unit is defined as one or more rooms arranged for the use of one or more individuals for shelter, sleeping, dining, and with permanent provisions for cooking and sanitation.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge	\$15.00	(I)
Energy Charge	4.3961 cents per kilowatt hour	(I)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for residential customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to residential customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charges, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

(I) – Indicates Increase

RATE RH - RESIDENTIAL SERVICE HEATING

AVAILABILITY

Available to residential or combined residential and farm customers using the Company's standard low voltage service for lighting, appliance operation, general household purposes and for commercial or professional activity where associated consumption represents less than 25% of the total monthly usage at the premise, and as the sole primary method of space heating except that the space heating system may be supplemented with renewable energy sources such as solar, wind, wood, or hydro.

Available only when supplied at 240 volt (or less) single phase service through a single meter directly by the Company to a single family dwelling or to an individual dwelling unit in a multiple dwelling structure. For the purposes of this rate, a dwelling unit is defined as one or more rooms arranged for the use of one or more individuals for shelter, sleeping, dining, and with permanent provisions for cooking and sanitation.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge \$15.00 (I)

Winter Monthly Rate — For the Billing Months of November through April:

Energy Charge 3.5813cents per kilowatt hour (I)

Summer Monthly Rate — For the Billing Months of May through October:

Energy Charge 4.3961cents per kilowatt hour (I)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for residential customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to residential customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

(I) – Indicates Increase

RATE RA - RESIDENTIAL SERVICE ADD-ON HEAT PUMP

AVAILABILITY

Available to residential or combined residential and farm customers using the Company's standard low voltage service for lighting, appliance operation, general household purposes and for commercial or professional activity where associated consumption represents less than 25% of the total monthly usage at the premise, and an add-on heat pump for space heating. Other energy sources may be used to supplement the add-on heat pump provided that the supplemental energy source is thermostatically controlled to operate only when the outdoor temperature falls to at least 40° F and the add-on heat pump cannot provide the total heating requirements.

Available only when supplied at 240 volt (or less) single phase service through a single meter directly by the Company to a single family dwelling or to an individual dwelling unit in a multiple dwelling structure. For the purposes of this rate, a dwelling unit is defined as one or more rooms arranged for the use of one or more individuals for shelter, sleeping, dining, and with permanent provisions for cooking and sanitation.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge \$15.00 (I)

Winter Monthly Rate — For the Billing Months of November through April:

Energy Charge 1.2199 cents per kilowatt hour (I)

Summer Monthly Rate — For the Billing Months of May through October:

Energy Charge 4.3961 cents per kilowatt hour (I)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for residential customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to residential customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

(I) – Indicates Increase

RATE GS/GM - GENERAL SERVICE SMALL AND MEDIUM

AVAILABILITY

Available for all the standard electric service taken on a small or medium general service customer's premises for which a residential rate is not available.

MONTHLY RATE FOR NON-DEMAND METERED CUSTOMERS

CUSTOMER CHARGE

Customer Distribution Charge..... \$15.00 (I)

ENERGY CHARGES

**Distribution Charge
cents per kilowatt-hour**

All kilowatt-hours 4.8981 (D)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

MONTHLY RATE FOR DEMAND METERED CUSTOMERS

DISTRIBUTION CHARGES

	<u>GM < 25 kW</u>	<u>GM ≥ 25 kW</u>	
Customer Charge	\$50.00	\$60.00	(I) (I)
Demand Charges	\$ per kilowatt		
First 5 kilowatts or less of Demand	No Charge	No Charge	
Additional kilowatts of Demand	4.65	4.62	(D) (D)
Energy Charges	¢ per kilowatt-hour		
All kilowatt-hours	1.2487	1.3175	(I) (I)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

(I) – Indicates Increase

(D) – Indicates Decrease

RATE GMH - GENERAL SERVICE MEDIUM HEATING

AVAILABILITY

Available for all the standard electric service taken on a customer's premises for which a residential rate is not available, where the Company's service is the sole method of space heating, and where the heat loss of the customer's premises is calculated in accordance with the ASHRAE* Handbook of Fundamentals, and where such calculated heat loss converted into kilowatt-hour consumption during the heating season is determined by the Company to be at least 25% of the customer's entire electric energy requirements during the heating season. The space heating system may be supplemented with renewable energy sources such as solar, wind, wood, or hydro.

*American Society of Heating, Refrigerating and Air Conditioning Engineers

CUSTOMER CHARGE

Customer Distribution Charge.....\$60.00 (I)

WINTER MONTHLY RATE

For the Billing Months of October through May:

ENERGY CHARGES

Distribution Charge
cents per kilowatt-hour

All kilowatt-hours 2.4022 (I)

SUMMER MONTHLY RATE

For the Billing Months of June through September:

DEMAND CHARGES

Distribution Charge
\$ per kilowatt

First 5 kilowatts or less of Demand No Charge
Additional kilowatts of Demand 4.65 (D)

RATE GMH - GENERAL SERVICE MEDIUM HEATING - (Continued)

MONTHLY RATE - (Continued)

SUMMER MONTHLY RATE – (Continued)

For the Billing Months of June through September: - (Continued)

ENERGY CHARGES

Distribution Charge
cents per kilowatt-hour

All kilowatt-hours	1.2487	
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(I)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for customers will be updated through competitive requests for proposal described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the “Calculation of Rate” section in Rider No. 8. Applicability of the Supply rate to non-demand metered customers, customers with monthly metered demand less than 25 kW and customers with monthly metered demand equal to or greater than 25 kW shall be as described in Rider No. 8 and for the effective periods defined in Rider No. 8.

For purposes of determining the monthly rate for demand metered customers, Duquesne Light shall evaluate the customer’s twelve (12) most recent months of monthly metered demand for that customer available in October of the preceding year. If the customer’s monthly metered demand is less than 25 kW in each of the twelve (12) months, then that customer shall be charged the monthly rate for demand metered customers less than 25 kW for the next calendar year and automatically assigned to that rate effective with their January billing. If the customer’s monthly metered demand is 25 kW or greater for any single month of the twelve (12) month period, then that customer shall be charged the monthly rate for demand metered customers equal to or greater than 25 kW for the next calendar year and automatically assigned to that rate as their default service rate effective with their January billing. In no instance shall a customer be eligible for more than one default service offering at a time. A new customer or a customer with limited or no historical data shall be eligible for and assigned to the applicable rate based on Duquesne Light’s estimate of the customer’s peak monthly metered demand for the next twelve (12) month period.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

(I) – Indicates Increase

RATE GL - GENERAL SERVICE LARGE**AVAILABILITY**

Available for all the standard electric service taken on a customer's premises where the demand is not less than 300 kilowatts.

MONTHLY RATE**SUPPLY**

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 9 – Hourly Price Service and will be billed in accordance with the terms contained therein.

DISTRIBUTION**DEMAND CHARGES**

First 300 kilowatts or less of Demand	\$2,787.00	(I)
Additional kilowatts of Demand	\$8.45per kW	(I)

ELECTRIC CHARGES

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy requirements from an EGS will be charged the full Distribution Charge by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the supplier becomes unavailable or during which the customer has not chosen a supplier, the Company will supply electricity pursuant to Rider No. 9 – Hourly Price Service.

Customers who choose an EGS may elect Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

RATE GLH - GENERAL SERVICE LARGE HEATING

AVAILABILITY

Available for all the standard electric service taken on a customer's premises for which a residential rate is not available, where the Company's service is the sole method of space heating, and where the heat loss of the customer's premises is calculated in accordance with the ASHRAE* Handbook of Fundamentals, and where such calculated heat loss converted into kilowatt-hour consumption during the heating season is determined by the Company to be at least 25% of the customer's entire electric energy requirements during the heating season. The space heating system may be supplemented with renewable energy sources such as solar, wind, wood, or hydro.

*American Society of Heating, Refrigerating and Air Conditioning Engineers

MONTHLY RATE

CUSTOMER CHARGE

Customer Distribution Charge..... \$60.00 (I)

SUPPLY

Customers who elect to purchase their electric supply requirements from the Company may do so under the provisions of Rider No. 9 – Hourly Price Service and will be billed in accordance with the terms contained therein.

DISTRIBUTION

For the Billing Months of October through May:

ENERGY CHARGES

All kilowatt-hours 2.1446 cents per kWh (I)

For the Billing Months of June through September:

Rate GL shall apply.

(I) – Indicates Increase

RATE L - LARGE POWER SERVICE

AVAILABILITY

Available for all the standard electric service taken on a customer's premises where the Contract Demand is not less than 5,000 kilowatts.

MONTHLY RATE

SUPPLY

Customers who elect to purchase their electric supply requirements from the Company may do so under the provisions of Rider No. 9 – Hourly Price Service and will be billed in accordance with the terms contained therein.

DISTRIBUTION

DEMAND CHARGES

Service Voltage Less than 138 Kv:		(C)
First 5,000 kilowatts or less of Demand	\$38,500.00	(I)
Additional kilowatts of Demand	\$12.30 per kW	(C) (I)
Service Voltage 138 Kv and Greater:		(C)
Fixed Monthly Charge	\$8,551.00 per month	(C)

ELECTRIC CHARGES

The Company will provide and charge for Transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy requirements from an EGS will be charged the full Distribution Charge by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the supplier becomes unavailable or during which the customer has not chosen a supplier, the Company will supply electricity pursuant to Rider No. 9 – Hourly Price Service.

Customers who choose an EGS may elect Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

RATE L - LARGE POWER SERVICE - (Continued)

STANDARD CONTRACT RIDERS

For modifications of the above rate under special conditions, see "Standard Contract Riders".

CONTRACT DEMAND

The Contract Demand is the maximum electrical capacity in kilowatts that the Company shall be required by the contract to deliver to the customer.

The customer shall not establish a demand greater than 105 percent of the individual demands specified in the customer's contract unless written approval shall first have been obtained from the Company. If the customer establishes a repeated pattern of exceeding the Contract Demand, the Contract Demand may be raised to the highest demand established for the remaining term of the contract.

CONTRACT PROVISIONS

Contracts shall be written for an original term of not less than five years for Contract Demand of 100,000 kilowatts or less, and not less than ten years for Contract Demands in excess of 100,000 kilowatts. Effective on January 26, 1985, such contracts shall continue in force after the expiration of the original term until one year following the date of written notice of cancellation by either party. Such notice of cancellation may not be given earlier than one year before the expiration of the original term.

When a customer takes delivery at 69 Kv or higher for delivery into its own electric system operated at either of such voltages, and has a Contract Demand of at least 100,000 kilowatts, the customer may apply for service at two or more delivery points interconnected by the customer's facilities. If the Company is satisfied that such multiple delivery points will protect the Company from substantial loss of load and otherwise will be consistent with operation of the Company's system, it will provide such multiple delivery points. In such case the various delivery points will be billed as if metered at one point, but the 5,000 kilowatt and additional kilowatt block of the Demand Charge will be multiplied by the number of delivery points before the rates stated for them are applied. (C)
(C)
(C)

The Company reserves the right to refuse contracts hereunder if, in its judgment, its generating or transmission capacity is no more than adequate to meet the requirements of its existing customers.

Where the customer has established an energy management and conservation program and has demonstrated to the satisfaction of the Company that such program has resulted in a reduced demand, the Company will, upon the customer's request, amend the contract to reflect such reduced demand for the purpose of calculating the Minimum Charge, but in no case shall the Billing Demand be reduced to less than 5,000 kilowatts if the customer remains on this rate.

RATE HVPS - HIGH VOLTAGE POWER SERVICE

AVAILABILITY

Available to customers with Contract On-Peak Demands greater than 30,000 kilowatts where service is supplied at 69,000 volts or higher.

MONTHLY RATE

SUPPLY

Customers who elect to purchase their electric supply requirements from the Company may do so under the provisions of Rider No. 9 – Hourly Price Service and will be billed in accordance with the terms contained therein.

DISTRIBUTION

FIXED MONTHLY CHARGE

Up to and Including 50,000 kW Billing Demand	\$8,551.00	(D)
50,001 kW to 100,000 kW Billing Demand	\$12,388.00	(D)
Greater than 100,000 kW Billing Demand	\$16,847.00	(D)

ELECTRIC CHARGES

The Company will provide and charge for Transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy requirements from an EGS will be charged the full Distribution Charge by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the supplier becomes unavailable or during which the customer has not chosen a supplier, the Company will supply electricity pursuant to Rider No. 9 – Hourly Price Service.

Customers who choose an EGS may elect Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

RATE AL - ARCHITECTURAL LIGHTING SERVICE

AVAILABILITY

Available for separately metered circuitry connected solely to outdoor architectural lighting equipment, with demand of 5 kilowatts or greater, to be operated during non-peak periods.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge	\$6.54	(D)
Demand Charge	\$1.22 per kilowatt	(D)
Energy Charge	0.1734 cents per kilowatt hour	(D)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate AL – Architectural Lighting Service customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the “Calculation of Rate” section in Rider No. 8. Applicability of the Supply rate to Rate AL customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charges, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

RATE SE - STREET LIGHTING ENERGY

AVAILABILITY

Available for the entire electric energy requirements of municipal street lighting systems where the municipality has not less than 15,000 street lamp installations and provides for the ownership, operation, and maintenance of its own street lamp installations and takes its entire energy requirements for street lighting under this rate.

MONTHLY RATE

DISTRIBUTION CHARGE

Monthly charge per lamp..... \$2.57 (D)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate SE – Street Lighting Energy customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to Rate SE customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charge, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

RATE SM - STREET LIGHTING MUNICIPAL

AVAILABILITY

Available for mercury vapor, high pressure sodium and light-emitting diode (LED) lighting of public streets, highways, bridges, parks and similar public places, for normal dusk to dawn operation of approximately 4,200 hours per year. (C)

(Available for mercury vapor street lighting only where served prior to January 30, 1983, and continuously thereafter at the same location.)

MONTHLY RATE

DISTRIBUTION CHARGE

Monthly Rate Per Unit

<u>Nominal Lamp Wattage</u>	<u>Nominal kWh Energy Usage per Unit per Month</u>	<u>Distribution Charge per Unit</u>	
Mercury Vapor			
100	44	\$11.52	(D)
175	74	\$11.76	(D)
250	102	\$11.99	(D)
400	161	\$12.46	(D)
1,000	386	\$14.34	(D)
Sodium Vapor			
70	29	\$11.87	(D)
100	50	\$11.91	(D)
150	71	\$12.15	(D)
250	110	\$12.47	(D)
400	170	\$12.97	(D)
1,000	387	\$14.93	(D)
Light-Emitting Diode (LED)			
43	15	\$12.16	
67	24	\$12.82	
106	37	\$13.97	
118	42	\$16.81	
196	69	\$18.78	
256	90	\$20.35	

(C)

RATE SM - STREET LIGHTING MUNICIPAL - (Continued)**MONTHLY RATE – (Continued)****SUPPLY CHARGES**

(C)

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

(C)

The Supply Charges for Rate SM – Street Lighting Municipal customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the “Calculation of Rate” section in Rider No. 8. Applicability of the Supply rate to Rate SM customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

(C)

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charge, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

RIDERS

Bills rendered under this schedule are subject to the charges stated in any applicable rider.

LATE PAYMENT CHARGE

Bills will be calculated on the rates stated herein, and are due and payable on or before thirty days from the date of mailing of the bill to the ratepayer. The bill is overdue when not paid on or before the due date indicated on the bill. An overdue bill is subject to a Late Payment Charge of 1.25% interest per month on the full unpaid and overdue balance of the Company charges on the bill. The Charge shall be calculated on the overdue portions of the Company charges on the bill and shall not be charged against any sum that falls due during a current billing period.

(C)

RATE SM - STREET LIGHT MUNICIPAL - (Continued)

MONTHLY RATE – (Continued)

(C)

POLES

(C)

No charge is made for wood poles used jointly for street lighting and the support of the Company's general distribution system or for tubular steel poles, trolley type, used jointly for street lighting and the support of trolley span wires.

Where the installation of one (1) or more wood poles is required to serve the customer, the customer has the option to install the pole(s) at his own expense in accordance with SPECIAL TERM AND CONDITION NO. 2 or the Company will install, own and maintain the pole(s) and bill the customer at the monthly rate of \$9.44 for each pole required.

(D)

SPECIAL TERMS AND CONDITIONS

1. The above charges include installation of standard Company facilities including lamps, fixtures or luminaries, brackets and ballasts, all when installed on the overhead distribution system. The above charges include normal operation and maintenance. Normal operation and maintenance does not include periodic tree trimming around the fixture or luminaire.
2. Where it is necessary to install wood, metal, or ornamental poles, or other special facilities or services not in conformance with the Company's standard overhead practice, the additional cost shall be borne by the customer. Title to all facilities, except as noted below, shall vest in the Company.
3. All facilities used in providing street lighting service shall be and remain the property of the Company and may be removed upon termination of service, except that poles, ducts, conduits, manholes and junction boxes shall be the property of and maintained by the customer if they are an integral part of bridges, viaducts or similar structures, or highway project constructed by the joint participation of the customer and other governmental agencies.
4. The customer agrees that the facilities installed under this rate shall not be removed or converted, or the use thereof discontinued by the customer, except upon payment to the Company of the original investment in such facilities, less depreciation to the date of discontinuance of such facilities, less salvage, plus the cost of removal.

RATE SH - STREET LIGHTING HIGHWAY

AVAILABILITY

Available for high intensity discharge lighting of state highways for normal dusk to dawn operation of approximately 4,200 hours per year where the highway lighting system acceptable to Duquesne Light Company is installed by the State and ownership of the entire highway lighting system has been transferred to the Company for a nominal consideration.

MONTHLY RATE

DISTRIBUTION CHARGE

Monthly Rate Per Unit

<u>Nominal Lamp Wattage</u>	<u>Nominal kWh Energy Usage per Unit per Month</u>	<u>Distribution Charge per Unit</u>	
Sodium Vapor			
100	50	\$11.37	(D)
150	71	\$11.53	(D)
200	95	\$11.68	(D)
400	170	\$12.30	(D)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate SH – Street Lighting Highway customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the “Calculation of Rate” section in Rider No. 8. Applicability of the Supply rate to Rate SH customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

(D) – Indicates Decrease

RATE UMS – UNMETERED SERVICE

AVAILABILITY

Available to customers using unmetered standard service at each point of connection for customer-owned and maintained equipment such as traffic signals, communication devices and billboard lighting.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge	\$10.00	(I)
Energy Charge	1.0192cents per kilowatt hour	(D)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate UMS – Unmetered Service customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to Rate UMS customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charges, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may elect Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

RATE PAL - PRIVATE AREA LIGHTING

AVAILABILITY

Available for high pressure sodium lighting, flood lighting and light-emitting diode (LED) lighting of residential, commercial and industrial private property installations including parking lots, for normal dusk to dawn operation of approximately 4,200 hours per year.

(C)

MONTHLY RATE

DISTRIBUTION CHARGE

DUQUESNE LIGHT COMPANY OWNED AND MAINTAINED EQUIPMENT

Monthly Rate Per Unit

<u>Nominal Lamp Wattage</u>	<u>Nominal kWh Energy Usage per Unit per Month</u>	<u>Distribution Charge per Unit</u>	
High Pressure Sodium			
70	29	\$11.87	(D)
100	50	\$11.91	(D)
150	71	\$12.15	(D)
250	110	\$12.47	(D)
400	170	\$12.97	(D)
Flood Lighting			
100	46	\$12.51	(D)
250	100	\$13.02	(D)
400	155	\$13.54	(D)
Light-Emitting Diode (LED)			
43	15	\$12.16	
67	24	\$12.82	
106	37	\$13.97	
118	42	\$16.81	
196	69	\$18.78	
256	90	\$20.35	

(C)

RATE PAL - PRIVATE AREA LIGHTING - (Continued)

MONTHLY RATE - (Continued)

DISTRIBUTION CHARGE - (Continued) (C)

DUQUESNE LIGHT COMPANY OWNED AND MAINTAINED EQUIPMENT - (Continued) (C)

Monthly Rate Per Unit - (Continued) (C)

<u>Nominal Lamp Wattage</u>	<u>Nominal kWh Energy Usage per Unit per Month</u>	<u>Distribution Charge per Unit</u>	
<u>UNMETERED ENERGY FOR CUSTOMER OWNED AND MAINTAINED EQUIPMENT</u> (C)			
70	29	\$2.57	(D)
100	46	\$2.57	(D)
150	67	\$2.57	(D)
250	100	\$2.57	(D)
400	155	\$2.57	(D)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate UMS – Unmetered Service customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the “Calculation of Rate” section in Rider No. 8. Applicability of the Supply rate to Rate UMS customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charge, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

(C)

RATE PAL - PRIVATE AREA LIGHTING - (Continued)MONTHLY RATE - (Continued)**ELECTRIC CHARGES – (Continued)**(C)
(C)

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

RIDERS

Bills rendered under this schedule are subject to the charges stated in any applicable rider.

LATE PAYMENT CHARGE

Bills will be calculated on the rates stated herein, and are due and payable on or before thirty days from the date of mailing of the bill to the ratepayer. The bill is overdue when not paid on or before the due date indicated on the bill. An overdue bill is subject to a Late Payment Charge of 1.25% interest per month on the full unpaid and overdue balance of the Company charges on the bill. The Charge shall be calculated on the overdue portions of the Company charges on the bill and shall not be charged against any sum that falls due during a current billing period.

POLES

No charge is made for wood poles used jointly for street lighting and the support of the Company's general distribution system or for tubular steel poles, trolley type, used jointly for street lighting and the support of trolley span wires.

Where the installation of one (1) or more wood poles is required to serve the customer, the customer has the option to install the pole(s) at his own expense in accordance with SPECIAL TERM AND CONDITION NO. 2 or the Company will install, own and maintain the pole(s) and bill the customer at the monthly rate of \$8.95 for each pole required.

(D)

SPECIAL TERMS AND CONDITIONS

1. The above charges include installation of standard Company facilities including lamps, fixtures or luminaries, brackets and ballasts, all when installed on the overhead distribution system. The above charges include normal operation and maintenance. Normal operation and maintenance does not include periodic tree trimming around the fixture or luminaire.
2. Where it is necessary to install wood, metal, or ornamental poles, or other special facilities or services not in conformance with the Company's standard overhead practice, the additional cost shall be borne by the customer. Title to all facilities, except as noted below, shall vest in the Company.
3. All facilities used in providing street lighting service shall be and remain the property of the Company and may be removed upon termination of service.
4. The customer agrees that the facilities installed under this rate shall not be removed or converted, or the use thereof discontinued by the customer, except upon payment to the Company of the original investment in such facilities, less depreciation to the date of discontinuance of such facilities, less salvage, plus the cost of removal.

STANDARD CONTRACT RIDERS – (Continued)

RIDER MATRIX

	RS	RH	RA	GS/GM	GMH	GL	GLH	L	HVPS	AL	SE	SM	SH	UMS	PAL
Rider No. 1	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Rider No. 2				X	X	X	X								
Rider No. 3				X	X	X	X	X							
Rider No. 4				X	X	X	X								
Rider No. 5	X	X	X												
Rider No. 6				X											
Rider No. 7	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Rider No. 8	X	X	X	X	X					X	X	X	X	X	X
Rider No. 9						X	X	X	X						
Rider No. 10	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Rider No. 11				X		X									
Rider No. 12				X	X										
Rider No. 13				X											
Rider No. 14	X														
Rider No. 15	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Rider No. 15A	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Rider No. 16				X	X	X	X	X							
Rider No. 17						X	X	X	X						
Rider No. 18	X	X	X	X	X	X	X								
Rider No. 20	X	X	X	X	X	X	X	X	X	X					
Rider No. 21	X	X	X	X	X	X									
Rider No. 22	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Appendix A	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

(C)

Rider Titles

- Rider No. 1 — Consumer Education Surcharge
- Rider No. 2 — Untransformed Service
- Rider No. 3 — School and Government Service Discount Period
- Rider No. 4 — Budget Billing HUD Finance Multi-Family Housing
- Rider No. 5 — Universal Service Charge
- Rider No. 6 — Temporary Service
- Rider No. 7 — SECA Charge
- Rider No. 8 — Default Service Supply
- Rider No. 9 — Day-Ahead Hourly Price Service
- Rider No. 10 — State Tax Adjustment
- Rider No. 11 — Street Railway Service
- Rider No. 12 — Billing Option – Volunteer Fire Companies and Nonprofit Senior Citizen Centers
- Rider No. 13 — General Service Separately Metered Electric Space Heating Service
- Rider No. 14 — Residential Service Separately Metered Electric Space and Water Heating
- Rider No. 15 — Energy Efficiency and Conservation and Demand Response Surcharge
- Rider No. 15A — Phase II Energy Efficiency and Conservation Surcharge
- Rider No. 16 — Service to Non-Utility Generating Facilities
- Rider No. 17 — Emergency Energy Conservation
- Rider No. 18 — Rates for Purchase of Electric Energy from Customer-Owned Renewable Resources Generating Facilities
- THESE PAGES INTENTIONALLY LEFT BLANK
- Rider No. 20 — Smart Meter Charge
- Rider No. 21 — Net Metering Service
- Rider No. 22 — Pension Rate Adjustment Mechanism
- Appendix A — Transmission Service Charges

(C)

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)**RIDER NO. 5 – UNIVERSAL SERVICE CHARGE - (Continued)**
(Applicable to Rate Schedules RS, RH and RA)**CALCULATION OF CHARGE – (Continued)**

previous year at normalized annual sales volumes. The projected customer additions to the CAP program during the Computational Year will be based on the number of CAP customers receiving a discount at the end of the Reconciliation Year plus a projection of the average monthly number of CAP customers during the Computational Year. The projected number of CAP customers will include net additions to the program (additions minus exits), an estimate of the average monthly number of auto-enrolled customers receiving a discount, and a projection of customers enrolled through expected changes in policy (e.g. changes in the definition of poverty, changes in regulatory mandates). An auto-enrolled customer is not considered to be a CAP participant for purposes of this Rider unless and until the customer has completed the CAP enrollment process. The projected CAP program costs will include the estimated costs for new applications, maintenance and annual recertification, and the projected CAP pre-program arrearages to be forgiven and written off during the USC Computational Year.

- Smart Comfort Program [Low Income Usage Reduction Program (“LIURP”): LIURP costs will be calculated based on the projected number of homes that participate in the usage reduction program and the average cost per visit.
- Customer Assistance and Referral Evaluation Services (“CARES”): CARES costs will be calculated based on the projected annual Community Based Organization (“CBO”) program costs and CBO costs for administering the program.
- Hardship Fund: Hardship Fund costs will be calculated based on the projected annual program costs and CBO costs for administering the program.
- Any other replacement or Commission-mandated Universal Service Program or low income program that is implemented during the Reconciliation or Computational Year.

- Cr = A credit to reduce CAP customer discounts included in the USC to the extent that the monthly CAP enrollment level exceeds 41,650 customers. Specifically, the recoverable CAP discounts will be reduced by the number of CAP participants in excess of 41,650 times the average CAP credit and arrearage forgiveness costs times 10.43%. The participation level above which the offset shall be applied will be reset in each distribution rate case. (I)
- E = The over- or under- collection of actual Universal Service Program costs and revenue that result from the billing of the USC during the USC Reconciliation Year (an over-collection is denoted by a positive E and an under-collection by a negative E), including applicable interest. Interest shall be computed monthly at the statutory legal rate of interest, from the month the over or under collection occurs to the effective month that the over collection is refunded or the under collection is recouped. (I)

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 8 – DEFAULT SERVICE SUPPLY – (Continued)

(Applicable to Rate Schedules RS, RH, RA, GS/GM, GMH, AL, SE, SM, SH, UMS and PAL)

DEFAULT SERVICE SUPPLY RATE – (Continued)

Lighting (Rate Schedules SM, SH and PAL) — Lamp wattage as available on applicable rate schedule.

Wattage	Nominal kWh Energy Usage per Unit per Month	Application Period			
		06/01/2013 through 11/30/2013	12/01/2013 through 05/31/2014	06/01/2014 through 11/30/2014	12/01/2014 through 05/31/2015
Supply Charge ¢ per kWh		3.9258	X.XXXX	X.XXXX	X.XXXX
Fixture Charge — \$ per Month					
Mercury Vapor					
100	44	1.73	X.XX	X.XX	X.XX
175	74	2.91	X.XX	X.XX	X.XX
250	102	4.00	X.XX	X.XX	X.XX
400	161	6.32	X.XX	X.XX	X.XX
1000	386	15.15	X.XX	X.XX	X.XX
High Pressure Sodium					
70	29	1.14	X.XX	X.XX	X.XX
100	50	1.96	X.XX	X.XX	X.XX
150	71	2.79	X.XX	X.XX	X.XX
200	95	3.73	X.XX	X.XX	X.XX
250	110	4.32	X.XX	X.XX	X.XX
400	170	6.67	X.XX	X.XX	X.XX
1000	387	15.19	X.XX	X.XX	X.XX
Flood Lighting - Unmetered					
70	29	1.14	X.XX	X.XX	X.XX
100	46	1.81	X.XX	X.XX	X.XX
150	67	2.63	X.XX	X.XX	X.XX
250	100	3.93	X.XX	X.XX	X.XX
400	155	6.08	X.XX	X.XX	X.XX
Light-Emitting Diode (LED)					
43	15	0.59			
67	24	0.94			
106	37	1.45			
118	42	1.65			
196	69	2.71			
256	90	3.53			

(C)

(C)

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)**RIDER NO. 8 – DEFAULT SERVICE SUPPLY – (Continued)**

(Applicable to Rate Schedules RS, RH, RA, GS/GM, GMH, AL, SE, SM, SH, UMS and PAL)

DEFAULT SERVICE SUPPLY RATE – (Continued)

The Company will provide default service supply under this Rider by obtaining the requirements from suppliers through competitive procurements using a Request for Proposal (“RFP”) process. The charges for DSS calculated based on the results of the RFP process for service under this Rider will be effective as defined above. (C)

DSS obtained through the RFP process includes energy, capacity, transmission and distribution line losses, congestion and congestion management costs, Alternative Energy Credits (“AECs”), ancillary services, PJM grid management charges and other such services or products that are required to provide default service to the Company’s customers including Auction Revenue Rights and Financial Transmission Rights (“ARRs/FTRs”). DSS shall not include transmission service within Duquesne’s zone. Duquesne will be responsible for and continue to provide network integration transmission service. The applicable charges for transmission service are defined in Appendix A of this Tariff.

Service under this Rider No. 8 – Default Service Supply shall commence in accordance with the switching protocols in Rule No. 45.1.

PROCUREMENT PROCESS

The Company will conduct separate RFP solicitations for DSS for each customer procurement group under this Rider. The customer procurement groups for the RFP solicitations are defined as residential and lighting, small commercial and industrial and medium commercial and industrial. The small commercial and industrial group includes those customers with monthly metered demand less than 25 kW. The medium commercial and industrial group includes those customers with monthly metered demand equal to or greater than 25 kW and less than 300 kW. The RFP process will be bid separately to ensure that there is no cross subsidization.

The Company will update the rates for the DSS according to the schedule in the above tables. The Company will issue RFPs prior to the beginning of each Application Period to update the default service supply rates. The updated rates will be based on the new price(s) available from the winning suppliers through the RFP process. The rates will include a reconciliation adjustment as described in the “Calculation of Rate” section of this Rider. In the month prior to the beginning of each Application Period, the Company will file new DSS charges with the Pennsylvania Public Utility Commission (“Commission”) for the subsequent Application Period, and, upon Commission approval, these charges shall become effective on the first day of the following month.

The load of the customer procurement group for the RFP will be divided into Tranches. Winning suppliers will provide DSS for the percentage of DSS load corresponding to the number of Tranches won in the RFP. Duquesne seeks to procure all Tranches in the RFP process pursuant to the RFP schedule approved by the Commission.

The selection of bids will be submitted to the Commission for its approval or rejection within one business day after submittal. If the bids are not acted on by the Commission within one business day, the Company may proceed on the basis that they are approved and award the bids pursuant to 52 Pa. Code § 54.188(d).

STANDARD CONTRACT RIDERS - (Continued)**RIDER NO. 10 - STATE TAX ADJUSTMENT****(Applicable to All Rates)**

In addition to the charges provided in this Tariff, a two-part surcharge will apply to all bills rendered by the Company, pursuant to the Pennsylvania Public Utility Commission authorization of March 10, 1970, to compensate the Company for new and increased taxes imposed by the General Assembly.

Part 1 of the surcharge, at a rate of 0.0000% will include Capital Stock Tax, Corporate Net Income Tax, and Public Utility Realty Tax, which will be applied to the distribution charges of customer bills. (C)

Part 2 of the surcharge, at a rate of 0.0000% will include Gross Receipts Tax and will be applied to all portions of customer bills.

The Company will recompute the surcharge using the elements prescribed by the Commission's March 10, 1970, authorization:

1. Whenever any of the tax rates used in computing the surcharge is changed, in which case the recomputation shall take into account the changed tax rate.
2. Whenever the Company makes effective increased or decreased rates (other than net energy clause), in which case the recomputation shall take into account the adjustments prescribed by the Commission's March 10, 1970, authorization.
3. On December 22, and each year thereafter.

Every recomputation made pursuant to the above paragraph shall be submitted to the Commission within ten (10) days after the occurrence of the event or date which occasions such recomputation; and if the recomputed surcharge is less than the one then in effect the Company will, and if the recomputed surcharge is more than the one then in effect the Company may, accompany such recomputation with a Tariff or supplement to reflect such recomputed surcharge, the effective date of which, shall be ten (10) days after filing.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 16 - SERVICE TO NON-UTILITY GENERATING FACILITIES**(Applicable to all General Service Rates Except Non-Demand Metered GS/GM Customers)**

(C)

The following applies to non-utility generating facilities including, but not limited to cogeneration and small power production facilities that are qualified in accord with Part 292 of Chapter I, Title 18, Code of Federal Regulations (qualifying facility). Electric energy will be delivered to a non-utility generating facility in accord with the following:

A. DEFINITIONS

Supplementary Power is electric energy and capacity supplied by the Company or by an Electric Generation Supplier (EGS) to a non-utility generating facility and regularly used in addition to that electric energy which the non-utility generating facility generates itself. The Company's regular and appropriate General Service Rates will be utilized for billing for Supplementary Power. Customers purchasing Supplementary Power from an EGS will be billed for charges according to their applicable rate and billing arrangement with their EGS.

(C)

Back-Up Power is electric energy and capacity supplied by the Company to a non-utility generating facility during any outage of the non-utility generating facility's electric generating equipment to replace electric energy ordinarily generated by the non-utility generating facility's generating equipment.

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Base Period is the twelve consecutive monthly billing periods applicable to the customer ending one month prior to the installation of new on-site generation or increase in capacity to existing on-site supply.

Contract Demand is the maximum electrical capacity in kilowatts that the Company shall be required by the contract to deliver to the customer for Back-Up Power. A Contract Demand may be established for Supplementary Power to the customer's facility.

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Supplementary Power Billing Determinants are the monthly billing period billing demand in kilowatts (kW) and the energy usage in kilowatt-hours (kWh) for Supplementary Power during the current billing month under which the on-site generation is operable. The Supplementary Power kW shall not exceed the Contract Demand kW for Supplementary Power, if applicable.

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Back-Up Power Billing Determinants are the monthly billing period billing demand in kilowatts (kW) and energy usage (kWh) in excess of those provided as Supplementary Power. If a Contract Demand exists for Supplementary Power, the Back-Up Billing Determinants are the kW and kWh in excess of the Supplementary Power Contract Demand.

(C)

Distribution Base Period Billing Determinants are the billing demand (kW) and the energy usage (kWh) for the month in the Base Period corresponding to the current billing month under which the on-site generation is operable. For new customers, the Company will use existing procedures to estimate Base Period Billing Determinants.

Supply Billing Determinants for customers on Rate Schedules GL, GLH, L and HVPS are the billing demand (kW) and energy usage (kWh) during the current billing month then in effect under Rider No. 9. Supply Billing Determinants for customers on Rate Schedule GS/GM and GMH shall be the same as those defined above for Distribution.

(C) – Indicates Change

ISSUED: AUGUST 2, 2013

EFFECTIVE: OCTOBER 1, 2013

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 16 - SERVICE TO NON-UTILITY GENERATING FACILITIES - (Continued)

(Applicable to all General Service Rates)

B. BACK-UP POWER

The Company will supply such service each month at the following rates:

DISTRIBUTION

A distribution charge of \$2.50 per kW shall be applied to the Back-Up Power Billing Determinants for Back-Up Power.

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The distribution charges will be applied in each month based on the customer's Contract Demand without regard to whether or not back-up energy is supplied.

SUPPLY

In any month that the Company provides energy to back up the customer's equipment, supply service shall be supplied and billed under Rider No. 9 for customers with Contract Demand of 300 kW or more. For customers having Contract Demand of less than 300 kW, the Company will bill the applicable supply demand and energy charges then in effect under Rate Schedule GS/GM.

The use of backup power at this price level will be limited to 15% usage for all hours in a year. Incremental usage above this limit will be billed on the applicable general service rates, including all ratchets applicable.

If a customer's actual kW demand at the time back-up is being supplied exceeds the customer's back-up Contract Demand by 5% or more, the actual kW demand as established will become the customer's new back-up Contract Demand for the remaining term of the back-up contract. If a customer's actual kW demand at the time back-up service is being supplied exceeds the customer's back-up Contract Demand by 10% or more, the customer will be assessed a fee determined by the difference between the actual demand established when back-up service is being supplied and the back-up Contract Demand multiplied by two times the applicable charge per kilowatt.

C. INTERCONNECTION

Each non-utility generating facility will be required to install at its expense or pay in advance to have the Company install interconnection equipment and facilities which are over and above that equipment and facilities required to provide electric service to the non-utility generating facility according to the Company's General Service Rates, except as noted below. Any such equipment to be installed by the non-utility generating facility must be reviewed and approved in writing by the Company prior to installation. Nothing in this Rider shall exempt a new customer from the application of Rule No. 7 and Rule No. 9 regarding Supply Line Extensions and Relocation of Facilities.

However, customers may elect to pay the cost of existing or newly required transformation equipment that is over and above that equipment necessary for the Company to supply the customer with its contracted Supplemental Power via a monthly charge rather than in total at the onset of the contract. The monthly charge for transformation equipment for customers with contract demand under this rider of 5,000 kW or more will be determined by the Company on a case-by-case basis. For all others, the rate of \$0.2523 per kW per month will apply.

STANDARD CONTRACT RIDERS - (Continued)

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RIDER NO. 22 – PENSION RATE ADJUSTMENT MECHANISM

(Applicable to all Rate Schedules)

PURPOSE

The Pension Rate Adjustment Mechanism is instituted as a cost adjustment instrument to modify, no more frequently than annually, the Company's base distribution rates to align future pension funding requirements with pension expense currently being recovered in base distribution rates as approved by the Commission at Docket No. R-2013-2372129.

APPLICABILITY

The Pension Rate Adjustment ("PRA") will be calculated independently for each applicable rate schedule in the Tariff using a Rate Class Factor. The Rate Class Factor is the share of each rate classes' pension expense recovered through base rates. The PRA will be calculated based on the allocated share of the change in pension expense funding for each rate class using the Rate Class Factor. The allocated change shall be computed for each rate class and applied to the applicable class billing units and will be used to reduce distribution rates in the applicable rate schedules in the event that the Company's current pension funding is reduced below the amount that was used to establish pension expense approved by the Commission in the Company's base rate proceeding at Docket No. R-2013-2372129. Accordingly, if the Company implements the PRA to reduce pension expense recovery and its pension costs increase, the Company will use the PRA to recover subsequent increases in pension expenses up to the level of pension expense included in base rates at Docket No. R-2013-2372129.

ADJUSTMENT TO BASE RATES

The PRA will be an adjustment to distribution rates as measured from the Base Expense Level and shall be determined in accordance with the formula set forth below and shall be applied to the applicable billing units once it becomes effective. The difference between the pension expense by rate class and the updated pension expense allocated to each rate class shall be the basis to calculate the adjustment to the applicable rate. The rate adjustment will be the difference divided by the billing units.

The PRA shall be applied to customers' bills as a non-bypassable adjustment and shall remain in effect until revised by the Company. The PRA will be made to the applicable distribution rates and become effective in sixty (60) days from the filing date.

$$PRA = \{ ((PEL - BEL) * RCF) / BU \}$$

Where **PRA** = Pension Rate Adjustment to be applied to the applicable distribution billing unit of each Rate Schedule under this Tariff.

PEL = The Projected Expense Level for the upcoming twelve (12) month period. The twelve (12) month period for which the Pension Funding Level will be determined shall be the twelve (12) months ending no later than fifteen (15) months from the beginning of the calendar quarter during which the filing is made. The Pension Expense Level shall be fifty percent (50%) of the Projected Funding Level.

STANDARD CONTRACT RIDERS - (Continued)

(C)

RIDER NO. 22 – PENSION RATE ADJUSTMENT MECHANISM - (Continued)

(Applicable to all Rate Schedules)

ADJUSTMENT TO BASE RATES - (Continued)

BEL = The Company's Base Expense Level as defined in the base rate case proceeding at Docket No. R-2013-2372129.

RCF = Rate Class Factor for each rate schedule as stated below:

Rate Schedule	Rate Class Factor
Rate RS	57.8%
Rate RH	4.7%
Rate RA	0.6%
Rate GS	2.0%
Rate GM < 25 kW	4.4%
Rate GM ≥ 25 kW	10.3%
Rate GMH < and ≥	1.5%
Rate GL	10.5%
Rate GLH	1.7%
Rate L	3.7%
Rate HVPS	0.0%
Rate SE	0.2%
Rates AL, SM, SH and PAL	2.4%
Rate UMS	0.1%

BU = The Billing Units shown in the Company's base rate proceeding at Docket No. R-2013-2372129. The following table summarizes the applicable Billing Units and affected rate for each rate schedule.

Rate Schedule	Billing Unit	Rate
Rate RS	kWh	¢/kWh
Rate RH	kWh	¢/kWh
Rate RA	kWh	¢/kWh
Rate GS	kWh	¢/kWh
Rate GM < 25 kW	kWh	¢/kWh
Rate GM ≥ 25 kW	kWh	¢/kWh
Rate GMH < and ≥	kWh	¢/kWh
Rate GL	kWh	\$/kW
Rate GLH	kWh	¢/kWh
Rate L	kWh	\$/kW
Rate HVPS	Bills	\$/Month
Rate AL	Bills	\$/Month
Rate SE	Fixtures	\$/Fixture/Month
Rates SM, SH and PAL	Fixtures	\$/Fixture/Month
Rate UMS	Bills	\$/Month

(C) – Indicates Change

ISSUED: AUGUST 2, 2013

EFFECTIVE: OCTOBER 1, 2013

STANDARD CONTRACT RIDERS - (Continued)

(C)

RIDER NO. 22 – PENSION RATE ADJUSTMENT MECHANISM - (Continued)**(Applicable to all Rate Schedules)****UPDATE**

Filing a PRA for the Commission's approval is at the sole discretion of the Company.

The PRA will be updated no more frequently than annually.

Subsequent filings will compute the change in distribution rates as measured from the Base Expense Level as established in the Company's base rate proceeding at Docket No. R-2013-2372129.

MISCELLANEOUS

This Rider will not increase base distribution rates greater than those established in the Company's base rate proceeding at Docket No. R-2013-2372129.

The Company will not seek to recover through this Rider pension costs in excess of those approved in the base rate case proceeding at Docket No. R-2013-2372129.

The PRA will be added to the applicable rate and not shown as a separate line item on the bill.

This Rider is applicable to the defined distribution units and is not subject to reconciliation.

The Rate Class Factors defined in this Rider will remain the same until revised by the Company in its next base rate proceeding.

Adjustments to rates pursuant to this Rider are subject to review and approval by the Commission.

Minimum bills shall not be reduced by reason of the PRA, nor shall charges hereunder be part of the monthly rate schedule minimum.

APPENDIX A

TRANSMISSION SERVICE CHARGES

(Applicable to All Rates)

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission (FERC) for customers who receive Default Service from the Company. Customers taking Default Service from the Company shall be charged in accordance with the charges of the applicable rate schedules stated below. These charges shall also apply to riders applicable to each rate schedule.

MONTHLY RATES

Rate Class	Energy Charge \$/kWh	Demand Charge \$/kW	Monthly Charge Per Fixture	Monthly Charge Per Fixture
RS	\$0.014587			
RH	\$0.006577			
RA	\$0.014550			
GS	\$0.008338			
GM < 25 kW	\$0.006195	\$1.09		
GM => 25 kW	\$0.007361	\$1.44		
GMH < 25 kW	\$0.007343	\$1.21 ⁽¹⁾		
GMH => 25 kW	\$0.005822	\$4.04 ⁽¹⁾		
GL		\$3.12		
GLH		\$3.18		
L		\$3.17		
HVPS		\$3.17		
AL	\$0.003455			
SE	\$0.001139			
UMS	\$0.000061	\$5.18		
			Rate Class	
			SH and PAL	SM
By Wattage				
Mercury Vapor				
100				\$0.12
175				\$0.20
250				\$0.28
400				\$0.44
1000				\$1.05
High Pressure Sodium				
70			\$0.04	\$0.08
100			\$0.07	\$0.14
150			\$0.10	\$0.19
200			\$0.14	
250			\$0.15	\$0.30
400			\$0.24	\$0.46
1000				\$1.05

(1) June through September

(C)

(C) – Indicates Change

ISSUED: AUGUST 2, 2013

EFFECTIVE: OCTOBER 1, 2013

APPENDIX A – (Continued)

TRANSMISSION SERVICE CHARGES – (Continued)

(Applicable to All Rates)

MONTHLY RATES – (Continued)

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Rate Class	Energy Charge \$/kWh	Demand Charge \$/kW	Monthly Charge Per Fixture	Monthly Charge Per Fixture
Flood Lighting - Unmetered				
70			\$0.04	
100			\$0.06	
150			\$0.09	
250			\$0.14	
400			\$0.22	
Light-Emitting Diode (LED)				
43			\$0.00	\$0.00
67			\$0.00	\$0.00
106			\$0.00	\$0.00
118			\$0.00	\$0.00
196			\$0.00	\$0.00
256			\$0.00	\$0.00

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BILLING DEMAND

Billing Demand subject to Transmission Service Charges for customers taking service under Rate Schedules GS/GM and GMH shall be the same as that determined for distribution and supply charges under the applicable rate schedules.

Billing Demand subject to Transmission Service Charges for Customers taking service under Rate Schedules GL, GLH, L, HVPS and UMS shall be the customer's daily network service coincident peak load contribution in MW. This quantity is determined based on the customer's load coincident with the annual peak of the Duquesne Zone (single coincident peak) as defined in the PJM Tariff Section 34.1.

ANNUAL UPDATE

The Transmission Service Charges (TSC) defined herein will be updated effective June 1st of each calendar year or more often upon determination that the rates then in effect would result in a significant over or under collection. On or about May 1st, the Company will file revised TSC rates with the PA Public Utility Commission (Commission) defining rates in effect from June 1 to May 31 of the following year, the computation year. These rates shall be determined based on the projected revenue requirement for the computation year, the projected cost of PJM charges and the over or under collection of expenses based on actual TSC revenue and expense incurred up to March 1 of each filing year. The revenue requirement and over or under collection shall be allocated to each rate class based on the class contribution to the Company's coincident peak load (1CP) and Default Service share of the 1CP load from the previous calendar year. The costs for ancillary services and PJM administrative expenses are included in the Default Service Supply rates defined in Rider No. 8. The costs for ancillary services and PJM administrative expenses for rate classes GL, GLH, L and HVPS will be billed in accordance with Rider No. 9. The rates applicable to each Rate Schedule shall be determined in accordance with the following formulas.

(C)

(C) – Indicates Change

APPENDIX A – (Continued)

TRANSMISSION SERVICE CHARGES – (Continued)

(Applicable to All Rates)

ANNUAL UPDATE - (Continued)

(C)

For Rate Schedules RS, RH, RA and applicable Riders:

$$\text{TSC-kWh} = \{ (\text{RCRR} - "e") / \text{RCSales} \} * \{ 1/(1-T) \}$$

For Rate Schedules GS/GM and GMH with monthly Billing Demand less than 25 kW:

Non-Demand Metered:

$$\text{TSC-kWh} = \{ (\text{RCRR} - "e") / \text{RCSales} \} * \{ 1/(1-T) \}$$

Demand Metered:

$$\text{TSC-kW} = \{ ((\text{RCRR} - "e") \times 50\%) / \text{RCDemand} \} * \{ 1/(1-T) \}$$

For Rate Schedules GS/GM and GMH with monthly Billing Demand less than 25 kW: - (Continued)

Demand Metered: - (Continued)

$$\text{TSC-kWh} = \{ ((\text{RCRR} - "e") \times 50\%) / \text{RCSales} \} * \{ 1/(1-T) \}$$

For Rate Schedules GS/GM and GMH with monthly Billing Demand equal to or greater than 25 kW:

$$\text{TSC-kW} = \{ ((\text{RCRR} - "e") \times 50\%) / \text{RCDemand} \} * \{ 1/(1-T) \}$$

$$\text{TSC-kWh} = \{ ((\text{RCRR} - "e") \times 50\%) / \text{RCSales} \} * \{ 1/(1-T) \}$$

For Rate Schedules GL, GLH, L, HVPS:

$$\text{TSC-kW} = \{ (\text{RCRR} - "e") / (\text{RC1CP} \times 12) \} * \{ 1/(1-T) \}$$

For Rate Schedule UMS:

$$\text{TSC-kW} = \{ (\text{RCRR} - "e") / (\text{RC1CP} \times 12) \} * \{ 1/(1-T) \}$$

(C)

APPENDIX A – (Continued)**TRANSMISSION SERVICE CHARGES – (Continued)****(Applicable to All Rates)****ANNUAL UPDATE - (Continued)****(C)****For Rate Schedules AL, SE, SM, SH and PAL:**

The annual revenue requirement and over or under collection shall be allocated to each rate class for cost recovery based on the rate class contribution to the coincident peak load from the previous calendar year. PJM charges that are load based will also be allocated to each rate class for cost recovery based on the rate class contribution to the coincident peak load. PJM charges that are energy based will be billed on a per kWh basis. All such charges will be adjusted for Pennsylvania gross receipts tax. For rate schedules SM, SH and PAL, a kWh charge will be determined to recover the allocated revenue requirement and PJM charges. An equivalent fixed monthly charge will be determined based on the monthly kWh usage applicable for each fixture.

Where:

- TSC = Transmission service charge to be applied to all Transmission billing units (either kWh or kW, as indicated.)
- RCRR = Projected total revenue requirement and PJM charges established for the computation year of June 1st through May 31st, corresponding to the PJM planning year. The revenue requirement shall be allocated to the specific rate classes by applying the ratio of the RC1CP to the Duquesne Zone 1CP for the prior year. PJM charges shall be allocated to each rate class on the basis incurred (i.e. 1CP, kW, kWh).
- "e" = Total over or under collection calculated by comparing total TSC revenues billed to the specific rate class during the reconciliation year of the twelve month period ending February 28th or 29th to the total charges billed by PJM under its OATT as approved or accepted by FERC and allocated to the specific rate class based upon its Default Service share of the Duquesne Zone 1CP for the prior year, including applicable interest. Interest shall be computed monthly at the statutory rate, from the month the over or under collection occurs to the effective month that the over collection is refunded or the under collection is recouped.
- RCSales = Projected kWh sales for the specific rate class for the computation year.
- RCDemand = Projected kW billing demand for the specific rate class for the computation year.
- RC1CP = Rate Class load coincident with the peak hour of the peak day of the Duquesne Zone during the calendar year prior to the computation year.
- T = The total Pennsylvania Gross Receipts Tax rate in effect during the billing month, expressed in decimal form.

APPENDIX A – (Continued)**(C)****TRANSMISSION SERVICE CHARGES – (Continued)****(Applicable to All Rates)****MISCELLANEOUS**

Minimum bills shall not be reduced by reason of the TSC, nor shall charges hereunder comprise any portion of a monthly rate schedule minimum. The TSC shall not be subject to any credits or discounts and shall not be affected by the State Tax Adjustment Surcharge (STAS).

The Company shall file a report of TSC collections within thirty days following the conclusion of each computation-year quarter. These reports will be in a form prescribed by the Commission.

Application of the TSC shall be subject to review and audit by the Commission at intervals it shall determine. The Commission shall review the level of charges produced by the TSC and the costs included therein.

Exhibit No. WVP-2

SUPPLEMENT NO. 81
TO ELECTRIC – PA. P.U.C. NO. 24



SCHEDULE OF RATES

For Electric Service in Allegheny and Beaver Counties

(For List of Communities Served, see Pages No. 4 and 5)

Issued By

DUQUESNE LIGHT COMPANY

411 Seventh Avenue
Pittsburgh, PA 15219

Richard Riazzi

President and Chief Executive Officer

ISSUED: August 2, 2013

EFFECTIVE: October 1, 2013

Filed at Docket No. R-2013-2372129

NOTICE

**THIS SUPPLEMENT MAKES CHANGES TO
THE TABLE OF CONTENTS, A RULE, RATE SCHEDULES AND RIDERS,
MAKES INCREASES AND DECREASES TO THE RATES AND ADDS A RIDER**

See Page Two

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGESList of Modifications Page No. 2

Pages No. 2A through 2D were added to the Tariff.

Table of Contents Twenty-Second Revised Page No. 3
Cancelling Twenty-First Revised Page No. 3

Pages No. 2A through 2D were added to the Table of Contents.

Rider No. 22 – Pension Rate Adjustment Mechanism, Original Pages No. 112B, 112C and 112D, was added to the Table of Contents.

Due to repagination, Page No. 116A was added to the Table of Contents.

Rule No. 21.1 Payment of Bills for Residential Service First Revised Page No. 23A
Cancelling Original Page No. 23A

Language has been modified to reflect the current operations of the Company.

Rate L – Large Power Service Fifth Revised Page No. 53
Cancelling Fourth Revised Page No. 53

Language has been modified to reflect the addition of “Service Voltage Less than 138 Kv” and “Service Voltage 138 Kv and Greater.”

The “Next 10,000 kilowatts of Demand” block has been eliminated from the Rate Schedule.

A Fixed Monthly Charge has been added under “Service Voltage 138 Kv and Greater.”

Rate L – Large Power Service Second Revised Page No. 54
Cancelling First Revised Page No. 54

Language has been modified in the second paragraph under “Contract Provisions” to reflect the elimination of the 10,000, 25,000 and 750,000 kilowatt-hour blocks under the Energy Charge.

Language has been modified to replace the word “Capacity” with the word “Demand.”

Rate SM – Street Lighting Municipal Sixth Revised Page No. 68
Cancelling Fifth Revised Page No. 68

Language has been modified to include Light-Emitting Diode (LED) fixtures and pricing.

Currently approved language has been moved to accommodate the addition of the Light-Emitting Diode (LED) fixtures and pricing information.

LIST OF MODIFICATIONS MADE BY THIS TARIFFCHANGES – (Continued)

Rate SM – Street Lighting Municipal Sixth Revised Page No. 69
Cancelling Fifth Revised Page No. 69

Rate SM – Street Lighting Municipal Second Revised Page No. 70
Cancelling First Revised Page No. 70

Currently approved language has been moved to accommodate the addition of the Light-Emitting Diode (LED) fixtures and pricing information.

Rate PAL – Private Area Lighting Sixth Revised Page No. 76
Cancelling Fifth Revised Page No. 76

Language has been modified to include Light-Emitting Diode (LED) fixtures and pricing.

Currently approved language has been moved to accommodate the addition of the Light-Emitting Diode (LED) fixtures and pricing information.

Rate PAL – Private Area Lighting Fifth Revised Page No. 77
Cancelling Fourth Revised Page No. 77

Rate PAL – Private Area Lighting Third Revised Page No. 78
Cancelling Second Revised Page No. 78

Currently approved language has been moved to accommodate the addition of the Light-Emitting Diode (LED) fixtures and pricing information.

Rider Matrix Third Revised Page No. 79A
Cancelling Second Revised Page No. 79A

Rider No. 22 – Pension Rate Adjustment Mechanism has been added to the Rider Matrix.

Rider No. 8 – Default Service Supply Third Revised Page No. 88A
Cancelling Second Revised Page No. 88A

The Table has been modified to include Light-Emitting Diode (LED) fixtures and pricing.

Currently approved language has been moved to accommodate the addition of the Light-Emitting Diode (LED) fixtures and pricing information.

Rider No. 8 – Default Service Supply Third Revised Page No. 88B
Cancelling Second Revised Page No. 88B

Currently approved language has been moved to accommodate the addition of the Light-Emitting Diode (LED) fixtures and pricing information.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rider No. 10 – State Tax Adjustment Ninth Revised Page No. 94
Eighth Revised Page No. 94

Rider No. 10 – State Tax Adjustment has been modified to reflect that Part 1 of the STAS has been set to zero.

Rider No. 16 – Service to Non-Utility Generating Facilities Fourth Revised Page No. 101
Cancelling Third Revised Page No. 101

Language and definitions have been modified to reflect current operations of the Company.

Rider No. 16 – Service to Non-Utility Generating Facilities Fourth Revised Page No. 102
Cancelling Third Revised Page No. 102

Language has been modified to remove the “Contract Demand” under B. Back-Up Power.

Language has been modified to add a distribution charge to be applied to the Back-Up Billing Determinants for Back-Up Power under B. Back-Up Power.

Rider No. 22 – Pension Rate Adjustment Mechanism Original Page No. 112B
Original Page No. 112C
Original Page No. 112D

Rider No. 22 – Pension Rate Adjustment Mechanism has been added to the Tariff.

Appendix A – Transmission Service Charges Twelfth Revised Page No. 113
Cancelling Eleventh Revised Page No. 113

Fifth Revised Page No. 114
Cancelling Fourth Revised Page No. 114

Fifth Revised Page No. 115
Cancelling Fourth Revised Page No. 115

Seventh Revised Page No. 116
Cancelling Sixth Revised Page No. 116

Original Page No. 116A

Currently approved language has been moved to accommodate the addition of the Light-Emitting Diode (LED) fixtures and pricing information.

LIST OF MODIFICATIONS MADE BY THIS TARIFFCHANGES – (Continued)

Appendix A – Transmission Service Charges Fifth Revised Page No. 114
Cancelling Fourth Revised Page No. 114

The table has been modified to include Light-Emitting Diode (LED) fixtures and pricing.

Appendix A – Transmission Service Charges Original Page No. 116A

Original Page No. 116A has been added to the Tariff to accommodate the addition of the Light-Emitting Diode (LED) fixtures and pricing information.

INCREASES

Rate RS – Residential Service Sixth Revised Page No. 32
Cancelling Fifth Revised Page No. 32

Rate RH – Residential Service Heating Sixth Revised Page No. 34
Cancelling Fifth Revised Page No. 34

Rate RA – Residential Service Add-On Heat Pump Sixth Revised Page No. 37
Cancelling Fifth Revised Page No. 37

Rate GS/GM – General Service Small and Medium Fifth Revised Page No. 40
Cancelling Fourth Revised Page No. 40

Rate GMH – General Service Medium Heating Fifth Revised Page No. 43
Cancelling Fourth Revised Page No. 43

Eighth Revised Page No. 44
Cancelling Seventh Revised Page No. 44

Rate GL – General Service Large Fifth Revised Page No. 47
Cancelling Fourth Revised Page No. 47

Rate GLH – General Service Large Heating Fifth Revised Page No. 50
Cancelling Fourth Revised Page No. 50

Rate L – Large Power Service Fifth Revised Page No. 53
Cancelling Fourth Revised Page No. 53

Rate PAL – Private Area Lighting Fifth Revised Page No. 77
Cancelling Fourth Revised Page No. 77

Rate PAL – Private Area Lighting Third Revised Page No. 78
Cancelling Second Revised Page No. 78

LIST OF MODIFICATIONS MADE BY THIS TARIFFINCREASES – (Continued)

Rate UMS – Unmetered Service Sixth Revised Page No.74
Cancelling Fifth Revised Page No. 74

Unit prices have changed resulting in increases.

Rider No. 5 – Universal Service Charge Fourth Revised Page No. 85
Cancelling Third Revised Page No. 85

Rider No. 5 – Universal Service Charge has been updated as directed in the Rider to reflect the participation level of CAP customers.

DECREASES

Rate GS/GM – General Service Small and Medium Fifth Revised Page No. 40
Cancelling Fourth Revised Page No. 40

Rate GMH – General Service Medium Heating Fifth Revised Page No. 43
Cancelling Fourth Revised Page No. 43

Rate HVPS – High Voltage Power Service Fifth Revised Page No. 57
Cancelling Fourth Revised Page No. 57

Rate AL – Architectural Lighting Service Sixth Revised Page No. 61
Cancelling Fifth Revised Page No. 61

Rate SE – Street Lighting Energy Sixth Revised Page No. 64
Cancelling Fifth Revised Page No. 64

Rate SM – Street Lighting Municipal Sixth Revised Page No. 68
Cancelling Fifth Revised Page No. 68

Rate SM – Street Lighting Municipal Second Revised Page No. 70
Cancelling First Revised Page No. 70

Rate SH – Street Lighting Highway Sixth Revised Page No. 71
Cancelling Fifth Revised Page No. 71

Rate UMS – Unmetered Service Sixth Revised Page No.74
Cancelling Fifth Revised Page No. 74

Rate PAL – Private Area Lighting Sixth Revised Page No. 76
Cancelling Fifth Revised Page No. 76

Unit prices have changed resulting in decreases.

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(C) – Indicates Change

RULES AND REGULATIONS – (Continued)

BILLS AND NET PAYMENT PERIODS – (Continued)

21.1 PAYMENT OF BILLS FOR RESIDENTIAL SERVICE The Company will designate a due date on its bill which shall be a business day no less than 20 days from the date of transmittal of the bill. The Company may accommodate changes to due dates for residential customers upon written customer request and when a demonstrated financial burden for the current due date exists ~~When the due date for residential service occurs from the 21st day of the month through the 5th day of the following month, the due date may be extended upon request to the 6th day of the latter month for ratepayers receiving Social Security or equivalent monthly checks or about the first of the month.~~ (C)

RATE RS - RESIDENTIAL SERVICE

AVAILABILITY

Available to residential or combined residential and farm customers using the Company's standard low voltage service for lighting, appliance operation, and general household purposes and for commercial or professional activity where associated consumption represents less than 25% of the total monthly usage at the premise.

Available only when supplied at 240 volt (or less) single phase service through a single meter directly by the Company to a single family dwelling or to an individual dwelling unit in a multiple dwelling structure. For the purposes of this rate, a dwelling unit is defined as one or more rooms arranged for the use of one or more individuals for shelter, sleeping, dining, and with permanent provisions for cooking and sanitation.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge	\$7.00 <u>\$15.00</u>	<u>(I)</u>
Energy Charge	4.3657 <u>4.3961</u> cents per kilowatt hour	<u>(I)</u>

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for residential customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the “Calculation of Rate” section in Rider No. 8. Applicability of the Supply rate to residential customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charges, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

(I) – Indicates Increase

RATE RH - RESIDENTIAL SERVICE HEATING

AVAILABILITY

Available to residential or combined residential and farm customers using the Company's standard low voltage service for lighting, appliance operation, general household purposes and for commercial or professional activity where associated consumption represents less than 25% of the total monthly usage at the premise, and as the sole primary method of space heating except that the space heating system may be supplemented with renewable energy sources such as solar, wind, wood, or hydro.

Available only when supplied at 240 volt (or less) single phase service through a single meter directly by the Company to a single family dwelling or to an individual dwelling unit in a multiple dwelling structure. For the purposes of this rate, a dwelling unit is defined as one or more rooms arranged for the use of one or more individuals for shelter, sleeping, dining, and with permanent provisions for cooking and sanitation.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge ~~\$7.00~~ \$15.00 (I)

Winter Monthly Rate — For the Billing Months of November through April:

Energy Charge ~~3.2174~~ 3.5813 cents per kilowatt hour (I)

Summer Monthly Rate — For the Billing Months of May through October:

Energy Charge ~~4.3657~~ 4.3961 cents per kilowatt hour (I)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for residential customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the “Calculation of Rate” section in Rider No. 8. Applicability of the Supply rate to residential customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

(I) – Indicates Increase

RATE RA - RESIDENTIAL SERVICE ADD-ON HEAT PUMP

AVAILABILITY

Available to residential or combined residential and farm customers using the Company's standard low voltage service for lighting, appliance operation, general household purposes and for commercial or professional activity where associated consumption represents less than 25% of the total monthly usage at the premise, and an add-on heat pump for space heating. Other energy sources may be used to supplement the add-on heat pump provided that the supplemental energy source is thermostatically controlled to operate only when the outdoor temperature falls to at least 40° F and the add-on heat pump cannot provide the total heating requirements.

Available only when supplied at 240 volt (or less) single phase service through a single meter directly by the Company to a single family dwelling or to an individual dwelling unit in a multiple dwelling structure. For the purposes of this rate, a dwelling unit is defined as one or more rooms arranged for the use of one or more individuals for shelter, sleeping, dining, and with permanent provisions for cooking and sanitation.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge ~~\$7.00~~ \$15.00 (I)

Winter Monthly Rate — For the Billing Months of November through April:

Energy Charge ~~0.99~~ 1.2199 cents per kilowatt hour (I)

Summer Monthly Rate — For the Billing Months of May through October:

Energy Charge ~~4.31~~ 4.3961 cents per kilowatt hour (I)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for residential customers will be updated through competitive requests for proposal described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to residential customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

(I) – Indicates Increase

ISSUED: AUGUST 2, 2013

EFFECTIVE: OCTOBER 1, 2013

RATE GMH - GENERAL SERVICE MEDIUM HEATING - (Continued)

MONTHLY RATE - (Continued)

SUMMER MONTHLY RATE – (Continued)

For the Billing Months of June through September: - (Continued)

ENERGY CHARGES

Distribution Charge
cents per kilowatt-hour

All kilowatt-hours

~~1.1159~~ 1.2487

(I)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for customers will be updated through competitive requests for proposal described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the “Calculation of Rate” section in Rider No. 8. Applicability of the Supply rate to non-demand metered customers, customers with monthly metered demand less than 25 kW and customers with monthly metered demand equal to or greater than 25 kW shall be as described in Rider No. 8 and for the effective periods defined in Rider No. 8.

For purposes of determining the monthly rate for demand metered customers, Duquesne Light shall evaluate the customer’s twelve (12) most recent months of monthly metered demand for that customer available in October of the preceding year. If the customer’s monthly metered demand is less than 25 kW in each of the twelve (12) months, then that customer shall be charged the monthly rate for demand metered customers less than 25 kW for the next calendar year and automatically assigned to that rate effective with their January billing. If the customer’s monthly metered demand is 25 kW or greater for any single month of the twelve (12) month period, then that customer shall be charged the monthly rate for demand metered customers equal to or greater than 25 kW for the next calendar year and automatically assigned to that rate as their default service rate effective with their January billing. In no instance shall a customer be eligible for more than one default service offering at a time. A new customer or a customer with limited or no historical data shall be eligible for and assigned to the applicable rate based on Duquesne Light’s estimate of the customer’s peak monthly metered demand for the next twelve (12) month period.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

(I) – Indicates Increase

ISSUED: AUGUST 2, 2013

EFFECTIVE: OCTOBER 1, 2013

RATE GL - GENERAL SERVICE LARGE

AVAILABILITY

Available for all the standard electric service taken on a customer's premises where the demand is not less than 300 kilowatts.

MONTHLY RATE

SUPPLY

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 9 – Hourly Price Service and will be billed in accordance with the terms contained therein.

DISTRIBUTION

DEMAND CHARGES

First 300 kilowatts or less of Demand	\$2,478.00 \$2,787.00	(I)
Additional kilowatts of Demand	\$7.53 \$8.45 per kW	(I)

ELECTRIC CHARGES

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy requirements from an EGS will be charged the full Distribution Charge by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the supplier becomes unavailable or during which the customer has not chosen a supplier, the Company will supply electricity pursuant to Rider No. 9 – Hourly Price Service.

Customers who choose an EGS may elect Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

(I) – Indicates Increase

ISSUED: AUGUST 2, 2013

EFFECTIVE: OCTOBER 1, 2013

RATE GLH - GENERAL SERVICE LARGE HEATING

AVAILABILITY

Available for all the standard electric service taken on a customer's premises for which a residential rate is not available, where the Company's service is the sole method of space heating, and where the heat loss of the customer's premises is calculated in accordance with the ASHRAE* Handbook of Fundamentals, and where such calculated heat loss converted into kilowatt-hour consumption during the heating season is determined by the Company to be at least 25% of the customer's entire electric energy requirements during the heating season. The space heating system may be supplemented with renewable energy sources such as solar, wind, wood, or hydro.

*American Society of Heating, Refrigerating and Air Conditioning Engineers

MONTHLY RATE

CUSTOMER CHARGE

| Customer Distribution Charge..... ~~\$43.00~~ **\$60.00** (I)

SUPPLY

Customers who elect to purchase their electric supply requirements from the Company may do so under the provisions of Rider No. 9 – Hourly Price Service and will be billed in accordance with the terms contained therein.

DISTRIBUTION

For the Billing Months of October through May:

ENERGY CHARGES

| All kilowatt-hours ~~1.7019~~ **2.1446** cents per kWh (I)

For the Billing Months of June through September:

Rate GL shall apply.

(I) – Indicates Increase

RATE L - LARGE POWER SERVICE - (Continued)

STANDARD CONTRACT RIDERS

For modifications of the above rate under special conditions, see "Standard Contract Riders".

CONTRACT DEMAND

The Contract Demand is the maximum electrical capacity in kilowatts that the Company shall be required by the contract to deliver to the customer.

The customer shall not establish a demand greater than 105 percent of the individual demands specified in the customer's contract unless written approval shall first have been obtained from the Company. If the customer establishes a repeated pattern of exceeding the Contract Demand, the Contract Demand may be raised to the highest demand established for the remaining term of the contract.

CONTRACT PROVISIONS

Contracts shall be written for an original term of not less than five years for Contract Demand of 100,000 kilowatts or less, and not less than ten years for Contract Demands in excess of 100,000 kilowatts. Effective on January 26, 1985, such contracts shall continue in force after the expiration of the original term until one year following the date of written notice of cancellation by either party. Such notice of cancellation may not be given earlier than one year before the expiration of the original term.

When a customer takes delivery at 69 Kv or higher for delivery into its own electric system operated at either of such voltages, and has a Contract Demand of at least 100,000 kilowatts, the customer may apply for service at two or more delivery points interconnected by the customer's facilities. If the Company is satisfied that such multiple delivery points will protect the Company from substantial loss of load and otherwise will be consistent with operation of the Company's system, it will provide such multiple delivery points. In such case the various delivery points will be billed as if metered at one point, but the 5,000 kilowatt, ~~10,000 kilowatt~~ and ~~25,000 additional~~ kilowatt blocks of the Capacity Demand Charge, and the ~~750,000 kilowatt-hour block of the~~ Energy Charge, will be multiplied by the number of delivery points before the rates stated for them are applied. (C) (C) (C)

The Company reserves the right to refuse contracts hereunder if, in its judgment, its generating or transmission capacity is no more than adequate to meet the requirements of its existing customers.

Where the customer has established an energy management and conservation program and has demonstrated to the satisfaction of the Company that such program has resulted in a reduced demand, the Company will, upon the customer's request, amend the contract to reflect such reduced demand for the purpose of calculating the Minimum Charge, but in no case shall the Billing Demand be reduced to less than 5,000 kilowatts if the customer remains on this rate.

(C) – Indicates Change

ISSUED: **AUGUST 2, 2013**

EFFECTIVE: **OCTOBER 1, 2013**

RATE HVPS - HIGH VOLTAGE POWER SERVICE

AVAILABILITY

Available to customers with Contract On-Peak Demands greater than 30,000 kilowatts where service is supplied at 69,000 volts or higher.

MONTHLY RATE

SUPPLY

Customers who elect to purchase their electric supply requirements from the Company may do so under the provisions of Rider No. 9 – Hourly Price Service and will be billed in accordance with the terms contained therein.

DISTRIBUTION

FIXED MONTHLY CHARGE

Up to and Including 50,000 kW Billing Demand	\$11,671.00 <u>\$8,551.00</u>	(D)
50,001 kW to 100,000 kW Billing Demand	\$16,908.00 <u>\$12,388.00</u>	(D)
Greater than 100,000 kW Billing Demand	\$22,994.00 <u>\$16,847.00</u>	(D)

ELECTRIC CHARGES

The Company will provide and charge for Transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy requirements from an EGS will be charged the full Distribution Charge by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the supplier becomes unavailable or during which the customer has not chosen a supplier, the Company will supply electricity pursuant to Rider No. 9 – Hourly Price Service.

Customers who choose an EGS may elect Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

(D) – Indicates Decrease

ISSUED: AUGUST 2, 2013

EFFECTIVE: OCTOBER 1, 2013

RATE AL - ARCHITECTURAL LIGHTING SERVICE

AVAILABILITY

Available for separately metered circuitry connected solely to outdoor architectural lighting equipment, with demand of 5 kilowatts or greater, to be operated during non-peak periods.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge	\$7.49 \$6.54	(D)
Demand Charge	\$1.40 \$1.22 per kilowatt	(D)
Energy Charge	0.1987 0.1734 cents per kilowatt hour	(D)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate AL – Architectural Lighting Service customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the “Calculation of Rate” section in Rider No. 8. Applicability of the Supply rate to Rate AL customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charges, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

(D) – Indicates Decrease

RATE SE - STREET LIGHTING ENERGY

AVAILABILITY

Available for the entire electric energy requirements of municipal street lighting systems where the municipality has not less than 15,000 street lamp installations and provides for the ownership, operation, and maintenance of its own street lamp installations and takes its entire energy requirements for street lighting under this rate.

MONTHLY RATE

DISTRIBUTION CHARGE

Monthly charge per lamp..... ~~\$3.16~~ \$2.57 (D)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate SE – Street Lighting Energy customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the “Calculation of Rate” section in Rider No. 8. Applicability of the Supply rate to Rate SE customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charge, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

(D) – Indicates Decrease

ISSUED: AUGUST 2, 2013

EFFECTIVE: OCTOBER 1, 2013

RATE SM - STREET LIGHTING MUNICIPAL

AVAILABILITY

Available for mercury vapor, ~~and~~ high pressure sodium and light-emitting diode (LED) lighting of public streets, highways, bridges, parks and similar public places, for normal dusk to dawn operation of approximately 4,200 hours per year. (C)

(Available for mercury vapor street lighting only where served prior to January 30, 1983, and continuously thereafter at the same location.)

MONTHLY RATE

DISTRIBUTION CHARGE

Monthly Rate Per Unit

<u>Nominal Lamp Wattage</u>	<u>Nominal kWh Energy Usage per Unit per Month</u>	<u>Distribution Charge per Unit</u>	
Mercury Vapor			
100	44	\$13.18 <u>\$11.52</u>	(D)
175	74	\$13.46 <u>\$11.76</u>	(D)
250	102	\$13.72 <u>\$11.99</u>	(D)
400	161	\$14.26 <u>\$12.46</u>	(D)
1,000	386	\$16.41 <u>\$14.34</u>	(D)
Sodium Vapor			
70	29	\$13.62 <u>\$11.87</u>	(D)
100	50	\$13.73 <u>\$11.91</u>	(D)
150	71	\$13.92 <u>\$12.15</u>	(D)
250	110	\$14.29 <u>\$12.47</u>	(D)
400	170	\$14.86 <u>\$12.97</u>	(D)
1,000	387	\$17.09 <u>\$14.93</u>	(D)
<u>Light-Emitting Diode (LED)</u> (C)			
<u>43</u>	<u>15</u>	<u>\$12.16</u>	
<u>67</u>	<u>24</u>	<u>\$12.82</u>	
<u>106</u>	<u>37</u>	<u>\$13.97</u>	
<u>118</u>	<u>42</u>	<u>\$16.81</u>	
<u>196</u>	<u>69</u>	<u>\$18.78</u>	
<u>256</u>	<u>90</u>	<u>\$20.35</u>	

(C)

(C) – Indicates Change (D) – Indicates Decrease

ISSUED: AUGUST 2, 2013

EFFECTIVE: OCTOBER 1, 2013

RATE SM - STREET LIGHTING MUNICIPAL - (Continued)**MONTHLY RATE – (Continued)****SUPPLY CHARGES****(C)**

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES—(Continued)**(C)**

The Supply Charges for Rate SM – Street Lighting Municipal customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the “Calculation of Rate” section in Rider No. 8. Applicability of the Supply rate to Rate SM customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

(C)

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charge, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

RIDERS

Bills rendered under this schedule are subject to the charges stated in any applicable rider.

LATE PAYMENT CHARGE

Bills will be calculated on the rates stated herein, and are due and payable on or before thirty days from the date of mailing of the bill to the ratepayer. The bill is overdue when not paid on or before the due date indicated on the bill. An overdue bill is subject to a Late Payment Charge of 1.25% interest per month on the full unpaid and overdue balance of the Company charges on the bill. The Charge shall be calculated on the overdue portions of the Company charges on the bill and shall not be charged against any sum that falls due during a current billing period.

(C)**(C) – Indicates Change****ISSUED: AUGUST 2, 2013****EFFECTIVE: OCTOBER 1, 2013**

RATE SM - STREET LIGHT MUNICIPAL - (Continued)

MONTHLY RATE – (Continued)

(C)

POLES

(C)

No charge is made for wood poles used jointly for street lighting and the support of the Company's general distribution system or for tubular steel poles, trolley type, used jointly for street lighting and the support of trolley span wires.

Where the installation of one (1) or more wood poles is required to serve the customer, the customer has the option to install the pole(s) at his own expense in accordance with SPECIAL TERM AND CONDITION NO. 2 or the Company will install, own and maintain the pole(s) and bill the customer at the monthly rate of ~~\$10.80~~ **\$9.44** for each pole required.

(D)

SPECIAL TERMS AND CONDITIONS

1. The above charges include installation of standard Company facilities including lamps, fixtures or luminaries, brackets and ballasts, all when installed on the overhead distribution system. The above charges include normal operation and maintenance. Normal operation and maintenance does not include periodic tree trimming around the fixture or luminaire.
2. Where it is necessary to install wood, metal, or ornamental poles, or other special facilities or services not in conformance with the Company's standard overhead practice, the additional cost shall be borne by the customer. Title to all facilities, except as noted below, shall vest in the Company.
3. All facilities used in providing street lighting service shall be and remain the property of the Company and may be removed upon termination of service, except that poles, ducts, conduits, manholes and junction boxes shall be the property of and maintained by the customer if they are an integral part of bridges, viaducts or similar structures, or highway project constructed by the joint participation of the customer and other governmental agencies.
4. The customer agrees that the facilities installed under this rate shall not be removed or converted, or the use thereof discontinued by the customer, except upon payment to the Company of the original investment in such facilities, less depreciation to the date of discontinuance of such facilities, less salvage, plus the cost of removal.

(C) – Indicates Change

(D) – Indicates Decrease

ISSUED: **AUGUST 2, 2013**EFFECTIVE: **OCTOBER 1, 2013**

RATE SH - STREET LIGHTING HIGHWAY

AVAILABILITY

Available for high intensity discharge lighting of state highways for normal dusk to dawn operation of approximately 4,200 hours per year where the highway lighting system acceptable to Duquesne Light Company is installed by the State and ownership of the entire highway lighting system has been transferred to the Company for a nominal consideration.

MONTHLY RATE

DISTRIBUTION CHARGE

Monthly Rate Per Unit

<u>Nominal Lamp Wattage</u>	<u>Nominal kWh Energy Usage per Unit per Month</u>	<u>Distribution Charge per Unit</u>	
Sodium Vapor			
100	50	\$13.01 \$11.37	<u>(D)</u>
150	71	\$13.19 \$11.53	<u>(D)</u>
200	95	\$13.37 \$11.68	<u>(D)</u>
400	170	\$14.08 \$12.30	<u>(D)</u>

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate SH – Street Lighting Highway customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the “Calculation of Rate” section in Rider No. 8. Applicability of the Supply rate to Rate SH customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

(D) – Indicates Decrease

ISSUED: AUGUST 2, 2013

EFFECTIVE: OCTOBER 1, 2013

RATE PAL - PRIVATE AREA LIGHTING

AVAILABILITY

Available for high pressure sodium lighting, ~~and~~ flood lighting and light-emitting diode (LED) lighting of residential, commercial and industrial private property installations including parking lots, for normal dusk to dawn operation of approximately 4,200 hours per year. (C)

MONTHLY RATE

DISTRIBUTION CHARGE

DUQUESNE LIGHT COMPANY OWNED AND MAINTAINED EQUIPMENT

Monthly Rate Per Unit

<u>Nominal Lamp Wattage</u>	<u>Nominal kWh Energy Usage per Unit per Month</u>	<u>Distribution Charge per Unit</u>	
High Pressure Sodium			
70	29	\$12.91 <u>\$11.87</u>	(D)
100	50	\$13.01 <u>\$11.91</u>	(D)
150	71	\$13.19 <u>\$12.15</u>	(D)
250	110	\$13.54 <u>\$12.47</u>	(D)
400	170	\$14.08 <u>\$12.97</u>	(D)
Flood Lighting			
100	46	\$14.32 <u>\$12.51</u>	(D)
250	100	\$14.90 <u>\$13.02</u>	(D)
400	155	\$15.49 <u>\$13.54</u>	(D)
<u>Light-Emitting Diode (LED)</u> (C)			
<u>43</u>	<u>15</u>	<u>\$12.16</u>	
<u>67</u>	<u>24</u>	<u>\$12.82</u>	
<u>106</u>	<u>37</u>	<u>\$13.97</u>	
<u>118</u>	<u>42</u>	<u>\$16.81</u>	
<u>196</u>	<u>69</u>	<u>\$18.78</u>	
<u>256</u>	<u>90</u>	<u>\$20.35</u>	

(C)

RATE PAL - PRIVATE AREA LIGHTING - (Continued)

MONTHLY RATE - (Continued)

| DISTRIBUTION CHARGE - (Continued) (C)

| **DUQUESNE LIGHT COMPANY OWNED AND MAINTAINED EQUIPMENT - (Continued)** (C)

| Monthly Rate Per Unit - (Continued) (C)

<u>Nominal Lamp Wattage</u>	<u>Nominal kWh Energy Usage per Unit per Month</u>	<u>Distribution Charge per Unit</u>	
<u>UNMETERED ENERGY FOR CUSTOMER OWNED AND MAINTAINED EQUIPMENT</u> (C)			
70	29	\$3.16 \$2.57	(D)
100	46	\$3.16 \$2.57	(D)
150	67	\$3.16 \$2.57	(D)
250	100	\$3.16 \$2.57	(D)
400	155	\$3.16 \$2.57	(D)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate UMS – Unmetered Service customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the “Calculation of Rate” section in Rider No. 8. Applicability of the Supply rate to Rate UMS customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charge, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

| (C)

RATE PAL - PRIVATE AREA LIGHTING - (Continued)

MONTHLY RATE - (Continued)

ELECTRIC CHARGES – (Continued)

(C)
(C)

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

RIDERS

Bills rendered under this schedule are subject to the charges stated in any applicable rider.

LATE PAYMENT CHARGE

Bills will be calculated on the rates stated herein, and are due and payable on or before thirty days from the date of mailing of the bill to the ratepayer. The bill is overdue when not paid on or before the due date indicated on the bill. An overdue bill is subject to a Late Payment Charge of 1.25% interest per month on the full unpaid and overdue balance of the Company charges on the bill. The Charge shall be calculated on the overdue portions of the Company charges on the bill and shall not be charged against any sum that falls due during a current billing period.

POLES

No charge is made for wood poles used jointly for street lighting and the support of the Company's general distribution system or for tubular steel poles, trolley type, used jointly for street lighting and the support of trolley span wires.

Where the installation of one (1) or more wood poles is required to serve the customer, the customer has the option to install the pole(s) at his own expense in accordance with SPECIAL TERM AND CONDITION NO. 2 or the Company will install, own and maintain the pole(s) and bill the customer at the monthly rate of ~~\$10.24~~ **\$8.95** for each pole required.

(D)

SPECIAL TERMS AND CONDITIONS

1. The above charges include installation of standard Company facilities including lamps, fixtures or luminaries, brackets and ballasts, all when installed on the overhead distribution system. The above charges include normal operation and maintenance. Normal operation and maintenance does not include periodic tree trimming around the fixture or luminaire.
2. Where it is necessary to install wood, metal, or ornamental poles, or other special facilities or services not in conformance with the Company's standard overhead practice, the additional cost shall be borne by the customer. Title to all facilities, except as noted below, shall vest in the Company.
3. All facilities used in providing street lighting service shall be and remain the property of the Company and may be removed upon termination of service.
4. The customer agrees that the facilities installed under this rate shall not be removed or converted, or the use thereof discontinued by the customer, except upon payment to the Company of the original investment in such facilities, less depreciation to the date of discontinuance of such facilities, less salvage, plus the cost of removal.

(C) – Indicates Change

(D) – Indicates Decrease

ISSUED: AUGUST 2, 2013

EFFECTIVE: OCTOBER 1, 2013

STANDARD CONTRACT RIDERS – (Continued)

RIDER MATRIX

	RS	RH	RA	GS/GM	GMH	GL	GLH	L	HVPS	AL	SE	SM	SH	UMS	PAL
Rider No. 1	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Rider No. 2				X	X	X	X								
Rider No. 3				X	X	X	X	X							
Rider No. 4				X	X	X	X								
Rider No. 5	X	X	X												
Rider No. 6				X											
Rider No. 7	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Rider No. 8	X	X	X	X	X					X	X	X	X	X	X
Rider No. 9						X	X	X	X						
Rider No. 10	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Rider No. 11				X		X									
Rider No. 12				X	X										
Rider No. 13				X											
Rider No. 14	X														
Rider No. 15	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Rider No. 15A	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Rider No. 16				X	X	X	X	X							
Rider No. 17						X	X	X	X						
Rider No. 18	X	X	X	X	X	X	X								
Rider No. 20	X	X	X	X	X	X	X	X	X	X					
Rider No. 21	X	X	X	X	X	X									
Rider No. 22	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Appendix A	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

(C)

Rider Titles

- Rider No. 1 — Consumer Education Surcharge
- Rider No. 2 — Untransformed Service
- Rider No. 3 — School and Government Service Discount Period
- Rider No. 4 — Budget Billing HUD Finance Multi-Family Housing
- Rider No. 5 — Universal Service Charge
- Rider No. 6 — Temporary Service
- Rider No. 7 — SECA Charge
- Rider No. 8 — Default Service Supply
- Rider No. 9 — Day-Ahead Hourly Price Service
- Rider No. 10 — State Tax Adjustment
- Rider No. 11 — Street Railway Service
- Rider No. 12 — Billing Option – Volunteer Fire Companies and Nonprofit Senior Citizen Centers
- Rider No. 13 — General Service Separately Metered Electric Space Heating Service
- Rider No. 14 — Residential Service Separately Metered Electric Space and Water Heating
- Rider No. 15 — Energy Efficiency and Conservation and Demand Response Surcharge
- Rider No. 15A — Phase II Energy Efficiency and Conservation Surcharge
- Rider No. 16 — Service to Non-Utility Generating Facilities
- Rider No. 17 — Emergency Energy Conservation
- Rider No. 18 — Rates for Purchase of Electric Energy from Customer-Owned Renewable Resources Generating Facilities
- THESE PAGES INTENTIONALLY LEFT BLANK
- Rider No. 20 — Smart Meter Charge
- Rider No. 21 — Net Metering Service
- Rider No. 22 — Pension Rate Adjustment Mechanism**
- Appendix A — Transmission Service Charges

(C)

(C) – Indicates Change

ISSUED: AUGUST 2, 2013

EFFECTIVE: OCTOBER 1, 2013

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 5 – UNIVERSAL SERVICE CHARGE - (Continued)
(Applicable to Rate Schedules RS, RH and RA)

CALCULATION OF CHARGE – (Continued)

previous year at normalized annual sales volumes. The projected customer additions to the CAP program during the Computational Year will be based on the number of CAP customers receiving a discount at the end of the Reconciliation Year plus a projection of the average monthly number of CAP customers during the Computational Year. The projected number of CAP customers will include net additions to the program (additions minus exits), an estimate of the average monthly number of auto-enrolled customers receiving a discount, and a projection of customers enrolled through expected changes in policy (e.g. changes in the definition of poverty, changes in regulatory mandates). An auto-enrolled customer is not considered to be a CAP participant for purposes of this Rider unless and until the customer has completed the CAP enrollment process. The projected CAP program costs will include the estimated costs for new applications, maintenance and annual recertification, and the projected CAP pre-program arrearages to be forgiven and written off during the USC Computational Year.

- Smart Comfort Program [Low Income Usage Reduction Program (“LIURP”): LIURP costs will be calculated based on the projected number of homes that participate in the usage reduction program and the average cost per visit.
- Customer Assistance and Referral Evaluation Services (“CARES”): CARES costs will be calculated based on the projected annual Community Based Organization (“CBO”) program costs and CBO costs for administering the program.
- Hardship Fund: Hardship Fund costs will be calculated based on the projected annual program costs and CBO costs for administering the program.
- Any other replacement or Commission-mandated Universal Service Program or low income program that is implemented during the Reconciliation or Computational Year.

Cr = A credit to reduce CAP customer discounts included in the USC to the extent that the monthly CAP enrollment level exceeds ~~35,700~~**41,650** customers. Specifically, the recoverable CAP discounts will be reduced by the number of CAP participants in excess of ~~35,700~~**41,650** times the average CAP credit and arrearage forgiveness costs times 10.43%. The participation level above which the offset shall be applied will be reset in each distribution rate case.

E = The over- or under- collection of actual Universal Service Program costs and revenue that result from the billing of the USC during the USC Reconciliation Year (an over-collection is denoted by a positive E and an under-collection by a negative E), including applicable interest. Interest shall be computed monthly at the statutory legal rate of interest, from the month the over or under collection occurs to the effective month that the over collection is refunded or the under collection is recouped.

(I) – Indicates Increase

ISSUED: AUGUST 2, 2013

EFFECTIVE: OCTOBER 1, 2013

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 8 – DEFAULT SERVICE SUPPLY – (Continued)

(Applicable to Rate Schedules RS, RH, RA, GS/GM, GMH, AL, SE, SM, SH, UMS and PAL)

DEFAULT SERVICE SUPPLY RATE – (Continued)

Lighting (Rate Schedules SM, SH and PAL) — Lamp wattage as available on applicable rate schedule.

Wattage	Nominal kWh Energy Usage per Unit per Month	Application Period			
		06/01/2013 through 11/30/2013	12/01/2013 through 05/31/2014	06/01/2014 through 11/30/2014	12/01/2014 through 05/31/2015
Supply Charge ¢ per kWh		3.9258	X.XXXX	X.XXXX	X.XXXX
		Fixture Charge — \$ per Month			
Mercury Vapor					
100	44	1.73	X.XX	X.XX	X.XX
175	74	2.91	X.XX	X.XX	X.XX
250	102	4.00	X.XX	X.XX	X.XX
400	161	6.32	X.XX	X.XX	X.XX
1000	386	15.15	X.XX	X.XX	X.XX
High Pressure Sodium					
70	29	1.14	X.XX	X.XX	X.XX
100	50	1.96	X.XX	X.XX	X.XX
150	71	2.79	X.XX	X.XX	X.XX
200	95	3.73	X.XX	X.XX	X.XX
250	110	4.32	X.XX	X.XX	X.XX
400	170	6.67	X.XX	X.XX	X.XX
1000	387	15.19	X.XX	X.XX	X.XX
Flood Lighting - Unmetered					
70	29	1.14	X.XX	X.XX	X.XX
100	46	1.81	X.XX	X.XX	X.XX
150	67	2.63	X.XX	X.XX	X.XX
250	100	3.93	X.XX	X.XX	X.XX
400	155	6.08	X.XX	X.XX	X.XX
Light-Emitting Diode (LED)					
43	15	0.59			
67	24	0.94			
106	37	1.45			
118	42	1.65			
196	69	2.71			
256	90	3.53			

(C)

(C)

(C) – Indicates Change

ISSUED: **AUGUST 2, 2013**

EFFECTIVE: **OCTOBER 1, 2013**

STANDARD CONTRACT RIDERS - (Continued)**RIDER NO. 8 – DEFAULT SERVICE SUPPLY – (Continued)****(Applicable to Rate Schedules RS, RH, RA, GS/GM, GMH, AL, SE, SM, SH, UMS and PAL)****DEFAULT SERVICE SUPPLY RATE – (Continued)**

The Company will provide default service supply under this Rider by obtaining the requirements from suppliers through competitive procurements using a Request for Proposal (“RFP”) process. The charges for DSS calculated based on the results of the RFP process for service under this Rider will be effective as defined above. **(C)**

DSS obtained through the RFP process includes energy, capacity, transmission and distribution line losses, congestion and congestion management costs, Alternative Energy Credits (“AECs”), ancillary services, PJM grid management charges and other such services or products that are required to provide default service to the Company’s customers including Auction Revenue Rights and Financial Transmission Rights (“ARRs/FTRs”). DSS shall not include transmission service within Duquesne’s zone. Duquesne will be responsible for and continue to provide network integration transmission service. The applicable charges for transmission service are defined in Appendix A of this Tariff.

Service under this Rider No. 8 – Default Service Supply shall commence in accordance with the switching protocols in Rule No. 45.1.

PROCUREMENT PROCESS

The Company will conduct separate RFP solicitations for DSS for each customer procurement group under this Rider. The customer procurement groups for the RFP solicitations are defined as residential and lighting, small commercial and industrial and medium commercial and industrial. The small commercial and industrial group includes those customers with monthly metered demand less than 25 kW. The medium commercial and industrial group includes those customers with monthly metered demand equal to or greater than 25 kW and less than 300 kW. The RFP process will be bid separately to ensure that there is no cross subsidization.

The Company will update the rates for the DSS according to the schedule in the above tables. The Company will issue RFPs prior to the beginning of each Application Period to update the default service supply rates. The updated rates will be based on the new price(s) available from the winning suppliers through the RFP process. The rates will include a reconciliation adjustment as described in the “Calculation of Rate” section of this Rider. In the month prior to the beginning of each Application Period, the Company will file new DSS charges with the Pennsylvania Public Utility Commission (“Commission”) for the subsequent Application Period, and, upon Commission approval, these charges shall become effective on the first day of the following month.

The load of the customer procurement group for the RFP will be divided into Tranches. Winning suppliers will provide DSS for the percentage of DSS load corresponding to the number of Tranches won in the RFP. Duquesne seeks to procure all Tranches in the RFP process pursuant to the RFP schedule approved by the Commission.

The selection of bids will be submitted to the Commission for its approval or rejection within one business day after submittal. If the bids are not acted on by the Commission within one business day, the Company may proceed on the basis that they are approved and award the bids pursuant to 52 Pa. Code § 54.188(d).

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 10 - STATE TAX ADJUSTMENT

(Applicable to All Rates)

In addition to the charges provided in this Tariff, a two-part surcharge will apply to all bills rendered by the Company, pursuant to the Pennsylvania Public Utility Commission authorization of March 10, 1970, to compensate the Company for new and increased taxes imposed by the General Assembly.

Part 1 of the surcharge, at a rate of ~~(0.1185%)~~ **0.0000%** will include Capital Stock Tax, Corporate Net Income Tax, and Public Utility Realty Tax, which will be applied to the distribution charges of customer bills. **(C)**

Part 2 of the surcharge, at a rate of 0.0000% will include Gross Receipts Tax and will be applied to all portions of customer bills.

The Company will recompute the surcharge using the elements prescribed by the Commission's March 10, 1970, authorization:

1. Whenever any of the tax rates used in computing the surcharge is changed, in which case the recomputation shall take into account the changed tax rate.
2. Whenever the Company makes effective increased or decreased rates (other than net energy clause), in which case the recomputation shall take into account the adjustments prescribed by the Commission's March 10, 1970, authorization.
3. On December 22, and each year thereafter.

Every recomputation made pursuant to the above paragraph shall be submitted to the Commission within ten (10) days after the occurrence of the event or date which occasions such recomputation: and if the recomputed surcharge is less than the one then in effect the Company will, and if the recomputed surcharge is more than the one then in effect the Company may, accompany such recomputation with a Tariff or supplement to reflect such recomputed surcharge, the effective date of which, shall be ten (10) days after filing.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 16 - SERVICE TO NON-UTILITY GENERATING FACILITIES

(Applicable to all General Service Rates Except Non-Demand Metered GS/GM Customers) (C)

The following applies to non-utility generating facilities including, but not limited to cogeneration and small power production facilities that are qualified in accord with Part 292 of Chapter I, Title 18, Code of Federal Regulations (qualifying facility). Electric energy will be delivered to a non-utility generating facility in accord with the following:

A. DEFINITIONS

Supplementary Power is electric energy and capacity supplied by the Company or by an Electric Generation Supplier (EGS) to a non-utility generating facility and regularly used in addition to that electric energy which the non-utility generating facility generates itself. The Company's regular and appropriate General Service Rates will be utilized for billing for Supplementary Power. Customers purchasing Supplementary Power from an EGS will be billed for charges according to their applicable rate and billing arrangement with their EGS. (C)

Back-Up Power is ~~defined~~ electric energy and capacity supplied by the Company to a non-utility generating facility during any outage of the non-utility generating facility's electric generating equipment to replace electric energy ordinarily generated by the non-utility generating facility's generating equipment. (C)

Base Period is the twelve consecutive monthly billing periods applicable to the customer ending one month prior to the installation of new on-site generation or increase in capacity to existing on-site supply.

Contract Demand is the maximum electrical capacity in kilowatts that the Company shall be required by the contract to deliver to the customer for Back-Up Power. for back-up service-A Contract Demand may be established for Supplementary Power to the customer's ~~generating~~ facility. (C)
(C)

~~Distribution~~ **Supplementary Power Billing Determinants** are the monthly billing period billing demand in kilowatts (kW) and the energy usage in kilowatt-hours (kWh) for Supplementary Power during the current billing month under which the on-site generation is operable. The Supplementary Power kW shall not exceed the Contract Demand kW for Supplementary Power, if applicable. (C)
(C)
(C)

Back-Up Power Billing Determinants are the monthly billing period billing demand in kilowatts (kW) and energy usage (kWh) in excess of those provided as Supplementary Power. If a Contract Demand exists for Supplementary Power, the Back-Up Billing Determinants are the kW and kWh in excess of the Supplementary Power Contract Demand. (C)

Distribution Base Period Billing Determinants are the billing demand (kW) and the energy usage (kWh) for the month in the Base Period corresponding to the current billing month under which the on-site generation is operable. For new customers, the Company will use existing procedures to estimate Base Period Billing Determinants.

Supply Billing Determinants for customers on Rate Schedules GL, GLH, L and HVPS are the billing demand (kW) and energy usage (kWh) during the current billing month then in effect under Rider No. 9. Supply Billing Determinants for customers on Rate Schedule GS/GM and GMH shall be the same as those defined above for Distribution.

(C) – Indicates Change

ISSUED: AUGUST 2, 2013

EFFECTIVE: OCTOBER 1, 2013

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 16 - SERVICE TO NON-UTILITY GENERATING FACILITIES - (Continued)

(Applicable to all General Service Rates)

B. BACK-UP POWER

The Company will supply such service each month at the following rates:

DISTRIBUTION

Contract Demand of 5,000 kW or more	_____	\$6.04 per kW, but no less than \$1,405.00	(C)
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Contract Demand of less than 5,000 kW	_____	\$6.45 per kW, but no less than \$185.00	(C)
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A distribution charge of \$2.50 per kW shall be applied to the Back-Up Power Billing Determinants for Back-Up Power.	(C)
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The distribution charges will be applied in each month based on the customer's Contract Demand without regard to whether or not back-up energy is supplied.

SUPPLY

In any month that the Company provides energy to back up the customer's equipment, supply service shall be supplied and billed under Rider No. 9 for customers with Contract Demand of 300 kW or more. For customers having Contract Demand of less than 300 kW, the Company will bill the applicable supply demand and energy charges then in effect under Rate Schedule GS/GM.

The use of backup power at this price level will be limited to 15% usage for all hours in a year. Incremental usage above this limit will be billed on the applicable general service rates, including all ratchets applicable.

If a customer's actual kW demand at the time back-up is being supplied exceeds the customer's back-up Contract Demand by 5% or more, the actual kW demand as established will become the customer's new back-up Contract Demand for the remaining term of the back-up contract. If a customer's actual kW demand at the time back-up service is being supplied exceeds the customer's back-up Contract Demand by 10% or more, the customer will be assessed a fee determined by the difference between the actual demand established when back-up service is being supplied and the back-up Contract Demand multiplied by two times the applicable charge per kilowatt.

C. INTERCONNECTION

Each non-utility generating facility will be required to install at its expense or pay in advance to have the Company install interconnection equipment and facilities which are over and above that equipment and facilities required to provide electric service to the non-utility generating facility according to the Company's General Service Rates, except as noted below. Any such equipment to be installed by the non-utility generating facility must be reviewed and approved in writing by the Company prior to installation. Nothing in this Rider shall exempt a new customer from the application of Rule No. 7 and Rule No. 9 regarding Supply Line Extensions and Relocation of Facilities.

However, customers may elect to pay the cost of existing or newly required transformation equipment that is over and above that equipment necessary for the Company to supply the customer with its contracted Supplemental Power via a monthly charge rather than in total at the onset of the contract. The monthly charge for transformation equipment for customers with contract demand under this rider of 5,000 kW or more will be determined by the Company on a case-by-case basis. For all others, the rate of \$0.2523 per kW per month will apply.

(C) – Indicates Change**ISSUED: AUGUST 2, 2013****EFFECTIVE: OCTOBER 1, 2013**

STANDARD CONTRACT RIDERS - (Continued)**(C)****RIDER NO. 22 – PENSION RATE ADJUSTMENT MECHANISM****(Applicable to all Rate Schedules)****PURPOSE**

The Pension Rate Adjustment Mechanism is instituted as a cost adjustment instrument to modify, no more frequently than annually, the Company's base distribution rates to align future pension funding requirements with pension expense currently being recovered in base distribution rates as approved by the Commission at Docket No. R-2013-2372129.

APPLICABILITY

The Pension Rate Adjustment ("PRA") will be calculated independently for each applicable rate schedule in the Tariff using a Rate Class Factor. The Rate Class Factor is the share of each rate classes' pension expense recovered through base rates. The PRA will be calculated based on the allocated share of the change in pension expense funding for each rate class using the Rate Class Factor. The allocated change shall be computed for each rate class and applied to the applicable class billing units and will be used to reduce distribution rates in the applicable rate schedules in the event that the Company's current pension funding is reduced below the amount that was used to establish pension expense approved by the Commission in the Company's base rate proceeding at Docket No. R-2013-2372129. Accordingly, if the Company implements the PRA to reduce pension expense recovery and its pension costs increase, the Company will use the PRA to recover subsequent increases in pension expenses up to the level of pension expense included in base rates at Docket No. R-2013-2372129.

ADJUSTMENT TO BASE RATES

The PRA will be an adjustment to distribution rates as measured from the Base Expense Level and shall be determined in accordance with the formula set forth below and shall be applied to the applicable billing units once it becomes effective. The difference between the pension expense by rate class and the updated pension expense allocated to each rate class shall be the basis to calculate the adjustment to the applicable rate. The rate adjustment will be the difference divided by the billing units.

The PRA shall be applied to customers' bills as a non-bypassable adjustment and shall remain in effect until revised by the Company. The PRA will be made to the applicable distribution rates and become effective in sixty (60) days from the filing date.

$$\text{PRA} = \{ ((\text{PEL} - \text{BEL}) * \text{RCF}) / \text{BU} \}$$

Where **PRA** = Pension Rate Adjustment to be applied to the applicable distribution billing unit of each Rate Schedule under this Tariff.

PEL = The Projected Expense Level for the upcoming twelve (12) month period. The twelve (12) month period for which the Pension Funding Level will be determined shall be the twelve (12) months ending no later than fifteen (15) months from the beginning of the calendar quarter during which the filing is made. The Pension Expense Level shall be fifty percent (50%) of the Projected Funding Level.

(C) – Indicates Change**ISSUED: AUGUST 2, 2013****EFFECTIVE: OCTOBER 1, 2013**

STANDARD CONTRACT RIDERS - (Continued)(C)RIDER NO. 22 – PENSION RATE ADJUSTMENT MECHANISM - (Continued)(Applicable to all Rate Schedules)ADJUSTMENT TO BASE RATES - (Continued)

BEL = The Company's Base Expense Level as defined in the base rate case proceeding at Docket No. R-2013-2372129.

RCF = Rate Class Factor for each rate schedule as stated below:

<u>Rate Schedule</u>	<u>Rate Class Factor</u>
<u>Rate RS</u>	<u>57.8%</u>
<u>Rate RH</u>	<u>4.7%</u>
<u>Rate RA</u>	<u>0.6%</u>
<u>Rate GS</u>	<u>2.0%</u>
<u>Rate GM < 25 kW</u>	<u>4.4%</u>
<u>Rate GM ≥ 25 kW</u>	<u>10.3%</u>
<u>Rate GMH < and ≥</u>	<u>1.5%</u>
<u>Rate GL</u>	<u>10.5%</u>
<u>Rate GLH</u>	<u>1.7%</u>
<u>Rate L</u>	<u>3.7%</u>
<u>Rate HVPS</u>	<u>0.0%</u>
<u>Rate SE</u>	<u>0.2%</u>
<u>Rates AL, SM, SH and PAL</u>	<u>2.4%</u>
<u>Rate UMS</u>	<u>0.1%</u>

BU = The Billing Units shown in the Company's base rate proceeding at Docket No. R-2013-2372129. The following table summarizes the applicable Billing Units and affected rate for each rate schedule.

<u>Rate Schedule</u>	<u>Billing Unit</u>	<u>Rate</u>
<u>Rate RS</u>	<u>kWh</u>	<u>c/kWh</u>
<u>Rate RH</u>	<u>kWh</u>	<u>c/kWh</u>
<u>Rate RA</u>	<u>kWh</u>	<u>c/kWh</u>
<u>Rate GS</u>	<u>kWh</u>	<u>c/kWh</u>
<u>Rate GM < 25 kW</u>	<u>kWh</u>	<u>c/kWh</u>
<u>Rate GM ≥ 25 kW</u>	<u>kWh</u>	<u>c/kWh</u>
<u>Rate GMH < and ≥</u>	<u>kWh</u>	<u>c/kWh</u>
<u>Rate GL</u>	<u>kWh</u>	<u>\$/kW</u>
<u>Rate GLH</u>	<u>kWh</u>	<u>c/kWh</u>
<u>Rate L</u>	<u>kWh</u>	<u>\$/kW</u>
<u>Rate HVPS</u>	<u>Bills</u>	<u>\$/Month</u>
<u>Rate AL</u>	<u>Bills</u>	<u>\$/Month</u>
<u>Rate SE</u>	<u>Fixtures</u>	<u>\$/Fixture/Month</u>
<u>Rates SM, SH and PAL</u>	<u>Fixtures</u>	<u>\$/Fixture/Month</u>
<u>Rate UMS</u>	<u>Bills</u>	<u>\$/Month</u>

(C) – Indicates ChangeISSUED: AUGUST 2, 2013EFFECTIVE: OCTOBER 1, 2013

STANDARD CONTRACT RIDERS - (Continued)

(C)

RIDER NO. 22 – PENSION RATE ADJUSTMENT MECHANISM - (Continued)

(Applicable to all Rate Schedules)

UPDATE

Filing a PRA for the Commission's approval is at the sole discretion of the Company.

The PRA will be updated no more frequently than annually.

Subsequent filings will compute the change in distribution rates as measured from the Base Expense Level as established in the Company's base rate proceeding at Docket No. R-2013-2372129.

MISCELLANEOUS

This Rider will not increase base distribution rates greater than those established in the Company's base rate proceeding at Docket No. R-2013-2372129.

The Company will not seek to recover through this Rider pension costs in excess of those approved in the base rate case proceeding at Docket No. R-2013-2372129.

The PRA will be added to the applicable rate and not shown as a separate line item on the bill.

This Rider is applicable to the defined distribution units and is not subject to reconciliation.

The Rate Class Factors defined in this Rider will remain the same until revised by the Company in its next base rate proceeding.

Adjustments to rates pursuant to this Rider are subject to review and approval by the Commission.

Minimum bills shall not be reduced by reason of the PRA, nor shall charges hereunder be part of the monthly rate schedule minimum.

(C) – Indicates Change

ISSUED: AUGUST 2, 2013

EFFECTIVE: OCTOBER 1, 2013

APPENDIX A

TRANSMISSION SERVICE CHARGES

(Applicable to All Rates)

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission (FERC) for customers who receive Default Service from the Company. Customers taking Default Service from the Company shall be charged in accordance with the charges of the applicable rate schedules stated below. These charges shall also apply to riders applicable to each rate schedule.

MONTHLY RATES

Rate Class	Energy Charge \$/kWh	Demand Charge \$/kW	Monthly Charge Per Fixture	Monthly Charge Per Fixture
RS	\$0.014587			
RH	\$0.006577			
RA	\$0.014550			
GS	\$0.008338			
GM < 25 kW	\$0.006195	\$1.09		
GM => 25 kW	\$0.007361	\$1.44		
GMH < 25 kW	\$0.007343	\$1.21 ⁽¹⁾		
GMH => 25 kW	\$0.005822	\$4.04 ⁽¹⁾		
GL		\$3.12		
GLH		\$3.18		
L		\$3.17		
HVPS		\$3.17		
AL	\$0.003455			
SE	\$0.001139			
UMS	\$0.000061	\$5.18		
			Rate Class	
By Wattage			SH and PAL	SM
Mercury Vapor				
100				\$0.12
175				\$0.20
250				\$0.28
400				\$0.44
1000				\$1.05
High Pressure Sodium				
70			\$0.04	\$0.08
100			\$0.07	\$0.14
150			\$0.10	\$0.19
200			\$0.14	
250			\$0.15	\$0.30
400			\$0.24	\$0.46
1000				\$1.05

(1) June through September

(C)

(C) – Indicates Change

ISSUED: **AUGUST 2, 2013**EFFECTIVE: **OCTOBER 1, 2013**

APPENDIX A – (Continued)

TRANSMISSION SERVICE CHARGES – (Continued)

(Applicable to All Rates)

MONTHLY RATES – (Continued)

(C)

Rate Class	Energy Charge \$/kWh	Demand Charge \$/kW	Monthly Charge Per Fixture	Monthly Charge Per Fixture
Flood Lighting - Unmetered				
70			\$0.04	
100			\$0.06	
150			\$0.09	
250			\$0.14	
400			\$0.22	
Light-Emitting Diode (LED)				
<u>43</u>			<u>\$0.00</u>	<u>\$0.00</u>
<u>67</u>			<u>\$0.00</u>	<u>\$0.00</u>
<u>106</u>			<u>\$0.00</u>	<u>\$0.00</u>
<u>118</u>			<u>\$0.00</u>	<u>\$0.00</u>
<u>196</u>			<u>\$0.00</u>	<u>\$0.00</u>
<u>256</u>			<u>\$0.00</u>	<u>\$0.00</u>

(C)

BILLING DEMAND

Billing Demand subject to Transmission Service Charges for customers taking service under Rate Schedules GS/GM and GMH shall be the same as that determined for distribution and supply charges under the applicable rate schedules.

Billing Demand subject to Transmission Service Charges for Customers taking service under Rate Schedules GL, GLH, L, HVPS and UMS shall be the customer's daily network service coincident peak load contribution in MW. This quantity is determined based on the customer's load coincident with the annual peak of the Duquesne Zone (single coincident peak) as defined in the PJM Tariff Section 34.1.

ANNUAL UPDATE

The Transmission Service Charges (TSC) defined herein will be updated effective June 1st of each calendar year or more often upon determination that the rates then in effect would result in a significant over or under collection. On or about May 1st, the Company will file revised TSC rates with the PA Public Utility Commission (Commission) defining rates in effect from June 1 to May 31 of the following year, the computation year. These rates shall be determined based on the projected revenue requirement for the computation year, the projected cost of PJM charges and the over or under collection of expenses based on actual TSC revenue and expense incurred up to March 1 of each filing year. The revenue requirement and over or under collection shall be allocated to each rate class based on the class contribution to the Company's coincident peak load (1CP) and Default Service share of the 1CP load from the previous calendar year. The costs for ancillary services and PJM administrative expenses are included in the Default Service Supply rates defined in Rider No. 8. The costs for ancillary services and PJM administrative expenses for rate classes GL, GLH, L and HVPS will be billed in accordance with Rider No. 9. The rates applicable to each Rate Schedule shall be determined in accordance with the following formulas.

(C)

(C) – Indicates Change

ISSUED: AUGUST 2, 2013

EFFECTIVE: OCTOBER 1, 2013

APPENDIX A – (Continued)

TRANSMISSION SERVICE CHARGES – (Continued)

(Applicable to All Rates)

ANNUAL UPDATE - (Continued)(C)

For Rate Schedules RS, RH, RA and applicable Riders:

$$\text{TSC-kWh} = \{ (\text{RCRR} - "e") / \text{RCSales} \} * \{ 1/(1-T) \}$$

For Rate Schedules GS/GM and GMH with monthly Billing Demand less than 25 kW:

Non-Demand Metered:

$$\text{TSC-kWh} = \{ (\text{RCRR} - "e") / \text{RCSales} \} * \{ 1/(1-T) \}$$

Demand Metered:

$$\text{TSC-kW} = \{ ((\text{RCRR} - "e") \times 50\%) / \text{RCDemand} \} * \{ 1/(1-T) \}$$

For Rate Schedules GS/GM and GMH with monthly Billing Demand less than 25 kW: - (Continued)

Demand Metered: - (Continued)

$$\text{TSC-kWh} = \{ ((\text{RCRR} - "e") \times 50\%) / \text{RCSales} \} * \{ 1/(1-T) \}$$

For Rate Schedules GS/GM and GMH with monthly Billing Demand equal to or greater than 25 kW:

$$\text{TSC-kW} = \{ ((\text{RCRR} - "e") \times 50\%) / \text{RCDemand} \} * \{ 1/(1-T) \}$$

$$\text{TSC-kWh} = \{ ((\text{RCRR} - "e") \times 50\%) / \text{RCSales} \} * \{ 1/(1-T) \}$$

For Rate Schedules GL, GLH, L, HVPS:

$$\text{TSC-kW} = \{ (\text{RCRR} - "e") / (\text{RC1CP} \times 12) \} * \{ 1/(1-T) \}$$

For Rate Schedule UMS:

$$\text{TSC-kW} = \{ (\text{RCRR} - "e") / (\text{RC1CP} \times 12) \} * \{ 1/(1-T) \}$$

(C)(C) – Indicates ChangeISSUED: AUGUST 2, 2013EFFECTIVE: OCTOBER 1, 2013

APPENDIX A – (Continued)

TRANSMISSION SERVICE CHARGES – (Continued)

(Applicable to All Rates)

ANNUAL UPDATE - (Continued)

(C)

For Rate Schedules AL, SE, SM, SH and PAL:

The annual revenue requirement and over or under collection shall be allocated to each rate class for cost recovery based on the rate class contribution to the coincident peak load from the previous calendar year. PJM charges that are load based will also be allocated to each rate class for cost recovery based on the rate class contribution to the coincident peak load. PJM charges that are energy based will be billed on a per kWh basis. All such charges will be adjusted for Pennsylvania gross receipts tax. For rate schedules SM, SH and PAL, a kWh charge will be determined to recover the allocated revenue requirement and PJM charges. An equivalent fixed monthly charge will be determined based on the monthly kWh usage applicable for each fixture.

Where:

- TSC = Transmission service charge to be applied to all Transmission billing units (either kWh or kW, as indicated.)
- RCRR = Projected total revenue requirement and PJM charges established for the computation year of June 1st through May 31st, corresponding to the PJM planning year. The revenue requirement shall be allocated to the specific rate classes by applying the ratio of the RC1CP to the Duquesne Zone 1CP for the prior year. PJM charges shall be allocated to each rate class on the basis incurred (i.e. 1CP, kW, kWh).
- “e” = Total over or under collection calculated by comparing total TSC revenues billed to the specific rate class during the reconciliation year of the twelve month period ending February 28th or 29th to the total charges billed by PJM under its OATT as approved or accepted by FERC and allocated to the specific rate class based upon its Default Service share of the Duquesne Zone 1CP for the prior year, including applicable interest. Interest shall be computed monthly at the statutory rate, from the month the over or under collection occurs to the effective month that the over collection is refunded or the under collection is recouped.
- RCSales = Projected kWh sales for the specific rate class for the computation year.
- RCDemand = Projected kW billing demand for the specific rate class for the computation year.
- RC1CP = Rate Class load coincident with the peak hour of the peak day of the Duquesne Zone during the calendar year prior to the computation year.
- T = The total Pennsylvania Gross Receipts Tax rate in effect during the billing month, expressed in decimal form.

(C) – Indicates Change

ISSUED: AUGUST 2, 2013

EFFECTIVE: OCTOBER 1, 2013

APPENDIX A – (Continued)(C)TRANSMISSION SERVICE CHARGES – (Continued)(Applicable to All Rates)**MISCELLANEOUS**

Minimum bills shall not be reduced by reason of the TSC, nor shall charges hereunder comprise any portion of a monthly rate schedule minimum. The TSC shall not be subject to any credits or discounts and shall not be affected by the State Tax Adjustment Surcharge (STAS).

The Company shall file a report of TSC collections within thirty days following the conclusion of each computation-year quarter. These reports will be in a form prescribed by the Commission.

Application of the TSC shall be subject to review and audit by the Commission at intervals it shall determine. The Commission shall review the level of charges produced by the TSC and the costs included therein.

(C) – Indicates ChangeISSUED: AUGUST 2, 2013EFFECTIVE: OCTOBER 1, 2013

Duquesne Light Company

**Digest of Proposed Changes
contained in
Tariff Electric – PA. P.U.C. No. 24
Supplement No. 81**

Docket No. R-2013-2372129

August 2, 2013

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I. General

Duquesne Light Company's Supplement No. 81 to Tariff Electric – PA. P.U.C. No. 24 issued August 2, 2013, to become effective October 1, 2013, results in an overall average increase of 17.6% in distribution revenues and is expected to produce \$76.3 million of additional annual distribution revenue under future test year conditions.

All customers will be notified of the proposed rate increase by a news release issued the day of the filing, newspaper advertisements in major service territory newspapers the day of the filing and by a bill insert to be mailed to all customers during the month after the filing is made.

Other modifications to the rules, rates and riders of Duquesne's tariff are being proposed and, together with a presentation of the proposed and current rates, are discussed below.

II. Proposed Changes to the Table of Contents

List of Modifications — Page No. 2A, Page No. 2B, Page No. 2C and Page No. 2D were added to the Table of Contents.

Rider No. 22 – Pension Rate Adjustment Mechanism (Pages No. 112B – 112D) was added to the Table of Contents

Appendix A – Transmission Service Charges — Page No. 116A was added to the Table of Contents.

III. Proposed Changes to Tariff Rules

Tariff Rule No. 21.1 – Payment of Bills for Residential Service — Language has been modified with the insertion of “The Company may accommodate changes to due dates for residential customers upon written customer request and when a demonstrated financial burden for the current due date exists for ratepayers receiving Social Security or equivalent monthly checks.” and the deletion of “When the due date for residential service occurs from the 21st day of the month through the 5th day of the following month, the due date may be extended upon request to the 6th day of the latter month for ratepayers receiving Social Security or equivalent monthly checks on or about the first of the month.” to reflect the current operations of the Company.

IV. Proposed Changes to Tariff Rate Schedules**Rate RS – Residential Service**

<u>Distribution</u>		<u>Current Rates with STAS</u>	<u>Proposed Rates with STAS</u>
Customer Charge		\$6.99	\$15.00
All kWh	\$/kWh	\$0.043605	\$0.043961

Rate RH – Residential Service Heating

<u>Distribution</u>		<u>Current Rates with STAS</u>	<u>Proposed Rates with STAS</u>
Customer Charge		\$6.99	\$15.00
Summer:			
All kWh	\$/kWh	\$0.043605	\$0.043961
Winter:			
All kWh	\$/kWh	\$0.032136	\$0.035813

Rate RA – Residential Service Add-on Heat Pump

<u>Distribution</u>		<u>Current Rates with STAS</u>	<u>Proposed Rates with STAS</u>
Customer Charge		\$6.99	\$15.00
Summer:			
All kWh	\$/kWh	\$0.043605	\$0.043961
Winter:			
All kWh	\$/kWh	\$0.009028	\$0.012199

IV. Proposed Changes to Tariff Rate Schedules – (Continued)

Rate GS/GM – General Service Small and Medium

Non-Demand Metered:

Rate GS

<u>Distribution</u>		<u>Current Rates with STAS</u>	<u>Proposed Rates with STAS</u>
Customer Charge		\$6.99	\$15.00
All kWh	\$/kWh	\$0.052948	\$0.048981

Demand Metered:

Rate GM < 25

<u>Distribution</u>		<u>Current Rates with STAS</u>	<u>Proposed Rates with STAS</u>
Customer Charge		\$29.96	\$50.00
Demand over 5 kW	\$/kW	\$6.15	\$4.65
All kWh	\$/kWh	\$0.011146	\$0.012487

Rate GM ≥ 25

<u>Distribution</u>		<u>Current Rates with STAS</u>	<u>Proposed Rates with STAS</u>
Customer Charge		\$42.95	\$60.00
Demand over 5 kW	\$/kW	\$4.97	\$4.62
All kWh	\$/kWh	\$0.009442	\$0.013175

IV. Proposed Changes to Tariff Rate Schedules – (Continued)**Rate GMH – General Service Medium Heating**

<u>Distribution</u>		<u>Current Rates with STAS</u>	<u>Proposed Rates with STAS</u>
Customer Charge		\$29.96	\$60.00
Summer:			
Demand over 5 kW	\$/kW	\$6.15	\$4.65
All kWh	\$/kWh	\$0.011146	\$0.012487
Winter:			
All kWh	\$/kWh	\$0.022639	\$0.024022

Rate GL – General Service Large

<u>Distribution</u>		<u>Current Rates with STAS</u>	<u>Proposed Rates with STAS</u>
First 300 kW or less		\$2,475.06	\$2,787.00
Additional kW		\$7.52	\$8.45

Rate GLH – General Service Large Heating

<u>Distribution</u>		<u>Current Rates with STAS</u>	<u>Proposed Rates with STAS</u>
Customer Charge		\$42.95	\$60.00
Summer:			
First 300 kW or less		\$2,475.06	\$2,787.00
Additional kW		\$7.52	\$8.45
Winter:			
All kWh	\$/kWh	\$0.016999	\$0.021446

IV. Proposed Changes to Tariff Rate Schedules – (Continued)**Rate L – Large Power Service**

Service Voltage Less than 138 Kv:

<u>Distribution</u>	<u>Current Rates with STAS</u>	<u>Proposed Rates with STAS</u>
First 5,000 kW or less	\$34,858.64	\$38,500.00
Next 10,000 kW \$/kW	\$6.90	\$12.30
Additional kW \$/kW	\$6.72	\$12.30

Service Voltage 138 Kv and Greater:

Fixed Monthly Charge	\$0,000.00	\$8,551.00
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Rate L – Large Power Service has been modified to reflect that it has been separated into “Service Voltage Less than 138 Kv” and “Service Voltage 138 Kv and Greater.”

Rate L – Large Power Service has been modified to reflect the elimination of “Next 10,000 kilowatts of Demand” block under “Service Voltage Less than 138 Kv.”

Rate L – Large Power Service has been modified to reflect the insertion of “Fixed Monthly Charge” under “Service Voltage 138 Kv and Greater.”

Rate L – Large Power Service. Language has been modified in the second paragraph under “Contract Provisions” to reflect the elimination of the 10,000, 25,000 and 750,000 kilowatt-hour blocks under the Energy Charge.

Rate L – Large Power Service. Language has been modified to replace the word “Capacity” with the word “Demand.”

IV. Proposed Changes to Tariff Rate Schedules – (Continued)

Rate HVPS – High Voltage Power Service

<u>Distribution</u>	<u>Current Rates with STAS</u>	<u>Proposed Rates with STAS</u>
Up to and Including 50,000 kW Billing Demand \$/kW	\$11,657.17	\$8,551.00
50,001 kW to 100,000 kW Billing Demand \$/kW	\$16,887.96	\$12,388.00
Greater than 100,000 kW Billing Demand \$/kW	\$22,966.75	\$16,847.00

Rate AL – Architectural Lighting Service

<u>Distribution</u>	<u>Current Rates with STAS</u>	<u>Proposed Rates with STAS</u>
Customer Charge	\$7.48	\$6.54
Demand all kW \$/kW	\$1.40	\$1.22
All kWh \$/kWh	\$0.001985	\$0.001734

Rate SE – Street Lighting Energy

<u>Distribution</u>	<u>Current Rates with STAS</u>	<u>Proposed Rates with STAS</u>
Customer Charge	\$3.16	\$2.57

IV. Proposed Changes to Tariff Rate Schedules – (Continued)

Rate SM – Street Lighting Municipal

<u>Distribution</u>		<u>Current Rates with STAS</u>	<u>Proposed Rates with STAS</u>
Mercury Vapor:			
100 watt	per month	\$13.16	\$11.52
175 watt	per month	\$13.44	\$11.76
250 watt	per month	\$13.70	\$11.99
400 watt	per month	\$14.24	\$12.46
1000 watt	per month	\$16.39	\$14.34
Sodium Vapor:			
70 watt	per month	\$13.60	\$11.87
100 watt	per month	\$13.71	\$11.91
150 watt	per month	\$13.90	\$12.15
250 watt	per month	\$14.27	\$12.47
400 watt	per month	\$14.84	\$12.97
1000 watt	per month	\$17.07	\$14.93
Light-Emitting Diode (LED)			
43 watt	per month	\$0.00	\$12.16
67 watt	per month	\$0.00	\$12.82
106 watt	per month	\$0.00	\$13.97
118 watt	per month	\$0.00	\$16.81
196 watt	per month	\$0.00	\$18.78
256 watt	per month	\$0.00	\$20.35
Poles	per month	\$10.79	\$9.44

Rate SM – Street Lighting Municipal. Language has been modified to include Light-Emitting Diode (LED) fixtures.

Rate SM – Street Lighting Municipal. Light-Emitting Diode (LED) fixtures and pricing have been added to the Rate Schedule.

Rate SM – Street Lighting Municipal. Due to the addition of the Light-Emitting Diode (LED) fixtures and pricing information, language on the Rate Schedule pages has been repaginated.

Rate SM – Street Lighting Municipal. The monthly rate per pole has changed resulting in a decrease.

IV. Proposed Changes to Tariff Rate Schedules – (Continued)**Rate SH – Street Lighting Highway**

<u>Distribution</u>		<u>Current Rates with STAS</u>	<u>Proposed Rates with STAS</u>
Sodium Vapor:			
100 watt	per month	\$12.99	\$11.37
150 watt	per month	\$13.17	\$11.53
200 watt	per month	\$13.35	\$11.68
400 watt	per month	\$14.06	\$12.30

Rate UMS – Unmetered Service

<u>Distribution</u>		<u>Current Rates with STAS</u>	<u>Proposed Rates with STAS</u>
Customer Charge		\$9.97	\$10.00
All kWh	\$/kWh	\$0.025551	\$0.010192

IV. Proposed Changes to Tariff Rate Schedules – (Continued)**Rate PAL – Private Area Lighting**

<u>Distribution</u>		<u>Current Rates with STAS</u>	<u>Proposed Rates with STAS</u>
High Pressure Sodium:			
70 watt	per month	\$12.89	\$11.87
100 watt	per month	\$12.99	\$11.91
150 watt	per month	\$13.17	\$12.15
250 watt	per month	\$13.52	\$12.47
400 watt	per month	\$14.06	\$12.97
Flood Lighting:			
100 watt	per month	\$14.30	\$12.51
250 watt	per month	\$14.88	\$13.02
400 watt	per month	\$15.47	\$13.54
Light-Emitting Diode (LED)			
43 watt	per month	\$0.00	\$12.16
67 watt	per month	\$0.00	\$12.82
106 watt	per month	\$0.00	\$13.97
118 watt	per month	\$0.00	\$16.81
196 watt	per month	\$0.00	\$18.78
256 watt	per month	\$0.00	\$20.35
Unmetered:			
70 watt	per month	\$3.16	\$2.57
100 watt	per month	\$3.16	\$2.57
150 watt	per month	\$3.16	\$2.57
250 watt	per month	\$3.16	\$2.57
400 watt	per month	\$3.16	\$2.57
Poles	per month	\$10.23	\$8.95

Rate PAL – Private Area Lighting. Language has been modified to include Light-Emitting Diode (LED) fixtures.

Rate PAL – Private Area Lighting. Light-Emitting Diode (LED) fixtures and pricing have been added to the Rate Schedule.

IV. Proposed Changes to Tariff Rate Schedules – (Continued)

Rate PAL – Private Area Lighting – (Continued)

Rate PAL – Private Area Lighting. Due to the addition of the Light-Emitting Diode (LED) fixtures and pricing information, language on the Rate Schedule pages has been repaginated.

Rate PAL – Private Area Lighting. The monthly rate per pole has changed resulting in a decrease.

V. Proposed Changes to Tariff Riders

Rider Matrix

Rider No. 22 – Pension Adjustment Mechanism has been added to the Rider Matrix (Page No. 79A).

Rider No. 5 – Universal Service Charge

Rider No. 5 – Universal Service Charge has been updated as directed in the Rider to reflect the participation level of CAP customers.

Rider No. 8 – Default Service Supply

Rider No. 8 – Default Service Supply. Language has been modified to include Light-Emitting Diode (LED) fixtures.

Rider No. 8 – Default Service Supply. Light-Emitting Diode (LED) fixtures and pricing have been added to the Rider.

Rider No. 8 – Default Service Supply. Due to the addition of the Light-Emitting Diode (LED) fixtures and pricing information, language on the Rider pages has been repaginated.

Rider No. 10 – State Tax Adjustment

Rider No. 10 – State Tax Adjustment has been modified to reflect that Part 1 of the STAS has been set to zero.

V. Proposed Changes to Tariff Riders – (Continued)**Rider No. 16 – Service to Non-Utility Generating Facilities**

Rider No. 16 – Service to Non-Utility Generating Facilities. Language has been modified to reflect current operations of the Company.

Rider No. 16 – Service to Non-Utility Generating Facilities. Language has been modified to remove the Contract Demand.

Rider No. 16 – Service to Non-Utility Generating Facilities. Language has been modified to add a distribution charge applicable to Back-Up Power Bill Determinants for Back-Up Power.

VI. Addition of Rider No. 22 – Pension Rate Adjustment Mechanism

Rider No. 22 – Pension Rate Adjustment Mechanism has been added to the retail Tariff.

VII. Appendix A – Transmission Service Charges

Rate Class	Energy Charge \$/kWh	Demand Charge \$/kW	Monthly Charge Per Fixture	Monthly Charge Per Fixture
Light-Emitting Diode (LED)				
43			\$0.00	\$0.00
67			\$0.00	\$0.00
106			\$0.00	\$0.00
118			\$0.00	\$0.00
196			\$0.00	\$0.00
256			\$0.00	\$0.00

Appendix A – Transmission Service Charges. Light-Emitting Diode (LED) fixtures and pricing have been added to the Appendix.

Appendix A – Transmission Service Charges. Due to the addition of the Light-Emitting Diode (LED) fixtures and pricing information, language on the Appendix pages has been repaginated.

Exhibit WVP-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
43 W LED Installation

Docket No. R-2013-2372129

Financial Input	Input
Capital Investment - Material	\$387.00
Capitalized Labor	\$228.59
Total Capitalized Investment	\$615.59

Years for straight line <u>book</u> depreciation	12
Book Depreciation Rate	8.33%
Years for straight line <u>tax</u> depreciation	12
Tax Depreciation Rate	8.33%
Tax Rate	
State	9.99%
Federal	35.00%
Combined	41.49%
Gross Revenue Adjustment	58.51%
Gross Revenue Conversion Factor	1.70921

PA Gross Receipts Tax 5.90%

Weighted Cost of Capital

	Capitalization Ratio	Rate	Weighted Return	WATCC
Debt	43.08%	5.18%	2.23%	1.30%
Preferred	5.03%	5.88%	0.30%	0.30%
Equity	51.89%	11.25%	5.84%	5.84%
	100.00%		8.36%	7.44%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	\$769.84
Levelized Annual Revenue Requirement	\$99.20
Annual O&M / Maintenance Expense	\$38.10
Annual Revenue Requirement	\$137.30
Net Monthly Tariff Rate	\$11.44
PA Gross Receipts Tax	\$0.72
Total Monthly Distribution Rate	\$12.16

A	B	C	D	E	F	G	H	I	J	K	L	M	N
Year	Capital B.O.Y. Plant	Return on Debt	Return on Preferred	Return on Equity	Total Return on Net Plant	Book Deprec.	Tax Deprec.	E.O.Y. Def. Inc. Tax	Income Tax on Preferred	Income Tax on Equity	Total Income Taxes	Revenue Requirement	Cumulative NPV
					C+D+E			(H-G)*Tax	D*(Tax/(1-Tax))	E*(Tax/(1-Tax))	J+K	F+G+L	
1	615.59	13.73	1.82	35.94	51.48	51.30	51.30	0.00	1.29	25.49	26.78	129.56	120.59
2	564.29	12.58	1.67	32.94	47.19	51.30	51.30	0.00	1.18	23.36	24.55	123.04	227.19
3	513.00	11.44	1.52	29.95	42.90	51.30	51.30	0.00	1.08	21.24	22.31	116.52	321.14
4	461.70	10.30	1.37	26.95	38.61	51.30	51.30	0.00	0.97	19.11	20.08	110.00	403.69
5	410.40	9.15	1.21	23.96	34.32	51.30	51.30	0.00	0.86	16.99	17.85	103.47	475.98
6	359.10	8.01	1.06	20.96	30.03	51.30	51.30	0.00	0.75	14.87	15.62	96.95	539.02
7	307.80	6.86	0.91	17.97	25.74	51.30	51.30	0.00	0.65	12.74	13.39	90.43	593.75
8	256.50	5.72	0.76	14.97	21.45	51.30	51.30	0.00	0.54	10.62	11.16	83.91	641.01
9	205.20	4.58	0.61	11.98	17.16	51.30	51.30	0.00	0.43	8.50	8.93	77.39	681.58
10	153.90	3.43	0.46	8.98	12.87	51.30	51.30	0.00	0.32	6.37	6.69	70.87	716.17
11	102.60	2.29	0.30	5.99	8.58	51.30	51.30	0.00	0.22	4.25	4.46	64.34	745.39
12	51.30	1.14	0.15	2.99	4.29	51.30	51.30	0.00	0.11	2.12	2.23	57.82	769.84
						PV Tax Shields	398.11						
						Tax on shields	165.19						
						Investment	615.59						
						After Tax Investment	450.40						

Adjust for Tax Gross-Up <-----> PV Rev Req

Exhibit WVP-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
67 W LED Installation

Docket No. R-2013-2372129

Financial Input	Input
Capital Investment - Material	\$433.00
Capitalized Labor	\$228.59
Total Capitalized Investment	\$661.59

Years for straight line book depreciation	12
Book Depreciation Rate	8.33%
Years for straight line tax depreciation	12
Tax Depreciation Rate	8.33%
Tax Rate	
State	9.99%
Federal	35.00%
Combined	41.49%
Gross Revenue Adjustment	58.51%
Gross Revenue Conversion Factor	1.70921

PA Gross Receipts Tax 5.90%

Weighted Cost of Capital

	Capitalization Ratio	Rate	Weighted Return	WATCC
Debt	43.08%	5.18%	2.23%	1.30%
Preferred	5.03%	5.88%	0.30%	0.30%
Equity	51.89%	11.25%	5.84%	5.84%
	100.00%		8.36%	7.44%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	\$827.36
Levelized Annual Revenue Requirement	\$106.61
Annual O&M / Maintenance Expense	\$38.10
Annual Revenue Requirement	\$144.71
Net Monthly Tariff Rate	\$12.06
PA Gross Receipts Tax	\$0.76
Total Monthly Distribution Rate	\$12.82

A	B	C	D	E	F	G	H	I	J	K	L	M	N
Year	Capital	Return			Total	Deferred Tax on Depreciation		Tax			Total	Revenue Requirement	Cumulative NPV
	B.O.Y. Plant	Return on Debt	Return on Preferred	Return on Equity	Return on Net Plant	Book Deprec.	Tax Deprec.	E.O.Y. Def. Inc. Tax	Income Tax on Preferred	Income Tax on Equity	Income Taxes		
					C+D+E			(H-G)*Tax	D*(Tax/(1-Tax))	E*(Tax/(1-Tax))	J+K	F+G+L	
1	661.59	14.75	1.96	38.62	55.33	55.13	55.13	0.00	1.39	27.39	28.78	139.24	129.60
2	606.46	13.52	1.79	35.40	50.72	55.13	55.13	0.00	1.27	25.11	26.38	132.23	244.16
3	551.33	12.29	1.63	32.18	46.11	55.13	55.13	0.00	1.16	22.83	23.98	125.22	345.14
4	496.20	11.07	1.47	28.97	41.50	55.13	55.13	0.00	1.04	20.54	21.58	118.22	433.86
5	441.06	9.84	1.30	25.75	36.89	55.13	55.13	0.00	0.93	18.26	19.19	111.21	511.55
6	385.93	8.61	1.14	22.53	32.28	55.13	55.13	0.00	0.81	15.98	16.79	104.20	579.30
7	330.80	7.38	0.98	19.31	27.67	55.13	55.13	0.00	0.69	13.70	14.39	97.19	638.11
8	275.66	6.15	0.82	16.09	23.05	55.13	55.13	0.00	0.58	11.41	11.99	90.18	688.91
9	220.53	4.92	0.65	12.87	18.44	55.13	55.13	0.00	0.46	9.13	9.59	83.17	732.52
10	165.40	3.69	0.49	9.66	13.83	55.13	55.13	0.00	0.35	6.85	7.19	76.16	769.68
11	110.27	2.46	0.33	6.44	9.22	55.13	55.13	0.00	0.23	4.57	4.80	69.15	801.09
12	55.13	1.23	0.16	3.22	4.61	55.13	55.13	0.00	0.12	2.28	2.40	62.14	827.36
						PV Tax Shields	427.86						
						Tax on shields	177.53						
						Investment	661.59						
						After Tax Investment	484.06						

Adjust for Tax Gross-Up **827.36** <-----> PV Rev Req **827.36**

Exhibit WVP-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
106 W LED Installation
Docket No. R-2013-2372129

Financial Input	Input
Capital Investment - Material	\$514.00
Capitalized Labor	\$228.59
Total Capitalized Investment	\$742.59

Years for straight line <u>book</u> depreciation	12
Book Depreciation Rate	8.33%
Years for straight line <u>tax</u> depreciation	12
Tax Depreciation Rate	8.33%
Tax Rate	
State	9.99%
Federal	35.00%
Combined	41.49%
Gross Revenue Adjustment	58.51%
Gross Revenue Conversion Factor	1.70921
PA Gross Receipts Tax	5.90%

Monthly Distribution Rate	
Sum of PV of Revenue Requirement	\$928.66
Levelized Annual Revenue Requirement	\$119.66
Annual O&M / Maintenance Expense	\$38.10
Annual Revenue Requirement	\$157.76
Net Monthly Tariff Rate	\$13.15
PA Gross Receipts Tax	\$0.82
Total Monthly Distribution Rate	\$13.97

Weighted Cost of Capital				
	Capitalization Ratio	Rate	Weighted Return	WATCC
Debt	43.08%	5.18%	2.23%	1.30%
Preferred	5.03%	5.88%	0.30%	0.30%
Equity	51.89%	11.25%	5.84%	5.84%
	100.00%		8.36%	7.44%

A	B	C	D	E	F	G	H	I	J	K	L	M	N
Year	Capital	Return			Total	Deferred Tax on Depreciation			Tax			Total	Cumulative NPV
	B.O.Y. Plant	Return on Debt	Return on Preferred	Return on Equity	Return on Net Plant	Book Deprec.	Tax Deprec.	E.O.Y. Def. Inc. Tax	Income Tax on Preferred	Income Tax on Equity	Income Taxes	Revenue Requirement	
					C+D+E			(H-G)*Tax	D*(Tax/(1-Tax))	E*(Tax/(1-Tax))	J+K	F+G+L	
1	742.59	16.56	2.20	43.35	62.11	61.88	61.88	0.00	1.56	30.74	32.30	156.29	145.47
2	680.71	15.18	2.01	39.74	56.93	61.88	61.88	0.00	1.43	28.18	29.61	148.42	274.05
3	618.83	13.80	1.83	36.12	51.76	61.88	61.88	0.00	1.30	25.62	26.92	140.56	387.39
4	556.95	12.42	1.65	32.51	46.58	61.88	61.88	0.00	1.17	23.06	24.23	132.69	486.98
5	495.06	11.04	1.46	28.90	41.40	61.88	61.88	0.00	1.04	20.50	21.53	124.82	574.18
6	433.18	9.66	1.28	25.29	36.23	61.88	61.88	0.00	0.91	17.93	18.84	116.95	650.22
7	371.30	8.28	1.10	21.67	31.05	61.88	61.88	0.00	0.78	15.37	16.15	109.09	716.24
8	309.41	6.90	0.92	18.06	25.88	61.88	61.88	0.00	0.65	12.81	13.46	101.22	773.25
9	247.53	5.52	0.73	14.45	20.70	61.88	61.88	0.00	0.52	10.25	10.77	93.35	822.20
10	185.65	4.14	0.55	10.84	15.53	61.88	61.88	0.00	0.39	7.69	8.08	85.48	863.91
11	123.77	2.76	0.37	7.22	10.35	61.88	61.88	0.00	0.26	5.12	5.38	77.62	899.17
12	61.88	1.38	0.18	3.61	5.18	61.88	61.88	0.00	0.13	2.56	2.69	69.75	928.66
						PV Tax Shields	480.24						
						Tax on shields	199.27						
						Investment	742.59						
						After Tax Investment	543.32						

Adjust for Tax Gross-Up 928.66 <-----> PV Rev Req 928.66

Exhibit WVP-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
219 W LED Installation

Docket No. R-2013-2372129

Financial Input	Input
Capital Investment - Material	\$713.00
Capitalized Labor	\$228.59
Total Capitalized Investment	\$941.59

Years for straight line book depreciation	12
Book Depreciation Rate	8.33%
Years for straight line tax depreciation	12
Tax Depreciation Rate	8.33%

Tax Rate		
State		9.99%
Federal		35.00%
Combined		41.49%
Gross Revenue Adjustment		58.51%
Gross Revenue Conversion Factor		1.70921

PA Gross Receipts Tax 5.90%

Weighted Cost of Capital

	Capitalization Ratio	Rate	Weighted Return	WATCC
Debt	43.08%	5.18%	2.23%	1.30%
Preferred	5.03%	5.88%	0.30%	0.30%
Equity	51.89%	11.25%	5.84%	5.84%
	100.00%		8.36%	7.44%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	\$1,177.52
Levelized Annual Revenue Requirement	\$151.73
Annual O&M / Maintenance Expense	\$38.10
Annual Revenue Requirement	\$189.83
Net Monthly Tariff Rate	\$15.82
PA Gross Receipts Tax	\$0.99
Total Monthly Distribution Rate	\$16.81

A	B	C	D	E	F	G	H	I	J	K	L	M	N
Year	Capital	Return			Total	Deferred Tax on Depreciation		Tax			Total	Revenue Requirement	Cumulative NPV
	B.O.Y. Plant	Return on Debt	Return on Preferred	Return on Equity	Return on Net Plant	Book Deprec.	Tax Deprec.	E.O.Y. Def. Inc. Tax	Income Tax on Preferred	Income Tax on Equity	Income Taxes		
					C+D+E			(H-G)*Tax	D*(Tax/(1-Tax))	E*(Tax/(1-Tax))	J+K	F+G+L	
1	941.59	21.00	2.78	54.97	78.75	78.47	78.47	0.00	1.98	38.98	40.96	198.17	184.45
2	863.13	19.25	2.55	50.39	72.19	78.47	78.47	0.00	1.81	35.73	37.54	188.20	347.50
3	784.66	17.50	2.32	45.81	65.62	78.47	78.47	0.00	1.65	32.49	34.13	178.22	491.21
4	706.20	15.75	2.09	41.23	59.06	78.47	78.47	0.00	1.48	29.24	30.72	168.25	617.48
5	627.73	14.00	1.86	36.64	52.50	78.47	78.47	0.00	1.32	25.99	27.31	158.27	728.04
6	549.26	12.25	1.62	32.06	45.94	78.47	78.47	0.00	1.15	22.74	23.89	148.30	824.46
7	470.80	10.50	1.39	27.48	39.37	78.47	78.47	0.00	0.99	19.49	20.48	138.32	908.17
8	392.33	8.75	1.16	22.90	32.81	78.47	78.47	0.00	0.82	16.24	17.07	128.34	980.47
9	313.86	7.00	0.93	18.32	26.25	78.47	78.47	0.00	0.66	12.99	13.65	118.37	1,042.53
10	235.40	5.25	0.70	13.74	19.69	78.47	78.47	0.00	0.49	9.75	10.24	108.39	1,095.43
11	156.93	3.50	0.46	9.16	13.12	78.47	78.47	0.00	0.33	6.50	6.83	98.42	1,140.13
12	78.47	1.75	0.23	4.58	6.56	78.47	78.47	0.00	0.16	3.25	3.41	88.44	1,177.52
						PV Tax Shields	608.94						
						Tax on shields	252.67						
						Investment	941.59						
						After Tax Investment	688.92						

Adjust for Tax Gross-Up 1,177.52 <-----> PV Rev Req 1,177.52

Exhibit WVP-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
196 W LED Installation

Docket No. R-2013-2372129

Financial Input	Input
Capital Investment - Material	\$851.00
Capitalized Labor	\$228.59
Total Capitalized Investment	\$1,079.59

Years for straight line <u>book</u> depreciation	12
Book Depreciation Rate	8.33%
Years for straight line <u>tax</u> depreciation	12
Tax Depreciation Rate	8.33%

Tax Rate		
State		9.99%
Federal		35.00%
Combined		41.49%
Gross Revenue Adjustment		58.51%
Gross Revenue Conversion Factor		1.70921

PA Gross Receipts Tax	5.90%
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Weighted Cost of Capital

	Capitalization Ratio	Rate	Weighted Return	WATCC
Debt	43.08%	5.18%	2.23%	1.30%
Preferred	5.03%	5.88%	0.30%	0.30%
Equity	51.89%	11.25%	5.84%	5.84%
	100.00%		8.36%	7.44%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	\$1,350.10
Levelized Annual Revenue Requirement	\$173.97
Annual O&M / Maintenance Expense	\$38.10
Annual Revenue Requirement	\$212.07
Net Monthly Tariff Rate	\$17.67
PA Gross Receipts Tax	\$1.11
Total Monthly Distribution Rate	\$18.78

A	B	C	D	E	F	G	H	I	J	K	L	M	N
Year	Capital	Return			Total Return on Net Plant	Deferred Tax on Depreciation		Tax			Total Income Taxes	Revenue Requirement	Cumulative NPV
	B.O.Y. Plant	Return on Debt	Return on Preferred	Return on Equity	Return on Net Plant	Book Deprec.	Tax Deprec.	E.O.Y. Def. Inc. Tax	Income Tax on Preferred	Income Tax on Equity			
					C+D+E			(H-G)*Tax	D*(Tax/(1-Tax))	E*(Tax/(1-Tax))	J+K	F+G+L	
1	1,079.59	24.07	3.19	63.02	90.29	89.97	89.97	0.00	2.26	44.70	46.96	227.22	211.49
2	989.63	22.07	2.93	57.77	82.77	89.97	89.97	0.00	2.08	40.97	43.05	215.78	398.42
3	899.66	20.06	2.66	52.52	75.24	89.97	89.97	0.00	1.89	37.25	39.13	204.34	563.20
4	809.70	18.06	2.39	47.27	67.72	89.97	89.97	0.00	1.70	33.52	35.22	192.90	707.98
5	719.73	16.05	2.13	42.02	60.19	89.97	89.97	0.00	1.51	29.80	31.31	181.47	834.74
6	629.76	14.04	1.86	36.76	52.67	89.97	89.97	0.00	1.32	26.07	27.39	170.03	945.30
7	539.80	12.04	1.60	31.51	45.15	89.97	89.97	0.00	1.13	22.35	23.48	158.59	1,041.28
8	449.83	10.03	1.33	26.26	37.62	89.97	89.97	0.00	0.94	18.62	19.57	147.15	1,124.17
9	359.86	8.02	1.06	21.01	30.10	89.97	89.97	0.00	0.75	14.90	15.65	135.72	1,195.32
10	269.90	6.02	0.80	15.76	22.57	89.97	89.97	0.00	0.57	11.17	11.74	124.28	1,255.97
11	179.93	4.01	0.53	10.50	15.05	89.97	89.97	0.00	0.38	7.45	7.83	112.84	1,307.23
12	89.97	2.01	0.27	5.25	7.52	89.97	89.97	0.00	0.19	3.72	3.91	101.40	1,350.10
						PV Tax Shields	698.18						
						Tax on shields	289.70						
						Investment	1,079.59						
						After Tax Investment	789.89						

Adjust for Tax Gross-Up 1,350.10 <----- = -----> PV Rev Req 1,350.10

Exhibit WVP-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
256 W LED Installation

Docket No. R-2013-2372129

Financial Input		Input
Capital Investment - Material		\$961.00
Capitalized Labor		\$228.59
Total Capitalized Investment		\$1,189.59

Years for straight line book depreciation		12
Book Depreciation Rate		8.33%
Years for straight line tax depreciation		12
Tax Depreciation Rate		8.33%
Tax Rate	State	9.99%
	Federal	35.00%
	Combined	41.49%
	Gross Revenue Adjustment	58.51%
	Gross Revenue Conversion Factor	1.70921

PA Gross Receipts Tax 5.90%

Weighted Cost of Capital

	Capitalization Ratio	Rate	Weighted Return	WATCC
Debt	43.08%	5.18%	2.23%	1.30%
Preferred	5.03%	5.88%	0.30%	0.30%
Equity	51.89%	11.25%	5.84%	5.84%
	100.00%		8.36%	7.44%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	\$1,487.66
Levelized Annual Revenue Requirement	\$191.70
Annual O&M / Maintenance Expense	\$38.10
Annual Revenue Requirement	\$229.80
Net Monthly Tariff Rate	\$19.15
PA Gross Receipts Tax	\$1.20
Total Monthly Distribution Rate	\$20.35

A	B	C	D	E	F	G	H	I	J	K	L	M	N
Year	Capital	Return			Total	Deferred Tax on Depreciation			Tax			Total	Total
	B.O.Y. Plant	Return on Debt	Return on Preferred	Return on Equity	Return on Net Plant	Book Deprec.	Tax Deprec.	E.O.Y. Def. Inc. Tax	Income Tax on Preferred	Income Tax on Equity	Income Taxes	Revenue Requirement	Cumulative NPV
					C+D+E			(H-G)*Tax	D*(Tax/(1-Tax))	E*(Tax/(1-Tax))	J+K	F+G+L	
1	1,189.59	26.53	3.52	69.44	99.49	99.13	99.13	0.00	2.50	49.25	51.75	250.37	233.04
2	1,090.46	24.32	3.23	63.66	91.20	99.13	99.13	0.00	2.29	45.15	47.43	237.77	439.02
3	991.33	22.11	2.93	57.87	82.91	99.13	99.13	0.00	2.08	41.04	43.12	225.16	620.58
4	892.20	19.90	2.64	52.08	74.62	99.13	99.13	0.00	1.87	36.94	38.81	212.56	780.11
5	793.06	17.69	2.35	46.30	66.33	99.13	99.13	0.00	1.66	32.83	34.50	199.96	919.80
6	693.93	15.47	2.05	40.51	58.04	99.13	99.13	0.00	1.46	28.73	30.19	187.35	1,041.61
7	594.80	13.26	1.76	34.72	49.75	99.13	99.13	0.00	1.25	24.63	25.87	174.75	1,147.37
8	495.66	11.05	1.47	28.94	41.45	99.13	99.13	0.00	1.04	20.52	21.56	162.15	1,238.71
9	396.53	8.84	1.17	23.15	33.16	99.13	99.13	0.00	0.83	16.42	17.25	149.54	1,317.11
10	297.40	6.63	0.88	17.36	24.87	99.13	99.13	0.00	0.62	12.31	12.94	136.94	1,383.94
11	198.27	4.42	0.59	11.57	16.58	99.13	99.13	0.00	0.42	8.21	8.62	124.34	1,440.42
12	99.13	2.21	0.29	5.79	8.29	99.13	99.13	0.00	0.21	4.10	4.31	111.74	1,487.66
						PV Tax Shields	769.32						
						Tax on shields	319.22						
						Investment	1,189.59						
						After Tax Investment	870.38						

Adjust for Tax Gross-Up 1,487.66 <----- = -----> PV Rev Req 1,487.66

Exhibit WVP-5

Duquesne Light Company

Pension Rate Adjustment Mechanism

Illustrative Calculation of Adjustment to Distribution Rates

Docket No. R-2013-2372129

Rate Schedule	Base Expense Level (\$000's)	Rate Class Factor	Projected Expense Level (\$000's)	Allocated Share	Expense Adjustment (\$000's)	Forecast Units	Billing Unit	Pension Rate Adjustment	Current Distribution Rate	Adjusted Distribution Rate	Unit Rate
	Note 1		Note 2			Note 3			Note 4		
	A	B=A/Total	C	D=B*C	E=D-A	F	G	H=E/F	I	J	K
FERC Account 926	26,043		20,000								
RS	14,980	57.5%		11,504	(3,476)	3,758,709,109	kWh	(0.0925)	4.3961	4.3036	Cents/kWh
RH (5)	1,211	4.7%		930	(281)	393,778,611	kWh	(0.0714)	4.3961	4.3247	Cents/kWh
RA (5)	143	0.5%		110	(33)	50,500,328	kWh	(0.0657)	4.3961	4.3304	Cents/kWh
GS	582	2.2%		447	(135)	90,997,477	kWh	(0.1484)	4.8981	4.7497	Cents/kWh
GM<25 kW	1,154	4.4%		886	(268)	593,062,708	kWh	(0.0452)	1.2487	1.2035	Cents/kWh
GM=>25 kW	2,717	10.4%		2,087	(630)	2,186,414,249	kWh	(0.0288)	1.3175	1.2887	Cents/kWh
GMH (6)	406	1.6%		312	(94)	289,817,195	kWh	(0.0325)	1.2487	1.2162	Cents/kWh
GL	2,716	10.4%		2,086	(630)	4,720,688	kW	(\$0.13)	\$8.45	\$8.32	\$/kW
GLH (7)	434	1.7%		333	(101)	337,105,005	kWh	(0.0299)	2.1446	2.1147	Cents/kWh
L	936	3.6%		719	(217)	1,280,702	kW	(\$0.17)	\$12.30	\$12.13	\$/kW
HVPS (8)	4	0.0%		3	(1)	48	Bills	(\$19.34)	\$8,551.00	\$8,531.66	\$/Month
SE	53	0.2%		41	(12)	482,342	Fixtures	(\$0.03)	\$2.57	\$2.54	\$/Fixture/Mo.
AL, SM,SH,PAL	674	2.6%		518	(156)	725,584					
AL						3	Bills	(\$0.22)	\$6.54	\$6.32	\$/Month
SM, SH, PAL (9)						725,581	Fixtures	(\$0.22)	\$11.52	\$11.30	\$/Fixture/Mo.
UMS	33	0.1%		25	(8)	66,079	Bills	(\$0.12)	\$10.00	\$9.88	\$/Month
Total	26,043	100.0%		20,000	(6,043)						

1/ Exhibit 6-2A, pages 7 and 8, line 125, FERC Account 926, Employee Pensions and Benefits.

2/ Hypothetical amount shown for illustrative purposes only.

3/ DFR IV-C, pages 1-23

4/ Proposed rates defined in Exhibit WVP-1 and WVP-3.

5/ May through October kWh rate shown. The Pension Rate Adjustment would also apply to the November through April kWh rate.

6/ June through September kWh rate shown. The Pension Rate Adjustment would also apply to the October through May kWh rate.

7/ Winter kWh rate only. There are no charges for summer kWh usage.

8/ Monthly rate shown for customers with billing demand less than 50,000 kW. The same Pension Rate Adjustment would apply to the other rate blocks.

9/ 100 W Mercury Vapor fixture rate shown for illustrative purposes. The same Pension Rate Adjustment would apply to the distribution charge of all fixture wattages.