

Delmarva Power & Light Company

Application for an Increase in Gas Base Rates

Direct Testimony of Witnesses McGowan, Collacchi,
Hevert and Ziminsky
(Book 2 of 3)

Before the Delaware Public Service Commission

December 7, 2012

Testimony of Kevin M. McGowan

DELMARVA POWER & LIGHT COMPANY
BEFORE THE
DELAWARE PUBLIC SERVICE COMMISSION
DIRECT TESTIMONY OF KEVIN M. MCGOWAN
DOCKET NO. _____

1 **Q1. Please state your name and position.**

2 A1. My name is Kevin M. McGowan. I am Vice President of Regulatory
3 Affairs for Pepco Holdings, Inc. (PHI). I am testifying on behalf of Delmarva
4 Power & Light Company (Delmarva or the Company).

5 **Q2. What are your responsibilities in your role as Vice President of Regulatory**
6 **Affairs?**

7 A2. I am responsible for all regulatory matters for PHI and its three regulated
8 utility subsidiaries, Atlantic City Electric Company, Delmarva Power & Light
9 Company, and Potomac Electric Power Company (Pepco). In this capacity, I am
10 responsible for regulation related to PHI's utility business before the Delaware
11 Public Service Commission (the Commission), the Maryland Public Service
12 Commission, the New Jersey Board of Public Utilities, the Public Service
13 Commission of the District of Columbia, and the Federal Energy Regulatory
14 Commission.

15 **Q3. Please state your educational background and professional experience.**

16 A3. I hold a Bachelor of Business Administration degree in both Accounting
17 and Business Data Systems from the University of Texas at San Antonio and a
18 Masters of Business Administration in Finance from the University Of Chicago
19 Graduate School Of Business. I am also a Certified Public Accountant.

1 In 1998, I joined Potomac Capital Investments, a subsidiary of Pepco, as
2 the Vice President and Treasurer. In 2004, I transferred to Pepco's Power
3 Delivery group and eventually to PHI, where I have held various financial
4 positions of increasing responsibility. In March 2009, I was promoted to Vice
5 President and Treasurer of PHI. In November 2012, I became Vice President,
6 Regulatory Affairs. Prior to joining Pepco, I worked for Duty Free International,
7 an international retail company, and prior to that I worked for Ernst & Young.

8 **Q4. What is the purpose of your Direct Testimony?**

9 A4. The purpose of my Direct Testimony is to provide an overview of the
10 Company's application for an increase in gas distribution rates. I will briefly
11 summarize the testimony of the Company's witnesses, discuss the Company's
12 capital structure and current credit ratings, and explain the importance of
13 Delmarva remaining a financially sound utility with investment grade credit
14 ratings. Finally, I will discuss why it is important for our customers that
15 Delmarva have access to capital on reasonable terms.

16 This testimony was prepared by me or under my direct supervision and
17 control. The source documents for my testimony are Company records and public
18 documents. I also rely upon my personal knowledge and experience.

19 **Q5. Please describe the Company's application.**

20 A5. This filing consists of the application for an increase in gas base
21 distribution rates, together with my Direct Testimony and that of six other
22 witnesses. As described more fully below, those witnesses and the topics they
23 address are as follows:

- 1 • Mr. Robert M. Collacchi, Jr., Director, Gas Operations and Engineering
2 provides testimony and exhibits in support of the Company's gas
3 construction program and other investments, including a discussion of the
4 need to replace certain facilities for both safety and reliability purposes.
5 Mr. Collacchi also supports the tariff change that will enable more
6 Delmarva customers to access the gas system.
- 7 • Mr. Robert B. Hevert, Managing Partner, Sussex Economic Advisors,
8 LLC, provides testimony and exhibits in support of the Company's
9 proposed cost of equity.
- 10 • Mr. Jay C. Ziminsky, Manager, Revenue Requirements, provides
11 testimony and exhibits in support of the Company's revenue requirement,
12 the test year and test period selections, and the proposed ratemaking
13 adjustments.
- 14 • Ms. Marlene C. Santacecilia, Regulatory Affairs Lead, provides testimony
15 and exhibits in support of the proposed rate design and Delmarva's
16 proposed tariffs.
- 17 • Mr. Michael T. Normand, Regulatory Affairs Analyst, provides testimony
18 and exhibits in support of the Company's cost of service studies.
- 19 • Ms. Kathleen A. White, Assistant Controller, provides testimony and
20 exhibits in support of the Company's accounting books and records and
21 PHI's cost and accounting procedures.

22 **Q6. Please summarize the Company's rate increase request.**

1 A6. The Company is requesting a \$12.174 million increase in gas base
2 distribution revenue based on a calendar year 2012 test period consisting of six
3 months of actual results and six months of forecasted results. The test period
4 results will be updated to actual as soon as they are available. A typical
5 residential customer using an average of 120 CCF in a winter month would see a
6 bill increase of \$8.67 or 6.1%, from \$141.79 to \$150.46. However, a typical
7 residential customer would see a winter month decrease of \$15.13 or 9.1%, from
8 \$165.59 to \$150.46, when the effect of the Gas Cost Rate decrease effective
9 November 1, 2012 is included in the comparison. Company Witness Santacecilia
10 provides additional information related to the billing comparison for the overall
11 proposed rate changes.

12 The test period of December 31, 2012, with the adjustments proposed,
13 represents a reasonable basis for establishing the Company's revenue
14 requirements absent the use of a fully forecasted test period. With the
15 adjustments presented in this filing, this test period provides a matching of
16 revenues, expenses, and rate base consistent with Commission regulations and
17 represents a reasonable basis for establishing the Company's revenue
18 requirements for the rate effective period. In addition, the Company is requesting
19 recovery of forecasted reliability plant additions through December 2013. As
20 approved by the Commission in Docket No. 09-414, the Commission allowed
21 recovery of reliability plant additions that were updated to actuals during the
22 course of the proceeding. Company Witness Ziminsky provides additional

1 information related to the support of the test period selection and forecasted
2 reliability plant additions.

3 The request is also based on a rate of return on equity (ROE) of 10.25%.
4 At current base rates, Delmarva's unadjusted ROE is 7.53% on its gas business,
5 which is far short of the 10.00% level approved by the Commission in Docket No.
6 10-237 in Order No. 7990 dated June 21, 2011, and even further below the current
7 10.25% return on equity capital supported by Company Witness Hevert.

8 **Q7. When did the Company last file for a gas base rate increase?**

9 A7. The Company last requested an increase in gas base rates on July 2, 2010
10 in Docket No. 10-237. As stated above, the Commission issued Order No. 7990
11 on June 21, 2011 that approved a Settlement Agreement reached by the parties
12 involved in that case. The Settlement Agreement provided for an annual gas base
13 rate increase of \$5.8 million, or approximately 3.09% of total gas revenues, based
14 on an overall rate of return of 7.56% and a return on equity of 10.00%. The full
15 proposed gas rates became effective on February 2, 2011 with the final approved
16 rates effective on July 1, 2011.

17 **Q8. Why is it necessary for the Company to file this gas rate increase?**

18 A8. Since the Company's last gas base rate case filed in 2010, the Company
19 has continued to undertake initiatives to ensure a high level of gas reliability and
20 system safety and has invested approximately \$38.6 million in its gas distribution
21 system since the last gas base rate case. As discussed in Company Witness
22 Collacchi's testimony, Delmarva is spending significant amounts of capital to

1 replace aging gas facilities. These replacements are essential to maintain
2 reliability and to ensure the continued safety of the gas system.

3 Given the need for these system improvements, Delmarva's rates for gas
4 distribution service must reflect the current costs of providing that service so that
5 the Company can continue to meet its obligation of providing safe and reliable
6 gas service to its customers. As I discuss below, this increase is also necessary to
7 maintain the Company's financial integrity in order for the Company to have
8 access to capital on reasonable terms to support the ongoing investments in the
9 gas distribution system.

10 As previously noted, Delmarva is currently earning well below its
11 authorized rate of return on its gas business. In fact, Delmarva's adjusted rate of
12 return, based on the analysis presented by Company Witness Ziminsky, is 4.87%,
13 which reflects a ROE of only 4.84%. This 4.84% is far below the 10.00% ROE
14 that the Commission authorized in the Company's last gas base rate case.

15 **Q9. What overall rate of return is Delmarva requesting?**

16 A9. As shown in Schedule (KMM)-1, the Company is requesting an overall
17 rate of return of 7.51% on its gas distribution rate base in Delaware.

18 **Q10. On what capital structure is the overall rate of return based?**

19 A10. This overall rate of return is the weighted average, based on the
20 Company's September 30, 2012 capital structure ratios of 48.78% common equity
21 and 51.22% long-term debt, its embedded long-term debt cost of 4.91% (see
22 Schedule (KMM)-1) and its return on common equity of 10.25%, as

recommended by Company Witness Hevert. This capital structure is consistent with the Company's goals and objectives.

Q11. Is this capital structure consistent with industry practice and averages?

A11. Yes. The Company's recommended capital structure is consistent with the 2011 full-year and 2012 year-to-date reported averages of 47.97% and 50.79%, respectively, of the common equity ratios of electric utilities as published in the October 4, 2012 edition of Regulatory Research Associates' "Regulatory Focus: Major Rate Case Decisions", as well as with a 2013 – 2017 forecast range from 49.0% to 49.5% for the average equity ratio of the Electric Utility (East) Industry sector between 2013 and 2017, as published by Value Line on August 24, 2012.

Q12. Are there other reasons this capital structure is appropriate for use in this proceeding?

A12. Yes. As indicated in the Direct Testimony of Company Witness Hevert, the Company's recommended capital structure is reasonable given a mean common equity ratio of 55.23% (range between 47.92% and 65.63%) for the nine companies comprising his peer group for the purpose of determining the cost of equity in this proceeding.

Q13: What are the Company's credit ratings by major rating agencies?

A13. Delmarva's long-term corporate credit ratings (unsecured debt ratings) are BBB+, Baa2 and A- from S&P, Moody's and Fitch, respectively. As noted in S&P's "Industry Report Card" dated October 22, 2012, 63% of U.S. investor-owned electric utilities carry ratings from BBB- to BBB+, with an additional 35% rated A-, or better.

1 For Delmarva to continue to have access to the capital necessary for the
2 significant investments in its gas distribution infrastructure, the Company must
3 maintain its financial integrity, as reflected in its earned rate of return on equity,
4 its credit ratings, and its other key financial metrics. The rate increase that
5 Delmarva seeks in this case is crucial to maintaining the level of financial
6 integrity necessary for the Company to access needed capital on reasonable terms.

7 **Q14. Does the State regulatory environment affect PHI's credit ratings?**

8 A14. Yes, it is a very important factor. In fact, in S&P's publications entitled
9 "Assessing U.S. Regulatory Environments," dated November 7, 2008 and updated
10 on March 11, 2010, and "Business and Financial Risks in the Investor-Owned
11 Utility Industry," dated November 26, 2008 and updated on October 28, 2010,
12 S&P indicated that the regulatory climate is perhaps the most important factor it
13 analyzes when evaluating investor-owned utilities. It noted that regulatory risk
14 will continue to be evaluated based on the environments in which companies
15 operate, as well as other factors, including ratemaking practices and procedures,
16 cash flow support and stability, political insulation, operating performance, credit
17 metrics, and particularly cash flow metrics. In Delaware, the regulatory
18 environment is viewed by rating agencies as positive.

19 **Q15. Please discuss the Company's need to maintain its financial health.**

20 A15. Delmarva continues to face rising costs to meet the needs of its customers
21 and fulfill its public service obligations. As discussed in the testimony of other
22 Company Witnesses, these rising costs include higher expenses, such as
23 workforce-related costs, and higher capital expenditures to ensure the continued

1 reliability and safe operation of the distribution infrastructure. As a result of these
2 rising costs, the Company's revenues are falling far short of the level necessary to
3 cover its costs, earn a reasonable rate of return, and preserve a strong investment
4 grade credit rating.

5 **Q16. Does the Company plan to place an interim increase of \$2.5 million into**
6 **effect as permitted under 26. Del. C. § 306 (c)?**

7 A16. Yes. If the Commission chooses to suspend the proposed rate changes for
8 the full suspension period, the Company plans to place in effect, on February 5,
9 2013, subject to refund, an interim annual increase of approximately \$2.5 million.
10 Modified Tariff Leafs reflecting the interim increase are supported by Company
11 Witness Santacecilia and are included in this Application. With the proposed
12 interim base rate increase, on February 5, 2013, a typical residential customer
13 using an average of 120 CCF in a winter month would see a bill increase of \$2.11
14 or 1.5%, from \$141.79 to \$143.90.

15 **Q17. Please summarize your testimony?**

16 A17. Providing safe and reliable gas service is essential for Delmarva's
17 customers. In order for Delmarva to continue to provide safe and reliable gas
18 service, and to continue the positive initiatives and investments in the gas system,
19 it is critically important that the financial integrity of Delmarva be maintained.
20 The gas base rate increase the Company is asking the Commission to authorize in
21 this case is necessary for Delmarva to earn a reasonable return on equity and to
22 continue to make the important investments in the gas distribution system on
23 behalf of its customers.

1 **Q18. Does this conclude your Direct Testimony?**

2 A18. Yes, it does.

Delmarva Power & Light Company
Overall Rate of Return
September 30, 2012
Delaware

		DPL Delaware	
<u>Type of Capital</u>	<u>Ratios</u>	<u>Cost Rate</u>	<u>Weighted Cost Rate</u>
Long-Term Debt	51.22%	4.91%	2.51%
Common Equity	<u>48.78%</u>	10.25%	<u>5.00%</u>
Total	<u>100.00%</u>		<u>7.51%</u>

Delmarva Power & Light Company
Capital Structure and Capitalization Ratios
September 30, 2012
Delaware

Type of Capital	Actual	
	September 30, 2012	
	Amount (\$)	Ratios
Long-Term Debt	1,023,230,000	
Unamortized Net Discount	(1,808,969)	
Unamortized Debt Issuance Costs	(5,729,392)	
Total Long-Term Debt	1,015,691,639	51.22%
Common Equity	967,443,845	48.78%
Total	1,983,135,485	100.00%

Delmarva Power & Light Company
Weighted Cost of Debt
September 30, 2012
Delaware
January 0, 1900

January 0, 1900								
Issue	Coupon Rate	Maturity	Offering Date	Current			Effective Cost Rate	Annual Net Cost
				Principal Amount Outstanding	Unamortized Debt Issuance Expense	Unamortized (Premium)/Discount		
<u>First Mortgage Bonds</u>								
Total First Mortgage Bonds	6.40%	12/1/2013	11/25/2008	\$250,000,000	\$512,069	\$136,012	6.63%	\$16,535,156
	4.00%	6/1/2042	6/26/2012	\$250,000,000	\$2,645,095	\$1,371,477	4.09%	\$10,061,526
				\$500,000,000	\$3,157,165	\$1,507,489		\$26,596,681
<u>Unsecured Notes</u>								
Total Unsecured Notes	5.00%	11/15/2014	11/19/2004	\$100,000,000	\$195,277	\$103,886	5.12%	\$5,104,458
	5.00%	6/1/2015	6/1/2005	\$100,000,000	\$231,288	\$107,638	5.11%	\$5,092,710
	5.22%	12/30/2016	12/20/2006	\$100,000,000	\$304,727	\$0	5.30%	\$5,281,522
				\$300,000,000	\$731,291	\$211,523		\$15,478,690
<u>Tax Exempt Fixed Rate Bonds</u>								
Total Tax Exempt Fixed Rate Bonds	5.40%	2/1/2031	4/1/2010	\$78,400,000	\$1,309,865	\$0	5.55%	\$4,275,141
				\$78,400,000	\$1,309,865	\$0		\$4,275,141
<u>Tax-Exempt Variable Rate Bonds</u>								
Total Tax Exempt Variable Rate Bonds	0.34%	10/1/2017	10/1/1987	\$8,000,000	\$52,382	\$0	0.48%	\$38,250
	0.34%	10/1/2017	9/28/1988	\$18,000,000	\$46,838	\$0	0.39%	\$70,879
	0.41%	10/1/2028	10/14/1993	\$15,500,000	\$131,831	\$0	0.47%	\$71,493
	0.33%	10/1/2029	10/12/1994	\$30,000,000	\$182,958	\$0	0.37%	\$111,775
	0.42%	7/1/2024	7/28/1999	\$22,330,000	\$94,062	\$0	0.55%	\$122,063
	0.50%	7/1/2024	7/28/1999	\$11,000,000	\$0	\$0	0.59%	\$64,500
				\$104,830,000	\$508,071	\$0		\$478,960
<u>Medium-Term Notes Series C</u>								
Total Medium-Term Notes Series C	7.58%	2/1/2017	2/10/1997	\$2,000,000	\$2,866	\$0	7.65%	\$152,852
	7.56%	2/1/2017	2/18/1997	\$12,000,000	\$17,194	\$0	7.63%	\$914,673
	6.81%	1/9/2018	1/9/1998	\$4,000,000	\$270	\$7,898	6.88%	\$274,622
	7.61%	12/2/2019	2/12/1997	\$12,000,000	\$2,669	\$82,059	7.68%	\$914,924
	7.72%	2/1/2027	2/7/1997	\$10,000,000	\$0	\$0	7.78%	\$778,476
				\$40,000,000	\$22,999	\$89,957		\$3,035,547
Total Long-Term Debt Balance - ACTUAL				\$1,023,230,000	\$5,729,392	\$1,808,969	4.91%	\$49,865,018

Delmarva Power & Light Company
Effective Cost Rate
Long-Term Debt
September 30, 2012
Delaware

Issue	Coupon Rate	Maturity	Offering Date	Original			Net Amount Per Unit	Yield to Maturity
				Principal Amount Issued	(Premium)/ Discount	Expense of Issuance		
<u>First Mortgage Bonds</u>								
	6.40%	12/1/2013	11/25/2008	\$250,000,000	\$512,500	\$1,925,105	\$99.02	6.63%
	4.00%	6/1/2042	6/26/2012	\$250,000,000	\$1,377,500	\$2,506,150	\$98.45	4.09%
<u>Unsecured Notes</u>								
	5.00%	11/15/2014	11/19/2004	\$100,000,000	\$0	\$928,224	\$99.07	5.12%
	5.00%	6/1/2015	6/1/2005	\$100,000,000	\$0	\$853,194	\$99.15	5.11%
	5.22%	12/30/2016	12/20/2006	\$100,000,000	\$0	\$600,000	\$99.40	5.30%
<u>Tax Exempt Fixed Rate Bonds</u>								
	5.40%	2/1/2031	4/1/2010	\$78,400,000	\$0	\$1,406,618	\$98.21	5.55%
<u>Tax-Exempt Variable Rate Bonds</u>								
	0.34%	10/1/2017	10/1/1987	\$8,000,000	\$0	\$315,360	\$96.06	0.48%
	0.34%	10/1/2017	9/28/1988	\$18,000,000	\$0	\$270,107	\$98.50	0.39%
	0.41%	10/1/2028	10/14/1993	\$15,500,000	\$0	\$275,796	\$98.22	0.47%
	0.33%	10/1/2029	10/12/1994	\$30,000,000	\$0	\$440,787	\$98.53	0.37%
	0.42%	7/1/2024	7/28/1999	\$22,330,000	\$0	\$669,900	\$97.00	0.55%
	0.50%	7/1/2024	7/28/1999	\$11,000,000	\$0	\$220,000	\$98.00	0.59%
<u>Medium-Term Notes Series C</u>								
	7.58%	2/1/2017	2/10/1997	\$2,000,000	\$0	\$15,000	\$99.25	7.65%
	7.56%	2/1/2017	2/18/1997	\$15,000,000	\$0	\$112,500	\$99.25	7.63%
	6.81%	1/9/2018	1/9/1998	\$33,000,000	\$0	\$247,500	\$99.25	6.88%
	7.61%	12/2/2019	2/12/1997	\$12,000,000	\$0	\$90,000	\$99.25	7.68%
	7.72%	2/1/2027	2/7/1997	\$30,000,000	\$0	\$225,000	\$99.25	7.78%

Testimony of Robert M. Collacchi

DELMARVA POWER & LIGHT COMPANY
BEFORE THE
DELAWARE PUBLIC SERVICE COMMISSION
DIRECT TESTIMONY OF ROBERT M. COLLACCHI
DOCKET NO. _____

1 **Q1. Please state your name and position.**

2 A1. My name is Robert M. Collacchi and I am Director of Gas Operations &
3 Engineering. I am testifying on behalf of Delmarva Power & Light Company (Delmarva
4 or the Company).

5 **Q2. What are your responsibilities in your role as Director of Gas Operations &**
6 **Engineering?**

7 A2. I am responsible for all aspects of reliability, safety, planning, engineering,
8 construction, and operations and maintenance for the regulated gas utility serving
9 123,335 customers in Delmarva's New Castle County service territory.

10 **Q3. Please state your educational background and professional experience.**

11 A3. I earned a Bachelor of Science degree in Business Management from Wilmington
12 College in 1988. After graduation from Wilmington College, I began working for
13 Delmarva in 1988. I completed a Wharton Executive Course in May of 2002. I have
14 worked for Delmarva and its affiliates for 24 years in various positions including,
15 Service Department Dispatcher, Gas Supply Analyst, Manager, Gas Trading, Director,
16 Gas Supply. From 1996 to June of 2010, I served in various roles in Conectiv Energy
17 including Director, Asset Management; Vice President, Asset Management; and Vice
18 President, Wholesale Operations. Prior to my current position, I was responsible for
19 supply of Standard Offer Service for Delmarva's and Potomac Electric's electricity

1 customers, Basic Generation Service for Atlantic City Electric's customers and natural
2 gas supply for Delmarva's natural gas customers.

3 **Q4. What is the purpose of your Direct Testimony?**

4 A4. The purpose of my testimony is to support the Company's Application for an
5 increase in Gas Base Rates. I will provide a brief overview of the Company's gas
6 delivery business; discuss the Company's investments since the last rate case required to
7 maintain a safe and reliable system and to meet new load; provide a brief update on the
8 Company's Advanced Metering Infrastructure (AMI) project for Gas that constitutes the
9 deployment of Interface Management Units (IMU); sponsor the design day demand; and
10 discuss the Company's proposed main extension tariff changes. I will also support
11 certain Minimum Filing Requirements.

12 This testimony was prepared by me or under my direct supervision and control.
13 The source documents for my testimony are Company records and public documents. I
14 also rely on my personal knowledge and experience.

15 **Q5. Why is the Company seeking a rate increase at this time?**

16 A5. The requested increase in revenues is due in significant part to the Company's
17 continued investment to ensure a safe and reliable gas transmission and distribution
18 system. The Company continuously assesses the integrity of its infrastructure and makes
19 investments to both maintain and enhance the safety and reliability of the system. Further
20 investments in gas system reliability are required to address aging infrastructure in our
21 territory as well as the promulgation of new regulations enacted in compliance with the
22 "Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011". In addition, the
23 Company must invest in its infrastructure in response to new regulations and

1 recommendations by the Federal Department of Transportation (DOT), the Pipeline and
2 Hazardous Materials Administration (PHMSA), the National Transportation Safety
3 Board (NTSB), applicable provisions of the Delaware Code and the Delaware Public
4 Service Commission Pipeline Safety Program.

5 Significant investments in the gas distribution system are being made to
6 rehabilitate and replace cast iron piping in Delmarva's territory. The Cast Iron
7 Replacement Program, which supports Delmarva's Distribution Integrity Management
8 Program (DIMP), created on August 2, 2011, and maintained in response to DOT Code,
9 Part 192, Subpart P, requires that all gas distribution companies document their periodic
10 comprehensive review and prioritization of risks normally associated with natural gas
11 distribution systems. Continued administration of the DIMP is an ongoing expense for
12 the Company. In addition to the DIMP, Delmarva is in the forefront of compliance with
13 evolving requirements associated with excavation safety, operational activities in high
14 traffic areas and working in confined space locations to operate its gas system. Each of
15 these requirements involves continued financial commitments, ultimately benefitting the
16 Company's efforts to provide a safe and reliable natural gas system for its customers and
17 for the public at large.

18 On average, Delmarva has invested approximately \$12 million each year as part
19 of its pipe rehabilitation and replacement program. Delmarva has retired, replaced or
20 cathodically protected 94 miles of Unprotected Bare Steel Main (94 miles as of 1985 to
21 less than a mile as of 2011), 107 miles of Unprotected Coated Steel Main (132 miles as
22 of 1985 to 25 miles as of 2011) and approximately 200 miles or 18,464 Steel & Copper
23 Services (51,110 miles as of 1985 to 31,600 miles as of 2011).

1 It is projected that all of Delmarva's cast iron mains will be either rehabilitated or
2 replaced within the next twenty years. Through the pipe rehabilitation and replacement
3 program, Delmarva works closely with other utility companies, municipalities, and
4 government transportation/highway officials to coordinate its work with road or other
5 infrastructure excavation activities. Based on leakage analysis and other continuous
6 surveillance activities, Delmarva promptly responds to lines that are determined to be
7 obsolete. It is important to recognize that much of the rehabilitation and replacement
8 work is located within the City of Wilmington where the costs of construction are high
9 due to the preponderance of paved surfaces. These surfaces increase the cost of both
10 excavation and surface restoration work. Where possible, the Company mitigates and
11 shares the relatively high costs of urban construction by working with state and local
12 governments and the Delaware Department of Transportation (DelDOT) to coordinate
13 Delmarva's work with other utilities that requires construction and replacement of paved
14 surfaces.

15 **Overview of Gas Delivery Business**

16 **Q6. Please provide a brief overview of the Company's gas business.**

17 A6. The Delmarva service area is the northern two-thirds of New Castle County,
18 defined generally as the area north of Boyd's Corner Road. As of the end of December
19 2012, Delmarva will serve 123,335 natural gas customers, of which 113,921 are
20 residential customers. The Company's gas delivery system serving the northern portion
21 of New Castle County consists of approximately 1,934 miles of gas mains fed by four
22 interstate pipelines via interconnections at four major and six minor gate stations.

1 **Company Investments**

2 **Q7. Please summarize the Company's capital investments since the last base rate case**
3 **(Years 2010 and 2011).**

4 A7. The capital investments in gas facilities since the last base rate case are
5 summarized in Schedule (RMC)-1. These investments are set forth in two categories:
6 Reliability and New Load Additions.

7 Since the last base rate case, project costs totaling \$38.6 million as set forth in
8 Schedule (RMC)-1 were incurred for reliability investments arising from annual load
9 forecast studies and reliability analyses. Main, service and safety replacements are the
10 result of continued pipeline surveillance and performance improvement programs.
11 Liquefied Natural Gas (LNG) plant capital expenditures are primarily the result of
12 planned equipment replacements and upgrades to improve operational performance and
13 safety systems. In addition, meter replacement costs associated with planned periodic
14 testing to maintain measurement reliability and accuracy have been incurred.

15 During the same period, new load projects totaling \$7.7 million were related
16 directly to installations of mains and services for residential and commercial customers.

17 **Q8. Please summarize the Company's Gas Delivery Capital Expenditure Program for**
18 **2012.**

19 A8. The 2012 Gas Delivery Capital Expenditures forecast for nine months actual and
20 three months budget (9&3) is presented as Schedule (RMC)-2. The 9&3 forecast
21 represents a mix of \$22.0 million in expenditures for reliability projects (80 %) and \$5.7
22 million in expenditures for growth (20%).

1 The reliability projects include \$8.1 million for implementing safe
2 management and replacement of cast iron, plastic and steel distribution mains, the
3 replacement of steel transmission mains and the protection of steel mains. Another
4 \$6.2 million is planned for service line replacements. An additional \$0.9 million is
5 for replacements related to minor highway projects, and \$1.8 million is planned for
6 the purchase and installation of gas meters. The majority of planned gas meter
7 purchases are related to scheduled replacements. Further, \$3.0 million is planned for
8 the installation of gas IMUs, and \$1.1 million is planned for reliability replacements
9 related to system capacity and pressure regulation. Approximately \$ 0.9 million is
10 planned for gate and regulator station improvements, Supervisory Control and Data
11 Acquisition (SCADA) communications equipment and LNG Plant replacements and
12 improvements.

13 The \$5.7 million related to new load growth includes \$2.9 million for
14 residential customer additions, \$1.3 million for commercial additions and \$1.5
15 million for approach main and new load regulator projects.

16 **Q9. Please explain the nature of Gas Construction Work In Progress (CWIP) addressed**
17 **by Company Witness Ziminsky.**

18 A9. Gas Delivery is typically engaged in a variety of projects with job durations
19 varying from weeks to months. Schedule 2-F–CWIP by Project, provided as part of the
20 Minimum Filing Requirement (MFR), lists the projects which make up the Construction
21 Work in Progress (CWIP) balance of \$9.6 million for the period ending December 31,
22 2012. The projects include \$8.8 million (91%) for reliability- related projects and \$0.8

1 million (9%) for new load-related work consistent with these categories as discussed
2 earlier in my testimony. In addition to these amounts, there are allocated CWIP balances
3 for Common Plant assets (\$0.1 million) and PHI Service Company assets (\$1.0 million)
4 included in the total rate base of \$10.7 million discussed by Company Witness Ziminsky.

5 The CWIP included in rate base reflects an assessment of the listed projects
6 determined to be used and useful and which have been closed to plant, or are expected to
7 be closed to plant prior to completion of this rate case. As of the time of this filing, \$2.8
8 million of reliability and \$1.1 million of new load projects have been closed to plant and
9 \$7.7 are expected to be closed by December 31, 2012. The Company will provide an
10 update during the course of this proceeding.

11 **Q10. Please explain the nature of the Company's Reliability-related Plant Closings for**
12 **2013 addressed by Company Witness Ziminsky.**

13 A10. The 2013 planned reliability costs, excluding AMI-related costs, total \$18.3
14 million as discussed in Company Witness Ziminsky in his post test period closing
15 adjustment. This total includes \$7.2 million for replacement, improvement and retirement
16 of cast iron, plastic and steel distribution mains, the replacement of steel transmission
17 mains and the protection of steel mains. Another \$6.6 million is planned for service line
18 replacements. An additional \$0.4 million is for replacements related to minor highway
19 projects, and \$2.2 million is planned for the purchase and installation of gas meters.
20 Further, \$0.8 million is planned for reliability replacements related to system capacity
21 and pressure regulation. Approximately \$1.1 million is planned for gate and regulator
22 station improvements and LNG Plant replacement and improvements.

1 **Advanced Metering Infrastructure Project**

2 **Q11. Please provide the status of the IMU deployment and activation in Delaware**
3 **which Company Witness Ziminsky addresses from a ratemaking perspective.**

4 A11. Approximately 32% of gas IMUs have been installed as of October 31, 2012.
5 Of this number, 3% have been optimized and activated for over the air meter reading.
6 The remainder of the Gas IMU deployment and activation is expected to be complete
7 by the third quarter of 2013. This project has been delayed due to a number of product
8 and technical issues. The Company and the product vendors and installers continue to
9 work together to resolve these issues in order to meet the 2013 target date for
10 completion and activation of the IMUs.

11 **Q12. What are the capabilities of the selected IMU technology?**

12 A12. When integrated into Delmarva's existing Advanced Metering operational and
13 information technology infrastructure and business processes, IMUs will be able to
14 provide automated meter reading of the gas meters.

15 **Design Day Demand**

16 **Q13. Has the Company prepared an estimate of the Delmarva Gas Delivery design day**
17 **demand?**

18 A13. Yes. I am sponsoring the Company's preparation of the estimated design day
19 demand which I provided to Company Witness Normand for his cost of service study.
20 This estimate was prepared using a National Association of Regulatory Commissioners
21 methodology.

Q14. Please explain the results and components of the design day demand estimate contained in Schedule (RMC) –3.

A14. The calculated design day demand estimate is 191,637 MCF. The details of this estimate are provided in Schedule (RMC)-3. The Residential Class component is 2,464 MCF, the Residential Space Heat Class component is 95,392 MCF, and the General Class is 44,801 MCF. The total firm customers with Contract (MDQ) based rates total 48,981 MCF. The components are: General 5,988 MCF; Medium 13,104 MCF; Large 23,514 MCF; and LVG-QFCP-RC 6,375 MCF.

Proposed Main Extension Tariff Changes

Q15. Why is the Company proposing a main extension tariff change?

A15. The Company believes that more residents of the State of Delaware should have choices in meeting their energy needs and that those choices should be based upon the current state of energy markets in Delaware. Many residential neighborhoods and commercial developments in Delmarva's territory were built during a period when extending natural gas mains was prohibited by federal regulation due to a perceived natural gas supply shortage. Clearly, both the natural gas supply situation, and the associated market prices, have changed rather dramatically over the past several years. As a result, increasing numbers of Delaware residents and small business owners have approached the Company seeking to lower their energy costs. Under the current Tariff, however, extending gas service to customers who have requested service has proven too expensive for the majority of our customers. The Company believes a revised main extension tariff will make gas service more affordable for residents and small business owners seeking to make such change and will reduce their energy costs and the

1 environmental impact of their energy use. These are benefits that accrue to all residents
2 of the State, and not just those seeking service from the Company.

3 **Q16. Please explain the Company's main extension tariff change proposal.**

4 A16. The Company's main extension tariff proposal simplifies the current process
5 and attempts to address the cost effectiveness concerns that have been raised by our
6 customers. Due to gas equipment efficiency improvements, such as furnaces and hot
7 water heaters, since the last tariff revision in 1997, today's average non-fuel revenue
8 per customer of \$406 is virtually the same as it was in 1997 when it was \$405.59. On
9 the other hand, the materials and construction costs of installing gas mains have
10 increased since 1997. Because the cost of gas main installation has increased but the
11 revenue per customer has not, the revenue payback/rate of return method from the
12 1997 tariff no longer works for our customers. Very few customers qualify for
13 service extensions under the current method. The result has been that customers who
14 could benefit significantly from this lower cost cleaner fuel do not have this option.
15 As a result, many customers have not been able to experience cost savings offered by
16 natural gas nor have the environmental benefits from reduced emissions been
17 realized.

18 To address this situation, Delmarva is proposing a tariff change for residential
19 extensions in existing subdivisions that includes providing a 100 foot main extension
20 per requesting customer similar to that in Chesapeake Utilities' approved tariff. In
21 other words, customers who wish to have natural gas service extended to their
22 premises would be provided with the first 100 feet of necessary main without charge.
23 After the first 100 feet, the contribution from a new customer would be \$40.23 per

1 foot of main which is based on the average cost of extension for the past three years.

2 One reason for the changes for residential extensions in existing subdivisions is to
3 provide a method for customer contribution that is easier to understand. In addition,
4 providing the first 100 foot of main extension to the customer without charge is more
5 on par with the average amount of feet of main per existing customer. This method
6 would better equalize the amount of plant installed for existing customers versus what
7 will be installed for new customers.

8 Delmarva is also proposing a change to clearly permit civic or maintenance
9 organizations for existing subdivisions to petition the residents and then act on their
10 behalf as a collective entity regarding the request for the extension. In new
11 subdivisions, there is a single applicant that is a collective entity regarding the request
12 for the extension for all the customers to be served by the extension. It seems
13 reasonable and fair to provide existing subdivisions with the ability to make a single
14 entity extension request on behalf of all the customers to be served by the extension.

15 The proposed tariff change for non-residential extensions includes providing
16 the same 100 foot main extension similar to that proposed for existing residential
17 subdivisions, for many of the same reasons outlined above for residential customers.
18 Many small commercial customers are often of similar load to that of a residential
19 home and would enjoy similar savings as residential customers given the opportunity
20 to convert to gas service. For larger commercial and industrial extensions, the three
21 year revenue test remains unchanged.

Minimum Filing Requirements

1 **Q17. Please list the Minimum Filing Requirements that you are sponsoring.**

2 A17. I am sponsoring the following filing requirements:

3 Schedule B – System Map

4 Schedule C-1 – 5 Year Strategic Natural Gas Supply Plan

5 Schedule 2-F, page 2 - CWIP by project

6

7 **Q18. Does this conclude your Direct Testimony?**

8 A18. Yes, it does.

Project	Description	Year		Grand Total	Reliability	New Load
		2010	2011			
RGACCRUALS	RGACCRUALS:Gas Capital Accruals		271,527	84,466	\$ 63,349	\$ 21,116
RGAMB1	RGAMB1:Regulated Gas AMI Meters Blueprint	(187,061)	549,454	7,219,813	\$ 7,219,813	
RGCR-1	RGCR-1:Gas Service Renewals	6,670,359	6,261,565	11,858,321	\$ 11,858,321	
RGCR-11	RGCR-11:Transmission Valve Projects	5,596,756	15,669	15,669	\$ 15,669	
RGCR-14	RGCR-14:Plastic Main Renewal	161,524	289,255	450,779	\$ 450,779	
RGCR-15	RGCR-15:Gas Reimbursable	10,869	49,543	60,412	\$ 60,412	
RGCR-2	RGCR-2:Cast Iron Renewals	4,508,005	4,273,021	8,781,026	\$ 8,781,026	
RGCR-3	RGCR-3:Steel Main Renewals	1,480,446	1,048,064	2,528,510	\$ 2,528,510	
RGCR-6	RGCR-6:Cathodic Protection	99,439	19,451	118,890	\$ 118,890	
RGEF-2	RGEF-2:Gas Equipment & Facilities	280,214	1,129,895	1,410,109	\$ 1,410,109	
RGHW-1	RGHW-1:Minor Highway Relocates	829,547	563,558	1,393,105	\$ 1,393,105	
RGMR-1	RGMR-1:Meters	494,447	-	494,447	\$ 494,447	
RGMR-2	RGMR-2:Gas Meter Purchases	891,279	1,350,766	2,242,045	\$ 2,242,045	
RGMRBGAS1	RGMRBGAS1:Gas AMI Equipment	3,675		3,675	\$ 3,675	
RGNL-1	RGNL-1:Approach Main S.I.	145,922	388,203	534,125	\$ 534,125	
RGNL-2	RGNL-2:Established Residential M&S	1,631,702	2,263,792	3,895,494	\$ 3,895,494	
RGNL-3	RGNL-3:Commerical M&S	597,105	912,042	1,509,147	\$ 1,509,147	
RGNL-4	RGNL-4:New Development M&S	917,183	658,912	1,576,095	\$ 1,576,095	
RGNL-5	RGNL-5:Regulators S&I	41,371	170,888	212,259	\$ 212,259	
RGPF-1	RGPF-1:Gas Plant & Facilities	147,790	-	147,790	\$ 147,790	
RGUP-1	RGUP-1:Capacity & Regulator	627,035	819,203	1,446,238	\$ 1,446,238	
RITG19	RITG19:IT Projects - Gas Delivery	310,864	(88,299)	222,565	\$ 222,565	
RITG20	RITG20:GAS IT	11,381	-	11,381	\$ 11,381	
UOIDBMR1	UOIDBMR1:AMI Auto Deployment Software DPL Gas	126,303	(25,351)	100,952	\$ 100,952	
Grand Total		25,396,157	20,921,158	46,317,315	\$ 38,565,402	\$ 7,751,912
Average Annual				23,158,657	83%	17%

Gas Delivery 2012 Capital Expenditures
9 Actual + 3 Forecast
Schedule (RMC) - 2

Line No.	Project	Description	1/31/12 Actual	2/28/12 Actual	3/31/12 Actual	4/30/12 Actual	5/31/12 Actual	6/30/12 Actual	7/31/12 Actual	8/31/12 Actual	9/30/12 Actual	10/31/12 Forecast	11/30/12 Forecast	12/31/12 Forecast	Total
1	Production	RGFF-2 Gas Equipment & Facilities	31,671	96,067	35,693	120,522	129,456	56,560	41,303	196,098	86,466	27,322	21,019	20,797	862,974
2	Distribution	RGAMB-1 Regulated Gas AMI Meters Blueprint	14,129	11,006	42,874	5,517	15,358	16,519	143,852	-214,928	512,385	640,000	713,000	1,062,591	2,963,303
3	Distribution	RGCR-1 Gas Service Renewals	401,531	623,495	698,548	522,437	380,441	899,821	458,885	919,654	443,263	317,000	258,000	276,925	6,200,000
4	Distribution	RGCR-2 Cast Iron Renewals	237,851	187,651	278,378	558,911	709,851	1,113,148	394,264	1,132,265	394,972	528,201	239,070	225,436	6,000,000
5	Distribution	RGCR-3 Steel Main Renewals	3,423	64,889	41,844	16,165	38,363	10,535	27,123	182,337	-16,158	114,756	55,732	121,001	660,000
6	Distribution	RGCR-6 Cathodic Protection	112,918	53,252	971	5,791	1,600	1,869	7,221	2,389	2,440	4,089	5,718	13,965	211,623
7	Distribution	RGCR-12 Transmission Renewals											303,774		303,774
8	Distribution	RGCR-14 Plastic Main Renewal	39,734	25,190	38,239	17,200	25,282	50,815	15,439	31,306	4,999	84,297	49,367	17,108	398,976
9	Distribution	RGCR-15 Gas Reimbursable	3,268	-	9,028	1,278	(1,064)	15,290	-4,918	-5,081	21,666	7,935	15,281	29,863	92,546
10	Distribution	RGACCRUALS Gas Capital Accruals	91,778	(77,969)	235,689	449,201	(16,146)	(108,018)	(503,807)	24,458	499,266		(136,412)		458,010
11	Distribution	RGHW-1 Minor Highway Relocates		56,324	-8,582	48,232	91,745	51,350	24,780	246,160	150,723	76,424	88,336	24,478	850,000
12	Distribution	RGMR-2 Gas Meter Purchases	210,880	47,880	207,632	475	384,732	266,721	225,736	71,018	2,022	86,123	171,061	180,452	1,854,732
13	Distribution	RGUP-1 Capacity & Regulator	19,446	121,720	81,183	154,230	76,577	144,586	12,376	53,540	190,009	75,248	132,514	78,611	1,150,000
14	General	RTG19 IT Projects - Gas Delivery	3,366	-	-	-	-	-	-	-	-	-	-	-	3,366
15															
16															
17															
18	New Business	RGNL-1 Approach Main	2,101	5,742	4,585	1,670	3,948	7,566	150	3,663	14,351	395,619	341,675	233,950	1,015,000
19	New Business	RGNL-2 Established Residential M&S	189,019	235,128	195,224	127,071	152,200	224,089	162,408	191,817	173,962	28,518	72,931	47,633	1,800,000
20	New Business	RGNL-3 Commercial M&S	27,343	49,741	56,584	39,366	41,041	268,466	405,055	181,166	96,028	19,984	36,424	18,802	1,240,000
21	New Business	RGNL-4 New Development M&S	48,598	135,941	79,689	106,016	258,912	60,594	81,773	160,595	46,690	55,871	44,300	23,021	1,100,000
22	New Business	RGNL-5 Regulators S&I	20,413	72,596	44,225	38,678	17,895	140,881	2212	57,592	77,301	10,286	10053	7868	500,000
23															
24															
25															
26															
		Total New Business	287,474	499,148	380,287	312,801	471,996	701,596	651,598	594,833	408,332	510,278	505,383	331,274	5,655,000
		Total Gas	1,457,471	1,708,653	2,051,794	2,212,760	2,309,181	3,220,792	1,493,802	3,234,049	2,700,385	2,471,673	2,421,843	2,381,901	27,664,304

NOTES:

Reliability Projects for cast iron ,plastic, steel transmission and distribution - line 4 to 10

Gas Service Renewals - line 3

Minor Highway Projects - line 11

Gas Meter Purchases line 12

Gas AMI - IMU's line 2

System Capacity and pressure regulation - line 13

Gate, regulator stations, SCADA, and LNG line 1

Residential Customer Additions line 19 and 21

Commercial Additions - line 20

Approach Main and Regulator Projects - line 18 and 22

Schedule (RMC) - 3

Delmarva Power Design Day Demand Estimate
A

	B	C	C	E	
	RES	RSH	GG	MDQ	TOTAL
1 Billed Sales Jan - Feb 2012 (MCF)	68,983	2,416,494	1,183,494		
2 Average Customers Jan-Feb 2012	10,140	104,234	9,415		
3 August 2012 Monthly Sales (MCF)	8,433	110,192	92,971		
4 August Average Daily Usage (MCF) = Line 3/31	272	3,555	2,999		
5 Customers - August 2012	9,929	104,210	9,264		
6 Non-Heating Usage (MCF) = Line 4 / Line 5 x (31 + 29) x Line 2	16,667	213,349	182,873		
7 Heating Usage (MCF) = Line 1 - Line 6	52,316	2,203,145	1,000,621		
8 Billed Heating Degree Days Jan-Feb 2012	1,608	1,608	1,608		
9 Heating Usage per Degree Day per Customer (=Line 7/ Line 8 / Line 2)	0.00321	0.01314	0.06609		
10 Design Degree Days	65	65	65		
11 Peak Day Heating Usage = Line 2 x Line 9 x Line 10	2,115	89,057	40,448		
12 Peak Day Non Heating Usage = Line 6 / (31+ 29)	278	3,556	3,048		
13 Design Day Contribution (MCF)	2,393	92,613	43,496		138,502
14 Maximum Daily Quantity (MDQ) for Contract customers (MCF) 1/2012				47,554	40,665
15 Design Contribution for Core Customers (MCF)	2,393	92,613	43,496	47,554	186,056
16 System Losses And Unaccounted For: tariff 3 %	72	2,778	1,305	1,427	5,582
17 Design Day Contribution including Loss and Unaccounted For	2,464	95,392	44,801	48,981	191,637
18 Design Day Contribution per Customer (MCF) =Line 16 / Line 2	0.24303	0.91517	4.75844		
19 Total Design Day Demand (MCF)					191,637

General	5,988
Medium	13,104
Large	23,514
LVG-QFCP-RC	6,375
	48,981

Testimony of Robert B. Hevert

DELMARVA POWER & LIGHT COMPANY
BEFORE THE
DELAWARE PUBLIC SERVICE COMMISSION
DIRECT TESTIMONY OF ROBERT B. HEVERT
DOCKET NO. _____

I. Introduction

Q1. Please state your name, affiliation and business address.

A1. My name is Robert B. Hevert. I am Managing Partner of Sussex Economic Advisors, LLC (Sussex). My business address is 161 Worcester Road, Suite 503, Framingham, Massachusetts 01701.

Q2. On whose behalf are you submitting this testimony?

A2. I am submitting this direct testimony (Direct Testimony) before the Delaware Public Service Commission (Commission) on behalf of Delmarva Power & Light Company (Delmarva Power or the Company), a wholly-owned operating subsidiary of Pepco Holdings, Inc. (PHI).

Q3. Please describe your educational background.

A3. I hold a Bachelor's degree in Business and Economics from the University of Delaware, and an MBA with a concentration in Finance from the University of Massachusetts. I also hold the Chartered Financial Analyst designation.

Q4. Please describe your experience in the energy and utility industries.

A4. I have worked in regulated industries for over twenty five years, having served as an executive and manager with consulting firms, a financial officer of a publicly-traded natural gas utility (at the time, Bay State Gas Company), and an analyst at a telecommunications utility. In my role as a consultant, I have advised numerous energy and utility clients on a wide range of financial and economic issues,

1 including corporate and asset-based transactions, asset and enterprise valuation,
2 transaction due diligence, and strategic matters. As an expert witness, I have
3 provided testimony in approximately 100 proceedings regarding various financial and
4 regulatory matters before numerous state utility regulatory agencies and the Federal
5 Energy Regulatory Commission. A summary of my professional and educational
6 background, including a list of my testimony in prior proceedings, is included in
7 Attachment A to my Direct Testimony.

8 **II. Purpose and Overview of Testimony**

9 **Q5. What is the purpose of your Direct Testimony?**

10 A5. The purpose of my Direct Testimony is to present evidence and provide a
11 recommendation regarding the Company's Cost of Equity (sometimes referred to as
12 the Return on Equity or ROE) and to provide an assessment of the capital structure to
13 be used for ratemaking purposes, as proposed in the Direct Testimony of Company
14 Witness McGowan. My analyses and conclusions are supported by the data
15 presented in Schedule (RBH)-1 through Schedule (RBH)-12, which have been
16 prepared by me or under my direction.

17 **Q6. What are your conclusions regarding the appropriate Cost of Equity and capital**
18 **structure for the Company?**

19 A6. My analyses indicate that the Company's Cost of Equity currently is in the
20 range of 10.00% to 10.75%. Based on the quantitative and qualitative analyses
21 discussed throughout my Direct Testimony, I conclude that the Company's proposed
22 ROE of 10.25% is reasonable and appropriate. As to its proposed capital structure,
23 which includes 48.78% common equity and 51.22% long-term debt, I conclude that

1 the Company's proposal is consistent with the capital structures that have been in
2 place over the last three years at comparable operating utility companies. In light of
3 its ongoing need to access external capital, and given the consistency of its proposal
4 with similarly-situated utility companies, I conclude that the Company's proposed
5 capital structure is reasonable and appropriate.

6 **Q7. Please provide a brief overview of the analyses that led to your ROE**
7 **recommendation.**

8 A7. Equity analysts and investors use multiple methods to develop their return
9 requirements for investments. In order to develop my ROE recommendation, I relied
10 on three widely-accepted approaches: the Quarterly Growth, Constant Growth, and
11 Multi-Stage forms of the Discounted Cash Flow (DCF) model, the Capital Asset
12 Pricing Model (CAPM), and the Bond Yield Plus Risk Premium approach.

13 My recommendations and conclusions consider the risks associated with (1)
14 the Company's comparatively small size; (2) the lack of revenue stabilization
15 mechanisms employed by the Company relative to the proxy group; and (3) flotation
16 costs associated with equity issuances. While I did not make any explicit adjustments
17 to my ROE estimates for those factors, I did take them into consideration in
18 determining the range in which the Company's Cost of Equity likely falls.

19 **Q8. How is the remainder of your Direct Testimony organized?**

20 A8. The remainder of my Direct Testimony is organized as follows:

- 21 • Section III – Discusses the regulatory guidelines and financial
22 considerations pertinent to the development of the cost of capital;

- 1 • Section IV – Explains my selection of the proxy group used to develop
- 2 my analytical results;
- 3 • Section V – Explains my analyses and the analytical bases for my
- 4 ROE recommendation;
- 5 • Section VI – Provides a discussion of specific business risks that have
- 6 a direct bearing on the Company's Cost of Equity;
- 7 • Section VII – Highlights the current capital market conditions and
- 8 their effect on the Company's Cost of Equity;
- 9 • Section VIII – Addresses the reasonableness of the Company's
- 10 proposed capital structure; and
- 11 • Section IX – Summarizes my conclusions and recommendations.

12 **III. Regulatory Guidelines and Financial Considerations**

13 **Q9. Please provide a brief summary of the guidelines established by the United**

14 **States Supreme Court (the Court) for the purpose of determining the ROE.**

15 A9. The Supreme Court established the guiding principles for establishing a fair

16 return for capital in two cases: (1) *Bluefield Water Works and Improvement Co. v.*

17 *Public Service Comm'n of West Virginia (Bluefield)*; and (2) *Federal Power Comm'n*

18 *v. Hope Natural Gas Co. (Hope)*. In those cases, the Court recognized that the fair

19 rate of return on equity should be (1) comparable to returns investors expect to earn

20 on other investments of similar risk, (2) sufficient to assure confidence in the

21 company's financial integrity, and (3) adequate to maintain and support the

22 company's credit and to attract capital.

1 **Q10. Does Delaware precedent provide similar guidance?**

2 A10. Yes. In Order No. 8011, for example, the Commission stated:

3 The requirement of a fair return recognizes that utilities compete
4 for capital with other investments. Accordingly, the return which a
5 utility investor can expect should be commensurate with the
6 returns that could be expected on other comparable-risk
7 investments. See J. BONBRIGHT, A. DANIELSON, and D.
8 KAMERSCHEN, *Principles of Public Utility Rates*, at 316 (2d ed.
9 1988). In keeping with this, the United States and Delaware
10 Supreme Courts have held that the return to a utility should be
11 sufficient to assure confidence in the utility's financial integrity, to
12 maintain its credit, and to attract capital. *Federal Power*
13 *Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944);
14 *Bluefield Water Works and Improvement Co. v. Public Service*
15 *Commission of West Virginia*, 262 U.S. 579 (1923); *Application of*
16 *Wilmington Suburban Water Co.*, 211 A.2d 602 (Del. 1965).¹

17 Based on those standards, the authorized ROE should provide the Company
18 with the opportunity to earn a fair and reasonable return and should enable efficient
19 access to external capital under a variety of market conditions.

20 **IV. Proxy Group Selection**

21 **Q11. As a preliminary matter, why is it necessary to select a group of proxy**
22 **companies to determine the Cost of Equity for Delmarva Power?**

23 A11. Since the ROE is a market-based concept, and Delmarva Power is not a
24 publicly traded entity, it is necessary to establish a group of comparable publicly-
25 traded companies to serve as its "proxy." Even if Delmarva Power were a publicly
26 traded entity, short-term events could bias its market value during a given period of
27 time. A significant benefit of using a proxy group is that it serves to moderate the
28 effects of anomalous, temporary events associated with any one company.

¹ Public Service Commission of the State of Delaware, Docket No. 09-414, Order No. 8011, *In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Changes* (Filed September 18, 2009), August 9, 2011, at 112.

1 **Q12. Does the selection of a proxy group suggest that analytical results will be tightly**
2 **clustered around average (i.e., mean) results?**

3 A12. No. For example, the DCF approach, defines the Cost of Equity as the sum of
4 the expected dividend yield and projected long-term growth. Despite the care taken
5 to ensure risk comparability, market expectations with respect to future risks and
6 growth opportunities will vary from company to company. Therefore, even within a
7 group of similarly situated companies, it is common for analytical results to reflect a
8 seemingly wide range. Consequently, at issue is how to estimate a Company's ROE
9 from within that range. That determination necessarily must consider a wide range of
10 both empirical and qualitative information.

11 **Q13. Please provide a summary profile of Delmarva Power.**

12 A13. Delmarva Power is a wholly-owned operating subsidiary of PHI (NYSE:
13 POM). The Company provides natural gas supply and distribution service to
14 approximately 124,000 customers in northern Delaware.² PHI's current long-term
15 issuer credit rating from Standard & Poor's (S&P) is BBB+ (outlook: Stable), Baa3
16 (outlook: Stable) from Moody's Investors Service (Moody's), and BBB (outlook:
17 Stable) from FitchRatings (Fitch). Delaware Power currently is rated BBB+
18 (outlook: Stable) by S&P, Baa2 (outlook: Stable) by Moody's, and BBB+ (outlook:
19 Stable) by Fitch.³

20 **Q14. How did you select the companies included in your proxy group?**

21 A14. I began with the universe of companies that Value Line classifies as Electric
22 or Natural Gas Utilities, which includes a group of 60 domestic U.S. utilities, and

² See Pepco Holdings, SEC Form 10-K for the fiscal year ended December 31, 2011, at 9.

³ Source: SNL Financial

1 applied the following screening criteria:

- 2 • I excluded companies that do not consistently pay quarterly cash dividends;
- 3 • All of the companies in my proxy group have been covered by at least two
- 4 utility industry equity analysts;
- 5 • All of the companies in my proxy group have investment grade senior
- 6 unsecured bond and/or corporate credit ratings from S&P;
- 7 • To ensure that my proxy group represents natural gas distribution operations, I
- 8 included companies with at least 60.00% of consolidated net operating income
- 9 derived from regulated natural gas utility operations; and
- 10 • I eliminated companies that are currently known to be party to a merger, or
- 11 other significant transaction.

12 **Q15. Did you include PHI in your analysis?**

13 A15. No. In order to avoid the circular logic that would otherwise occur, it has
14 been my consistent practice to exclude the subject company (or its parent) from the
15 proxy group. In any event, the percentage of operating income derived from
16 Delmarva Power's regulated gas operations relative to the combined entity would not
17 have met my 60.00% threshold.

18 **Q16. What companies met those screening criteria?**

19 A16. The criteria discussed above resulted in a proxy group of the following nine
20 companies:

Table 1: Proxy Group Screening Results

Company	Ticker
AGL Resources	GAS
Atmos Energy	ATO
Laclede Group	LG
New Jersey Resources	NJR
Northwest Natural Gas	NWN
Piedmont Natural Gas	PNY
South Jersey Industries	SJI
Southwest Gas	SWX
Washington Gas Light	WGL

Q17. Do you believe that a proxy group of nine companies is sufficiently large?

A17. Yes. The analyses performed in estimating the ROE are more likely to be representative of the subject utility's Cost of Equity to the extent that the chosen proxy companies are fundamentally comparable to the subject utility. Because all analysts use some form of screening process to arrive at a proxy group, the group, by definition, is not randomly drawn from a larger population. Consequently, there is no reason to place more reliance on the quantitative results of a larger proxy group simply by virtue of the resulting larger number of observations.

Moreover, because I am using market-based data, my analytical results will not necessarily be tightly clustered around a central point. Results that may be somewhat dispersed, however, do not suggest that the screening approach is inappropriate or the results less meaningful. In my view, including companies whose fundamental comparability is tenuous at best simply for the purpose of expanding the number of observations does not add relevant information to the analysis.

V. Cost of Equity Estimation

Q18. Please briefly discuss the ROE in the context of the regulated rate of return.

A18. Regulated utilities primarily use common stock and long-term debt to finance their capital investments. The overall rate of return (ROR) weighs the costs of the individual sources of capital by their respective book values. While the cost of debt and cost of preferred stock can be directly observed, the Cost of Equity is market-based and, therefore, must be estimated based on observable market information.

Q19. How is the required ROE determined?

A19. I estimated the ROE using analyses based on market data to quantify a range of investor expectations of required equity returns. By their very nature, quantitative models produce a range of results from which the market required ROE must be estimated. As discussed throughout my Direct Testimony, that estimation must be based on a comprehensive review of relevant data and information, and does not necessarily lend itself to a strict mathematical solution. Consequently, the key consideration in determining the ROE is to ensure that the overall analysis reasonably reflects investors' view of the financial markets in general and the subject company (in the context of the proxy companies) in particular.

Quarterly Growth DCF Model

Q20. Are DCF models widely used in regulatory proceedings?

A20. Yes. In my experience, the DCF model is widely recognized in regulatory proceedings, as well as in financial literature. Nonetheless, neither the DCF nor any other model should be applied without considerable judgment in the selection of data and the interpretation of results.

1 **Q21. Please describe the DCF approach.**

2 A21. The DCF approach is based on the theory that a stock's current price
3 represents the present value of all expected future cash flows. In its simplest form,
4 the DCF model expresses the Cost of Equity as the sum of the expected dividend
5 yield and long-term growth rate, and is expressed as follows:

$$6 \quad P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \dots + \frac{D_\infty}{(1+k)^\infty} \quad \text{Equation [1]}$$

7 where P represents the current stock price, $D_1 \dots D_\infty$ represent expected future
8 dividends, and k is the discount rate, or required ROE. Equation [1] is a standard
9 present value calculation that can be simplified and rearranged into the familiar form:

$$10 \quad k = \frac{D_0 (1+g)}{P} + g \quad \text{Equation [2]}$$

11 Equation [2] often is referred to as the "Constant Growth DCF" model, in which the
12 first term is the expected dividend yield and the second term is the expected long-
13 term annual growth rate.

14 In essence, the DCF model assumes that the total return received by investors
15 includes the dividend yield, and the rate of growth. As explained below, under the
16 model's assumptions, the rate of growth equals the rate of capital appreciation. That
17 is, the model assumes that the investor's return is the sum of the dividend yield and
18 the increase in the stock price. However, most dividend or distribution-paying
19 companies, including utilities, pay dividends on a quarterly (as opposed to an annual)
20 basis. The yield component of the Quarterly Growth DCF model, therefore, accounts
21 for the quarterly payment of dividends. Thus, the Quarterly Growth DCF model
22 incorporates investors' expectation of the quarterly payment of dividends, and the

1 associated quarterly compounding of those dividends as they are reinvested at
2 investors' required ROE. As noted by Dr. Roger Morin:

3 Clearly, given that dividends are paid quarterly and that the
4 observed stock price reflects the quarterly nature of dividend
5 payments, the market-required return must recognize quarterly
6 compounding, for the investor receives dividend checks and
7 reinvests the proceeds on a quarterly schedule ... The annual DCF
8 model inherently understates the investors' true return because it
9 assumes all cash flows received by investors are paid annually.⁴

10 **Q22. How is the dividend yield component of the Quarterly Growth DCF model**
11 **calculated?**

12 A22. The dividend yield is calculated such that it incorporates the time value of
13 money associated with quarterly compounding. To do so, *D* component of the
14 Constant Growth DCF model is replaced with the following equation:

$$D = d_1(1+k)^{.75} + d_2(1+k)^{.50} + d_3(1+k)^{.25} + d_4(1+k)^0 \quad \text{Equation [3]}$$

16 where:

17 d_1, d_2, d_3, d_4 = expected quarterly dividends over the coming year

18 k = the required Return on Equity

19 Due to the fact that the required ROE (k) is a variable in the dividend calculation, the
20 Quarterly Growth DCF model is solved in an iterative fashion.

21 **Q23. What market data did you use to calculate the dividend yield in your Quarterly**
22 **Growth DCF model?**

23 A23. To calculate the expected dividends over the coming year for the proxy group
24 companies (*i.e.*, d_1, d_2, d_3 , and d_4), I obtained the last four paid quarterly dividends for
25 each company, and multiplied them by one plus the growth rate (*i.e.*, $1 + g$). For the

⁴ Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006 at 344.

1 P_0 component of the dividends yield, I obtained the closing stock prices over the 30-,
2 90-, and 180-trading days ended October 12, 2012 for each company in the proxy
3 group.

4 **Q24. Why did you use three averaging periods to calculate an average stock price?**

5 A24. I did so to ensure that the model's results are not skewed by anomalous events
6 that may affect stock prices on any given trading day. At the same time, the
7 averaging period should be reasonably representative of expected capital market
8 conditions over the long term. In my view, using 30-, 90-, and 180-day averaging
9 periods reasonably balances those concerns.

10 **Q25. Is it important to select appropriate measures of long-term growth in applying**
11 **the DCF model?**

12 A25. Yes. In its Constant Growth form, the DCF model (*i.e.*, as presented in
13 Equation [2] above) assumes a single growth estimate in perpetuity. This same
14 assumption is made in the Quarterly Growth DCF model. Accordingly, in order to
15 reduce the long-term growth rate to a single measure, one must assume a fixed payout
16 ratio, and the same constant growth rate for earnings per share (EPS), dividends per
17 share, and book value per share. Since dividend growth can only be sustained by
18 earnings growth, the model should incorporate a variety of measures of long-term
19 earnings growth. That can be accomplished by averaging those measures of long-
20 term growth that tend to be least influenced by capital allocation decisions that
21 companies may make in response to near-term changes in the business environment.
22 Since such decisions may directly affect near-term dividend payout ratios, estimates
23 of earnings growth are more indicative of long-term investor expectations than are

dividend growth estimates. Therefore, for the purposes of the Quarterly Growth DCF model, growth in EPS represents the appropriate measure of long-term growth.

Q26. Please summarize the findings of academic research on the appropriate measure for estimating equity returns using the DCF model.

A26. The relationship between various growth rates and stock valuation metrics has been the subject of much academic research.⁵ As noted over 40 years ago by Charles Phillips in The Economics of Regulation:

For many years, it was thought that investors bought utility stocks largely on the basis of dividends. More recently, however, studies indicate that the market is valuing utility stocks with reference to total per share earnings, so that the earnings-price ratio has assumed increased emphasis in rate cases.⁶

Philips' conclusion continues to hold true. Subsequent academic research has clearly and consistently indicated that measures of earnings and cash flow are strongly related to returns, and that analysts' forecasts of growth are superior to other measures of growth in predicting stock prices.⁷ For example, Vander Weide and Carleton state that, "[our] results...are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions."⁸ Other research specifically notes the importance of analysts' growth estimates in determining the Cost of Equity, and in

⁵ See, for example, Harris, Robert, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management, Spring 1986.

⁶ Charles F. Phillips, Jr., The Economics of Regulation, Revised Edition, 1969, Richard D. Irwin, Inc., at 285.

⁷ See, for example, Christofi, Christofi, Lori and Moliver, *Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate*, Journal of Investing (Spring 1999); Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, 21 (Summer 1992); and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management, Spring 1988.

⁸ Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management, Spring 1988.

1 the valuation of equity securities. Dr. Robert Harris noted that “a growing body of
2 knowledge shows that analysts’ earnings forecast are indeed reflected in stock
3 prices.” Citing Cragg and Malkiel, Dr. Harris notes that those authors “found that the
4 evaluations of companies that analysts make are the sorts of ones on which market
5 valuation is based.”⁹ Similarly, Brigham, Shome and Vinson noted that “evidence in
6 the current literature indicates that (i) analysts’ forecasts are superior to forecasts
7 based solely on time series data; and (ii) investors do rely on analysts’ forecasts.”¹⁰

8 To that point, the research of Carleton and Vander Weide demonstrates that
9 earnings growth projections have a statistically significant relationship to stock
10 valuation levels, while dividend growth rates do not.¹¹ Those findings suggest that
11 investors form their investment decisions based on expectations of growth in
12 earnings, not dividends. Consequently, earnings growth not dividend growth is the
13 appropriate estimate for the purpose of the Constant Growth DCF model.

14 **Q27. Please describe the Retention Growth estimate as applied in your Quarterly**
15 **Growth DCF model.**

16 A27. The Retention Growth model, which is a generally recognized and widely
17 taught method of estimating long-term growth, is an alternative approach to the use of
18 analysts’ earnings growth estimates. In essence, the model is premised on the
19 proposition that a firm’s growth is a function of its expected earnings, and the extent
20 to which it retains earnings to invest in the enterprise. In its simplest form, the model

⁹ Robert S. Harris, *Using Analysts’ Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management, Spring 1986.

¹⁰ Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility’s Cost of Equity*, Financial Management, Spring 1985.

¹¹ See Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management, Spring 1988.

represents long-term growth as the product of the retention ratio (*i.e.*, the percentage of earnings not paid out as dividends, referred to below as (“b”) and the expected return on book equity (referred to below as “r”). Thus, the simple “b x r” form of the model projects growth as a function of internally generated funds. That form of the model is limiting, however, in that it does not provide for growth funded from external equity.

The “br + sv” form of the Retention Growth estimate used in my DCF analysis is meant to reflect growth from both internally generated funds (*i.e.*, the “br” term) and from issuances of equity (*i.e.*, the “sv” term). The first term, which is the product of the retention ratio (*i.e.*, “b”, or the portion of net income not paid in dividends) and the expected Return on Equity (*i.e.*, “r”) represents the portion of net income that is “plowed back” into the Company as a means of funding growth. The “sv” term is represented as:

$$\left(\frac{m}{b} - 1\right) \times \text{Growth rate in Common Shares} \quad \text{Equation [4]}$$

where $\frac{m}{b}$ is the Market-to-Book ratio.

In this form, the “sv” term reflects an element of growth as the product of (a) the growth in shares outstanding, and (b) that portion of the market-to-book ratio that exceeds unity. As shown in Schedule (RBH)-3, all of the components of the Retention Growth model can be derived from data provided by Value Line.

Q28. How did you calculate the high and low DCF results?

A28. I calculated the proxy group mean high DCF results by using the maximum EPS growth rate as reported by Value Line, Zack’s, First Call and the Retention

Growth estimate for each proxy group company in combination with the dividend yield for each of the proxy group companies. The proxy group mean high results then reflect the average of the maximum DCF results for the proxy group as a whole. I used a similar approach to calculate the proxy group mean low results using instead the minimum of the Value Line, Zack's, First Call and the Retention Growth estimate for each proxy group company.

Q29. What are the results of your Quarterly Growth DCF analysis?

A29. My Quarterly Growth DCF results are summarized in Table 2, below (*see also* Schedule (RBH)-1).

Table 2: Quarterly Growth DCF Results¹²

	<i>Mean Low</i>	<i>Mean</i>	<i>Mean High</i>
30-Day Average	7.51%	9.35%	11.37%
90-Day Average	7.55%	9.39%	11.42%
180-Day Average	7.62%	9.46%	11.49%

Constant Growth DCF Model

Q30. What assumptions are required for the Constant Growth DCF model?

A30. The Constant Growth DCF model assumes: (1) a constant average annual growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate. Under those assumptions, dividends, earnings, book value, and the stock price all grow at the same, constant rate.

¹² DCF results presented in Table 2 are unadjusted (*i.e.*, prior to any adjustment for flotation costs).

1 **Q31. What market data did you use to calculate the dividend yield component of your**
2 **DCF model?**

3 A31. The dividend yield is based on the proxy companies' current annualized
4 dividend, and average closing stock prices over the 30-, 90-, and 180-trading day
5 periods as of October 12, 2012.

6 **Q32. Did you make any adjustments to the dividend yield to account for periodic**
7 **growth in dividends?**

8 A32. Yes. Since utilities increase their quarterly dividends at different times
9 throughout the year, it is reasonable to assume that dividend increases will be evenly
10 distributed over calendar quarters. Given that assumption, it is appropriate to
11 calculate the expected dividend yield by applying one-half of the long-term growth
12 rate to the current dividend yield.¹³ That adjustment ensures that the expected
13 dividend yield is representative of the coming twelve-month period, and does not
14 overstate the dividends to be paid during that time.

15 **Q33. What growth rates did you use in your Constant Growth DCF model analysis?**

16 A33. I used the same projected EPS growth rates as well as the Retention Growth
17 estimate applied in my Quarterly Growth DCF model analysis.

18 **Q34. Please summarize your inputs to the Constant Growth DCF model.**

19 A34. I used the following inputs for the price and dividend terms:

- 20 1. The average daily closing prices for the 30-, 90-, and 180-trading days
21 ended October 12, 2012, for the term P_0 ; and
- 22 2. The annualized dividend per share as of October 12, 2012, for the term

¹³ See Schedule (RBH)-2.

D_0 .

I then calculated my DCF results using each of the following growth terms:

1. The Zacks consensus long-term earnings growth estimates;
2. The First Call consensus long-term earnings growth estimates;
3. The Value Line long-term earnings growth estimates; and
4. An estimate of Retention Growth.

Q35. What are the results of your Constant Growth DCF analysis?

A35. My Constant Growth DCF results are summarized in Table 3, below (*see also* Schedule (RBH)-2).

Table 3: Constant Growth DCF Results¹⁴

	<i>Mean Low</i>	<i>Mean</i>	<i>Mean High</i>
30-Day Average	7.38%	9.16%	11.12%
90-Day Average	7.42%	9.20%	11.16%
180-Day Average	7.49%	9.27%	11.23%

Multi-Stage DCF Model

Q36. What other forms of the DCF model have you used?

A36. In order to address certain limiting assumptions underlying the Constant Growth form of the DCF model, I also considered the results of the Multi-Stage (three-stage) DCF Model. The Multi-Stage model, which is an extension of the Constant Growth form, enables the analyst to specify growth rates over three distinct stages. As with the Constant Growth form of the DCF model, the Multi-Stage form defines the Cost of Equity as the discount rate that sets the current price equal to the

¹⁴ DCF results presented in Table 3 are unadjusted (*i.e.*, prior to any adjustment for flotation costs).

discounted value of future cash flows. Unlike the Constant Growth form, however, the Multi-Stage model must be solved in an iterative fashion.

Q37. Please generally describe the structure of your Multi-Stage model.

A37. As noted above, the model sets the subject company's stock price equal to the present value of future cash flows received over three "stages". In the first two stages, "cash flows" are defined as projected dividends. In the third stage, "cash flows" equal both dividends and the expected price at which the stock will be sold at the end of the period (*i.e.*, the "terminal price"). I calculated the terminal price based on the Gordon model, which defines the price as the expected dividend divided by the difference between the Cost of Equity (*i.e.*, the discount rate) and the long-term expected growth rate. In essence, the terminal price is defined by the present value of the remaining "cash flows" in perpetuity. In each of the three stages, the dividend is the product of the projected earnings per share and the expected dividend payout ratio. A summary description of the model is provided in Table 4 (below).

Table 4: Multi-Stage DCF Structure

Stage	0	1	2	3
Cash Flow Component	Initial Stock Price	Expected Dividend	Expected Dividend	Expected Dividend + Terminal Value
Inputs	Stock Price Earnings Per Share (EPS) Dividends Per Share (DPS)	Expected EPS Expected DPS	Expected EPS Expected DPS	Expected EPS Expected DPS Terminal Value
Assumptions	30-, 90-, and 180-day average stock price	EPS Growth Rate Payout Ratio	Growth Rate Change Payout Ratio Change	Long-term Growth Rate Long-term Payout Ratio

1 **Q38. What are the analytical benefits of your three-stage model?**

2 A38. The primary benefits relate to the flexibility provided by the model's
3 formulation. Since the model provides the ability to specify near, intermediate and
4 long-term growth rates, for example, it avoids the sometimes limiting assumption that
5 the subject company will grow at the same, constant rate in perpetuity. In addition,
6 by calculating the dividend as the product of earnings and the payout ratio, the model
7 enables analysts to reflect assumptions regarding the timing and extent of changes in
8 the payout ratio to reflect, for example, increases or decreases in expected capital
9 spending, or transition from current payout levels to long-term expected levels. In
10 that regard, because the model relies on multiple sources of earnings growth rate
11 assumptions, it is not limited to a single source, such as Value Line, for all inputs, and
12 mitigates the potential bias associated with relying on a single source of growth
13 estimates.¹⁵

14 The model also enables the analyst to assess the reasonableness of the inputs
15 and results by reference to certain market-based metrics. For example, the stock price
16 estimate can be divided by the expected earnings per share in the final year to
17 calculate an average Price to Earnings (P/E) ratio. Similarly, the terminal P/E ratio
18 can be divided by the terminal growth rate to develop a Price to Earnings Growth
19 (PEG) ratio. To the extent that either the projected P/E or PEG ratios are inconsistent
20 with either historical or expected levels, it may indicate incorrect or inconsistent
21 assumptions within the balance of the model.

¹⁵ See, for example, Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, 21 (Summer 1992).

1 **Q39. Please summarize your inputs to the Multi-Stage DCF model.**

2 A39. I applied the Multi-Stage model to the proxy group described earlier in my
3 Direct Testimony. My assumptions with respect to the various model inputs are
4 described in Table 5 (below).

5 **Table 5: Multi-Stage DCF Model Assumptions**

Stage	Initial	First	Transition	Terminal
Stock Price	30-, 90-, and 180-day average stock price as of October 12, 2012			
Earnings Growth	2011 actual EPS escalated by Period 1 growth rate	EPS growth as average of (1) Value Line; (2) Zacks; (3) First Call; (4) Retention Growth rates	Transition to Long-term GDP growth	Long-term GDP growth
Payout Ratio		Value Line company-specific	Transition to long-term industry payout ratio	Long-term expected payout ratio
Terminal Value				Expected dividend in final year divided by solved Cost of Equity less long-term growth rate

6

7 **Q40. How did you calculate the long-term Gross Domestic Product (GDP) growth**
8 **rate?**

9 A40. The long-term growth rate of 5.77% is based on the real GDP growth rate of

1 3.24% from 1929 through 2011,¹⁶ and an inflation rate of 2.45%.¹⁷ The GDP growth
2 rate is calculated as the compound growth rate in the chain-weighted GDP for the
3 period from 1929 through 2011. The rate of inflation of 2.45% is a compound annual
4 forward rate starting in ten years (*i.e.*, 2022, which is the beginning of the terminal
5 period) and is based on the 30-day average projected inflation based on the spread
6 between yields on long-term nominal Treasury Securities and long-term Treasury
7 Inflation Protected Securities, known as the “TIPS spread”.

8 In essence, my real GDP growth rate projection is based on the assumption
9 that absent specific knowledge to the contrary, it is reasonable to assume that over
10 time, real GDP growth will revert to its long-term mean. Furthermore, since
11 estimating the Cost of Equity is a market-based exercise, it is important to reflect the
12 sentiments and expectations of investors to the extent possible. In that important
13 respect, the TIPS spread represents the collective views of investors regarding long-
14 term inflation expectations. Equally important, by using forward yields, we are able
15 to infer the level of long-term inflation expected by investors as of the terminal period
16 of the Multi-Stage model (that is, ten years in the future).

17 **Q41. What were your specific assumptions with respect to the payout ratio?**

18 A41. As noted in Table 5, for the first two periods, I relied on the first year and
19 long-term projected payout ratios reported by Value Line¹⁸ for each of the proxy
20 group companies. I then assumed that by the end of the second period (*i.e.*, the end of

¹⁶ See Bureau of Economic Analysis, September 27, 2012 update.

¹⁷ See Board of Governors of the Federal Reserve System, Table H.15 Selected Interest Rates.

¹⁸ As reported in the Value Line Investment Survey as “All Div’ds to Net Prof.”

year 10), the payout ratio will converge to the industry expected ratio of 69.79%.¹⁹

Discounted Cash Flow Model Results

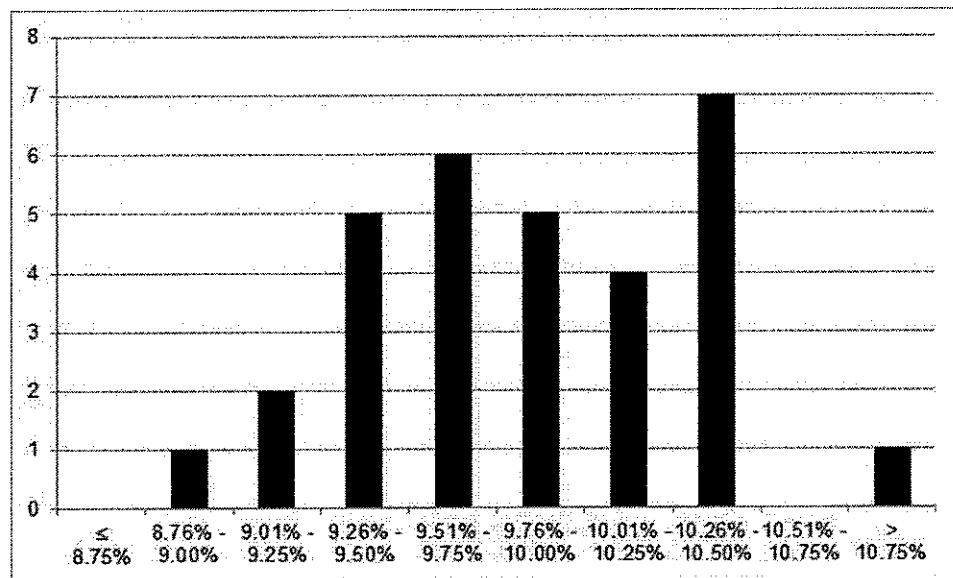
Q42. Have you considered the mean low results of your DCF models in determining your recommended ROE range?

A42. No. The mean low results of my DCF models are far below any reasonable estimation of the Company's ROE. In fact, of the 945 rate cases in which an authorized ROE has been disclosed since 1980, there has been only one instance in which the authorized ROE was below 9.00% for a natural gas utility in any jurisdiction.²⁰ That authorized ROE, 8.83%, is still approximately 120 to 145 basis points higher than the mean low results of my Quarterly Growth DCF and Constant Growth DCF models. In fact, from January 1, 2011 through October 12, 2012, the median authorized ROE was 10.00%. Chart 1 (below), shows that the most frequently authorized ROE over that period was between 10.25% and 10.50%.

¹⁹ Source: Bloomberg Professional

²⁰ Source: SNL Financial

Chart 1: Frequency of Natural Gas Authorized ROEs
(January 1, 2011 – October 12, 2012)



In that regard, Baird Equity Research has also noted that, “[i]nvestors view a 10.0% authorized ROE as an acceptable floor. Authorized ROEs materially below that level are typically viewed negatively by investors.”²¹ As such, I did not consider the mean low results from the three DCF models when determining the appropriate ROE for Delmarva Power.

Q43. If you do not believe the mean low results of your DCF models are reasonable, why have you provided them throughout your Direct Testimony?

A43. While I do not believe any weight should be given to the mean low DCF results, I believe it is important to provide transparency in the presentation of analyses. As such, I have presented the mean low results, which reflect the converse calculation of the mean high results.

²¹ Baird Equity Research, *Utilities: Initial Publication of Baird’s Regulatory Toolkit*, September 20, 2011, at 3.

Q44. Please summarize the results of your DCF analyses.

A44. Table 6 (below) (see also Schedule (RBH)-1, Schedule (RBH)-2 and Schedule (RBH)-4) presents the results of the Quarterly Growth, Constant Growth and Multi-Stage DCF analyses. Setting aside the low results, the Quarterly Growth DCF produces a range of results from 9.35% to 11.49%. The Constant Growth DCF model produces a range of results from 9.16% to 11.23%. The Multi-Stage DCF analysis produces a range of results from 9.98% to 10.99%.

Table 6: Summary of DCF Model Results²²

	<i>Mean Low</i>	<i>Mean</i>	<i>Mean High</i>
<i>Quarterly Growth DCF Results</i>			
30-Day Average	7.51%	9.35%	11.37%
90-Day Average	7.55%	9.39%	11.42%
180-Day Average	7.62%	9.46%	11.49%
<i>Constant Growth DCF Results</i>			
30-Day Average	7.38%	9.16%	11.12%
90-Day Average	7.42%	9.20%	11.16%
180-Day Average	7.49%	9.27%	11.23%
<i>Multi-Stage DCF Results</i>			
	<i>Low</i>	<i>Mean</i>	<i>High</i>
30-Day Average	9.26%	9.98%	10.89%
90-Day Average	9.28%	10.02%	10.92%
180-Day Average	9.33%	10.10%	10.99%

Q45. Did you undertake any additional analyses to support your recommendation?

A45. Yes. As noted earlier, I also applied the CAPM and Risk Premium analyses in estimating the Company's Cost of Equity.

²² DCF results presented in Table 6 are unadjusted (i.e., prior to any adjustment for flotation costs).

1 **CAPM Analysis**

2 **Q46. Please briefly describe the general form of the CAPM analysis.**

3 A46. The CAPM analysis is a risk premium approach that estimates the Cost of
 4 Equity for a given security as a function of a risk-free return plus a risk premium (to
 5 compensate investors for the non-diversifiable or “systematic” risk of that security).
 6 As shown in Equation [5], the CAPM is defined by four components, each of which
 7 theoretically must be a forward-looking estimate:

$$8 \quad k = r_f + \beta(r_m - r_f) \quad \text{Equation [5]}$$

9 where:

10 k = the required market ROE for a security;

11 β = the Beta coefficient of that security;

12 r_f = the risk-free rate of return; and

13 r_m = the required return on the market as a whole.

14 In Equation [5], the term $(r_m - r_f)$ represents the Market Risk Premium.²³
 15 According to the theory underlying the CAPM, since unsystematic risk can be
 16 diversified away by adding securities to their investment portfolio, investors should
 17 be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is
 18 measured by the Beta coefficient, which is defined as:

$$19 \quad \beta_j = \frac{\sigma_j}{\sigma_m} \times \rho_{j,m} \quad \text{Equation [6]}$$

20 Where σ_j is the standard deviation of returns for company “j,” σ_m is the standard
 21 deviation of returns for the broad market (as measured, for example, by the S&P 500

²³ The Market Risk Premium is defined as the incremental return of the market over the risk-free rate.

1 Index), and $\rho_{j,m}$ is the correlation of returns in between company j and the broad
2 market. The Beta coefficient therefore represents both relative volatility (*i.e.*, the
3 standard deviation) of returns, and the correlation in returns between the subject
4 company and the overall market.

5 Intuitively, higher Beta coefficients indicate that the subject company's
6 returns have been relatively volatile, and have moved in tandem with the overall
7 market. Consequently, if a company has a Beta coefficient of 1.00, it is as risky as
8 the market and does not provide any diversification benefit.

9 **Q47. Has the CAPM been affected by recent economic conditions?**

10 A47. Yes. For example, the risk-free rate, " r_f " is represented by the yield on long-
11 term U.S. Treasury securities. During periods of increased equity market volatility,
12 investors tend to allocate their capital to low-risk securities such as Treasury bonds,
13 thereby bidding down the yield on those securities. In addition, since the 2008
14 Lehman Brothers bankruptcy filing, the Federal Reserve has focused on maintaining
15 low long-term interest rates. However, the capital markets continue to change by
16 some measures quite significantly. For example, over the 90 trading days ended
17 October 12, 2012, the 30-year Treasury yield ranged from a low of 2.46% to a high of
18 3.09%. In addition (and as discussed later in my Direct Testimony), the Equity Risk
19 Premium is not constant, and tends to move in the opposite direction as changes in
20 interest rates occur. Consequently, the CAPM results can be relatively volatile.

21 **Q48. With those observations in mind, what assumptions did you include in your**
22 **CAPM analysis?**

23 A48. Since utility assets represent long-term investments, I used two different

estimates of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds (*i.e.*, 2.87%); and (2) the near-term projected 30-year Treasury yield (*i.e.*, 3.15%).²⁴

Q49. Why have you relied upon the 30-year Treasury yield for your CAPM analysis?

A49. In determining the security most relevant to the application of the CAPM, it is important to select the term (or maturity) that best matches the life of the underlying investment. Natural gas utilities typically are long-duration investments and as such, the 30-year Treasury yield is more suitable for the purpose of calculating the Cost of Equity.

Q50. What Market Risk Premium did you use in your CAPM analysis?

A50. Because the model is forward-looking, I developed two forward-looking estimates of the Market Risk Premium. The first approach uses the market required return, less the current 30-year Treasury bond yield. To estimate the market required return, I calculated the average ROE based on the Constant Growth DCF model. To do so, I relied on data from Bloomberg and Capital IQ, respectively. For both Bloomberg and Capital IQ, I calculated the average expected dividend yield (using the same one-half growth rate assumption described earlier) and combined that amount with the average projected earnings growth rate to arrive at the average DCF result. I then subtracted the current 30-year Treasury yield from that amount to arrive at the market DCF-derived *ex-ante* Market Risk Premium estimate. The results of those two calculations are provided in Schedule (RBH)-5.

²⁴ See Blue Chip Financial Forecasts, Vol. 31, No. 10, October 1, 2012, at 2. Consensus projections of the 30-year Treasury yield for the six quarters ending March 2014. As noted above, the 30-year Treasury yield ranged from 2.46% to 3.09% in the 90 trading days ending October 12, 2012.

1 **Q51. Please describe the second approach.**

2 A51. The second approach is based on fundamental financial principle that
 3 investors require higher returns for higher risk. In essence, this approach uses
 4 market-based data to determine whether investors expect future risk to be higher,
 5 lower, or approximately equal to historical market risk. To the extent the market
 6 expects risk to be higher than historical levels, the Market Risk Premium would be
 7 higher than historical levels; the converse also is true.

8 In terms of its application, this approach relies on the Sharpe, which is the
 9 ratio of the long-term average Risk Premium for the S&P 500 Index, to the risk of
 10 that index.²⁵ The formula I used for calculating the Sharpe Ratio is expressed as
 11 follows:

$$12 \quad S_x = \frac{(R_x - R_f)}{\sigma_x} \quad \text{Equation [7]}$$

13 where:

14 S_x = Sharpe Ratio for the S&P 500 Index;

15 R_x = the average return of the S&P 500;

16 R_f = the rate of return of a risk-free security; and

17 σ_x = the standard deviation of the return on the S&P 500.

18 As shown in Schedule (RBH)-5, I calculated the constant Sharpe Ratio as the ratio of
 19 the historical Market Risk Premium of 6.60% (the numerator of Equation [7] above)

²⁵ The Sharpe Ratio is relied upon by financial professionals to assess the incremental return received for holding a risky (*i.e.*, more volatile) asset rather than a risk-free (*i.e.*, less volatile) asset. Risk is measured by the standard deviation of returns. That is, the higher the volatility of returns, the greater the risk.

and the historical standard deviation of 20.30% (the denominator of Equation [7]).²⁶

Equation [7] can be re-arranged as:

$$MRP = S_x \times \sigma_{ex} \quad \text{Equation [8]}$$

Equation [8] basically states that the expected Market Risk Premium is determined by investors' historical required return per unit of risk (the historical Sharpe Ratio) times expected market risk. To measure expected market risk, I used the 30-day average of the Chicago Board Options Exchange's (CBOE) three-month volatility index (*i.e.*, the VXV) and the average of settlement prices over the same 30-day period of futures on the CBOE's one-month volatility index (*i.e.*, the VIX) for March 2013 through May 2013. Both of those indices are market-based, observable measures of investors' expectations regarding future market volatility.

Q52. What Beta coefficients did you use in your CAPM model?

A52. My approach includes the average reported Beta coefficient from Bloomberg and Value Line for each of the proxy group companies. While both of those services adjust their calculated (or raw) Beta coefficients to reflect the tendency of the Beta coefficient to regress to the market mean of 1.00, Value Line calculates the Beta coefficient over a five-year period, while Bloomberg's calculation is based on two years of data.

Q53. What are the results of your CAPM analysis?

A53. The results of my CAPM analysis are summarized in Table 7, below (*see* also

²⁶ The standard deviation is calculated from data provided by Morningstar in its annual Valuation Yearbook. (*See*, Morningstar Inc., Ibbotson SBBI 2012 Valuation Yearbook, Large Company Stocks: Total Returns Table B-1, at 168-169). I recognize that the VIX forward settlement prices are liquid for approximately six to eight months; nonetheless, that data represents a market-based measure of expected volatility that should be considered in estimating the *ex-ante* Market Risk Premium.

Schedule (RBH)-7).

Table 7: Summary of CAPM Results

	<i>Sharpe Ratio Derived Market Risk Premium</i>	<i>Bloomberg Derived Market Risk Premium</i>	<i>Capital IQ Derived Market Risk Premium</i>
<i>Average Bloomberg Beta Coefficient</i>			
Current 30-Year Treasury (2.87%)	8.38%	10.24%	10.19%
Near Term Projected 30-Year Treasury (3.15%)	8.66%	10.52%	10.47%
<i>Average Value Line Beta Coefficient</i>			
Current 30-Year Treasury (2.87%)	7.85%	9.52%	9.48%
Near Term Projected 30-Year Treasury (3.15%)	8.13%	9.80%	9.76%

Bond Yield Plus Risk Premium Approach

Q54. Please generally describe the Bond Yield Plus Risk Premium approach.

A54. This approach is based on the basic financial tenet that, since equity investors bear the residual risk of ownership, their returns are subject to more risk than are the returns to bondholders. As such, equity holders require a premium over the returns available to debt holders. Risk premium approaches, therefore, estimate the Cost of Equity as the sum of an Equity Risk Premium²⁷ and a bond yield. The Equity Risk Premium is the difference between the historical Cost of Equity and long-term Treasury yields. Since we are calculating the risk premium for natural gas utilities, a reasonable approach is to use actual authorized returns for natural gas utilities as the historical measure of the Cost of Equity.

²⁷ The Equity Risk Premium is defined as the incremental return that an equity investment provides over a risk-free rate.

1 **Q55. Please explain how you performed your Bond Yield Plus Risk Premium analysis.**

2 A55. As discussed above, I first defined the Risk Premium as the difference
3 between authorized ROEs and the then-prevailing level of long-term (*i.e.*, 30-year)
4 Treasury yield. I then gathered data from 945 natural gas rate proceedings between
5 January 1, 1980 and October 12, 2012. In addition to the authorized ROE, I also
6 calculated the average period between the filing of the case and the date of the final
7 order (the lag period). In order to reflect the prevailing level of interest rates during
8 the pendency of the proceedings, I calculated the average 30-year Treasury yield over
9 the average lag period (approximately 188 days).

10 Because the data covers a number of economic cycles,²⁸ the analysis also may
11 be used to assess the stability of the Equity Risk Premium. As noted above, the
12 Equity Risk Premium is not constant over time; prior research has shown that it is
13 directly related to expected market volatility, and inversely related to the level of
14 interest rates.²⁹ That finding is particularly relevant given the historically low level of
15 current Treasury yields.

16 **Q56. How did you model the relationship between interest rates and the Equity Risk**
17 **Premium?**

18 A56. The basic method used was regression analysis, in which the observed Equity
19 Risk Premium is the dependent variable, and the average 30-year Treasury yield is the
20 independent variable. Relative to the long-term historical average, the analytical

²⁸ See National Bureau of Economic Research, *U.S. Business Cycle Expansion and Contractions*.

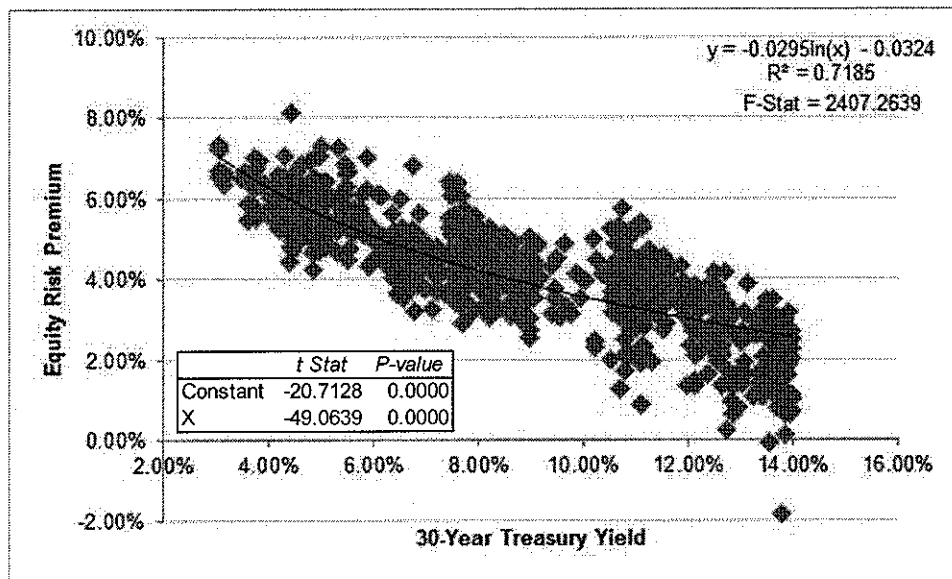
²⁹ See, e.g., Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, *Financial Management*, Summer 1992, at 63-70; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, *Financial Management*, Spring 1985, at 33-45; and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, *Financial Management*, Autumn 1995, at 89-95.

period includes interest rates and authorized ROEs that are quite high during one period (*i.e.*, the 1980s) and that are quite low during another (*i.e.*, the post-Lehman bankruptcy period). To account for that variability, I used the semi-log regression, in which the Equity Risk Premium is expressed as a function of the natural log of the 30-year Treasury yield:

$$RP = \alpha + \beta(\ln(T_{30})) \quad \text{Equation [9]}$$

As shown on Chart 2 (below), the semi-log form is useful when measuring an absolute change in the dependent variable (in this case, the Risk Premium) relative to a proportional change in the independent variable (the 30-year Treasury yield).

Chart 2: Equity Risk Premium



As Chart 2 illustrates, over time there has been a statistically significant, negative relationship between the 30-year Treasury yield and the Equity Risk Premium. Consequently, simply applying the long-term average Equity Risk Premium of 4.34% would significantly understate the Cost of Equity and produce results well below any reasonable estimate. Based on the regression coefficients in

Chart 2, however, the implied ROE is between 10.12% and 10.74% (*see* Schedule (RBH)-8).

VI. Business Risks

Q57. What additional information did you consider in assessing the analytical results noted above?

A57. Because the analytical methods discussed above provide a range of estimates, there are several additional factors that should be taken into consideration when establishing a reasonable range for the Company's Cost of Equity. Those factors include the Company's comparatively small size, the lack of revenue stabilization mechanisms employed by the Company relative to the proxy group, and the costs associated with the flotation of common stock.

Small Size Premium

Q58. Please explain the risk associated with small size.

A58. Both the financial and academic communities have long accepted the proposition that the Cost of Equity for small firms is subject to a "size effect."³⁰ While empirical evidence of the size effect often is based on studies of industries beyond regulated utilities, utility analysts have noted the risks associated with small market capitalizations. Specifically, Public Utilities Fortnightly noted that "[f]or small utilities, investors face additional obstacles, such as smaller customer base, limited financial resources, and a lack of diversification across customers, energy

³⁰ See Mario Levis, *The record on small companies: A review of the evidence*, Journal of Asset Management, March 2002, for a review of literature relating to the size effect.

sources, and geography. These obstacles imply a higher investor return.”³¹

Q59. How does Delmarva Power compare in size to the proxy companies?

A59. Delmarva Power is somewhat smaller than the average for the proxy group companies, both in terms of number of customers and annual revenues. Because Delmarva Power is not a separately traded entity, an estimated stand-alone market capitalization for Delmarva Power must be calculated. Schedule (RBH)-9 shows this calculation. The implied market capitalization is calculated by applying the median market-to-book ratio for the proxy group of 1.61 to the Company’s implied total common stock book equity of \$0.13 billion.³² The implied market capitalization based on that calculation is \$0.21 billion, compared to the proxy group average of \$2.25 billion, which indicates Delmarva Power is significantly smaller than the size of the proxy group average on a market capitalization basis.

Q60. How did you evaluate the risks associated with the Company’s relatively small size?

A60. In its *Risk Premia Over Time Report: 2012*, Morningstar Inc. (Morningstar) calculates the size premium for deciles of market capitalizations relative to the S&P 500 Index. As shown on Schedule (RBH)-9, based on recent market data, the average market capitalization of the proxy group is approximately \$2.25 billion, and the median market capitalization of the proxy group is \$2.03 billion, which correspond to the fifth decile of Morningstar’s market capitalization data. Based on the Morningstar analysis, the proxy group has a size premium of 1.74%. The implied

³¹ Michael Annin, *Equity and the Small-Stock Effect*, Public Utilities Fortnightly, October 15, 1995.

³² Equity value of Delmarva Power estimated from proposed rate base and recommended capital structure.

1 market capitalization for Delmarva Power is approximately \$0.21 billion, which falls
2 within the ninth decile and corresponds to a size premium of 2.80%, suggesting that a
3 size premium as high as 106 basis points (2.80% – 1.74%) is expected for Delmarva
4 Power relative to the proxy group. However, rather than propose a specific
5 adjustment, I considered the effect of small size in determining where the Company's
6 ROE falls within the range of results.

7 ***Revenue Stabilization Mechanisms***

8 **Q61. Have you considered the Company's current tariff mechanisms in your**
9 **assessment of the appropriate ROE?**

10 A61. Yes. As shown in Schedule (RBH)-10, each of the companies in my proxy
11 group employs a fuel adjustment mechanism similar to that which the Company
12 employs, indicating that the Company is comparable to the proxy group in that
13 regard. Again, all of the proxy companies employ some form of revenue stabilization
14 mechanism in at least one of their operating jurisdictions; only one of the proxy
15 companies does not employ a decoupling mechanism in at least one of its operating
16 jurisdictions. Because the Company does not have such a structure in place, my
17 recommended ROE reflects the Company's higher risk relative to the proxy group.

18 ***Flotation Costs***

19 **Q62. What are flotation costs?**

20 A62. Flotation costs are the costs associated with the sale of new issues of common
21 stock. These include out-of-pocket expenditures for preparation, filing, underwriting,
22 and other costs of issuance.

1 **Q63. Are flotation costs part of the utility's invested costs or part of the utility's**
2 **expenses?**

3 A63. Flotation costs are part of capital costs, which are properly reflected on the
4 balance sheet under "paid in capital" rather than current expenses on the income
5 statement. Flotation costs are incurred over time, just as investments in rate base or
6 debt issuance costs. As a result, the great majority of flotation costs are incurred prior
7 to the test year, but remain part of the cost structure during the test year and beyond.

8 **Q64. How did you calculate the flotation cost recovery adjustment?**

9 A64. I modified the DCF calculation to provide a dividend yield that would
10 reimburse investors for issuance costs. My flotation cost adjustment recognizes the
11 costs of issuing equity that were incurred by PHI and the proxy group companies in
12 their most recent two issuances. As shown in Schedule (RBH)-11, an adjustment of
13 0.14% (*i.e.*, 14 basis points) reasonably represents flotation costs for the Company.

14 **Q65. Are you proposing to adjust your recommended ROE by 14 basis points to**
15 **reflect the effect of flotation costs on Delmarva Power's ROE?**

16 A65. No. Rather, I have considered the effect of flotation costs, in addition to the
17 Company's other business risks, in determining where the Company's ROE falls
18 within the range of results.

19 **VII. Capital Market Environment**

20 **Q66. Do economic conditions influence the required cost of capital and required**
21 **return on common equity?**

22 A66. Yes. As discussed in Section V, the models used to estimate the Cost of
23 Equity are meant to reflect, and therefore are influenced by, current and expected

capital market conditions.

Q67. Have you reviewed any specific indices to assess the relationship between current market conditions and investor return requirements?

A67. Yes. I considered two principal measures of capital market conditions: (1) the relationship between Treasury yields and the Cost of Equity; and (2) incremental credit spreads on investment grade utility debt. As discussed below, both of those measures provide information that is relevant to the implementation of models used to estimate the Cost of Equity and in the interpretation of the model results.

Relationship Between Historically Low Treasury Yields and the Cost of Equity

Q68. As a preliminary matter, has the Cost of Equity fallen in tandem with the recent decline in long-term Treasury yields?

A68. No. The fear of taking the risks of equity ownership, for example, has motivated many investors to move their capital into the relative safety of Treasury securities. In doing so, investors have bid down yields to the point that they currently are receiving yields on ten-year Treasury bonds that are below the rate of inflation.³³ In effect, those investors are willing to accept a *negative* real return on Treasury bonds rather than be subject to the risk of owning equity securities.

At the same time, the Federal Reserve's policy of buying longer-dated Treasury securities and selling short-term securities also may have had the effect of lowering long-term Treasury yields. That is, of course, the objective of the Federal

³³ See, for example, *Treasurys Slide After Lackluster Sale*, The Wall Street Journal, August 8, 2012.

1 Reserve's "maturity extension program" which began in June 2011.³⁴ As the Federal

2 Reserve noted:

3 Under the maturity extension program, the Federal Reserve intends
4 to sell or redeem a total of \$667 billion of shorter-term Treasury
5 securities by the end of 2012 and use the proceeds to buy longer-
6 term Treasury securities. This will extend the average maturity of
7 the securities in the Federal Reserve's portfolio.

8 ***

9 By reducing the supply of longer-term Treasury securities in the
10 market, this action should put downward pressure on longer-term
11 interest rates, including rates on financial assets that investors
12 consider to be close substitutes for longer-term Treasury securities.
13 The reduction in longer-term interest rates, in turn, will contribute
14 to a broad easing in financial market conditions that will provide
15 additional stimulus to support the economic recovery.³⁵

16 Consequently, two factors are at work: (1) the continued focus on capital
17 preservation on the part of investors has caused them to reallocate capital to the
18 relative safety of Treasury securities, thereby bidding up the price and bidding down
19 the yield; and (2) the Federal Reserve's continued policy of buying long-term
20 Treasury securities in order to lower the yield. As the Federal Reserve noted in its
21 June 2012 Open Market Committee meeting minutes, the effect of those two factors
22 has been a continued decline in Treasury yields:

23 Yields on longer-dated nominal and inflation-protected Treasury
24 securities moved down substantially, on net, over the intermeeting
25 period. The yield on nominal 10-year Treasury securities reached
26 a historically low level immediately following the release of the
27 May employment report. A sizable portion of the decline in
28 longer-term Treasury rates over the period appeared to reflect
29 greater safe-haven demands by investors, along with some increase
30 in market participants' expectations of further Federal Reserve

³⁴ On September 13, 2012, the Federal Reserve announced that, in addition to continuing the maturity extension program announced in June, they would also begin buying mortgage-backed securities at a pace of \$40 billion per month. See Federal Reserve Press Release, dated September 13, 2012.

³⁵ <http://www.federalreserve.gov/monetarypolicy/maturityextensionprogram.htm>

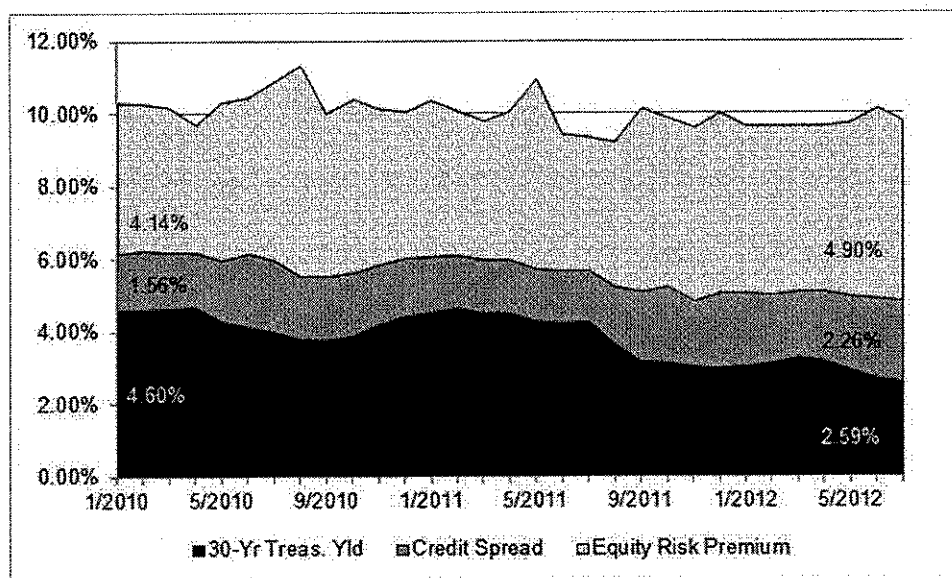
1 balance sheet actions.³⁶

2 At issue, then, is whether those two factors, the continuing tendency of
3 investors to seek the relative safety of long-term Treasury securities and the Federal
4 Reserve's policy of lowering long-term Treasury yields, have caused the required
5 Return on Equity to fall in a fashion similar to the recent decline in interest rates. In
6 large measure, that issue becomes a question of whether the premium required by
7 debt and equity investors also has remained constant as Treasury yields have
8 decreased. To the extent that the risk premium has increased, the higher premium has
9 offset, at least to some degree, the decline in Treasury yields, indicating that the Cost
10 of Equity has not fallen in lock step with the decline in interest rates.

11 One method of performing that analysis is to analyze recently authorized
12 ROEs for natural gas utilities on a "build-up" basis. From that perspective, the
13 required market return represents the sum of: (1) long-term Treasury yields; (2) the
14 credit spread (*i.e.*, the incremental return required by debt investors over Treasury
15 yields; and (3) the Equity Risk Premium (*i.e.*, the incremental return required by
16 equity investors over the cost of debt). As shown on Chart 3 (below), that has been
17 the case; both debt and equity investors have required increased risk premiums as
18 long-term Treasury yields have fallen.

³⁶ Minutes of the Federal Open Market Committee June 19–20, 2012, at 4.

Chart 3: Components of Authorized ROE (2010 – 2012)³⁷



Incremental Credit Spreads

Q69. How have credit spreads been affected by current market conditions?

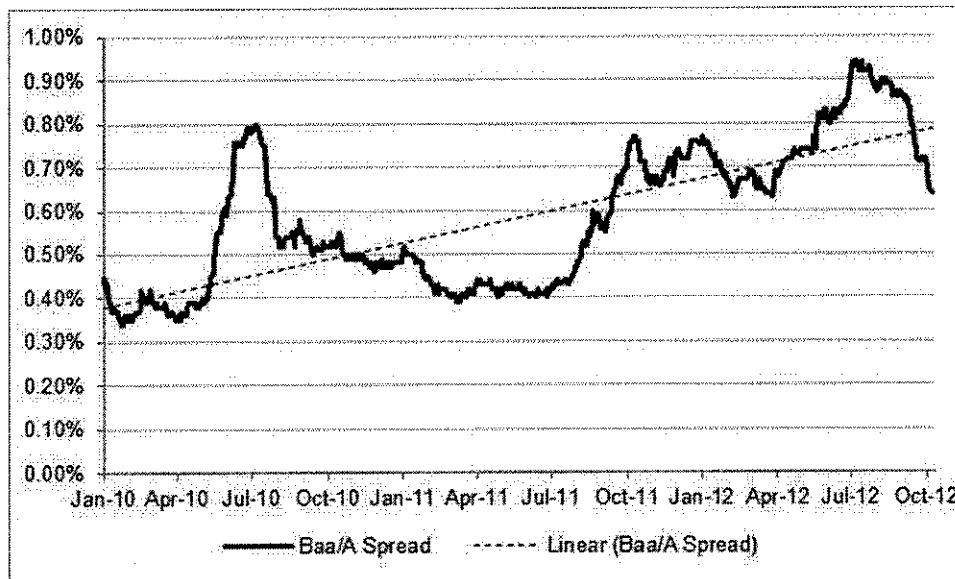
A69. The “credit spread” is the return required by debt investors to take on the risk of lower credit quality. For a given credit rating, the credit spread is measured by reference to a Treasury security of similar tenure. That is, the credit spread on A-rated utility bonds may be measured by reference to the 30-year Treasury Bond yield; the same would be true of Baa-rated securities.³⁸ Lower credit ratings reflect higher levels of risk; therefore, credit spreads typically are higher for lower-rated securities. In that regard, the incremental credit spread (e.g., the difference between the credit spreads associated with A and Baa-rated securities, respectively) is an indication of

³⁷ Sources: Regulatory Research Associates and Bloomberg Professional.

³⁸ The minimum maturity for the bonds in this index is 20 years, with an average of 30 years. Moody’s Long-Term Corporate Bond Yield Averages are derived from pricing data on a regularly replenished population of nearly 100 seasoned corporate bonds in the U.S. market, each with current outstandings over \$100 million. The bonds have maturities as close as possible to 30 years and are dropped from the list if their remaining life falls below 20 years, if they are susceptible to redemption, or if their ratings change. All yields are yield-to-maturity calculated on a semi-annual basis. Each observation is an unweighted average, with Average Corporate yields representing the unweighted average of the corresponding Average Industrial and Average Public Utility observations. See Bloomberg.com.

additional return required by investors to take on additional levels of risk. As Chart 4 demonstrates, since the beginning of 2010, the Moody's Utility Bond Index Baa/A credit spread has steadily increased, indicating that debt investors have increased their marginal return requirements.

Chart 4: Moody's Utility Bond Index Baa-A Credit Spread³⁹

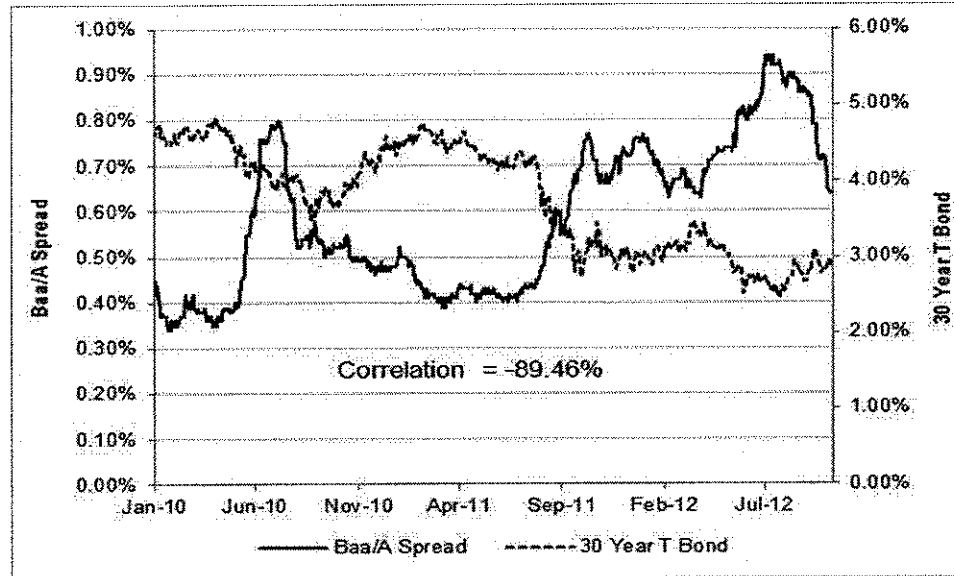


It is also interesting to note that the incremental credit spread has increased as long-term Treasury yields have decreased. In fact, as Chart 5 demonstrates, even since January 2010, changes in the incremental credit spread are negatively correlated with changes in the 30-year Treasury yield.

³⁹

Source: Bloomberg Professional.

Chart 5: Moody's Utility Bond Index Baa-A Credit Spread



Q70. What are the implications of those findings in assessing the Company's Cost of Equity?

A70. The implications are twofold. First, the recent decline in long-term Treasury yields has been accompanied by an increase in the premium required by investors to accept incremental levels of credit risk. That is, the incremental credit spread has increased as the level of Treasury yields have decreased. While that inverse relationship applies to the cost of debt, prior academic research has demonstrated that the Equity Risk Premium likewise is inversely related to interest rates.⁴⁰ Consequently, neither the Cost of Equity nor the cost of debt has decreased in lock step with Treasury yields.

Second, those results also demonstrate the importance of maintaining a

⁴⁰ See Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985, at 33-45; and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, Autumn 1995, at 89-95.

1 financial and credit profile that supports the Company's current BBB+ rating.⁴¹
2 Because incremental credit spreads have steadily increased, the benefit of maintaining
3 a BBB+ rating is greater in the current market than it has been, even over the past two
4 years. That conclusion is consistent with recent findings by Fitch, which noted that:

5 While it appears that the credit spread differential between the
6 rating categories has a relatively small impact during times of
7 economic stability, during recent periods of economic stress, a
8 higher credit rating produces a meaningful difference in credit
9 spreads ... and provides more assured access to capital.⁴²

10 Since regulatory actions affect credit ratings in several, often significant ways,
11 the Commission's decision in this proceeding will directly affect the Company's
12 credit profile and influence its ability to maintain a credit profile that enables
13 continued access to capital at reasonable costs. Given the Company's substantial
14 capital investment plans and external funding needs, the benefits of reliable and cost-
15 effective capital access are significant.

16 **VIII. Capital Structure**

17 **Q71. What is the Company's proposed capital structure?**

18 A71. As described in the Direct Testimony of Company Witness McGowan, the
19 Company has proposed a capital structure comprised of 48.78% common equity and
20 51.22% long-term debt.

21 **Q72. Is there a generally accepted approach to developing the appropriate capital**
22 **structure for a regulated natural gas utility?**

23 A72. Yes. There are a number of approaches to developing the appropriate capital

⁴¹ As noted above, Delaware Power currently is rated BBB+ (outlook: Stable) by S&P, Baa2 (outlook: Stable) by Moody's and BBB+ (outlook: Stable) by Fitch.

⁴² *Fitch's Review of Utility ROE Trends*, FitchRatings, March 22, 2010, at 3.

1 structure. The reasonableness of the approach depends on the nature and
2 circumstances of the subject company. In cases where the subject company does not
3 issue its own securities, it may be reasonable to look to the parent's capital structure
4 or to develop a "hypothetical" capital structure based on the proxy group companies
5 or other industry data. Regardless of the approach taken, however, it is important to
6 consider the resulting capital structure in light of industry norms and investor
7 requirements. That is, the capital structure should enable the subject company to
8 maintain its financial integrity, thereby enabling access to capital at competitive rates
9 under a variety of economic and financial market conditions.

10 **Q73. How does the capital structure affect the Cost of Equity?**

11 A73. The capital structure relates to a company's financial risk, which represents
12 the risk that a company may not have adequate cash flows to meet its financial
13 obligations, and is a function of the percentage of debt (or financial leverage) in its
14 capital structure. In that regard, as the percentage of debt in the capital structure
15 increases, so do the fixed obligations for the repayment of that debt. Consequently,
16 as the degree of financial leverage increases, the risk of financial distress (*i.e.*,
17 financial risk) also increases. Since the capital structure can affect the subject
18 company's overall level of risk,⁴³ it is an important consideration in establishing a just
19 and reasonable rate of return.

20 **Q74. Please discuss your analysis of the capital structures of the proxy group**
21 **companies.**

22 A74. I calculated the average capital structure for each of the proxy group

⁴³ See Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 45-46.

1 companies over the last three years. As shown in Schedule (RBH)-12, the mean of
2 the proxy group actual capital structures is 55.23% common equity and 44.77% long-
3 term debt. The common equity ratios range from 47.92% to 65.63%. Based on that
4 review, it is apparent that the Company's proposed capital structure is generally
5 consistent with the capital structures of the proxy group companies.

6 **Q75. What is the basis for using average capital components rather than a point-in-**
7 **time measurement?**

8 A75. Measuring the capital components at a particular point in time can skew the
9 capital structure by the specific circumstances of a particular period. Therefore, it is
10 more appropriate to normalize the relative relationship between the capital
11 components over a period of time.

12 **Q76. What is your conclusion regarding an appropriate capital structure for**
13 **Delmarva Power?**

14 A76. Considering the average actual equity ratio of 55.23% for the proxy group
15 companies, I believe that Delmarva Power's proposed common equity ratio of
16 48.78% is appropriate as it is consistent with the proxy group companies.

17 **IX. Conclusions and Recommendation**

18 **Q77. What is your conclusion regarding the Company's Cost of Equity?**

19 A77. I believe that a rate of return on common equity in the range of 10.00% to
20 10.75% represents the range of equity investors' required rate of return for investment
21 in natural gas utilities similar to Delmarva Power in today's capital markets. Within
22 that range, it is my view that the Company's proposed ROE of 10.25% is reasonable
23 and appropriate.

1 As discussed earlier in my testimony, my recommendation reflects analytical
2 results based on a proxy group of primarily natural gas utilities. My recommendation
3 also takes into consideration the Company's risk profile relative to the proxy group
4 analytical results with respect to: (1) its relatively small size compared to the proxy
5 group; (2) the lack of revenue stabilization mechanisms employed by it relative to the
6 proxy group; and (3) flotation costs associated with equity issuances.

7 Lastly, I conclude that the Company's proposed capital structure, which
8 consists of 48.78% common equity and 51.22% long-term debt, is consistent with
9 industry practice and on that basis, is reasonable and appropriate.

10 **Q78. Does this conclude your Direct Testimony?**

11 **A78.** Yes, it does.

Robert B. Hevert, CFA
Managing Partner
Sussex Economic Advisors, LLC

Mr. Hevert is an economic and financial consultant with broad experience in regulated industries. He has an extensive background in the areas of corporate finance, corporate strategic planning, energy market assessment, mergers, and acquisitions, asset-based transactions, feasibility and due diligence analyses, and providing expert testimony in litigated proceedings. Mr. Hevert has significant management experience with both operating and professional services companies.

REPRESENTATIVE PROJECT EXPERIENCE

Litigation Support and Expert Testimony

Provided expert testimony and support of litigation in various regulatory proceedings on a variety of energy and economic issues including: cost of capital for ratemaking purposes; the proposed transfer of power purchase agreements; procurement of residual service electric supply; the legal separation of generation assets; merger-related synergies; assessment of economic damages; and specific financing transactions. Services provided include collaborating with counsel, business and technical staff to develop litigation strategies, preparing and reviewing discovery and briefing materials, preparing presentation materials and participating in technical sessions with regulators and intervenors.

Financial and Economic Advisory Services

Retained by numerous leading energy companies and financial institutions throughout North America to provide services relating to the strategic evaluation, acquisition, sale or development of a variety of regulated and non-regulated enterprises. Specific services have included: developing strategic and financial analyses and managing multi-faceted due diligence reviews of proposed corporate M&A counter-parties; developing, screening and recommending potential M&A transactions and facilitating discussions between senior utility executives regarding transaction strategy and structure; performing valuation analyses and financial due diligence reviews of electric generation projects, retail marketing companies, and wholesale trading entities in support of significant M&A transactions.

Specific divestiture-related services have included advising both buy and sell-side clients in transactions for physical and contractual electric generation resources. Sell-side services have included: development and implementation of key aspects of asset divestiture programs such as marketing, offering memorandum development, development of transaction terms and conditions, bid process management, bid evaluation, negotiations, and regulatory approval process. Buy-side services have included comprehensive asset screening, selection, valuation and due diligence reviews. Both buy and sell-side services have included the use of sophisticated asset valuation techniques, and the development and delivery of fairness opinions.

Specific corporate finance experience while a Vice President with Bay State Gas included: negotiation, placement and closing of both private and public long-term debt, preferred and common equity; structured and project financing; corporate cash management; financial analysis, planning and forecasting; and various aspects of investor relations.

Regulatory Analysis and Ratemaking

On behalf of electric, natural gas and combination utilities throughout North America, provided services relating to energy industry restructuring including merchant function exit, residual energy supply obligations, and stranded cost assessment and recovery. Specific services provided include: performing strategic review and development of merchant function exit strategies including analysis of provider of last

resort obligations in both electric and gas markets; and developing value optimizing strategies for physical generation assets.

Energy Market Assessment

Retained by numerous leading energy companies and financial institutions nationwide to manage or provide assessments of regional energy markets throughout the U.S. and Canada. Such assessments have included development of electric and natural gas price forecasts, analysis of generation project entry and exit scenarios, assessment of natural gas and electric transmission infrastructure, market structure and regulatory situation analysis, and assessment of competitive position. Market assessment engagements typically have been used as integral elements of business unit or asset-specific strategic plans or valuation analyses.

Resource Procurement, Contracting and Analysis

Assisted various clients in evaluating alternatives for acquiring fuel and power supplies, including the development and negotiation of energy contracts and tolling agreements. Assignments also have included developing generation resource optimization strategies. Provided advice and analyses of transition service power supply contracts in the context of both physical and contractual generation resource divestiture transactions.

Business Strategy and Operations

Retained by numerous leading North American energy companies and financial institutions nationwide to provide services relating to the development of strategic plans and planning processes for both regulated and non-regulated enterprises. Specific services provided include: developing and implementing electric generation strategies and business process redesign initiatives; developing market entry strategies for retail and wholesale businesses including assessment of asset-based marketing and trading strategies; and facilitating executive level strategic planning retreats. As Vice President, of Bay State was responsible for the company's strategic planning and business development processes, played an integral role in developing the company's non-regulated marketing affiliate, EnergyUSA, and managed the company's non-regulated investments, partnerships and strategic alliances.

PROFESSIONAL HISTORY

Sussex Economic Advisors, LLC (2012 – Present)

Managing Partner

Concentric Energy Advisors, Inc. (2002 – 2012)

President

Navigant Consulting, Inc. (1997 – 2001)

Managing Director (2000 – 2001)

Director (1998 – 2000)

Vice President, REED Consulting Group (1997 – 1998)

Bay State Gas Company (now Columbia Gas Company of Massachusetts) (1987 – 1997)

Vice President and Assistant Treasurer

Boston College (1986 – 1987)

Financial Analyst

General Telephone Company of the South (1984 – 1986)

Revenue Requirements Analyst

EDUCATION

M.B.A., University of Massachusetts at Amherst, 1984
B.S., University of Delaware, 1982

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Chartered Financial Analyst, 1991
Association for Investment Management and Research
Boston Security Analyst Society

PUBLICATIONS/PRESENTATIONS

Has made numerous presentations throughout the United States and Canada on several topics, including:

- Generation Asset Valuation and the Use of Real Options
 - Retail and Wholesale Market Entry Strategies
 - The Use Strategic Alliances in Restructured Energy Markets
 - Gas Supply and Pipeline Infrastructure in the Northeast Energy Markets
 - Nuclear Asset Valuation and the Divestiture Process
-

AVAILABLE UPON REQUEST

Extensive client and project listings, and specific references.

DELMARVA (Hevert)
Attachment A

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Arizona Corporation Commission				
Southwest Gas Corporation	11/10	Southwest Gas Corporation	Docket No. G-01551A-10-0458	Return on Equity
Arkansas Public Service Commission				
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	01/07	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	Docket No. 06-161-U	Return on Equity
Colorado Public Utilities Commission				
Public Service Company of Colorado	11/11	Public Service Company of Colorado	Docket No. 11AL-947E	Return on Equity (electric)
Xcel Energy, Inc.	12/10	Public Service Company of Colorado	Docket No. 10AL-963G	Return on Equity (electric)
Atmos Energy Corporation	07/09	Atmos Energy Colorado-Kansas Division	Docket No. 09AL-507G	Return on Equity (gas)
Xcel Energy, Inc.	12/06	Public Service Company of Colorado	Docket No. 06S-656G	Return on Equity (gas)
Xcel Energy, Inc.	04/06	Public Service Company of Colorado	Docket No. 06S-234EG	Return on Equity (electric)
Xcel Energy, Inc.	08/05	Public Service Company of Colorado	Docket No. 05S-369ST	Return on Equity (steam)
Xcel Energy, Inc.	05/05	Public Service Company of Colorado	Docket No. 05S-264G	Return on Equity (gas)
Connecticut Department of Public Utility Control				
Southern Connecticut Gas Company	09/08	Southern Connecticut Gas Company	Docket No. 08-08-17	Return on Equity
Southern Connecticut Gas Company	12/07	Southern Connecticut Gas Company	Docket No. 05-03-17PH02	Return on Equity
Connecticut Natural Gas Corporation	12/07	Connecticut Natural Gas Corporation	Docket No. 06-03-04PH02	Return on Equity

DELMARVA (Hevert)
Attachment A

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Delaware Public Service Commission				
Delmarva Power & Light Company	12/11	Delmarva Power & Light Company	Case No. 11-528	Return on Equity
District of Columbia Public Service Commission				
Potomac Electric Power Company	07/11	Potomac Electric Power Company	Formal Case No. FC1087	Return on Equity
Federal Energy Regulatory Commission				
Public Service Company of New Mexico	10/10	Public Service Company of New Mexico	Docket No. ER11-1915-000	Return on Equity
Portland Natural Gas Transmission System	05/10	Portland Natural Gas Transmission System	Docket No. RP10-729-000	Return on Equity
Florida Gas Transmission Company, LLC	10/09	Florida Gas Transmission Company, LLC	Docket No. RP10-21-000	Return on Equity
Maritimes and Northeast Pipeline, LLC	07/09	Maritimes and Northeast Pipeline, LLC	Docket No. RP09-809-000	Return on Equity
Spectra Energy	02/08	Saltville Gas Storage	Docket No. RP08-257-000	Return on Equity
Panhandle Energy Pipelines	08/07	Panhandle Energy Pipelines	Docket No. PL07-2-000	Response to draft policy statement regarding inclusion of MLPs in proxy groups for determination of gas pipeline ROEs
Southwest Gas Storage Company	08/07	Southwest Gas Storage Company	Docket No. RP07-541-000	Return on Equity
Southwest Gas Storage Company	06/07	Southwest Gas Storage Company	Docket No. RP07-34-000	Return on Equity
Sea Robin Pipeline LLC	06/07	Sea Robin Pipeline LLC	Docket No. RP07-513-000	Return on Equity
Transwestern Pipeline Company	09/06	Transwestern Pipeline Company	Docket No. RP06-614-000	Return on Equity
GPU International and Aquila	11/00	GPU International	Docket No. EC01-24-000	Market Power Study

DELMARVA (Hevert)
Attachment A

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Georgia Public Service Commission				
Atlanta Gas Light Company	05/10	Atlanta Gas Light Company	Docket No. 31647-U	Return on Equity
Hawaiian				
Hawaiian Electric Light Company	08/12	Hawaiian Electric Light Company	Docket No. 2012-0099	Return on Equity
Illinois Commerce Commission				
Ameren Illinois Company d/b/a Ameren Illinois	02/11	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 11-0279	Return on Equity (electric)
Ameren Illinois Company d/b/a Ameren Illinois	02/11	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 11-0282	Return on Equity (gas)
Indiana Utility Regulatory Commission				
Northern Indiana Public Service Company	05/09	Northern Indiana Public Service Company	Cause No. 43894	
Maine Public Utilities Commission				
Central Maine Power Company	06/11	Central Maine Power Company	Docket No. 2010-327	Response to Bench Analysis provided by Commission Staff relating to the Company's credit and collections processes
Maryland Public Service Commission				
Potomac Electric Power Company	12/11	Potomac Electric Power Company	Case No. 9286	Return on Equity
Delmarva Power & Light Company	12/11	Delmarva Power & Light Company	Case No. 9285	Return on Equity
Delmarva Power & Light Company	12/10	Delmarva Power & Light Company	Case No. 9249	Return on Equity
Massachusetts Department of Public Utilities				
Bay State Gas Company d/b/a Columbia Gas of Massachusetts	04/12	Bay State Gas Company d/b/a Columbia Gas of Massachusetts	DPU 12-25	Capital Cost Recovery
National Grid	08/09	Massachusetts Electric Company d/b/a National Grid	DPU 09-39	Revenue Decoupling and Return on Equity

DELMARVA (Hevert)
Attachment A

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
National Grid	08/09	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 09-38	Return on Equity – Solar Generation
Bay State Gas Company	04/09	Bay State Gas Company	DTE 09-30	Return on Equity
NSTAR Electric	09/04	NSTAR Electric	DTE 04-85	Divestiture of Power Purchase Agreement
NSTAR Electric	08/04	NSTAR Electric	DTE 04-78	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	DTE 04-68	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	DTE 04-61	Divestiture of Power Purchase Agreement
NSTAR Electric	06/04	NSTAR Electric	DTE 04-60	Divestiture of Power Purchase Agreement
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Minnesota Public Utilities Commission				
Otter Tail Power Corporation	04/10	Otter Tail Power Company	Docket No. E-017/GR-10-239	Return on Equity
Minnesota Power a division of ALLETE, Inc.	11/09	Minnesota Power	Docket No. E-015/GR-09-1151	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	11/08	CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-08-1075	Return on Equity
Otter Tail Power Corporation	10/07	Otter Tail Power Company	Docket No. E-017/GR-07-1178	Return on Equity
Xcel Energy, Inc.	11/05	NSP-Minnesota	Docket No. E-002/GR-05-1428	Return on Equity (electric)
Xcel Energy, Inc.	09/04	NSP Minnesota	Docket No. G-002/GR-04-1511	Cost of Capital (gas)

DELMARVA (Hevert)
Attachment A

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Mississippi Public Service Commission				
CenterPoint Energy Resources, Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Mississippi Gas	07/09	CenterPoint Energy Mississippi Gas	Docket No. 09-UN-334	Return on Equity
Missouri Public Service Commission				
Union Electric Company d/b/a Ameren Missouri	02/12	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2012-0166	Return on Equity (electric)
Union Electric Company d/b/a AmerenUE	09/10	Union Electric Company d/b/a AmerenUE	Case No. ER-2011-0028	Return on Equity (electric)
Union Electric Company d/b/a AmerenUE	06/10	Union Electric Company d/b/a AmerenUE	Case No. GR-2010-0363	Return on Equity (gas)
Montana Public Service Commission				
Northwestern Corporation	09/12	Northwestern Corporation	Docket No. D2012.9.94	Return on Equity (gas)
Nevada Public Utilities Commission				
Southwest Gas Corporation	04/12	Southwest Gas Corporation	Docket No. 12-04005	Return on Equity (gas)
Nevada Power Company	06/11	Nevada Power Company	Docket No. 11-06006	Return on Equity (electric)
New Hampshire Public Utilities Commission				
EnergyNorth Natural Gas d/b/a National Grid NH	02/10	EnergyNorth Natural Gas d/b/a National Grid NH	Docket No. DG 10-017	Return on Equity
Unitil Energy Systems, Inc. ("Unitil"), EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	08/08	Unitil Energy Systems, Inc. ("Unitil"), EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	Docket No. DG 07-072	Carrying Charge Rate on Cash Working Capital
New Jersey Board of Public Utilities				
Atlantic City Electric Company	08/11	Atlantic City Electric Company	Docket No. ER11080469	Return on Equity

DELMARVA (Hevert)
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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Pepco Holdings, Inc.	09/06	Atlantic City Electric Company	Docket No. EMO6090638	Divestiture and Valuation of Electric Generating Assets
Pepco Holdings, Inc.	12/05	Atlantic City Electric Company	Docket No. EM05121058	Market Value of Electric Generation Assets; Auction
Conectiv	06/03	Atlantic City Electric Company	Docket No. EO03020091	Market Value of Electric Generation Assets; Auction Process
New Mexico Public Regulation Commission				
Southwestern Public Service Company	02/11	Southwestern Public Service Company	Case No. 10-00395-UT	Return on Equity (electric)
Public Service Company of New Mexico	06/10	Public Service Company of New Mexico	Case No. 10-00086-UT	Return on Equity (electric)
Public Service Company of New Mexico	09/08	Public Service Company of New Mexico	Case No. 08-00273-UT	Return on Equity (electric)
Xcel Energy, Inc.	07/07	Southwestern Public Service Company	Case No. 07-00319-UT	Return on Equity (electric)
New York State Public Service Commission				
Niagara Mohawk Corporation d/b/a National Grid for Electric Service	04/12	Niagara Mohawk Corporation d/b/a National Grid for Electric Service	Case No. 12-E-0201	Return on Equity
Niagara Mohawk Corporation d/b/a National Grid for Gas Service	04/12	Niagara Mohawk Corporation d/b/a National Grid for Gas Service	Case No. 12-G-0202	Return on Equity
Orange and Rockland Utilities, Inc.	07/11	Orange and Rockland Utilities, Inc.	Case No. 11-E-0408	Return on Equity (electric)
Orange and Rockland Utilities, Inc.	07/10	Orange and Rockland Utilities, Inc.	Case No. 10-E-0362	Return on Equity (electric)

DELMARVA (Hevert)
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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Consolidated Edison Company of New York, Inc.	11/09	Consolidated Edison Company of New York, Inc.	Case No. 09-G-0795	Return on Equity (gas)
Consolidated Edison Company of New York, Inc.	11/09	Consolidated Edison Company of New York, Inc.	Case No. 09-S-0794	Return on Equity (steam)
Niagara Mohawk Power Corporation	07/01	Niagara Mohawk Power Corporation	Case No. 01-E-1046	Power Purchase and Sale Agreement; Standard Offer Service Agreement
North Carolina Utilities Commission				
Dominion North Carolina Power	03/12	Dominion Resources	Docket No. E-22, Sub 479	Return on Equity (electric)
Duke Energy Carolinas, LLC	07/11	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 989	Return on Equity (electric)
North Dakota Public Service Commission				
Otter Tail Power Company	11/08	Otter Tail Power Company	Docket No. 08-862	Return on Equity (electric)
Oklahoma Corporation Commission				
Oklahoma Gas & Electric Company	07/11	Oklahoma Gas & Electric Company	Cause No. PUD201100087	Return on Equity
CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	03/09	CenterPoint Energy Oklahoma Gas	Cause No. PUD200900055	Return on Equity
Rhode Island Public Utilities Commission				
The Narragansett Electric Company d/b/a National Grid	04/12	The Narragansett Electric Company d/b/a National Grid	Docket No. 4323	Return on Equity (electric & gas)
National Grid RI – Gas	08/08	National Grid RI – Gas	Docket No. 3943	Revenue Decoupling and Return on Equity
South Carolina Public Service Commission				

DELMARVA (Hevert)
Attachment A

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
South Carolina Electric & Gas	10/12	South Carolina Electric & Gas	Docket No. 2012-218-E	Return on Equity
Duke Energy Carolinas, LLC	08/11	Duke Energy Carolinas, LLC	Docket No. 2011-271-E	Return on Equity
South Carolina Electric & Gas	03/10	South Carolina Electric & Gas	Docket No. 2009-489-E	Return on Equity
South Dakota Public Utilities Commission				
Otter Tail Power Company	08/10	Otter Tail Power Company	Docket No. EL10-011	Return on Equity (electric)
Northern States Power Company	06/09	South Dakota Division of Northern States Power	Docket No. EL09-009	Return on Equity (electric)
Otter Tail Power Company	10/08	Otter Tail Power Company	Docket No. EL08-030	Return on Equity (electric)
Texas Public Utility Commission				
Wind Energy Texas Transmission, LLC	08/12	Wind Energy Texas Transmission, LLC	Docket No. 40606	Return on Equity
Southwestern Electric Power Company	07/12	Southwestern Electric Power Company	Docket No. 40443	Return on Equity
Oncor Electric Delivery Company, LLC	01/11	Oncor Electric Delivery Company, LLC	Docket No. 38929	Return on Equity
Texas-New Mexico Power Company	08/10	Texas-New Mexico Power Company	Docket No. 38480	Return on Equity (electric)
CenterPoint Energy Houston Electric LLC	07/10	CenterPoint Energy Houston Electric LLC	Docket No. 38339	Return on Equity
Xcel Energy, Inc.	05/10	Southwestern Public Service Company	Docket No. 38147	Return on Equity (electric)
Texas-New Mexico Power Company	08/08	Texas-New Mexico Power Company	Docket No. 36025	Return on Equity (electric)
Xcel Energy, Inc.	05/06	Southwestern Public Service Company	Docket No. 32766	Return on Equity (electric)
Texas Railroad Commission				

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Attachment A

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/12	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10182	Return on Equity
Atmos Energy Corporation – West Texas Division	06/12	Atmos Energy Corporation – West Texas Division	GUD 10175	Return on Equity
Atmos Energy Corporation – Mid-Texas Division	06/12	Atmos Energy Corporation – Mid-Texas Division	GUD 10171	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	12/10	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10038	Return on Equity
Atmos Pipeline - Texas	09/10	Atmos Pipeline - Texas	GUD 10000	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/09	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 9902	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas	03/08	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas	GUD 9791	Return on Equity
Utah Public Service Commission				
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	Return on Equity
Vermont Public Service Board				
Central Vermont Public Service Corporation; Green Mountain Power	02/12	Central Vermont Public Service Corporation; Green Mountain Power	Docket No. 7770	Merger Policy
Central Vermont Public Service Corporation	12/10	Central Vermont Public Service Corporation	Docket No. 7627	Return on Equity (electric)

DELMARVA (Hevert)
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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Green Mountain Power	04/06	Green Mountain Power	Docket Nos. 7175 and 7176	Return on Equity (electric)
Vermont Gas Systems, Inc.	12/05	Vermont Gas Systems	Docket Nos. 7109 and 7160	Return on Equity (gas)
Virginia State Corporation Commission				
Columbia Gas Of Virginia, Inc.	06/06	Columbia Gas Of Virginia, Inc.	Case No. PUE-2005-00098	Merger Synergies
Dominion Resources	10/01	Virginia Electric and Power Company	Case No. PUE000584	Corporate Structure and Electric Generation Strategy

Quarterly Discounted Cash Flow Model
30 Day Average Stock Price

Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Average Stock Price	[10] Zacks Earnings Growth	[11] First Call Earnings Growth	[12] Value Line Earnings Growth	[13] Sustainable Growth Estimate	[14] Average Earnings Growth	[15] Low ROE	[16] Mean ROE	[17] High ROE
AGL Resources Inc.	GAS	\$0.45	\$0.46	\$0.46	\$0.46	\$0.48	\$0.49	\$0.49	\$0.49	\$40.94	4.28%	NA	8.00%	6.81%	6.36%	9.10%	11.32%	13.06%
Amos Energy Corporation	ATO	\$0.35	\$0.35	\$0.35	\$0.35	\$0.36	\$0.36	\$0.36	\$0.36	\$35.64	5.83%	5.50%	4.00%	4.37%	4.93%	8.15%	9.13%	10.08%
Laclede Group, Inc. (The)	LG	\$0.42	\$0.42	\$0.42	\$0.42	\$0.43	\$0.43	\$0.43	\$0.43	\$42.63	3.00%	5.30%	2.00%	5.86%	4.04%	6.06%	8.21%	10.14%
New Jersey Resources Corporation	NJR	\$0.38	\$0.38	\$0.38	\$0.40	\$0.40	\$0.40	\$0.40	\$0.42	\$45.75	3.35%	2.70%	5.50%	7.20%	4.69%	6.24%	8.32%	10.95%
Northwest Natural Gas Company	NWN	\$0.45	\$0.45	\$0.45	\$0.46	\$0.47	\$0.47	\$0.47	\$0.48	\$49.23	4.17%	4.50%	4.50%	7.56%	5.18%	8.07%	9.13%	11.63%
Piedmont Natural Gas Company, Inc.	PNY	\$0.29	\$0.30	\$0.30	\$0.30	\$0.30	\$0.31	\$0.31	\$0.31	\$32.23	5.23%	5.35%	2.50%	2.19%	3.82%	6.05%	7.76%	9.37%
South Jersey Industries, Inc.	SJI	\$0.40	\$0.40	\$0.40	\$0.40	\$0.44	\$0.44	\$0.44	\$0.44	\$52.20	6.00%	9.00%	9.00%	11.58%	8.90%	9.38%	12.41%	15.21%
Southwest Gas Corporation	SWX	\$0.27	\$0.30	\$0.30	\$0.30	\$0.28	\$0.31	\$0.31	\$0.31	\$43.92	4.37%	4.05%	9.00%	6.92%	6.08%	6.84%	8.95%	11.98%
WGL Holdings, Inc.	WGL	\$0.39	\$0.40	\$0.40	\$0.40	\$0.41	\$0.42	\$0.42	\$0.42	\$39.89	5.37%	5.60%	3.50%	3.92%	4.60%	7.74%	8.90%	9.95%
Mean											4.62%	5.25%	5.33%	6.27%	5.40%	7.51%	9.35%	11.37%

Notes:

- [1] Source: Bloomberg Professional Service
- [2] Source: Bloomberg Professional Service
- [3] Source: Bloomberg Professional Service
- [4] Source: Bloomberg Professional Service
- [5] Equals Col. [1] x (1 + Col. [14])
- [6] Equals Col. [2] x (1 + Col. [14])
- [7] Equals Col. [3] x (1 + Col. [14])
- [8] Equals Col. [4] x (1 + Col. [14])
- [9] Source: Bloomberg Professional Service, equals indicated number of trading day average as of October 12, 2012
- [10] Source: Zacks
- [11] Source: Yahoo! Finance
- [12] Source: Value Line
- [13] Schedule (RBH)-3
- [14] Equals Average (Cols. [10], [11], [12], [13])
- [15] Implied Low DCF
- [16] Implied Mean DCF
- [17] Implied High DCF

Quarterly Discounted Cash Flow Model
90 Day Average Stock Price

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]
Company	Dividend 1	Dividend 2	Dividend 3	Dividend 4	Expected Dividend 1	Expected Dividend 2	Expected Dividend 3	Expected Dividend 4	Average Stock Price	Zacks Earnings Growth	First Call Earnings Growth	Value Line Earnings Growth	Sustainable Growth Rate	Average Earnings Growth	Low ROE	Mean ROE	High ROE
Ticker																	
AGL Resources Inc.	GAS	\$0.45	\$0.46	\$0.46	\$0.46	\$0.48	\$0.49	\$0.49	\$39.92	4.28%	NA	8.00%	6.81%	6.36%	9.22%	11.44%	13.19%
Amos Energy Corporation	ATO	\$0.35	\$0.35	\$0.35	\$0.36	\$0.36	\$0.36	\$0.36	\$35.58	5.83%	5.50%	4.00%	4.37%	4.93%	8.16%	9.13%	10.08%
Laclede Group, Inc. (The)	LG	\$0.42	\$0.42	\$0.42	\$0.43	\$0.43	\$0.43	\$0.43	\$41.42	3.00%	5.30%	2.00%	5.86%	4.04%	6.18%	8.34%	10.26%
New Jersey Resources Corporation	NJR	\$0.38	\$0.38	\$0.38	\$0.40	\$0.40	\$0.40	\$0.40	\$45.09	3.35%	2.70%	5.50%	7.20%	4.69%	6.29%	8.37%	11.00%
Northwest Natural Gas Company	NWN	\$0.45	\$0.45	\$0.45	\$0.47	\$0.47	\$0.47	\$0.48	\$48.60	4.17%	4.50%	4.50%	7.56%	5.18%	8.12%	9.19%	11.69%
Piedmont Natural Gas Company, Inc.	PNY	\$0.29	\$0.30	\$0.30	\$0.30	\$0.30	\$0.31	\$0.31	\$32.04	5.23%	5.35%	2.50%	2.19%	3.82%	6.07%	7.78%	9.40%
South Jersey Industries, Inc.	SJI	\$0.40	\$0.40	\$0.40	\$0.44	\$0.44	\$0.44	\$0.44	\$51.89	6.00%	9.00%	9.00%	11.58%	8.90%	9.40%	12.43%	15.24%
Southwest Gas Corporation	SWX	\$0.27	\$0.30	\$0.30	\$0.28	\$0.31	\$0.31	\$0.31	\$44.02	4.37%	4.05%	9.00%	6.92%	6.09%	6.84%	8.95%	11.97%
WGL Holdings, Inc.	WGL	\$0.39	\$0.40	\$0.40	\$0.41	\$0.42	\$0.42	\$0.42	\$40.13	5.37%	5.60%	3.50%	3.92%	4.60%	7.71%	8.87%	9.93%
Mean										4.62%	5.25%	5.33%	6.27%	5.40%	7.55%	9.39%	11.42%

Notes:

- [1] Source: Bloomberg Professional Service
- [2] Source: Bloomberg Professional Service
- [3] Source: Bloomberg Professional Service
- [4] Source: Bloomberg Professional Service
- [5] Equals Col. [1] x (1 + Col. [14])
- [6] Equals Col. [2] x (1 + Col. [14])
- [7] Equals Col. [3] x (1 + Col. [14])
- [8] Equals Col. [4] x (1 + Col. [14])
- [9] Source: Bloomberg Professional Service, equals indicated number of trading day average as of October 12, 2012
- [10] Source: Zacks
- [11] Source: Yahoo! Finance
- [12] Source: Value Line
- [13] Schedule (RBH)-3
- [14] Equals Average (Cols. [10], [11], [12], [13])
- [15] Implied Low DCF
- [16] Implied Mean DCF
- [17] Implied High DCF

Quarterly Discounted Cash Flow Model
180 Day Average Stock Price

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]
Company	Dividend	Dividend	Dividend	Dividend	Expected	Expected	Expected	Expected	Average	Zacks	First Call	Value Line	Sustainable	Average	Low	Mean	High
Ticker	1	2	3	4	Dividend	Dividend	Dividend	Dividend	Stock Price	Earnings	Earnings	Earnings	Growth	Earnings	ROE	ROE	ROE
AGL Resources Inc.	\$0.45	\$0.46	\$0.46	\$0.46	\$0.48	\$0.49	\$0.49	\$0.49	\$39.52	4.28%	NA	8.00%	6.81%	6.36%	9.27%	11.50%	13.24%
Almos Energy Corporation	\$0.35	\$0.35	\$0.35	\$0.35	\$0.36	\$0.36	\$0.36	\$0.36	\$33.74	5.83%	5.50%	4.00%	4.37%	4.93%	8.39%	9.37%	10.32%
Laclede Group, Inc. (The)	\$0.42	\$0.42	\$0.42	\$0.42	\$0.43	\$0.43	\$0.43	\$0.43	\$40.64	3.00%	5.30%	2.00%	5.86%	4.04%	6.26%	8.42%	10.35%
New Jersey Resources Corporation	\$0.38	\$0.38	\$0.38	\$0.40	\$0.40	\$0.40	\$0.40	\$0.42	\$44.88	3.35%	2.70%	5.50%	7.20%	4.69%	6.31%	8.39%	11.02%
Northwest Natural Gas Company	\$0.45	\$0.45	\$0.45	\$0.46	\$0.47	\$0.47	\$0.47	\$0.48	\$37.36	4.17%	4.50%	4.50%	7.56%	5.18%	8.23%	9.23%	11.80%
Piedmont Natural Gas Company, Inc.	\$0.29	\$0.30	\$0.30	\$0.30	\$0.30	\$0.31	\$0.31	\$0.31	\$31.62	5.23%	5.35%	2.50%	2.19%	3.82%	6.12%	7.84%	9.45%
South Jersey Industries, Inc.	\$0.40	\$0.40	\$0.40	\$0.40	\$0.44	\$0.44	\$0.44	\$0.44	\$51.17	6.00%	9.00%	9.00%	11.58%	8.90%	9.45%	12.48%	15.29%
Southwest Gas Corporation	\$0.27	\$0.30	\$0.30	\$0.30	\$0.28	\$0.31	\$0.31	\$0.31	\$43.16	4.37%	4.05%	9.00%	6.92%	6.09%	6.89%	9.00%	12.03%
WGL Holdings, Inc.	\$0.39	\$0.40	\$0.40	\$0.40	\$0.41	\$0.42	\$0.42	\$0.42	\$40.18	5.37%	5.60%	3.50%	3.92%	4.60%	7.70%	8.86%	9.92%
Mean										4.62%	5.25%	5.33%	6.27%	5.40%	7.62%	9.46%	11.49%

Notes:

- [1] Source: Bloomberg Professional Service
- [2] Source: Bloomberg Professional Service
- [3] Source: Bloomberg Professional Service
- [4] Source: Bloomberg Professional Service
- [5] Equals Col. [1] x (1 + Col. [14])
- [6] Equals Col. [2] x (1 + Col. [14])
- [7] Equals Col. [3] x (1 + Col. [14])
- [8] Equals Col. [4] x (1 + Col. [14])
- [9] Source: Bloomberg Professional Service, equals indicated number of trading day average as of October 12, 2012
- [10] Source: Zacks
- [11] Source: Yahoo! Finance
- [12] Source: Value Line
- [13] Schedule (RBH)-3
- [14] Equals Average (Cols. [10], [11], [12], [13])
- [15] Implied Low DCF
- [16] Implied Mean DCF
- [17] Implied High DCF

Constant Growth Discounted Cash Flow Model
30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Sustainable Growth Estimate	[9] Average Earnings Growth	[10] Low ROE	[11] Mean ROE	[12] High ROE
AGL Resources Inc.	GAS	\$1.84	\$40.94	4.49%	4.64%	4.28%	NA	8.00%	6.81%	6.36%	8.87%	11.00%	12.67%
Atmos Energy Corporation	ATO	\$1.38	\$35.64	3.87%	3.97%	5.83%	5.50%	4.00%	4.37%	4.93%	7.95%	8.89%	9.81%
Laclede Group, Inc. (The)	LG	\$1.66	\$42.63	3.89%	3.97%	3.00%	5.30%	2.00%	5.86%	4.04%	5.93%	8.01%	9.87%
New Jersey Resources Corporation	NJR	\$1.60	\$45.75	3.50%	3.58%	3.35%	2.70%	5.50%	7.20%	4.69%	6.24%	8.27%	10.82%
Northwest Natural Gas Company	NWN	\$1.82	\$49.23	3.70%	3.79%	4.17%	4.50%	4.50%	7.56%	5.18%	7.94%	8.97%	11.40%
Piedmont Natural Gas Company, Inc.	PNY	\$1.20	\$32.23	3.72%	3.79%	5.23%	5.35%	2.50%	2.19%	3.82%	5.95%	7.61%	9.17%
South Jersey Industries, Inc.	SJI	\$1.61	\$52.20	3.08%	3.22%	6.00%	9.00%	9.00%	11.58%	8.90%	9.18%	12.12%	14.84%
Southwest Gas Corporation	SWX	\$1.18	\$43.92	2.69%	2.77%	4.37%	4.05%	9.00%	6.92%	6.09%	6.79%	8.85%	11.81%
WGL Holdings, Inc.	WGL	\$1.60	\$39.89	4.01%	4.10%	5.37%	5.60%	3.50%	3.92%	4.60%	7.58%	8.70%	9.72%
Mean				3.66%	3.76%	4.62%	5.25%	5.33%	6.27%	5.40%	7.38%	9.16%	11.12%

Notes:

- [1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service, equals indicated number of trading day average as of October 12, 2012
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Schedule (RBH)-3
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

Constant Growth Discounted Cash Flow Model
90 Day Average Stock Price

Company	Ticker	[1]		[2]		[3]		[4]		[5]		[6]		[7]		[8]		[9]		[10]		[11]		[12]	
		Annualized Dividend	Average Stock Price	Dividend	Expected Dividend Yield	Dividend Yield	Yield	Expected Dividend Yield	Yield	Zacks Earnings Growth	Zacks Earnings Growth	First Call Earnings Growth	First Call Earnings Growth	Value Line Earnings Growth	Value Line Earnings Growth	Sustainable Growth Estimate	Sustainable Growth Estimate	Average Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
AGL Resources Inc.	GAS	\$1.84	\$39.92	4.61%	4.76%	4.61%	4.76%	4.76%	4.76%	4.28%	4.28%	NA	NA	8.00%	8.00%	6.81%	6.81%	6.36%	6.36%	8.99%	11.12%	12.79%	8.99%	11.12%	12.79%
Atmos Energy Corporation	ATO	\$1.38	\$35.58	3.88%	3.97%	3.88%	3.97%	3.97%	3.97%	5.83%	5.83%	5.50%	5.50%	4.00%	4.00%	4.37%	4.37%	4.93%	4.93%	7.96%	8.90%	9.82%	7.96%	8.90%	9.82%
Laclede Group, Inc. (The)	LG	\$1.66	\$41.42	4.01%	4.09%	4.01%	4.09%	4.09%	4.09%	3.00%	3.00%	5.30%	5.30%	2.00%	2.00%	5.86%	5.86%	4.04%	4.04%	6.05%	8.13%	9.99%	6.05%	8.13%	9.99%
New Jersey Resources Corporation	NJR	\$1.60	\$45.09	3.55%	3.63%	3.55%	3.63%	3.63%	3.63%	3.35%	3.35%	2.70%	2.70%	5.50%	5.50%	7.20%	7.20%	4.69%	4.69%	6.30%	8.32%	10.87%	6.30%	8.32%	10.87%
Northwest Natural Gas Company	NWN	\$1.82	\$48.60	3.75%	3.84%	3.75%	3.84%	3.84%	3.84%	4.17%	4.17%	4.50%	4.50%	4.50%	4.50%	7.56%	7.56%	5.18%	5.18%	7.99%	9.02%	11.45%	7.99%	9.02%	11.45%
Piedmont Natural Gas Company, Inc.	PNY	\$1.20	\$32.04	3.75%	3.82%	3.75%	3.82%	3.82%	3.82%	5.23%	5.23%	5.35%	5.35%	2.50%	2.50%	2.19%	2.19%	3.82%	3.82%	5.98%	7.63%	9.20%	5.98%	7.63%	9.20%
South Jersey Industries, Inc.	SJI	\$1.61	\$51.89	3.10%	3.24%	3.10%	3.24%	3.24%	3.24%	6.00%	6.00%	9.00%	9.00%	9.00%	9.00%	11.58%	11.58%	8.90%	8.90%	9.20%	12.14%	14.86%	9.20%	12.14%	14.86%
Southwest Gas Corporation	SWX	\$1.18	\$44.02	2.68%	2.76%	2.68%	2.76%	2.76%	2.76%	4.37%	4.37%	4.05%	4.05%	9.00%	9.00%	6.92%	6.92%	6.09%	6.09%	6.79%	8.85%	11.80%	6.79%	8.85%	11.80%
WGL Holdings, Inc.	WGL	\$1.60	\$40.13	3.99%	4.08%	3.99%	4.08%	4.08%	4.08%	5.37%	5.37%	5.60%	5.60%	3.50%	3.50%	3.92%	3.92%	4.60%	4.60%	7.56%	8.68%	9.70%	7.56%	8.68%	9.70%
Mean				3.70%	3.80%	3.70%	3.80%	3.80%	3.80%	4.62%	4.62%	5.25%	5.25%	5.33%	5.33%	6.27%	6.27%	5.40%	5.40%	7.42%	9.20%	11.16%	7.42%	9.20%	11.16%

Notes:

- [1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service, equals indicated number of trading day average as of October 12, 2012
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Schedule (RBH)-3
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

Constant Growth Discounted Cash Flow Model
180 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Sustainable Growth Estimate	[9] Average Earnings Growth	[10] Low ROE	[11] Mean ROE	[12] High ROE
AGL Resources Inc.	GAS	\$1.84	\$39.52	4.66%	4.80%	4.28%	NA	8.00%	6.81%	6.36%	9.04%	11.17%	12.84%
Atmos Energy Corporation	ATO	\$1.38	\$33.74	4.09%	4.19%	5.83%	5.50%	4.00%	4.37%	4.93%	8.17%	9.12%	10.04%
Laclede Group, Inc. (The)	LG	\$1.66	\$40.64	4.08%	4.17%	3.00%	5.30%	2.00%	5.86%	4.04%	6.13%	8.21%	10.06%
New Jersey Resources Corporation	NJR	\$1.60	\$44.88	3.57%	3.65%	3.35%	2.70%	5.50%	7.20%	4.69%	6.31%	8.34%	10.89%
Northwest Natural Gas Company	NWN	\$1.82	\$47.36	3.84%	3.94%	4.17%	4.50%	4.50%	7.56%	5.18%	8.09%	9.12%	11.55%
Piedmont Natural Gas Company, Inc.	PNY	\$1.20	\$31.62	3.80%	3.87%	5.23%	5.35%	2.50%	2.19%	3.82%	6.03%	7.69%	9.25%
South Jersey Industries, Inc.	SJI	\$1.61	\$51.17	3.15%	3.29%	6.00%	9.00%	9.00%	11.58%	8.90%	9.24%	12.18%	14.91%
Southwest Gas Corporation	SWX	\$1.18	\$43.16	2.73%	2.82%	4.37%	4.05%	9.00%	6.92%	6.09%	6.84%	8.90%	11.86%
WGL Holdings, Inc.	WGL	\$1.60	\$40.18	3.98%	4.07%	5.37%	5.60%	3.50%	3.92%	4.60%	7.55%	8.67%	9.69%
Mean				3.77%	3.87%	4.62%	5.25%	5.33%	6.27%	5.40%	7.49%	9.27%	11.23%

Notes:

- [1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service, equals indicated number of trading day average as of October 12, 2012
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Schedule (RBH)-3
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

Retention Growth Estimate

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	
Company	Projected Earnings per share 2015-17	Projected Dividend per share 2015-17	Retention Ratio (B)	Projected Book Value per Share 2015-17	Return on Book Value (R)	B x R	Projected Common Shares Outstanding 2013	Projected Common Shares Outstanding 2015-17	Common Shares Growth Rate	2012 High Price	2012 Low Price	2012 price midpoint	Projected Book Value per Share 2012	Market/Book Ratio	"S"	"V"	S x V	BR + SV	
AGI Resources Inc.	GAS	4.20	2.00	52.38%	33.75	12.44%	6.52%	119.00	122.00	0.83%	42.9	36.6	\$ 39.75	29.25	1.36	1.12%	26.42%	0.30%	6.81%
Almos Energy Corporation	ATO	2.70	1.48	45.19%	34.65	7.79%	3.52%	91.00	103.00	4.17%	37.3	30.4	\$ 33.85	28.10	1.20	5.03%	16.99%	0.85%	4.37%
Laclede Group, Inc. (The)	LG	3.10	1.81	41.61%	27.15	11.42%	4.75%	23.50	25.00	2.08%	43.3	36.5	\$ 39.90	25.95	1.54	3.17%	34.96%	1.11%	5.98%
New Jersey Resources Corporation	NJR	3.45	1.68	51.30%	24.60	14.02%	7.20%	40.00	40.00	0.00%	50.3	41.1	\$ 45.70	18.20	2.51	0.00%	60.18%	0.00%	7.20%
Northwest Natural Gas Company	NWN	3.45	1.94	43.77%	29.10	11.86%	5.19%	28.00	31.00	3.42%	50.1	43.9	\$ 47.00	27.75	1.69	5.79%	40.96%	2.37%	7.58%
Piedmont Natural Gas Company, Inc.	PNY	1.85	1.35	27.03%	14.65	12.63%	3.41%	70.00	68.00	-0.95%	34.8	28.9	\$ 31.75	13.90	2.28	-2.17%	56.22%	-1.22%	2.19%
South Jersey Industries, Inc.	SJI	4.50	2.25	50.00%	28.55	15.76%	7.88%	32.00	35.00	3.00%	58.0	46.5	\$ 52.25	23.40	2.23	6.70%	32.94%	3.70%	11.58%
Southwest Gas Corporation	SWX	3.75	1.60	57.33%	36.25	10.34%	5.93%	48.00	51.00	2.02%	46.1	39.5	\$ 42.80	28.70	1.49	3.01%	32.94%	0.99%	6.92%
WGL Holdings, Inc.	WGL	2.85	1.75	38.60%	28.85	9.88%	3.81%	51.75	52.00	0.16%	45.0	37.7	\$ 41.35	24.55	1.68	0.27%	40.63%	0.11%	3.92%

Notes:

- [1] Source: Value Line
- [2] Source: Value Line
- [3] Equals 1 - [2] / [1]
- [4] Source: Value Line
- [5] Equals [1] / [4]
- [6] Equals [3] x [5]
- [7] Source: Value Line
- [8] Source: Value Line
- [9] Equals ([8] / [7]) + 0.33 - 1
- [10] Source: Value Line
- [11] Source: Value Line
- [12] Equals Average ([10], [11])
- [13] Source: Value Line
- [14] Equals [12] / [13]
- [15] Equals [9] x [14]
- [16] Equals 1 - (1 / [14])
- [17] Equals [15] x [16]
- [18] Equals [6] + [17]

Multistage Growth Discounted Cash Flow Model
30 Day Average Stock Price

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]				
		Stock	EPS Growth Rate Estimates				Long-Term		Payout Ratio			Iterative Solution		Terminal	Terminal				
			Sustainable																
Company	Ticker	Price	Zacks	First Call	Value Line	Growth	Average	Growth	2012	2016	2023	Proof	IRR	P/E Ratio	PEG Ratio				
AGL Resources Inc.	GAS	\$40.94	4.28%	NA	8.00%	6.81%	6.36%	5.77%	66.00%	48.00%	69.79%	\$0.00	9.89%	16.93	2.94				
Atmos Energy Corp.	ATO	\$35.64	5.83%	5.50%	4.00%	4.37%	4.93%	5.77%	61.00%	54.00%	69.79%	\$0.00	10.39%	15.08	2.62				
Laclede Group, Inc.	LG	\$42.63	3.00%	5.30%	2.00%	5.86%	4.04%	5.77%	62.00%	58.00%	69.79%	\$0.00	10.44%	14.92	2.59				
New Jersey Resources	NJR	\$45.75	3.35%	2.70%	5.50%	7.20%	4.69%	5.77%	53.00%	48.00%	69.79%	\$0.00	9.74%	17.57	3.05				
Northwest Natural Gas	NWN	\$49.23	4.17%	4.50%	4.50%	7.56%	5.18%	5.77%	73.00%	56.00%	69.79%	\$0.00	9.44%	19.00	3.30				
Piedmont Natural Gas	PNY	\$32.23	5.23%	5.35%	2.50%	2.19%	3.82%	5.77%	77.00%	72.00%	69.79%	\$0.00	9.26%	19.98	3.47				
South Jersey Industries	SJI	\$52.20	6.00%	9.00%	9.00%	11.58%	8.90%	5.77%	54.00%	53.00%	69.79%	\$0.00	10.89%	13.61	2.36				
Southwest Gas Corp.	SWX	\$43.92	4.37%	4.05%	9.00%	6.92%	6.09%	5.77%	46.00%	42.00%	69.79%	\$0.00	9.93%	16.74	2.90				
WGL Holdings, Inc.	WGL	\$39.89	5.37%	5.60%	3.50%	3.92%	4.60%	5.77%	62.00%	61.00%	69.79%	\$0.00	9.87%	17.00	2.95				
												MEAN	9.98%						
												MAX	10.89%						
												MIN	9.26%						
Projected Annual Earnings per Share																			
		[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]	
Company	Ticker	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
AGL Resources Inc.	GAS	\$2.12	\$2.25	\$2.40	\$2.55	\$2.71	\$2.89	\$3.07	\$3.26	\$3.45	\$3.66	\$3.87	\$4.10	\$4.33	\$4.58	\$4.85	\$5.13	\$5.42	
Atmos Energy Corp.	ATO	\$2.26	\$2.37	\$2.49	\$2.61	\$2.74	\$2.87	\$3.02	\$3.18	\$3.35	\$3.53	\$3.73	\$3.94	\$4.17	\$4.41	\$4.67	\$4.94	\$5.22	
Laclede Group, Inc.	LG	\$2.86	\$2.98	\$3.10	\$3.22	\$3.35	\$3.49	\$3.64	\$3.81	\$3.99	\$4.20	\$4.43	\$4.68	\$4.95	\$5.24	\$5.54	\$5.86	\$6.20	
New Jersey Resources	NJR	\$2.58	\$2.70	\$2.83	\$2.96	\$3.10	\$3.24	\$3.40	\$3.57	\$3.76	\$3.96	\$4.18	\$4.43	\$4.68	\$4.95	\$5.24	\$5.54	\$5.86	
Northwest Natural Gas	NWN	\$2.39	\$2.51	\$2.64	\$2.78	\$2.93	\$3.08	\$3.24	\$3.41	\$3.60	\$3.80	\$4.02	\$4.25	\$4.49	\$4.75	\$5.03	\$5.32	\$5.62	
Piedmont Natural Gas	PNY	\$1.57	\$1.63	\$1.69	\$1.76	\$1.82	\$1.89	\$1.97	\$2.06	\$2.16	\$2.27	\$2.39	\$2.53	\$2.68	\$2.83	\$2.99	\$3.17	\$3.35	
South Jersey Industries	SJI	\$2.89	\$3.15	\$3.43	\$3.73	\$4.06	\$4.43	\$4.80	\$5.17	\$5.55	\$5.93	\$6.30	\$6.67	\$7.05	\$7.46	\$7.89	\$8.34	\$8.82	
Southwest Gas Corp.	SWX	\$2.43	\$2.58	\$2.73	\$2.90	\$3.08	\$3.27	\$3.46	\$3.67	\$3.89	\$4.11	\$4.35	\$4.61	\$4.87	\$5.15	\$5.45	\$5.76	\$6.09	
WGL Holdings, Inc.	WGL	\$2.25	\$2.35	\$2.46	\$2.57	\$2.69	\$2.82	\$2.95	\$3.10	\$3.26	\$3.44	\$3.63	\$3.84	\$4.06	\$4.29	\$4.54	\$4.80	\$5.08	
Projected Annual Dividend Payout Ratio																			
		[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]			
Company	Ticker	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026			
AGL Resources Inc.	GAS	66.00%	61.50%	57.00%	52.50%	48.00%	51.63%	55.26%	58.90%	62.53%	66.16%	69.79%	69.79%	69.79%	69.79%	69.79%			
Atmos Energy Corp.	ATO	61.00%	59.25%	57.50%	55.75%	54.00%	56.63%	59.26%	61.90%	64.53%	67.16%	69.79%	69.79%	69.79%	69.79%	69.79%			
Laclede Group, Inc.	LG	62.00%	61.00%	60.00%	59.00%	58.00%	59.97%	61.93%	63.90%	65.86%	67.83%	69.79%	69.79%	69.79%	69.79%	69.79%			
New Jersey Resources	NJR	53.00%	51.75%	50.50%	49.25%	48.00%	51.63%	55.26%	58.90%	62.53%	66.16%	69.79%	69.79%	69.79%	69.79%	69.79%			
Northwest Natural Gas	NWN	73.00%	68.75%	64.50%	60.25%	56.00%	58.30%	60.50%	62.90%	65.19%	67.49%	69.79%	69.79%	69.79%	69.79%	69.79%			
Piedmont Natural Gas	PNY	77.00%	75.75%	74.50%	73.25%	72.00%	71.63%	71.26%	70.90%	70.53%	70.16%	69.79%	69.79%	69.79%	69.79%	69.79%			
South Jersey Industries	SJI	54.00%	53.75%	53.50%	53.25%	53.00%	55.80%	58.60%	61.40%	64.19%	66.99%	69.79%	69.79%	69.79%	69.79%	69.79%			
Southwest Gas Corp.	SWX	46.00%	45.00%	44.00%	43.00%	42.00%	46.63%	51.26%	55.90%	60.53%	65.16%	69.79%	69.79%	69.79%	69.79%	69.79%			
WGL Holdings, Inc.	WGL	62.00%	61.75%	61.50%	61.25%	61.00%	62.47%	63.93%	65.40%	66.86%	68.33%	69.79%	69.79%	69.79%	69.79%	69.79%			
Projected Annual Cash Flows																			
		[47]	[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]		
Company	Ticker	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Terminal Value		
AGL Resources Inc.	GAS	\$1.48	\$1.48	\$1.45	\$1.42	\$1.39	\$1.58	\$1.80	\$2.03	\$2.29	\$2.56	\$2.86	\$3.02	\$3.20	\$3.38	\$3.58	\$91.84		
Atmos Energy Corp.	ATO	\$1.45	\$1.47	\$1.50	\$1.53	\$1.55	\$1.71	\$1.88	\$2.07	\$2.28	\$2.50	\$2.75	\$2.91	\$3.08	\$3.26	\$3.44	\$78.74		
Laclede Group, Inc.	LG	\$1.84	\$1.89	\$1.93	\$1.98	\$2.02	\$2.18	\$2.36	\$2.55	\$2.77	\$3.00	\$3.27	\$3.46	\$3.66	\$3.87	\$4.09	\$92.50		
New Jersey Resources	NJR	\$1.43	\$1.46	\$1.49	\$1.53	\$1.56	\$1.76	\$1.97	\$2.21	\$2.48	\$2.77	\$3.09	\$3.27	\$3.46	\$3.65	\$3.87	\$102.94		
Northwest Natural Gas	NWN	\$1.84	\$1.82	\$1.79	\$1.78	\$1.72	\$1.89	\$2.07	\$2.26	\$2.48	\$2.71	\$2.96	\$3.14	\$3.32	\$3.51	\$3.71	\$106.82		
Piedmont Natural Gas	PNY	\$1.28	\$1.28	\$1.31	\$1.34	\$1.36	\$1.41	\$1.47	\$1.53	\$1.60	\$1.68	\$1.77	\$1.87	\$1.98	\$2.09	\$2.21	\$66.92		
South Jersey Industries	SJI	\$1.70	\$1.84	\$2.00	\$2.16	\$2.35	\$2.68	\$3.03	\$3.41	\$3.81	\$4.22	\$4.65	\$4.92	\$5.20	\$5.50	\$5.82	\$120.10		
Southwest Gas Corp.	SWX	\$1.19	\$1.23	\$1.28	\$1.32	\$1.37	\$1.61	\$1.88	\$2.17	\$2.49	\$2.84	\$3.21	\$3.40	\$3.60	\$3.80	\$4.02	\$102.01		
WGL Holdings, Inc.	WGL	\$1.46	\$1.52	\$1.58	\$1.65	\$1.72	\$1.84	\$1.98	\$2.13	\$2.30	\$2.48	\$2.68	\$2.83	\$2.99	\$3.17	\$3.35	\$86.27		
Projected Annual Data Investor Cash Flows																			
		[63]	[64]	[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]	
Company	Ticker	Initial	Outflow	10/12/12	12/31/12	6/30/13	6/30/14	6/30/15	6/30/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26
AGL Resources Inc.	GAS	(\$40.94)	\$0.00	\$0.33	\$1.54	\$1.45	\$1.42	\$1.39	\$1.58	\$1.80	\$2.03	\$2.29	\$2.56	\$2.86	\$3.02	\$3.20	\$3.38	\$95.42	
Atmos Energy Corp.	ATO	(\$35.64)	\$0.00	\$0.32	\$1.48	\$1.50	\$1.53	\$1.55	\$1.71	\$1.88	\$2.07	\$2.28	\$2.50	\$2.75	\$2.91	\$3.08	\$3.26	\$82.18	
Laclede Group, Inc.	LG	(\$42.63)	\$0.00	\$0.40	\$1.88	\$1.93	\$1.98	\$2.02	\$2.18	\$2.36	\$2.55	\$2.77	\$3.00	\$3.27	\$3.46	\$3.66	\$3.87	\$96.59	
New Jersey Resources	NJR	(\$45.74)	\$0.00	\$0.31	\$1.46	\$1.49	\$1.53	\$1.56	\$1.76	\$1.97	\$2.21	\$2.48	\$2.77	\$3.09	\$3.27	\$3.46	\$3.65	\$106.80	
Northwest Natural Gas	NWN	(\$49.23)	\$0.00	\$0.40	\$1.88	\$1.79	\$1.76	\$1.72	\$1.89	\$2.07	\$2.26	\$2.48	\$2.71	\$2.96	\$3.14	\$3.32	\$3.51	\$110.53	
Piedmont Natural Gas	PNY	(\$32.23)	\$0.00	\$0.28	\$1.28	\$1.31	\$1.34	\$1.36	\$1.41	\$1.47	\$1.53	\$1.60	\$1.68	\$1.77	\$1.87	\$1.98	\$2.09	\$69.13	
South Jersey Industries	SJI	(\$52.20)	\$0.00	\$0.37	\$1.77	\$2.00	\$2.16	\$2.35	\$2.68	\$3.03	\$3.41	\$3.81	\$4.22	\$4.65	\$4.92	\$5.20	\$5.50	\$125.93	
Southwest Gas Corp.	SWX	(\$43.92)	\$0.00	\$0.26	\$1.22	\$1.28	\$1.32	\$1.37	\$1.61	\$1.88	\$2.17	\$2.49	\$2.84	\$3.21	\$3.40	\$3.60	\$3.80	\$106.03	
WGL Holdings, Inc.	WGL	(\$39.89)	\$0.00	\$0.32	\$1.49	\$1.58	\$1.65	\$1.72	\$1.84	\$1.98	\$2.13	\$2.30	\$2.48	\$2.68	\$2.83	\$2.99	\$3.17	\$89.62	

Multistage Growth Discounted Cash Flow Model
90 Day Average Stock Price

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]			
		Stock	EPS Growth Rate Estimates				Long-Term		Payout Ratio			Iterative Solution		Terminal	Terminal			
			Sustainable															
Company	Ticker	Price	Zacks	First Call	Value Line	Growth	Average	Growth	2012	2016	2023	Proof	IRR	P/E Ratio	PEG Ratio			
AGL Resources Inc.	GAS	\$39.92	4.28%	NA	8.00%	6.81%	6.36%	5.77%	66.00%	48.00%	69.79%	30.00	9.99%	16.53	2.87			
Atmos Energy Corp.	ATO	\$35.58	5.83%	5.50%	4.00%	4.37%	4.93%	5.77%	61.00%	54.00%	69.79%	30.00	10.40%	15.06	2.61			
Laclede Group, Inc.	LG	\$41.42	3.00%	5.30%	2.00%	5.86%	4.04%	5.77%	62.00%	58.00%	69.79%	30.00	10.58%	14.50	2.51			
New Jersey Resources	NJR	\$45.09	3.35%	2.70%	5.50%	7.20%	4.69%	5.77%	53.00%	48.00%	69.79%	30.00	9.79%	17.33	3.01			
Northwest Natural Gas	NWN	\$48.60	4.17%	4.50%	4.50%	7.56%	5.18%	5.77%	73.00%	56.00%	69.79%	30.00	9.49%	18.76	3.25			
Piedmont Natural Gas	PNY	\$32.04	5.23%	5.35%	2.50%	2.19%	3.82%	5.77%	77.00%	72.00%	69.79%	30.00	9.28%	19.86	3.45			
South Jersey Industries	SJI	\$51.89	6.00%	9.00%	9.00%	11.58%	8.90%	5.77%	54.00%	53.00%	69.79%	30.00	10.92%	13.54	2.35			
Southwest Gas Corp.	SWX	\$44.02	4.37%	4.05%	9.00%	6.92%	6.09%	5.77%	46.00%	42.00%	69.79%	30.00	9.93%	16.77	2.91			
WGL Holdings, Inc.	WGL	\$40.13	5.37%	5.60%	3.50%	3.92%	4.60%	5.77%	62.00%	61.00%	69.79%	30.00	9.85%	17.09	2.97			
												MEAN	10.02%					
												MAX	10.92%					
												MIN	9.28%					
Projected Annual Earnings per Share																		
		[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]
Company	Ticker	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
AGL Resources Inc.	GAS	\$2.12	\$2.25	\$2.40	\$2.55	\$2.71	\$2.89	\$3.07	\$3.26	\$3.45	\$3.66	\$3.87	\$4.10	\$4.33	\$4.58	\$4.85	\$5.13	\$5.42
Atmos Energy Corp.	ATO	\$2.26	\$2.37	\$2.49	\$2.61	\$2.74	\$2.87	\$3.02	\$3.18	\$3.35	\$3.53	\$3.73	\$3.94	\$4.17	\$4.41	\$4.67	\$4.94	\$5.22
Laclede Group, Inc.	LG	\$2.86	\$2.98	\$3.10	\$3.22	\$3.35	\$3.49	\$3.64	\$3.81	\$3.99	\$4.20	\$4.43	\$4.68	\$4.95	\$5.24	\$5.54	\$5.86	\$6.20
New Jersey Resources	NJR	\$2.58	\$2.70	\$2.83	\$2.96	\$3.10	\$3.24	\$3.40	\$3.57	\$3.76	\$3.96	\$4.18	\$4.43	\$4.68	\$4.95	\$5.24	\$5.54	\$5.86
Northwest Natural Gas	NWN	\$2.39	\$2.51	\$2.64	\$2.78	\$2.93	\$3.08	\$3.24	\$3.41	\$3.60	\$3.80	\$4.02	\$4.25	\$4.49	\$4.75	\$5.03	\$5.32	\$5.62
Piedmont Natural Gas	PNY	\$1.57	\$1.63	\$1.69	\$1.76	\$1.82	\$1.89	\$1.97	\$2.06	\$2.16	\$2.27	\$2.39	\$2.53	\$2.68	\$2.83	\$2.99	\$3.17	\$3.35
South Jersey Industries	SJI	\$2.89	\$3.15	\$3.43	\$3.73	\$4.06	\$4.43	\$4.80	\$5.17	\$5.55	\$5.93	\$6.30	\$6.67	\$7.05	\$7.46	\$7.89	\$8.34	\$8.82
Southwest Gas Corp.	SWX	\$2.43	\$2.58	\$2.73	\$2.90	\$3.08	\$3.27	\$3.46	\$3.67	\$3.89	\$4.11	\$4.35	\$4.61	\$4.87	\$5.15	\$5.45	\$5.76	\$6.09
WGL Holdings, Inc.	WGL	\$2.26	\$2.35	\$2.46	\$2.57	\$2.69	\$2.82	\$2.95	\$3.10	\$3.26	\$3.44	\$3.63	\$3.84	\$4.06	\$4.29	\$4.54	\$4.80	\$5.08
Projected Annual Dividend Payout Ratio																		
		[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]		
Company	Ticker	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		
AGL Resources Inc.	GAS	66.00%	61.50%	57.00%	52.50%	48.00%	51.63%	55.26%	58.90%	62.53%	66.16%	69.79%	69.79%	69.79%	69.79%	69.79%		
Atmos Energy Corp.	ATO	61.00%	59.25%	57.50%	55.75%	54.00%	56.63%	59.26%	61.90%	64.53%	67.16%	69.79%	69.79%	69.79%	69.79%	69.79%		
Laclede Group, Inc.	LG	62.00%	61.00%	60.00%	59.00%	58.00%	59.97%	61.93%	63.90%	65.86%	67.83%	69.79%	69.79%	69.79%	69.79%	69.79%		
New Jersey Resources	NJR	53.00%	51.75%	50.50%	49.25%	48.00%	51.63%	55.26%	58.90%	62.53%	66.16%	69.79%	69.79%	69.79%	69.79%	69.79%		
Northwest Natural Gas	NWN	73.00%	68.75%	64.50%	60.25%	56.00%	58.30%	60.60%	62.90%	65.19%	67.49%	69.79%	69.79%	69.79%	69.79%	69.79%		
Piedmont Natural Gas	PNY	77.00%	75.75%	74.50%	73.25%	72.00%	71.63%	71.26%	70.90%	70.53%	70.16%	69.79%	69.79%	69.79%	69.79%	69.79%		
South Jersey Industries	SJI	54.00%	53.75%	53.50%	53.25%	53.00%	55.80%	58.60%	61.40%	64.19%	66.99%	69.79%	69.79%	69.79%	69.79%	69.79%		
Southwest Gas Corp.	SWX	46.00%	45.00%	44.00%	43.00%	42.00%	46.63%	51.26%	55.90%	60.53%	65.16%	69.79%	69.79%	69.79%	69.79%	69.79%		
WGL Holdings, Inc.	WGL	62.00%	61.75%	61.50%	61.25%	61.00%	62.47%	63.93%	65.40%	66.86%	68.33%	69.79%	69.79%	69.79%	69.79%	69.79%		
Projected Annual Cash Flows																		
		[47]	[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]	
Company	Ticker	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Terminal Value	
AGL Resources Inc.	GAS	\$1.49	\$1.48	\$1.45	\$1.42	\$1.39	\$1.58	\$1.80	\$2.03	\$2.29	\$2.56	\$2.86	\$3.02	\$3.20	\$3.38	\$3.58	\$89.62	
Atmos Energy Corp.	ATO	\$1.45	\$1.47	\$1.50	\$1.53	\$1.55	\$1.71	\$1.88	\$2.07	\$2.28	\$2.50	\$2.75	\$2.91	\$3.08	\$3.26	\$3.44	\$78.60	
Laclede Group, Inc.	LG	\$1.84	\$1.89	\$1.93	\$1.98	\$2.02	\$2.18	\$2.36	\$2.55	\$2.77	\$3.00	\$3.27	\$3.46	\$3.66	\$3.87	\$4.09	\$89.88	
New Jersey Resources	NJR	\$1.43	\$1.46	\$1.49	\$1.53	\$1.56	\$1.76	\$1.97	\$2.21	\$2.48	\$2.77	\$3.09	\$3.27	\$3.46	\$3.65	\$3.87	\$101.52	
Northwest Natural Gas	NWN	\$1.84	\$1.82	\$1.79	\$1.76	\$1.72	\$1.89	\$2.07	\$2.26	\$2.48	\$2.71	\$2.96	\$3.14	\$3.32	\$3.51	\$3.71	\$105.44	
Piedmont Natural Gas	PNY	\$1.26	\$1.28	\$1.31	\$1.34	\$1.36	\$1.41	\$1.47	\$1.53	\$1.60	\$1.68	\$1.77	\$1.87	\$1.98	\$2.09	\$2.21	\$66.52	
South Jersey Industries	SJI	\$1.70	\$1.84	\$2.00	\$2.16	\$2.35	\$2.58	\$3.03	\$3.41	\$3.81	\$4.22	\$4.65	\$4.92	\$5.20	\$5.50	\$5.82	\$119.43	
Southwest Gas Corp.	SWX	\$1.19	\$1.23	\$1.28	\$1.32	\$1.37	\$1.61	\$1.88	\$2.17	\$2.49	\$2.84	\$3.21	\$3.40	\$3.60	\$3.80	\$4.02	\$102.22	
WGL Holdings, Inc.	WGL	\$1.46	\$1.52	\$1.58	\$1.65	\$1.72	\$1.84	\$1.98	\$2.13	\$2.30	\$2.48	\$2.68	\$2.83	\$2.99	\$3.17	\$3.35	\$86.78	
Projected Annual Data Investor Cash Flows																		
		[63]	[64]	[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]
Company	Ticker	Initial	10/12/12	12/31/12	6/30/13	6/30/14	6/30/15	6/30/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26
AGL Resources Inc.	GAS	(\$39.92)	\$0.00	\$0.33	\$1.54	\$1.45	\$1.42	\$1.39	\$1.58	\$1.80	\$2.03	\$2.29	\$2.56	\$2.86	\$3.02	\$3.20	\$3.38	\$93.20
Atmos Energy Corp.	ATO	(\$35.58)	\$0.00	\$0.32	\$1.48	\$1.50	\$1.53	\$1.55	\$1.71	\$1.88	\$2.07	\$2.28	\$2.50	\$2.75	\$2.91	\$3.08	\$3.26	\$82.04
Laclede Group, Inc.	LG	(\$41.42)	\$0.00	\$0.40	\$1.88	\$1.93	\$1.98	\$2.02	\$2.18	\$2.36	\$2.55	\$2.77	\$3.00	\$3.27	\$3.46	\$3.66	\$3.87	\$93.97
New Jersey Resources	NJR	(\$45.09)	\$0.00	\$0.31	\$1.46	\$1.49	\$1.53	\$1.56	\$1.76	\$1.97	\$2.21	\$2.48	\$2.77	\$3.09	\$3.27	\$3.46	\$3.65	\$105.39
Northwest Natural Gas	NWN	(\$48.60)	\$0.00	\$0.40	\$1.88	\$1.79	\$1.76	\$1.72	\$1.89	\$2.07	\$2.26	\$2.48	\$2.71	\$2.96	\$3.14	\$3.32	\$3.51	\$109.15
Piedmont Natural Gas	PNY	(\$32.04)	\$0.00	\$0.28	\$1.28	\$1.31	\$1.34	\$1.36	\$1.41	\$1.47	\$1.53	\$1.60	\$1.68	\$1.77	\$1.87	\$1.98	\$2.09	\$68.73
South Jersey Industries	SJI	(\$51.89)	\$0.00	\$0.37	\$1.77	\$2.00	\$2.16	\$2.35	\$2.58	\$3.03	\$3.41	\$3.81	\$4.22	\$4.65	\$4.92	\$5.20	\$5.50	\$125.25
Southwest Gas Corp.	SWX	(\$44.02)	\$0.00	\$0.26	\$1.22	\$1.28	\$1.32	\$1.37	\$1.61	\$1.88	\$2.17	\$2.49	\$2.84	\$3.21	\$3.40	\$3.60	\$3.80	\$106.24
WGL Holdings, Inc.	WGL	(\$40.13)	\$0.00	\$0.32	\$1.48	\$1.58	\$1.65	\$1.72	\$1.84	\$1.98	\$2.13	\$2.30	\$2.48	\$2.68	\$2.83	\$2.99	\$3.17	\$90.13

Multistage Growth Discounted Cash Flow Model
180 Day Average Stock Price

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]			
		Stock	EPS Growth Rate Estimates				Long-Term		Payout Ratio		Iterative Solution		Terminal	Terminal				
			Sustainable															
Company	Ticker	Price	Zacks	First Call	Value Line	Growth	Average	Growth	2012	2016	2023	Proof	IRR	P/E Ratio	PEG Ratio			
AGL Resources Inc.	GAS	\$39.52	4.28%	NA	8.00%	6.81%	6.36%	5.77%	66.00%	48.00%	69.79%	\$0.00	10.03%	16.36	2.84			
Atmos Energy Corp.	ATO	\$33.74	5.83%	5.50%	4.00%	4.37%	4.93%	5.77%	61.00%	54.00%	69.79%	\$0.00	10.65%	14.29	2.48			
Laclede Group, Inc.	LG	\$44.84	3.00%	5.30%	2.00%	5.86%	4.04%	5.77%	62.00%	58.00%	69.79%	\$0.00	10.67%	14.23	2.47			
New Jersey Resources	NJR	\$44.88	3.35%	2.70%	5.50%	7.20%	4.69%	5.77%	53.00%	48.00%	69.79%	\$0.00	9.81%	17.25	2.99			
Northwest Natural Gas	NWN	\$47.36	4.17%	4.50%	4.50%	7.56%	5.18%	6.77%	73.00%	56.00%	69.79%	\$0.00	9.58%	18.28	3.17			
Piedmont Natural Gas	PNY	\$31.62	5.23%	5.35%	2.50%	2.19%	3.82%	5.77%	77.00%	72.00%	69.79%	\$0.00	9.33%	19.59	3.40			
South Jersey Industries	SJI	\$51.17	6.00%	9.00%	9.00%	11.58%	8.90%	5.77%	54.00%	53.00%	69.79%	(\$0.00)	10.99%	13.36	2.32			
Southwest Gas Corp.	SWX	\$43.16	4.37%	4.05%	9.00%	6.92%	6.09%	5.77%	46.00%	42.00%	69.79%	\$0.00	10.00%	16.46	2.86			
WGL Holdings, Inc.	WGL	\$40.18	5.37%	5.60%	3.50%	3.92%	4.80%	5.77%	62.00%	61.00%	69.79%	\$0.00	9.84%	17.12	2.97			
													MEAN	10.10%				
													MAX	10.99%				
													MIN	9.33%				
Projected Annual Earnings per Share																		
		[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]
Company	Ticker	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
AGL Resources Inc.	GAS	\$2.12	\$2.25	\$2.40	\$2.55	\$2.71	\$2.89	\$3.07	\$3.26	\$3.45	\$3.66	\$3.87	\$4.10	\$4.33	\$4.58	\$4.85	\$5.13	\$5.42
Atmos Energy Corp.	ATO	\$2.26	\$2.37	\$2.49	\$2.61	\$2.74	\$2.87	\$3.02	\$3.18	\$3.35	\$3.53	\$3.73	\$3.94	\$4.17	\$4.41	\$4.67	\$4.94	\$5.22
Laclede Group, Inc.	LG	\$2.86	\$2.98	\$3.10	\$3.22	\$3.35	\$3.49	\$3.64	\$3.81	\$3.99	\$4.20	\$4.43	\$4.68	\$4.95	\$5.24	\$5.54	\$5.86	\$6.20
New Jersey Resources	NJR	\$2.58	\$2.70	\$2.83	\$2.96	\$3.10	\$3.24	\$3.40	\$3.57	\$3.76	\$3.96	\$4.18	\$4.43	\$4.68	\$4.95	\$5.24	\$5.54	\$5.86
Northwest Natural Gas	NWN	\$2.39	\$2.51	\$2.64	\$2.78	\$2.93	\$3.08	\$3.24	\$3.41	\$3.60	\$3.80	\$4.02	\$4.25	\$4.49	\$4.75	\$5.03	\$5.32	\$5.62
Piedmont Natural Gas	PNY	\$1.57	\$1.63	\$1.69	\$1.76	\$1.82	\$1.89	\$1.97	\$2.06	\$2.16	\$2.27	\$2.39	\$2.53	\$2.68	\$2.83	\$2.99	\$3.17	\$3.35
South Jersey Industries	SJI	\$2.89	\$3.15	\$3.43	\$3.73	\$4.06	\$4.43	\$4.80	\$5.17	\$5.55	\$5.93	\$6.30	\$6.67	\$7.05	\$7.46	\$7.89	\$8.34	\$8.82
Southwest Gas Corp.	SWX	\$2.43	\$2.58	\$2.73	\$2.90	\$3.08	\$3.27	\$3.46	\$3.67	\$3.89	\$4.11	\$4.35	\$4.61	\$4.87	\$5.15	\$5.45	\$5.76	\$6.09
WGL Holdings, Inc.	WGL	\$2.25	\$2.35	\$2.46	\$2.57	\$2.69	\$2.82	\$2.95	\$3.10	\$3.26	\$3.44	\$3.63	\$3.84	\$4.06	\$4.29	\$4.54	\$4.80	\$5.08
Projected Annual Dividend Payout Ratio																		
		[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]		
Company	Ticker	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		
AGL Resources Inc.	GAS	66.00%	61.50%	57.00%	52.50%	48.00%	51.63%	55.26%	58.90%	62.53%	66.16%	69.79%	69.79%	69.79%	69.79%	69.79%		
Atmos Energy Corp.	ATO	61.00%	59.25%	57.50%	55.75%	54.00%	56.63%	59.26%	61.90%	64.53%	67.16%	69.79%	69.79%	69.79%	69.79%	69.79%		
Laclede Group, Inc.	LG	62.00%	61.00%	60.00%	59.00%	58.00%	59.97%	61.93%	63.30%	65.66%	67.83%	69.79%	69.79%	69.79%	69.79%	69.79%		
New Jersey Resources	NJR	53.00%	51.75%	50.50%	49.25%	48.00%	51.63%	55.26%	58.90%	62.53%	66.16%	69.79%	69.79%	69.79%	69.79%	69.79%		
Northwest Natural Gas	NWN	73.00%	68.75%	64.50%	60.25%	56.00%	58.30%	60.60%	62.90%	65.19%	67.49%	69.79%	69.79%	69.79%	69.79%	69.79%		
Piedmont Natural Gas	PNY	77.00%	73.75%	74.50%	73.25%	72.00%	71.63%	71.26%	70.90%	70.53%	70.16%	69.79%	69.79%	69.79%	69.79%	69.79%		
South Jersey Industries	SJI	54.00%	53.75%	53.50%	53.25%	53.00%	55.80%	58.60%	61.40%	64.19%	66.99%	69.79%	69.79%	69.79%	69.79%	69.79%		
Southwest Gas Corp.	SWX	46.00%	45.00%	44.00%	43.00%	42.00%	46.83%	51.26%	55.90%	60.53%	65.16%	69.79%	69.79%	69.79%	69.79%	69.79%		
WGL Holdings, Inc.	WGL	62.00%	61.75%	61.50%	61.25%	61.00%	62.47%	63.93%	65.40%	66.86%	68.33%	69.79%	69.79%	69.79%	69.79%	69.79%		
Projected Annual Cash Flows																		
		[47]	[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]	
Company	Ticker	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Terminal Value	
AGL Resources Inc.	GAS	\$1.49	\$1.48	\$1.45	\$1.42	\$1.39	\$1.58	\$1.80	\$2.03	\$2.29	\$2.56	\$2.86	\$3.02	\$3.20	\$3.38	\$3.58	\$88.74	
Atmos Energy Corp.	ATO	\$1.45	\$1.47	\$1.50	\$1.53	\$1.55	\$1.71	\$1.88	\$2.07	\$2.28	\$2.50	\$2.75	\$2.91	\$3.08	\$3.26	\$3.44	\$74.59	
Laclede Group, Inc.	LG	\$1.84	\$1.89	\$1.93	\$1.98	\$2.02	\$2.18	\$2.36	\$2.55	\$2.77	\$3.00	\$3.27	\$3.46	\$3.66	\$3.87	\$4.09	\$88.19	
New Jersey Resources	NJR	\$1.43	\$1.46	\$1.49	\$1.53	\$1.56	\$1.76	\$1.97	\$2.21	\$2.48	\$2.77	\$3.09	\$3.27	\$3.46	\$3.65	\$3.87	\$101.05	
Northwest Natural Gas	NWN	\$1.84	\$1.82	\$1.79	\$1.76	\$1.72	\$1.89	\$2.07	\$2.26	\$2.48	\$2.71	\$2.96	\$3.14	\$3.32	\$3.51	\$3.71	\$102.77	
Piedmont Natural Gas	PNY	\$1.26	\$1.28	\$1.31	\$1.34	\$1.36	\$1.41	\$1.47	\$1.53	\$1.60	\$1.68	\$1.77	\$1.87	\$1.98	\$2.09	\$2.21	\$65.61	
South Jersey Industries	SJI	\$1.70	\$1.84	\$2.00	\$2.16	\$2.35	\$2.68	\$3.03	\$3.41	\$3.81	\$4.22	\$4.65	\$4.92	\$5.20	\$5.50	\$5.82	\$117.87	
Southwest Gas Corp.	SWX	\$1.19	\$1.23	\$1.28	\$1.32	\$1.37	\$1.61	\$1.88	\$2.17	\$2.49	\$2.84	\$3.21	\$3.40	\$3.60	\$3.80	\$4.02	\$100.34	
WGL Holdings, Inc.	WGL	\$1.46	\$1.52	\$1.58	\$1.65	\$1.72	\$1.84	\$1.98	\$2.13	\$2.30	\$2.48	\$2.68	\$2.83	\$2.99	\$3.17	\$3.35	\$86.90	
Projected Annual Data Investor Cash Flows																		
		[63]	[64]	[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]
Company	Ticker	Initial	10/12/12	12/31/12	6/30/13	6/30/14	6/30/15	6/30/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26
AGL Resources Inc.	GAS	(\$39.52)	\$0.00	\$0.33	\$1.54	\$1.45	\$1.42	\$1.39	\$1.58	\$1.80	\$2.03	\$2.29	\$2.56	\$2.86	\$3.02	\$3.20	\$3.38	\$92.32
Atmos Energy Corp.	ATO	(\$33.74)	\$0.00	\$0.32	\$1.48	\$1.50	\$1.53	\$1.55	\$1.71	\$1.88	\$2.07	\$2.28	\$2.50	\$2.75	\$2.91	\$3.08	\$3.26	\$78.04
Laclede Group, Inc.	LG	(\$40.64)	\$0.00	\$0.40	\$1.88	\$1.93	\$1.98	\$2.02	\$2.18	\$2.36	\$2.55	\$2.77	\$3.00	\$3.27	\$3.46	\$3.66	\$3.87	\$92.28
New Jersey Resources	NJR	(\$44.88)	\$0.00	\$0.31	\$1.46	\$1.49	\$1.53	\$1.56	\$1.76	\$1.97	\$2.21	\$2.48	\$2.77	\$3.09	\$3.27	\$3.46	\$3.65	\$104.91
Northwest Natural Gas	NWN	(\$47.36)	\$0.00	\$0.40	\$1.88	\$1.79	\$1.76	\$1.72	\$1.89	\$2.07	\$2.26	\$2.48	\$2.71	\$2.96	\$3.14	\$3.32	\$3.51	\$106.47
Piedmont Natural Gas	PNY	(\$31.62)	\$0.00	\$0.28	\$1.28	\$1.31	\$1.34	\$1.36	\$1.41	\$1.47	\$1.53	\$1.60	\$1.68	\$1.77	\$1.87	\$1.98	\$2.09	\$67.82
South Jersey Industries	SJI	(\$51.17)	\$0.00	\$0.37	\$1.77	\$2.00	\$2.16	\$2.35	\$2.68	\$3.03	\$3.41	\$3.81	\$4.22	\$4.65	\$4.92	\$5.20	\$5.50	\$123.69
Southwest Gas Corp.	SWX	(\$43.16)	\$0.00	\$0.26	\$1.22	\$1.28	\$1.32	\$1.37	\$1.61	\$1.88	\$2.17	\$2.49	\$2.84	\$3.21	\$3.40	\$3.60	\$3.80	\$104.36
WGL Holdings, Inc.	WGL	(\$40.18)	\$0.00	\$0.32	\$1.49	\$1.58	\$1.65	\$1.72	\$1.84	\$1.98	\$2.13	\$2.30	\$2.48	\$2.68	\$2.83	\$2.99	\$3.17	\$90.25

Multi-Stage DCF Notes:

- [1] Source: Bloomberg; based on 30-, 90-, and 180-day historical average
- [2] Source: Zacks
- [3] Source: Yahoo! Finance
- [4] Source: Value Line
- [5] Source: Schedule (RBH)-3
- [6] Equals average Columns [2], [3], [4], [5]
- [7] Source: Federal Reserve, Bureau of Economic Analysis
- [8] Source: Value Line
- [9] Source: Value Line
- [10] Source: Bloomberg Professional
- [11] Equals Column [1] + Column [63]
- [12] Equals result of Excel Solver function; goal: Column [11] equals \$0.00
- [13] Equals Column [62] / Column [31]
- [14] Equals Column [13] / (Column [7] x 100)
- [15] Source: Value Line
- [16] Equals Column [15] x (1 + Column [6])
- [17] Equals Column [16] x (1 + Column [6])
- [18] Equals Column [17] x (1 + Column [6])
- [19] Equals Column [18] x (1 + Column [6])
- [20] Equals Column [19] x (1 + Column [6])
- [21] Equals (1 + (Column [6] + (((Column [7] - Column [6]) / (2021 - 2016 + 1)) x (2017 - 2016)))) x Column [20]
- [22] Equals (1 + (Column [6] + (((Column [7] - Column [6]) / (2021 - 2016 + 1)) x (2018 - 2016)))) x Column [21]
- [23] Equals (1 + (Column [6] + (((Column [7] - Column [6]) / (2021 - 2016 + 1)) x (2019 - 2016)))) x Column [22]
- [24] Equals (1 + (Column [6] + (((Column [7] - Column [6]) / (2021 - 2016 + 1)) x (2020 - 2016)))) x Column [23]
- [25] Equals (1 + (Column [6] + (((Column [7] - Column [6]) / (2021 - 2016 + 1)) x (2021 - 2016)))) x Column [24]
- [26] Equals Column [25] x (1 + Column [7])
- [27] Equals Column [26] x (1 + Column [7])
- [28] Equals Column [27] x (1 + Column [7])
- [29] Equals Column [28] x (1 + Column [7])
- [30] Equals Column [29] x (1 + Column [7])
- [31] Equals Column [30] x (1 + Column [7])
- [32] Equals Column [8]
- [33] Equals Column [32] + ((Column [36] - Column [32]) / 4)
- [34] Equals Column [33] + ((Column [36] - Column [32]) / 4)
- [35] Equals Column [34] + ((Column [36] - Column [32]) / 4)
- [36] Equals Column [9]
- [37] Equals Column [36] + ((Column [42] - Column [36]) / 6)
- [38] Equals Column [37] + ((Column [42] - Column [36]) / 6)
- [39] Equals Column [38] + ((Column [42] - Column [36]) / 6)
- [40] Equals Column [39] + ((Column [42] - Column [36]) / 6)
- [41] Equals Column [40] + ((Column [42] - Column [36]) / 6)
- [42] Equals Column [10]
- [43] Equals Column [10]
- [44] Equals Column [10]
- [45] Equals Column [10]
- [46] Equals Column [10]
- [47] Equals Column [16] x Column [32]
- [48] Equals Column [17] x Column [33]
- [49] Equals Column [18] x Column [34]
- [50] Equals Column [19] x Column [35]
- [51] Equals Column [20] x Column [36]
- [52] Equals Column [21] x Column [37]
- [53] Equals Column [22] x Column [38]
- [54] Equals Column [23] x Column [39]
- [55] Equals Column [24] x Column [40]
- [56] Equals Column [25] x Column [41]
- [57] Equals Column [26] x Column [42]
- [58] Equals Column [27] x Column [43]
- [59] Equals Column [28] x Column [44]
- [60] Equals Column [29] x Column [45]
- [61] Equals Column [30] x Column [46]
- [62] Equals (Column [61] x (1 + Column [7])) / (Column [12] - Column [7])
- [63] Equals negative net present value; discount rate equals Column [12], cash flows equal Column [64] through Column [79]
- [64] Equals \$0.00
- [65] Equals (12/31/2012 - 10/12/2012) x Column [47]
- [66] Equals Column [47] x (1 + (0.5 x Column [6]))
- [67] Equals Column [49]
- [68] Equals Column [50]
- [69] Equals Column [51]
- [70] Equals Column [52]
- [71] Equals Column [53]
- [72] Equals Column [54]
- [73] Equals Column [55]
- [74] Equals Column [56]
- [75] Equals Column [57]
- [76] Equals Column [58]
- [77] Equals Column [59]
- [78] Equals Column [60]
- [79] Equals Column [61] + [62]

Sharpe Ratio Derived *Ex-Ante* Market Risk Premium

[1]	[2]	[3]	[4]	[5]
RP _h	Vol _h	VOL _e	Historical Sharpe Ratio	RP _e
6.60%	20.30%	23.15%	32.52%	7.53%
	[6]	[7]	[8]	[9]
Date	VXV	Mar 13 VIX Futures	Apr 13 VIX Futures	May 13 VIX Futures
10/12/2012	17.74	22.00	22.90	23.60
10/11/2012	17.57	22.20	23.30	23.95
10/10/2012	18.13	22.55	23.80	24.40
10/9/2012	18.01	22.55	23.70	24.30
10/8/2012	17.36	22.30	23.55	24.20
10/5/2012	16.93	22.40	23.55	24.20
10/4/2012	17.06	22.45	23.65	24.35
10/3/2012	17.58	22.95	24.15	24.80
10/2/2012	17.74	23.25	24.35	24.95
10/1/2012	17.92	23.45	24.50	25.15
9/28/2012	17.61	23.35	24.50	25.15
9/27/2012	17.07	23.25	24.40	25.00
9/26/2012	18.50	23.75	24.95	25.60
9/25/2012	17.60	23.65	24.85	25.50
9/24/2012	16.59	23.40	24.60	25.15
9/21/2012	16.79	23.70	24.75	25.25
9/20/2012	16.75	23.50	24.60	25.20
9/19/2012	16.49	23.60	24.55	25.25
9/18/2012	16.63	23.90	24.75	25.40
9/17/2012	17.13	24.25	25.10	25.65
9/14/2012	16.90	24.60	25.35	25.80
9/13/2012	16.45	24.50	25.35	25.95
9/12/2012	17.60	25.30	26.05	26.40
9/11/2012	18.29	25.95	26.70	27.05
9/10/2012	18.30	26.25	26.95	27.25
9/7/2012	17.59	25.85	26.50	26.85
9/6/2012	18.62	26.40	27.10	27.40
9/5/2012	19.99	27.30	27.85	28.20
9/4/2012	20.68	27.75	28.35	28.60
8/31/2012	20.62	27.65	28.25	28.50
Average:		23.15		

Notes:

[1] Source: Morningstar, Inc.

RP_h = historical arithmetic average Risk Premium

[2] Source: Morningstar, Inc.

Vol_h = historical market volatility

[3] Vol_e = expected market volatility (average of Cols. [6] to [9])

[4] Equals [1] / [2]

[5] RP_e = expected Risk Premium ([3] x [4])

[6] Source: Bloomberg Professional

[7] Source: Bloomberg Professional

[8] Source: Bloomberg Professional

[9] Source: Bloomberg Professional

Ex-Ante Market Risk Premium
Market DCF Method Based - Bloomberg

[1]	[2]	[3]
S&P 500 Est. Required Market Return	Current 30-Year Treasury (30-day average)	Implied Market Risk Premium
12.93%	2.87%	10.06%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional

[3] Equals [1] - [2]

Ex-Ante Market Risk Premium
Market DCF Method Based - Capital IQ

[1]	[2]	[3]
S&P 500 Est. Required Market Return	Current 30-Year Treasury (30-day average)	Implied Market Risk Premium
12.87%	2.87%	10.00%

Notes:

[1] Source: Capital IQ

[2] Source: Bloomberg Professional

[3] Equals [1] - [2]

Bloomberg and Value Line Beta Coefficients

Company	Ticker	[1]	[2]
		Bloomberg	Value Line
AGL Resources Inc.	GAS	0.761	0.75
Atmos Energy Corporation	ATO	0.695	0.70
Laclede Group, Inc. (The)	LG	0.654	0.60
New Jersey Resources Corporation	NJR	0.723	0.65
Northwest Natural Gas Company	NWN	0.652	0.55
Piedmont Natural Gas Company, Inc.	PNY	0.799	0.65
South Jersey Industries, Inc.	SJI	0.783	0.65
Southwest Gas Corporation	SWX	0.771	0.75
WGL Holdings, Inc.	WGL	0.752	0.65
Mean		0.732	0.66

Notes:

[1] Source: Bloomberg Professional Service

[2] Source: Value Line

Capital Asset Pricing Model Results
Sharpe Ratio, Bloomberg, and Capital IQ Derived Market Risk Premium

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
	Ex-Ante Market Risk Premium					CAPM Result		
	Risk-Free Rate	Average Beta Coefficient	Sharpe Ratio Derived	Bloomberg Market DCF Derived	Capital IQ Market DCF Derived	Sharpe Ratio Derived	Bloomberg Market DCF Derived	Capital IQ Market DCF Derived
PROXY GROUP BLOOMBERG BETA COEFFICIENT								
Current 30-Year Treasury (30-day average) [9]	2.87%	0.732	7.53%	10.06%	10.00%	8.38%	10.24%	10.19%
Near-Term Projected 30-Year Treasury [10]	3.15%	0.732	7.53%	10.06%	10.00%	8.66%	10.52%	10.47%
Mean						8.52%	10.38%	10.33%
	Ex-Ante Market Risk Premium					CAPM Result		
	Risk-Free Rate	Average Beta Coefficient	Sharpe Ratio Derived	Bloomberg Market DCF Derived	Capital IQ Market DCF Derived	Sharpe Ratio Derived	Bloomberg Market DCF Derived	Capital IQ Market DCF Derived
PROXY GROUP VALUE LINE AVERAGE BETA COEFFICIENT								
Current 30-Year Treasury (30-day average) [9]	2.87%	0.661	7.53%	10.06%	10.00%	7.85%	9.52%	9.48%
Near-Term Projected 30-Year Treasury [10]	3.15%	0.661	7.53%	10.06%	10.00%	8.13%	9.80%	9.76%
Mean						7.99%	9.66%	9.62%

Notes:

[1] See Notes [9] and [10]

[2] Source: Schedule (RBH)-6

[3] Source: Schedule (RBH)-5

[4] Source: Schedule (RBH)-5

[5] Source: Schedule (RBH)-5

[6] Equals Col. [1] + (Col. [2] x Col. [3])

[7] Equals Col. [1] + (Col. [2] x Col. [4])

[8] Equals Col. [1] + (Col. [2] x Col. [5])

[9] Source: Bloomberg Professional

[10] Source: Blue Chip Financial Forecasts, Vol. 31, No. 10, October 1, 2012, at 2

Bond Yield Plus Risk Premium

	[1]	[2]	[3] 30-Year Treasury Yield	[4] Risk Premium	[5] Return on Equity
	Constant	Slope			
Current	-3.24%	-2.95%	2.87%	7.25%	10.12%
Near Term Projected	-3.24%	-2.95%	3.15%	6.98%	10.13%
Long-Term Projected	-3.24%	-2.95%	5.30%	5.44%	10.74%

Notes:

[1] Constant of regression equation

[2] Slope of regression equation

[3] Source: Current = Bloomberg Professional,

Near Term Projected = Blue Chip Financial Forecasts, Vol. 31, No. 10, October 1, 2012, at 2,

Long Term Projected = Blue Chip Financial Forecasts, Vol. 31, No. 6, June 1, 2012, at 14

[4] Equals [1] + [2] x ln([3])

[5] Equals [3] + [4]

Small Size Premium

	[1]	[2]
	Customers (Mil)	(\$Bil)
Delmarva Power & Light Company Equity	0.1	\$0.13
Median Market to Book for Comp Group		1.61
Delmarva Power & Light Company Implied Market Cap		\$0.21

		[3]	[4]	[5]
Company Name	Ticker	Customers (Mil)	Market Cap (\$Bil)	Market to Book Ratio
AGL Resources Inc.	GAS	2.5	\$4.81	1.42
Atmos Energy Corporation	ATO	3.2	\$3.21	1.36
Laclede Group, Inc. (The)	LG	0.6	\$0.96	1.56
New Jersey Resources Corporation	NJR	0.5	\$1.90	2.28
Northwest Natural Gas Company	NWN	0.7	\$1.32	1.79
Piedmont Natural Gas Company, Inc.	PNY	1.0	\$2.32	2.22
South Jersey Industries, Inc.	SJI	0.3	\$1.61	2.36
Southwest Gas Corporation	SWX	1.8	\$2.03	1.58
WGL Holdings, Inc.	WGL	1.1	\$2.06	1.61
MEDIAN		1.0	\$2.03	1.61
MEAN		1.3	\$2.25	1.80

Market Capitalization (\$Mil) [6]				
Decile	Low	High	Size Premium	
2	\$ 6,927.557	\$ 15,408.314	0.78%	
3	\$ 3,596.535	\$ 6,896.389	0.94%	
4	\$ 2,366.464	\$ 3,577.774	1.17%	
5	\$ 1,621.096	\$ 2,362.532	1.74%	
6	\$ 1,090.652	\$ 1,620.860	1.75%	
7	\$ 683.059	\$ 1,090.515	1.77%	
8	\$ 422.999	\$ 682.750	2.51%	
9	\$ 206.802	\$ 422.811	2.80%	
10	\$ 1.028	\$ 206.795	6.10%	

Notes:

[1] SEC Form 10-K for the fiscal year ended December 31, 2011, p. 9

[2] Application for Increase in Rates

[3] Source: SNL Financial

[4] Source: Bloomberg, 30-day average

[5] Source: Bloomberg, 30-day average

[6] Source: Ibbotson Associates, 2012 Ibbotson SBBI Risk Premia Over Time Report

Revenue Stabilization Mechanisms

Company	Ticker	Infrastructure	Decoupling	Expense
AGL Resources Inc.	GAS	✓	✓	✓
Atlanta Gas Light Co.		✓ [1], [2]		✓ [1]
Northern Illinois Gas Co.				✓ [1], [2]
Virginia Natural Gas			✓ [1], [2]	✓ [1], [2]
Elizabethtown Gas		✓ [1], [2]	✓ [1], [2]	
Florida City Gas				✓ [1]
Chattanooga Gas			✓ [1], [2]	✓ [1], [2]
Atmos Energy Corporation	ATO	✓	✓	✓
Atmos Energy (Colorado)				✓ [2]
Atmos Energy (Georgia)		✓ [2]	✓ [1], [2]	
Atmos Energy (Iowa)				
Atmos Energy (Illinois)				
Atmos Energy (Kansas)		✓ [1], [2]	✓ [1], [2]	✓ [2]
Atmos Energy (Kentucky)		✓ [1], [2]	✓ [1], [2]	✓ [1], [2]
Atmos Energy (Louisiana)			✓ [1], [2]	✓ [2]
Atmos Energy (Mississippi)			✓ [1], [2]	✓ [2]
Atmos Energy (Missouri)		✓ [1], [2]		✓ [2]
Atmos Energy (Tennessee)			✓ [1], [2]	✓ [1], [2]
Atmos Energy (Texas)		✓ [1], [2]	✓ [1], [2]	✓ [2]
Atmos Energy (Virginia)			✓ [2]	✓ [2]
Laclede Group, Inc. (The)	LG	✓		✓
Laclede Gas Co.		✓ [1], [2]		✓ [1], [2]
New Jersey Resources Corporation	NJR	✓	✓	
New Jersey Natural Gas		✓ [1], [2]	✓ [1], [2]	
Northwest Natural Gas Company	NWN	✓	✓	
Northwest Natural Gas (Oregon)		✓ [1], [2]	✓ [1], [2]	
Northwest Natural Gas (Washington)				
Piedmont Natural Gas Company, Inc.	PNY		✓	✓
Piedmont Natural Gas (North Carolina)			✓ [1], [2]	✓ [2]
Piedmont Natural Gas (South Carolina)			✓ [1], [2]	✓ [2]
Piedmont Natural Gas (Tennessee)			✓ [1], [2]	✓ [2]
South Jersey Industries, Inc.	SJI	✓	✓	✓
SJG		✓ [1], [2]	✓ [1], [2]	✓ [3]
Southwest Gas Corporation	SWX		✓	✓
Southwest Gas Corporation (Arizona)			✓ [1], [2]	
Southwest Gas Corporation (California)			✓ [1], [2]	
Southwest Gas Corporation (Nevada)			✓ [1], [2]	✓ [1], [2]
WGL Holdings, Inc.	WGL	✓	✓	✓
Washington Gas - DC				✓ [2]
Washington Gas - MD			✓ [1], [2]	✓ [2]
Washington Gas - VA		✓ [1], [2]	✓ [1]	✓ [2]

[1] RRA Adjustment Clauses and Rate Riders, March 21, 2012

[2] AGA, Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms: Current List, March 2012

[3] 2011 SEC Form 10-K

Flotation Cost Adjustment

Two most recent open market common stock issuances per company, if available

Company	Date	Shares Issued	Offering Price	Underwriting Discount	Offering Expense	Net Proceeds Per Share	Total Flotation Costs	Gross Equity Issue Before Costs	Net Proceeds	Flotation Cost Percentage
Pepeco Holdings, Inc.	3/5/2012	17,922,077	\$19.25	\$0.6738	\$500,000	\$18.55	\$12,574,999	\$344,999,982	\$332,424,983	3.645%
Pepeco Holdings, Inc.	11/5/2008	16,100,000	\$16.50	\$0.6188	\$200,000	\$15.87	\$10,161,875	\$265,650,000	\$255,488,125	3.825%
AGL Resources Inc.	11/13/2004	11,040,000	\$31.01	\$0.9300	\$400,000	\$30.04	\$10,687,200	\$342,350,400	\$331,683,200	3.116%
AGL Resources Inc.	2/11/2003	6,440,000	\$22.00	\$0.7700	\$250,000	\$21.19	\$9,208,800	\$141,680,000	\$136,471,200	3.676%
Almos Energy Corporation	12/7/2006	6,325,000	\$31.50	\$1.1025	\$400,000	\$30.33	\$7,373,313	\$199,237,500	\$191,864,188	3.701%
Almos Energy Corporation	10/21/2004	16,100,000	\$24.75	\$0.9900	\$400,000	\$23.74	\$16,339,000	\$398,475,000	\$382,136,000	4.100%
Laclede Group, Inc. (The)	5/25/2004	1,725,000	\$26.80	\$0.8710	\$100,000	\$25.87	\$1,602,475	\$46,230,000	\$44,627,525	3.466%
Northwest Natural Gas Company	3/30/2004	1,290,000	\$31.00	\$1.0100	\$175,000	\$29.85	\$1,477,900	\$39,990,000	\$38,512,100	3.696%
Piedmont Natural Gas Company, Inc.	1/20/2004	4,897,500	\$42.50	\$1.4900	\$550,000	\$40.94	\$7,632,375	\$207,718,750	\$200,086,375	3.674%
WGL Holdings, Inc.	6/20/2001	2,058,500	\$26.73	\$0.8950	\$56,218	\$25.81	\$1,898,576	\$55,023,705	\$53,125,130	3.450%
Mean							\$7,493,651	\$204,135,534		3.671%

WEIGHTED AVERAGE FLOTATION COSTS: 3.671%

Constant Growth Discounted Cash Flow Model Adjusted for Flotation Costs - 30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Adjusted for Flot. Costs	[6] Zacks Earnings Growth	[7] First Call Earnings Growth	[8] Value Line Earnings Growth	[9] Sustainable Growth	[10] Average Earnings Growth	[11] DCF k(e)	[12] Flotation Adjusted DCF k(e)
AGL Resources Inc.	GAS	\$1.84	\$40.94	4.49%	4.64%	4.81%	4.28%	NA	8.00%	6.81%	6.36%	11.00%	11.18%
Almos Energy Corporation	ATO	\$1.38	\$35.64	3.87%	3.97%	4.12%	5.83%	5.50%	4.00%	4.37%	4.93%	8.89%	9.04%
Laclede Group, Inc. (The)	LG	\$1.66	\$42.63	3.89%	3.97%	4.12%	3.00%	5.30%	2.00%	5.86%	4.04%	8.01%	8.16%
New Jersey Resources Corporation	NJR	\$1.60	\$45.75	3.50%	3.58%	3.72%	3.35%	2.70%	5.50%	7.20%	4.69%	8.27%	8.40%
Northwest Natural Gas Company	NWN	\$1.82	\$49.23	3.70%	3.79%	3.94%	4.17%	4.50%	4.50%	7.56%	5.18%	8.97%	9.12%
Piedmont Natural Gas Company, Inc.	PNY	\$1.20	\$32.23	3.72%	3.79%	3.94%	5.23%	5.35%	2.50%	2.19%	3.82%	7.61%	7.76%
South Jersey Industries, Inc.	SJI	\$1.61	\$52.20	3.08%	3.22%	3.34%	6.00%	9.00%	9.00%	11.58%	8.90%	12.12%	12.24%
Southwest Gas Corporation	SWX	\$1.18	\$43.92	2.69%	2.77%	2.87%	4.37%	4.05%	9.00%	6.92%	6.09%	8.85%	8.96%
WGL Holdings, Inc.	WGL	\$1.60	\$39.89	4.01%	4.10%	4.26%	5.37%	5.80%	3.50%	3.92%	4.80%	8.70%	8.86%
PROXY GROUP MEAN												9.16%	9.30%

Notes:

The proxy group DCF result is adjusted for flotation costs by dividing each company's expected dividend yield by (1 - flotation cost). The flotation cost adjustment is derived as the difference between the unadjusted DCF result and the DCF result adjusted for flotation costs.

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional

[3] Equals [1] / [2]

[4] Equals [3] x (1 + 0.5 x [10])

[5] Equals [4] / (1 - 0.0367)

[6] Source: Zacks

[7] Source: Yahoo! Finance

[8] Source: Value Line

[9] Source: Schedule (RBH)-3

[10] Equals Average([6], [7], [8], [9])

[11] Equals [4] + [10]

[12] Equals [5] + [10]

[13] Equals average [12] - average [11]

DCF Result Adjusted For Flotation Costs: 9.30%

DCF Result Unadjusted For Flotation Costs: 9.16%

Difference (Flotation Cost Adjustment): 0.14% [13]

Proxy Group Capital Structure

Company	Ticker	2011	% Long-Term Debt		
			2010	2009	Average
AGL Resources Inc.	GAS	47.28%	44.80%	45.77%	45.95%
Atmos Energy Corporation	ATO	53.69%	49.00%	53.53%	52.08%
Laclede Group, Inc. (The)	LG	45.64%	46.97%	49.16%	47.26%
New Jersey Resources Corporation	NJR	33.38%	34.35%	35.38%	34.37%
Northwest Natural Gas Company	NWN	45.72%	46.05%	47.69%	46.48%
Piedmont Natural Gas Company, Inc.	PNY	46.45%	48.63%	50.37%	48.48%
South Jersey Industries, Inc.	SJI	43.87%	44.34%	36.68%	41.63%
Southwest Gas Corporation	SWX	42.62%	50.64%	53.44%	48.90%
WGL Holdings, Inc.	WGL	36.50%	38.53%	38.26%	37.76%
Mean		43.91%	44.81%	45.58%	44.77%

Operating Company Capital Structure

Operating Company	Parent	2011	% Long-Term Debt	
			2010	2009
Pivotal Utility Holdings, Inc.	GAS	N/A	N/A	N/A
Northern Illinois Gas Company	GAS	43.88%	43.55%	43.00%
Atlanta Gas Light Company	GAS	47.52%	47.12%	49.68%
Chattanooga Gas Company	GAS	48.07%	47.82%	49.15%
Virginia Natural Gas, Inc.	GAS	49.67%	40.70%	41.25%
Atmos Energy Corporation	ATO	53.69%	49.00%	53.53%
Laclede Group, Inc. (The)	LG	45.64%	46.97%	49.16%
New Jersey Natural Gas Company	NJR	33.38%	34.35%	35.38%
Northwest Natural Gas Company	NWN	45.72%	46.05%	47.69%
Piedmont Natural Gas Company, Inc.	PNY	46.45%	48.63%	50.37%
South Jersey Gas Company	SJI	43.87%	44.34%	36.68%
Southwest Gas Corporation	SWX	42.62%	50.64%	53.44%
Washington Gas Light Company	WGL	36.50%	38.53%	38.26%

Source: SNL Financial

Proxy Group Capital Structure

Company	Ticker	2011	% Common Equity		Average
			2010	2009	
AGL Resources Inc.	GAS	52.72%	55.20%	54.23%	54.05%
Atmos Energy Corporation	ATO	46.31%	51.00%	46.47%	47.92%
Laclede Group, Inc. (The)	LG	54.36%	53.03%	50.84%	52.74%
New Jersey Resources Corporation	NJR	66.62%	65.65%	64.62%	65.63%
Northwest Natural Gas Company	NWN	54.28%	53.95%	52.31%	53.52%
Piedmont Natural Gas Company, Inc.	PNY	53.55%	51.37%	49.63%	51.52%
South Jersey Industries, Inc.	SJI	56.13%	55.66%	63.32%	58.37%
Southwest Gas Corporation	SWX	57.38%	49.36%	46.56%	51.10%
WGL Holdings, Inc.	WGL	63.50%	61.47%	61.74%	62.24%
Mean		56.09%	55.19%	54.42%	55.23%

Operating Company Capital Structure

Operating Company	Parent	2011	% Common Equity	
			2010	2009
Pivotal Utility Holdings, Inc.	GAS	N/A	N/A	N/A
Northern Illinois Gas Company	GAS	56.12%	56.45%	57.00%
Atlanta Gas Light Company	GAS	52.48%	52.88%	50.32%
Chattanooga Gas Company	GAS	51.93%	52.18%	50.85%
Virginia Natural Gas, Inc.	GAS	50.33%	59.30%	58.75%
Atmos Energy Corporation	ATO	46.31%	51.00%	46.47%
Laclede Group, Inc. (The)	LG	54.36%	53.03%	50.84%
New Jersey Natural Gas Company	NJR	66.62%	65.65%	64.62%
Northwest Natural Gas Company	NWN	54.28%	53.95%	52.31%
Piedmont Natural Gas Company, Inc.	PNY	53.55%	51.37%	49.63%
South Jersey Gas Company	SJI	56.13%	55.66%	63.32%
Southwest Gas Corporation	SWX	57.38%	49.36%	46.56%
Washington Gas Light Company	WGL	63.50%	61.47%	61.74%

Testimony of Jay C. Ziminsky

DELMARVA POWER & LIGHT COMPANY
BEFORE THE
DELAWARE PUBLIC SERVICE COMMISSION
DIRECT TESTIMONY OF JAY C. ZIMINSKY
DOCKET NO. _____

1 **Q1. Please state your name and position.**

2 A1. My name is Jay C. Ziminsky. I am Manager, Revenue Requirements, in
3 the Regulatory Affairs Department of Pepco Holdings, Inc. (PHI). I am testifying
4 on behalf of Delmarva Power & Light Company (Delmarva, Delmarva Power or
5 the Company).

6 **Q2. What are your responsibilities in your role as Manager of Revenue**
7 **Requirements?**

8 A2. I am responsible for the coordination of revenue requirement
9 determinations in New Jersey, Delaware and Maryland as well as coordinating
10 various other regulatory compliance matters.

11 **Q3. Please state your educational background and professional experience.**

12 A3. I received a Bachelor of Science Degree in Business Administration with a
13 concentration in Accounting from Drexel University in 1988 and a Masters in
14 Business Administration with a concentration in Finance from the University of
15 Delaware in 1996. I earned my Certified Public Accountant certification in the
16 State of Pennsylvania in 1988.

17 In 1988, I joined Price Waterhouse as a Tax Associate. In 1991, I joined
18 Delmarva as a Staff Accountant in the General Accounting section of the
19 Controller's Department. In 1994, I joined the Management Information Process
20 Redesign team as a Senior Accountant. In 1995, I joined the Conectiv Enterprises
21 Business & Financial Management team as a Senior Financial Analyst. In 1996, I

1 was promoted to Finance & Accounting Manager of Conectiv Communications,
2 where I was later promoted to Finance & Accounting Director (in 1999) and Vice
3 President – Finance (in 2000). In 2002, I joined the PHI Treasury Department as
4 Finance Manager. In 2006, I joined the PHI Regulatory Department and was
5 promoted to my current position in October 2008.

6 **Q4. What is the purpose of your Direct Testimony?**

7 A4. The purpose of my Direct Testimony is to present the per book Earnings
8 and Rate Base for use in this filing as well as the quantification and support of
9 certain ratemaking adjustments. I summarize the proposed adjustments as well as
10 the overall revenue requirement request of the Company. I sponsor certain
11 adjustments which are described in my Direct Testimony with supporting detail
12 that can be found in Schedules (JCZ) 1-20, which accompany this filing. I am
13 also sponsoring certain Minimum Filing Requirements (MFR).

14 This testimony was prepared by me or under my direct supervision and
15 control. The source documents for my testimony are Company records, public
16 documents, and my personal knowledge and experience.

17 **Filing Requirements**

18 **Q5. What MFR are you sponsoring?**

19 A5. I am sponsoring the following filing requirements:

20	Schedule A	Test Year and Test Period Defined
21	Schedule C	Elements of Rate Increase
22	Schedule 1	Financial Summary
23	Schedule 2	Rate Base Summary

1	Schedule 2A	Used and Useful Utility Plant
2	Schedule 2B	Intangible Assets
3	Schedule 2C	Accumulated Depreciation & Amortization,
4		and Customer Advances
5		
6	Schedule 2D	Accumulated Deferred Income Taxes &
7		Investment Tax Credit
8	Schedule 2E	Materials and Supplies
9	Schedule 2F	Other Elements of Property and CWIP
10	Schedule 3	Summary of Net Operating Income
11	Schedule 3A	Revenues
12	Schedule 3B	Operating Expenses
13	Schedule 3C	Payroll Costs
14	Schedule 3E	Sales Promotion and Advertising
15	Schedule 3F	Contributions
16	Schedule 3G	Association Dues
17	Schedule 3H	Rate Case Expense
18	Schedule 3I	Income Taxes and Provisions
19	Schedule 3J	Federal and State Income Taxes
20	Schedule 3K	Deferred Federal and State Income Taxes
21	Schedule 3L	Investment Tax Credit
22	Schedule 3M	Other Taxes
23	Schedule 3O	Other Income
24	Schedule 5	Revenue Conversion Factor

25 **Q6. What are the test year and the test period presented in this filing?**

1 A6. The test year, which is used for cost allocation purposes, is the actual
2 twelve months data ending June 2012. The test period, which is used for revenue
3 requirement purposes, is the six months actual and six months forecast ending
4 December 2012. The test period will be updated to the twelve months of actual
5 information ending December 2012 during the course of this proceeding.

6 **Q7. Is this test period a reasonable one?**

7 A7. Yes. In the absence of the use of a fully forecasted test period, a partially
8 forecasted test period with ratemaking adjustments represents a reasonable test
9 period from which rates can be established for the rate effective period. For this
10 filing, the rate effective period represents the period from July 2013 through June
11 2014. With the adjustments presented in this filing, this test period provides a
12 matching of revenues, expenses and rate base consistent with Commission
13 regulations and, in the absence of a fully forecasted test period, represents a
14 reasonable basis for establishing the Company's revenue requirements for the rate
15 effective period.

16 **Q8. Please describe how the Company plans on providing updated test period**
17 **data to the Commission as required by the Minimum Filing Requirements.**

18 A8. The test period represents the six months actual and six months of
19 forecasted data ending December 31, 2012. The MFR require that three additional
20 months of total Company data be provided 60 days after the quarter closes. While
21 the Company is only required to update that actual total Company data for the
22 period July 2012 through September 2012, the Company will provide a complete
23 updated fully adjusted test period based on all actual data for the twelve months

1 ending December 31, 2012 to the Staff and all parties in March 2013. This timing
2 will allow the Staff and parties adequate time to perform discovery and complete
3 their analysis.

4 **Q9. Please describe the development of per books rate base and earnings.**

5 A9. The rate base for the test year and test period is comprised of year-end
6 balances and is summarized on Schedule (JCZ)-1, Pages 1 and 2. Earnings for the
7 test year and test period are also summarized on Schedule (JCZ)-1, Pages 1 and 2.

8 The source of the data for the test year and test period consists of the
9 Company's actual books and records provided by Company Witness White. The
10 forecasted data has been similarly assembled and organized to provide the
11 monthly data for the parties in this proceeding. Detail for the test year and test
12 period can be found in the workpapers contained in Book 3 that accompanies the
13 Company's Application.

14 Earnings include Operating Revenues less Operating Expense and Interest
15 on Customer Deposits plus the Allowance for Funds Used During Construction
16 (AFUDC), as shown on Schedule (JCZ)-1. A number of pre-cost study
17 adjustments have been made to the books to allow the resulting cost of service
18 returns by class to be representative for distribution rate design purposes. As
19 discussed in Company Witness Santacecilia's testimony, the basis for designing
20 rates is the class returns resulting from the cost of service. The pre-cost study
21 earnings adjustments are detailed in the workpapers contained in Book 3.

22 The following pre-cost study adjustments are supported by Company
23 Witness Santacecilia:

- 1 • Removal of the effect of the Environmental Fund Rate Revenues;
- 2
- 3 • Maximum Daily Quantity (MDQ) Annualization Adjustment;
- 4 • Weather Normalization Adjustment;
- 5 • Removal of the effects of Utility Tax;
- 6 • Bill Frequency Adjustment;
- 7 • Large Volume Gas Sales Service (LVG) Adjustment;
- 8 • Balancing Volume Adjustment;
- 9 • Removal of the effect of Gas Cost Recovery Fuel Revenues
- 10 • Annualized Billing System Miscellaneous Adjustment; and
- 11 • Year-End Customer Adjustment.

12 I support the following pre-cost adjustments:

- 13 • Removal of Environmental Fund Rate Expenses;
- 14 • Removal of the effect of Gas Cost Recovery Fuel Expenses;
- 15 • Removal of the effect of Unbilled Revenues;
- 16 • Removal of Gas Cost Rate Margin Sharing; and
- 17 • Restatement of Federal and State Deferred Income Taxes.

18 The per book rate base is detailed by component on Schedule (JCZ)-1.
19
20 Additions to rate base are included as they represent investment in facilities used
21 to serve the Company's customers as well as investor-supplied working capital
22 necessary for the Company's day-to-day operations. Certain items are deducted
23 from rate base as they represent funds supplied by customers (or at least not
24 investor-provided). Rate base includes Net Plant, Construction Work in Progress
25 (CWIP), Materials and Supplies and Working Capital, less Accumulated Deferred

1 Income Taxes, Unamortized Investment Tax Credits, Customer Advances and
2 Customer Deposits.

3 **Q10. Does the Company's rate base and earnings proposed in this Docket conform**
4 **to the last litigated Electric decision in Docket No. 09-414?**

5 A10. Yes, although there are three items that differ from the Commission's
6 decision in Docket No. 09-414, which I have outlined below:

- 7 • I have included CWIP in per books rate base with the
8 corresponding accrued AFUDC in earnings since many of the
9 projects are technically complete, with AFUDC no longer being
10 accrued, and serving customers but their costs have not yet been
11 transferred to plant in service. The Commission did not include
12 CWIP in rate base in that decision but indicated that it was within
13 their discretion in future cases to determine whether CWIP should
14 be included in rate base so I request that the Commission include
15 CWIP in rate base in this filing. .
- 16 • I use year-end, not average, rate base to better reflect the assets
17 which will be serving customers during the rate effective period.
18 This adjustment is described later in my Direct Testimony.
- 19 • I have removed executive incentive compensation in this filing but,
20 as I explain later in my Direct Testimony, I am requesting that the
21 Commission include in rates the incentive compensation for non-
22 executive employees.

1 **Q11. Was a lead/lag study prepared by the Company to determine the cash**
2 **working capital requirement in its current filing?**

3 A11. Yes. The results of the lead/lag study are reflected in Schedule (JCZ)-20.
4 The total per books distribution Delmarva Power cash working capital
5 requirement is a reduction to rate base of \$9,000.

6 **Q12. What was the time period used for preparing the lead/lag study?**

7 A12. All transactions used in the preparation of the lead/lag study were either
8 from 2011 for revenues or 2010 for disbursements.

9 **Q13. Have the factors developed in the lead/lag study been applied to the test**
10 **period results of operations?**

11 A13. Yes. The cash working capital lag factors were applied to the test period
12 results of operations.

13 **Q14. Please summarize the Company's overall revenue deficiency.**

14 A14. Schedule (JCZ)-2, page 1, provides a listing of each adjustment supported
15 by the Company. Schedule (JCZ)-2, page 2, displays the calculation of the
16 Company's revenue deficiency of \$12,174,000. This calculation includes the
17 effect of all of the pro-forma adjustments to the test period level of earnings and
18 rate base and uses Company Witness McGowan's recommended rate of return of
19 7.51%. Schedule C of the MFR provides detail as to the drivers of the overall
20 revenue deficiency.

21 **Proforma Adjustments**

22 **Q15. Please list the pro forma adjustments that you are sponsoring in this**
23 **proceeding.**

1 A15. The pro forma adjustments that I am sponsoring are as follows:

- 2 • Adjustment No. 1 – Remove Employee Association Expense;
- 3 • Adjustment No. 2 – Normalize Regulatory Commission Expense;
- 4 • Adjustment No. 3 – Reflect price changes associated with the Company's
- 5 Wage and FICA Expense;
- 6 • Adjustment No. 4 – Remove Executive Incentive Compensation Expense;
- 7 • Adjustment No. 5 – Remove Certain Executive Compensation;
- 8 • Adjustment No. 6 – Normalize Uncollectible Expense;
- 9 • Adjustment No. 7 – Normalize Injuries and Damages Expense;
- 10 • Adjustment No. 8 – Adjust Benefits Expense;
- 11 • Adjustment No. 9 – Reflect Pro-forma Forecasted Reliability Plant Closings
- 12 from January 2013 to December 2013;
- 13 • Adjustment No. 10 – Remove Bloom Energy Incremental Rate Base;
- 14 • Adjustment No. 11 – Reflect Gas Advanced Metering Infrastructure (AMI)
- 15 Pro-forma Net Plant Additions;
- 16 • Adjustment No. 12 – Normalize Meter Reading Expense;
- 17 • Adjustment No. 13 – Amortize Actual Refinancing Transactions;
- 18 • Adjustment No. 14 – Remove Post 1980 Vintage Investment Tax Credit (ITC)
- 19 Amortization;
- 20 • Adjustment No. 15 – Recover Credit Facilities Expense;
- 21 • Adjustment No. 16 – Reflect Deferred Income Taxes Related to Medicare Part
- 22 D Subsidy;
- 23 • Adjustment No. 17 – Annualize Depreciation on Year-End Plant

- 1 • Adjustment No. 18 – Reflect effects of Interest Synchronization; and
- 2 • Adjustment No. 19 – Reflect Cash Working Capital-Related to all Pro-forma
- 3 Adjustments.

4 **Q16. Why are you making these adjustments?**

5 A16. These adjustments are being made to the test period to establish the rate
6 effective period as a basis for providing just and reasonable rates. Many of these
7 adjustments reflect the approved ratemaking treatment by the Commission. Other
8 adjustments have been made to assure that the rate effective period reflects a
9 matching of all elements of the ratemaking formula for known and measurable
10 changes. Workpapers supporting each of these adjustments are included in Book
11 3 of this filing.

12 **Q17. Please describe the removal of Employee Association Expense, Adjustment**
13 **No. 1.**

14 A17. Consistent with the treatment included in Docket Nos. 94-22, 03-127, 05-
15 304 and 09-414, the amounts charged to expense for support of the Employee's
16 Association were removed for ratemaking purposes. This adjustment is detailed
17 on Schedule (JCZ)-3 and reflects an \$18,000 increase to test period operating
18 income.

19 **Q18. Please describe the normalization of Regulatory Commission Expense,**
20 **Adjustment No. 2.**

21 A18. Consistent with the treatment included in Docket Nos. 94-22, 03-127, 05-
22 304 and 09-414, the amount expensed in the test period was adjusted for two
23 items. The first item is to normalize the test period level of expense using a three-

1 year average. The second item is to adjust the test period level of expense to
2 reflect the cost of this filing, including the costs of the other parties, amortized
3 over a three-year period with the unamortized amount of these costs being
4 included as a rate base item. As detailed on Schedule (JCZ)-4, this adjustment
5 results in a \$137,000 decrease to test period operating income and a \$250,000
6 increase to test period rate base.

7 **Q19. Please describe the adjustment to reflect the Company's Proposed Wage and**
8 **FICA expense, Adjustment No. 3.**

9 A19. Consistent with the treatment included in Docket Nos. 94-22, 03-127, 05-
10 304 and 09-414, the Company's test period wage and FICA levels of expense
11 were adjusted for the known price changes required to be made to be reflective of
12 the rate effective period. These include:

- 13 • the actual wage increase of 2.00% for International Brotherhood of
14 Electrical Workers (IBEW) Local 1238 effective in February 2012 for
15 1 month,
- 16 • the actual non-union wage increase of 3.00% effective March 2012 for
17 2 months,
- 18 • the actual wage increase of 2.00% for IBEW Local 1307 effective in
19 June 2012 for 6 months,
- 20 • an estimated wage increase of 2.00% for IBEW Local 1238 effective
21 in February 2013 for 12 months,
- 22 • an estimated non-union wage increase of 3.00% effective March 2013
23 for 12 months,

- 1 • an estimated wage increase of 2.00% for IBEW Local 1307 effective
- 2 in June 2013 for 12 months,
- 3 • an estimated wage increase of 2.00% for IBEW Local 1238 effective
- 4 in February 2014 for 5 months, and
- 5 • an estimated non-union wage increase of 3.00% effective March 2014
- 6 for 3 months.

7 These wage increases have been applied to the Company's test period

8 salaries and wages to be reflective of the rate effective period, July 2013 through

9 June 2014. Updates to estimated information will be provided during the course

10 of the proceeding. This adjustment is detailed on Schedule (JCZ)-5 and reflects a

11 decrease of \$378,000 to test period operating income.

12 **Q20. Please describe the removal of Executive Incentive Compensation expense,**

13 **Adjustment No. 4.**

14 A20. Consistent with the treatment in Docket No. 09-414, this adjustment

15 removes the test period level of expense associated with executive incentives.

16 While these "compensation at risk" payments are an important component of the

17 Company's total executive compensation and we believe these incentives are

18 appropriate and necessary, the Company has chosen, without waiving its rights in

19 future filings, not to include these amounts in the proposed revenue requirement

20 determination in this proceeding. As displayed on Schedule (JCZ)-6, this

21 adjustment reflects a \$425,000 increase to test period operating income.

22 **Q21. Please explain your proposed treatment of Non-Executive Incentive**

23 **Compensation.**

1 A21. I propose the inclusion of the test period level of non-executive incentive
2 compensation in the Company's cost of service for this filing. In Docket No. 09-
3 414, the Commission did not include the expense associated with non-executive
4 incentives in cost of service because there was a concern whether the detail
5 associated with the components related to safety, reliability and similar goals was
6 entered into the record of the proceeding. The Commission, in its deliberation,
7 discussed being consistent with its decision in the prior proceeding, Docket No.
8 05-304. In Docket No. 05-304, the Commission had included incentive costs
9 associated with achieving safety, reliability and similar goals as part of its
10 approved revenue requirements.

11 **Q22. What has the Commission stated previously about incentive programs?**

12 A22. While the Commission has previously excluded the inclusion of incentive
13 compensation payments that are primarily triggered by the achievement of
14 financial triggers, the Commission has allowed incentives that are triggered by the
15 achievement of safety, reliability and similar goals. The Commission's Order in
16 Docket No. 05-304 discussed that this was a difficult issue for the Commission
17 and they recognized that they have allowed payments made under incentive plans
18 to be included in rates in the past. The Commission has stated that such programs
19 benefit ratepayers by extending the period between rate cases.

20 The non-executive incentives included in the test period are a part of the
21 total compensation package paid to employees and such programs benefit
22 customers by extending the period between rate cases. The Company's
23 performance incentive plans are part of employees' total compensation package.

1 While base salaries could be increased to reflect a higher level of compensation in
2 lieu of incentives, having an at-risk portion of compensation available is widely
3 used to motivate employees to be more efficient and productive. For Delmarva
4 Power, this program helps to focus employees' attention and efforts on achieving
5 the Company's goals. Many of these goals are explicitly related to safety and
6 customers and to the extent that other goals are financial in nature, such goals
7 help motivate employees to keep costs down and thus will benefit customers in
8 the ratemaking process.

9 While the specifics of the annual incentive program differ from area to
10 area, or among levels, they all have the same framework of drivers. In particular,
11 all of the programs have an employee measure such, as safety. All of the
12 programs also have a customer satisfaction component as well as a reliability
13 measure. Finally, the programs all have financial components such as O&M
14 expense control, managing capital expenditures and achieving our net income
15 targets overall, which, if achieved, lower the revenue requirements to customers
16 and will extend time between base rate filings.

17 All three of these areas work in concert – motivated employees looking
18 out for the safety of themselves and the public, serving the needs and expectations
19 of satisfied customers, and doing so in a financially responsible way. These
20 incentives motivate employees to work safely, promote efficiency and focus on
21 critical processes such as diversity, reliability and our customers' needs.

1 For these reasons I have not removed the non-executive incentive expense.
2 I feel that all of the goals, including the financial triggered goals, should be
3 included in rates.

4 **Q23. Can you quantify the Non-Executive Incentive Expense that is included in**
5 **the Company's filed test period?**

6 A23. Yes, I can. For the test period used in this filing, the non-executive
7 incentives total \$489,000 for the Delaware Gas jurisdiction and of this total,
8 \$228,000 is related to customer (customer satisfaction and reliability - \$76,000),
9 safety (\$85,000), process improvement projects (\$36,000) and Affirmative Action
10 (\$31,000). I will provide an update to this partially forecasted amount when the
11 Company provides its update for all actual information during the course of this
12 proceeding.

13 **Q24. What is your proposed treatment of Non-Executive Incentive expense?**

14 A24. I propose that all non-executive incentive expense be included in the final
15 cost of service approved by the Commission in this proceeding. A key part of the
16 total compensation paid to employees is these incentives, which aid in the
17 motivation of employees to work safely, promote efficiency and focus on critical
18 processes such as diversity, reliability and our customers' needs.

19 **Q25. Please describe the removal of Certain Executive Compensation, Adjustment**
20 **No. 5.**

21 A25. Consistent with the treatment approved in Docket No. 09-414, this
22 adjustment removes the test level period of expense associated with certain
23 executive compensation, which are specifically listed on Schedule (JCZ)-7. As

1 shown on that Schedule, this adjustment reflects a \$14,000 increase to test period
2 operating income.

3 **Q26. Please describe the normalization of the Company's Uncollectible Expense,**
4 **Adjustment No. 6.**

5 A26. Consistent with the treatment included in Docket Nos. 03-127, 05-304,
6 and 09-414, I have normalized the Company's test period level of uncollectible
7 expense using a three year average of this expense to mitigate year-to-year
8 expense volatility, which could distort the test period results. This adjustment is
9 detailed on Schedule (JCZ)-8 and results in a \$284,000 decrease to test period
10 operating income.

11 **Q27. Please describe the normalization of Injuries and Damages Expense,**
12 **Adjustment No. 7.**

13 A27. Consistent with the treatment included in Docket Nos. 03-127, 05-304,
14 and 09-414, I am including an adjustment to normalize Injuries and Damages
15 Expense using a three year period average of this expense to mitigate year-to-year
16 expense volatility, which could distort the test period results. This adjustment
17 will result in a \$17,000 increase to test period operating income and is detailed on
18 Schedule (JCZ)-9.

19 **Q28. Please describe the adjustment made to reflect price changes related to the**
20 **Company's employee medical, dental and vision benefits program,**
21 **Adjustment No. 8.**

22 A28. Consistent with the treatment submitted in Docket No. 10-237 as well as
23 the Commission's decision in Docket No. 09-414, this adjustment recognizes the

1 increases in employee medical, vision and dental expenses expected in the rate
2 effective period based on forecasts by the Company's expert benefits consultant,
3 The Lake Consulting Group (Lake), which analyzes benefit cost trends each
4 quarter in the Mid-Atlantic region. A copy of the most recent Lake study is
5 attached as Schedules (JCZ)-10.1 – (JCZ)-10.3. The study shows that annual
6 benefit costs are forecasted to increase as follows:

7 ☐ Medical: The expected Average Rate of 9.5% is as follows: (average of the
8 Company's two primary types of medical plan offering - Health Maintenance
9 Organization (HMO) [9.4%] and Preferred Provider Organization (PPO)
10 [9.6%]). HMO survey range is 8.3% – 12.0%. PPO survey range is 7.6% –
11 12.0%;

12 ☐ Dental: Average Rate is 6.1%. Survey range is 5.0% – 7.8%;

13 ☐ Vision: Average Rate is 6.1% (not specifically tracked in Lake study;
14 however, Lake notes that these cost trends generally follow dental cost
15 increase trends).

16 The Company is using the rates set forth below for its projection of
17 benefit costs for financial forecasting purposes. The Company is including these
18 same rates in its projection of benefit expenses. The medical, dental, and vision
19 increases requested by Delmarva are as follows:

20 ☐ Medical: 8.00%;

21 ☐ Dental: 5.00%; and

22 ☐ Vision: 5.00%.

As shown in Schedule (JCZ)-10, the adjustment reflects a decrease of \$183,000 to test period earnings.

Q29. Please describe the adjustment made to proform Forecasted Reliability Plant Closings, from January 2013 to December 2013, Adjustment No. 9.

A29. As approved by the Commission in Docket No. 09-414, this adjustment reflects the annualization of reliability plant added to Plant in Service beyond the end of the test period. The actual reliability plant additions should be included in rate base to properly synchronize the value that customers will realize during the rate effective period to the amount included in rates.

I have included forecasted reliability plant closings through December 2013 as that date represents the mid-point of the rate effective period of July 2013 through June 2014. This adjustment also reflects the annualization of any retirements to plant that occurred during this period. This adjustment is detailed on Schedule (JCZ)-11 and results in a decrease to test period earnings of \$240,000 and an increase to test period rate base of \$18,029,000.

Q30. Please describe the adjustment made to remove Bloom Energy incremental rate base and related depreciation expense, Adjustment No. 10.

A30. This adjustment removes incremental rate base and depreciation expense related to Bloom Energy at its Brookside and Red Lion facilities as Bloom Energy has its own tariff which specifically recovers the cost of these items. This adjustment is detailed on Schedule (JCZ)-12 and results in an increase to test period earnings of \$1,000 and a decrease to test period rate base of \$483,000.

AMI Ratemaking

1 **Q31. Please discuss the Commission's ruling in Docket No. 07-28 in regard to**
2 **treatment of Advanced Metering Infrastructure (AMI) Costs.**

3 A31. In Order No. 7420 in Docket No. 07-28, the Commission approved the
4 AMI deployment by stating:

5 The Commission approves the diffusion of advanced metering
6 technology into the electric and natural gas distribution system networks
7 and the Commission permits Delmarva to establish a regulatory asset to
8 cover recovery of and on the appropriate operating costs associated with
9 the deployment of Advanced Metering Infrastructure and demand
10 response equipment. The Commission, Staff and other parties remain free
11 to challenge the level or any other aspects of the asset's recovery in rates
12 when Delmarva seeks recovery of the regulatory asset in base rates. For
13 ratemaking purposes, the Commission may wish to consider an
14 appropriately valued regulatory asset for advanced metering infrastructure
15 investment consistent with the matching principle giving consideration to
16 both costs and savings in the context of its next base rate case.

17
18 In his Direct Testimony, Company Witness Collacchi provides details as to the
19 deployment of the Interface Management Units (IMU) which will measure and
20 remotely transmit customers' gas usage and remotely transmit as part of the
21 Company's AMI diffusion.

22 **Q32. Prior to describing the AMI ratemaking proposal, please discuss how the**
23 **deployment of AMI is recorded in the financial records of the Company.**

24 A32. There are capital expenses associated with AMI which are reflected in the
25 Company's plant in service accounts in its accounting records. In terms of the
26 IMUs, the cost of procuring and installing the IMUs is recorded in account 107 -
27 Construction Work in Progress, upon acquisition. Upon meter installation, the
28 cost is transferred from account 107 to account 101 - Gas Plant in Service. Within
29 account 101, the cost is recorded in account 381.1 - IMUs, to properly segregate
30 IMU costs from other meter-related costs. Unlike the electric AMI deployment,

1 gas meters are not being replaced in this deployment. The IMUs are being
2 attached to the gas meters. Meters located inside customer buildings are fitted
3 with a remote index due to access issues, which made it difficult to perform meter
4 reading. To avoid customer inconvenience and repeated estimated bills, these
5 inside gas meters were fitted with these remote indexes known as "Hexagrams"
6 that allow meter readers to obtain meter readings from outside a customer
7 building. These remote indexes are being replaced in the process of installing
8 IMUs.

9 In terms of other plant in service, there are communication network assets
10 recorded on the Company's books and related hardware and software assets that
11 are recorded as plant in service on the PHI Service Company's balance sheet
12 since these assets support the PHI-wide AMI deployment. For ratemaking
13 purposes, these Service Company assets are allocated to the utilities.

14 There are several other costs related to AMI deployment which are, or will
15 be, recorded as regulatory assets. These costs, pursuant to Order No. 7420,
16 include:

- 17 • Loss related to early retirement of remote indexes;
- 18 • Incremental depreciation expense -- IMUs compared to remote indexes;
- 19 • Deferred O&M expense;
- 20 • AMI-related savings (recorded as an offset to the regulatory assets); and
- 21 • Returns earned on assets related to AMI deployment.

1 **Q33. Please describe the adjustment to reflect the Gas AMI net plant-related costs**
2 **which are included as part of the revenue requirement in this proceeding,**
3 **Adjustment No. 11.**

4 A33. As discussed in the Direct Testimony of Company Witness Collacchi, the
5 Company has made significant investment in Gas AMI-related plant in service
6 such as IMUs, communication network equipment as well as information
7 technology hardware and software. Total Gas AMI-related plant in service at full
8 deployment will total a forecasted \$14.8 million by June 2013 with IMU
9 activations forecasted to conclude by September 2013, so these assets will be used
10 and useful for the majority of the rate effective period. As such, the IMU and
11 related plant in service balances are included in the adjusted rate base while the
12 remote indexes have been removed from plant in service and are part of the AMI
13 regulatory asset recovery proposal described later in my Direct Testimony. For
14 the AMI-related plant in service, a ratemaking adjustment is proposed to account
15 for the difference in rate base and earnings related to full deployment at the start
16 of the rate effective period compared to those same items at the end of the test
17 period. This adjustment is shown in Schedule (JCZ)-13 and reflects a \$519,000
18 decrease to test period earnings and a \$4.245 million increase to test period rate
19 base.

20 **Q34. Please describe the normalization of meter reading expense, Adjustment No.**
21 **12.**

22 A34. I have included an adjustment to remove a non-recurring test period
23 reduction to meter reading expense related to settlement proceeds from Silver

1 Spring Network, the manufacturer of the IMUs. These products had
2 manufacturing issues related to them which caused the suspension of deployment.
3 These settlement proceeds compensate for higher-than-expected manual meter
4 reading expenses incurred by the Company, which resulted from a delayed IMU
5 deployment. By removing the credit, the meter reading expense reflects the
6 expected level which will be reflective of the rate effective period prior to any
7 O&M savings being realized. As those savings are realized, they will be credited
8 to the aggregate AMI regulatory asset balances to reduce the overall balance. This
9 adjustment is detailed on Schedule (JCZ)-14 and results in a decrease to test
10 period earnings of \$681,000.

11 **Q35. Please describe the proposed ratemaking concept related to the recovery of**
12 **costs associated with the AMI-related regulatory assets.**

13 A35. The Company proposes the recovery of its AMI-related regulatory assets
14 to correlate with the achievement of the Docket No. 07-28 business plan Gas-
15 related primary milestone. The achievement of utility operational savings is the
16 benefit for Gas customers with the primary milestone relating to remote meter
17 reading and the subsequent reduction of manual meter reading expenses. Unlike
18 the electric AMI, natural gas is not subject to hourly pricing. Gas is priced on a
19 daily basis. Accordingly, there is no AMI-enabled Gas dynamic pricing benefit
20 for customers.

21 Subsequently, the proposed Gas AMI regulatory asset recovery plan will
22 be tied to the achievement of a customer benefit, similar to the agreed-upon AMI
23 regulatory asset recovery plan in Docket No. 11-528. However, the Gas recovery

1 of the aggregate regulatory asset balance will be tied to the achievement of a
2 single milestone, which is the reduction in manual meter reading expense due to
3 IMU-enabled remote meter reading, as opposed to multiple milestones used in the
4 electric AMI regulatory asset phase-in recovery plan.

5 Like the recovery of the electric AMI regulatory assets in Docket No. 11-
6 528, Delmarva's Gas Division will not be able to collect any of the balance of the
7 regulatory assets until it has established that the IMUs are actually providing the
8 remote reading benefit to customers as set forth in the AMI Business Case from
9 PSC Docket No. 07-28. Remote meter reading through IMUs and the related
10 reduction in manual meter reading expense is the customer benefit offered in the
11 Business Plan and it is the primary benefit upon which the Commission based its
12 Gas AMI approval in Order No. 7420. Delmarva affirms its position that there
13 should be no recovery of the Gas AMI regulatory assets aggregate balance until
14 the remote meter reading benefit is achieved.

15 **Q36. Please describe the AMI-related regulatory assets.**

16 A36. The descriptions of the AMI-related regulatory assets as well as balances
17 as of October 2012 were:

- 18 • The net book value of remote indexes that have been retired early due to
19 AMI deployment of IMUs. The balance is \$984,000.
- 20 • Deferred O&M costs incurred from August 2010 (the deferred costs
21 incurred prior to that date were approved for recovery in Docket No. 10-
22 237). The balance is \$1.986 million.

- 1 • AMI Returns representing recovery of and on the appropriate costs
2 associated with the AMI regulatory assets as well as AMI incremental net
3 rate base (AMI meters net of non-AMI meters, communication equipment,
4 software and hardware). These returns have been calculated at the
5 Company's authorized rate of return. The balance is \$235,000.
- 6 • Incremental IMU depreciation expense compared to the expense related to
7 the remote indexes. Customer's current base rates reflect the inclusion of
8 the depreciation expense level associated with the remote indexes. As
9 IMUs have replaced the remote indexes, the Company has recorded a
10 higher level of depreciation expense for financial reporting purposes
11 compared to the depreciation expense established in rates. Since customers
12 have been paying for a lower level of depreciation expense than the
13 Company has recorded for financial reporting purposes for these assets,
14 the incremental depreciation expense has been recorded in a regulatory
15 asset. The balance is \$113,000.
- 16 • Operational & Maintenance expense savings as detailed in the business
17 case in Docket No. 07-28, attached as Schedule (JCZ)-13.1, include:
 - 18 • reduction of manual meter reading costs;
 - 19 • reduction of off-cycle meter reading labor costs;
 - 20 • improvement of billing activities;
 - 21 • elimination of hardware, software, maintenance and operation costs
22 for the Itron handheld data collection system;
 - 23 • reduction of expenses related to revenue protection;

- improvement of complaint call handling; and
- reduction of volume of customer calls related to metering.

As the IMUs are fully deployed and activated, O&M savings will begin to be realized at which time they will represent a reduction to the aggregate AMI regulatory asset balance. Given that O&M savings have not yet been realized, the balance in the regulatory asset is \$0; however, the balance will be reduced once savings are realized and recorded.

In summary, the net balance of all of the above-mentioned regulatory assets is \$3.318 million as of October 2012.

Q37. Please describe the proposed ratemaking process in terms of the achievement of the primary Gas AMI-related milestone and the subsequent recovery of AMI regulatory assets.

A37. Similar to the approved plan for phasing in the electric AMI regulatory asset in Docket No. 11-528, upon demonstration by Delmarva that it is successfully reading at least 95% of eligible natural gas meters remotely through the IMUs, which is expected to be completed by or before the end of the rate effective period, the Company will file with the Commission to establish in rates the recovery of the aggregate regulatory asset balances at the time. There will be no recovery unless and until remote meter reading is accomplished. Similar to the process agreed upon in the settlement in Docket No. 11-528, the other parties would have a 60 day period for discovery in regard to the regulatory asset balances and achievement of the remote meter reading customer benefit. The regulatory asset balances are proposed to be amortized over a 15-year life (similar

1 to the amortization period authorized for Gas AMI deferred costs in Docket No.
2 10-237) with the unamortized balance provided rate base treatment.

3 Upon Commission approval, the revenue requirement related to these
4 costs will be included in base rates without the necessity of being included as part
5 of a future base rate case proceeding. In the meantime, the aggregate regulatory
6 asset balances will continue to change over the coming months. Items such as
7 deferred O&M, incremental depreciation expense and returns will increase the
8 balance while O&M savings will reduce the balance.

9 **Q38. Please summarize the proposed ratemaking related to Gas AMI cost recovery.**

10 A38. There are two phases of Gas AMI cost recovery:

- 11 • Costs included in this base rate case filing for Plant in Service items such as
12 IMUs, communication equipment and related software and hardware. These
13 assets are forecasted to be used and useful for the majority of the rate effective
14 period.
- 15 • Recovery of AMI-related regulatory asset aggregate balances upon
16 achievement of remote meter reading. This recovery would be included in
17 base rates only upon Commission approval and only after Delmarva has
18 established that remote meter reading has been achieved, with related savings
19 credited to the Gas AMI aggregate regulatory asset balance prior to that
20 approval.

21 In summary, this Gas AMI ratemaking proposal provides for a
22 synchronization of cost recovery to the successful completion of the major
23 definable customer benefit associated with the Gas IMUs - specifically, the

1 regulatory asset balance recovery process by which the Company is required
2 to achieve its primary Gas AMI customer benefit. There will be no recovery
3 on the regulatory asset balance until the remote meter reading customer
4 benefit milestone is met.

5 **Q39. Please describe the Amortization of Actual Refinancing transactions,**
6 **Adjustment No. 13.**

7 A39. I have included in this filing the earnings and rate base treatment of
8 refinancings that were allocated to the Gas business. This ratemaking treatment is
9 consistent with the approved treatment that has been included in prior
10 Commission decisions, beginning in Docket No. 86-24 and continuing through
11 Docket No. 09-414. Lower cost rates in the Company's capital structure resulting
12 from the Company's refinancings provide a benefit to customers. This adjustment
13 is detailed on Schedule (JCZ)-15 and reflects a \$125,000 decrease to test period
14 operating income and a \$1.205 million increase to test period rate base.

15 **Q40. Please describe the removal of Post 1980 Vintage ITC Amortization,**
16 **Adjustment No. 14.**

17 A40. Consistent with the ratemaking approved on Docket Nos. 84-23, 91-24,
18 94-22 and 09-414, I have removed post-1980 vintage Investment Tax Credit
19 (ITC) amortizations. This adjustment reflects the requirements of the Economic
20 Recovery Tax Act of 1981 (ERTA) on post-1980 vintage projects for rate case
21 purposes. The Company has been amortizing ITC on a property service life basis.
22 Under ERTA, Delmarva is an Option One Company for ratemaking purposes for
23 post-1980 vintages. The related ratemaking treatment is to deduct the post-1980

1 accumulated unamortized balance from rate base, and at the same time, not
2 include the related post-1980 vintage amortizations as a reduction of operating
3 expenses. This adjustment is detailed on Schedule (JCZ)-16 as a \$50,000 decrease
4 to test period earnings.

5 **Q41. Please describe the adjustment made to recover credit facilities expense,**
6 **Adjustment No. 15.**

7 A41. Consistent with ratemaking treatment approved in the Company's filing in
8 Docket No. 09-414, this adjustment reflects the Company's cost related to the PHI
9 credit facility. PHI's credit facility is vital for serving the day-to-day cash needs of
10 its companies, such as Delmarva. These costs are recorded as interest expense for
11 financial reporting purposes of the Company; however, they are not reflected in the
12 cost of capital for ratemaking purposes and would not be included in rates at all.
13 On August 2, 2012, PHI renewed its credit facility for a five-year term. As shown
14 in Schedule (JCZ)-17, the costs related to the current credit facility are reflected
15 and the related adjustment results in a \$67,000 decrease to test period earnings as
16 well as a \$190,000 increase to test period rate base.

17 **Q42. Please describe the Amortization of Medicare subsidy costs, Adjustment No.**
18 **16.**

19 A42. This adjustment involves additional taxes related to a change in the law
20 regarding Medicare Part D. The Patient Protection and Affordable Care Act,
21 which became law in March 2010, resulted in a deferred tax charge to the
22 Company's Federal income tax expense. The law changes the tax treatment of
23 federal subsidies paid to the Company to offset the costs for certain retiree health

benefits. The charge to tax expense was deferred in the financial records of the Company. While these costs have not been addressed by the Commission in the Company's Delaware filings, they have been recently approved for recovery in the Company's Maryland Case No. 9285 as the Commission in Order No. 85029 stated:

We conclude that the additional tax expense related to changes in Medicare Part D should be amortized. We find that the Company has had to adjust its deferred income taxes and will in fact pay higher taxes for health care benefits as a result of the tax policy change. Therefore we authorize amortization of the increased tax expense over three years, which will increase the rate base by \$38,000 and decrease the corresponding operating income by \$15,000.

Similar to the Maryland Commission's approved amortization period, the Company proposes to recover these deferred costs over a three-year period. This adjustment is shown on Schedule (JCZ)-18 and results in a \$7,000 decrease to test period earnings as well as a \$14,000 increase to test period rate base.

Q43. Describe the Annualization of Depreciation on Year-End Plant, Adjustment No. 17.

A43. The adjustment compares the 6 months actual and 6 months forecast ending December 2012 test year amount of depreciation expense to an annualized level of depreciation expense amount based on the year ended December 2012 plant assets using the Commission-approved depreciation rates. In addition, an adjustment is included to the accumulated depreciation reserve to recognize the difference in annualized depreciation expense to the test period level of depreciation expense. My proposed adjustment to rate base and operating income

1 is shown on Schedule (JCZ)-19 and results in a \$321,000 decrease to test period
2 earnings and a \$321,000 decrease to test period rate base.

3 **Q44. Please describe the adjustment for Interest Synchronization, Adjustment No.**
4 **18.**

5 A44. Consistent with the precedent in Docket No. 09-414, this adjustment
6 synchronizes the interest expense utilized in the per books income tax calculation
7 with the adjusted rate base and the tax deductible component included in the cost
8 of capital. Absent this adjustment, the interest expense would not properly match
9 the rate base proposed in this filing. This adjustment is detailed on Schedule
10 (JCZ)-20 and represents a \$362,000 increase to test period earnings.

11 **Q45. Please describe the adjustment for Cash Working Capital, Adjustment No.**
12 **19.**

13 A45. Consistent with the precedent in Docket No. 09-414, this adjustment
14 reflects the inclusion of the calculated cash working capital effect of all earning
15 adjustments using the ratios supported in my Direct Testimony. Absent this
16 adjustment, the cash working capital in rate base would only reflect the amount
17 related to per books balances. This adjustment is detailed on Schedule (JCZ)-20
18 and represents a \$9,000 reduction to test period rate base.

19 **Q46. Please summarize the Company's overall revenue deficiency.**

20 A46. Schedule (JCZ)-2, Page 2 displays the calculation of the Company's
21 revenue deficiency of \$ 12,174,000. This calculation includes the effect of all of
22 the pro-forma adjustments to the test period level of earnings and rate base and
23 uses rate of return of 7.51%.

1 **Q47. Does this conclude your Direct Testimony?**

2 A47. Yes, it does.

Delmarva Power & Light Company
Delaware Gas Rate of Return
6+6 Months Ending December 31, 2012

(1) Line No.	(2) <u>Item</u>	(3) <u>Per Books System Gas</u>	(4) <u>Pre-Cost Study Adjustments</u>	(5) <u>Adjusted System Gas</u>
1	<u>Rate Base</u>			
2	Electric Plant in Service	\$ 480,540,872	\$ -	\$ 480,540,872
3	Less: Depreciation Reserve	\$ 202,439,479	\$ -	\$ 202,439,479
4	Net Plant in Service	\$ 278,101,393	\$ -	\$ 278,101,393
5				
6	CWIP	\$ 10,747,414	\$ -	\$ 10,747,414
7	Working Capital	\$ 12,162,089	\$ -	\$ 12,162,089
8	Plant Materials & Supplies	\$ 12,890,975	\$ -	\$ 12,890,975
9	Prepaid Balances	\$ 16,720,169	\$ -	\$ 16,720,169
10	Deferred Federal and State Tax Balance	\$ (76,685,758)	\$ -	\$ (76,685,758)
11	Deferred Investment Tax Credit	\$ (489,224)	\$ -	\$ (489,224)
12	Customer Deposits	\$ (3,398,845)	\$ -	\$ (3,398,845)
13	Customer Advances	\$ -	\$ -	\$ -
14				
15	Total Rate Base	\$ 250,048,213	\$ -	\$ 250,048,213
16				
17	<u>Earnings</u>			
18	Operating Revenues	\$ 169,907,697	\$ (97,884,760)	\$ 72,022,938
19				
20	O & M Expense	\$ 135,474,273	\$ (102,102,886)	\$ 33,371,387
21	Depreciation and Amortization Expense	\$ 12,584,315	\$ (63,655)	\$ 12,520,660
22	Taxes Other than Income Taxes	\$ 6,963,089	\$ (2,246,153)	\$ 4,716,935
23	Deferred FIT Expense	\$ 1,855,952	\$ 7,317,988	\$ 9,173,940
24	Deferred SIT Expense	\$ 1,647,567	\$ 850,110	\$ 2,497,677
25	Net ITC Adjustment	\$ (56,561)	\$ -	\$ (56,561)
26	Interest on Customer Deposits	\$ 4,166	\$ -	\$ 4,166
27	State Income Tax	\$ 526,765	\$ (1,679,085)	\$ (1,152,320)
28	Federal Income Tax	\$ 2,068,267	\$ (6,300,724)	\$ (4,232,457)
29	Total Operating Expenses	\$ 161,067,833	\$ (104,224,405)	\$ 56,843,428
30				
31	Operating Income	\$ 8,839,864	\$ 6,339,646	\$ 15,179,510
32				
33	AFUDC	\$ 286,900	\$ -	\$ 286,900
34	Earnings	\$ 9,126,764	\$ 6,339,646	\$ 15,466,410

Delmarva Power & Light Company
Delaware Gas Rate of Return
12 Months Ending June 30, 2012

(1) Line No.	(2) <u>Item</u>	(3) <u>Per Books System Gas</u>	(4) <u>Pre-Cost Study Adjustments</u>	(5) <u>Adjusted System Gas</u>
1	<u>Rate Base</u>			
2	Electric Plant in Service	\$ 463,662,746	\$ -	\$ 463,662,746
3	Less: Depreciation Reserve	\$ 197,016,654	\$ -	\$ 197,016,654
4	Net Plant in Service	\$ 266,646,092	\$ -	\$ 266,646,092
5				
6	CWIP	\$ 13,893,223	\$ -	\$ 13,893,223
7	Working Capital	\$ 13,513,878	\$ -	\$ 13,513,878
8	Plant Materials & Supplies	\$ 12,332,993	\$ -	\$ 12,332,993
9	Prepaid Balances	\$ 18,684,107	\$ -	\$ 18,684,107
10	Deferred Federal and State Tax Balance	\$ (73,053,447)	\$ -	\$ (73,053,447)
11	Deferred Investment Tax Credit	\$ (517,500)	\$ -	\$ (517,500)
12	Customer Deposits	\$ (3,613,014)	\$ -	\$ (3,613,014)
13	Customer Advances	\$ -	\$ -	\$ -
14				
15	Total Rate Base	\$ 247,886,332	\$ -	\$ 247,886,332
16				
17	<u>Earnings</u>			
18	Operating Revenues	\$ 185,971,351	\$ (114,730,253)	\$ 71,241,098
19				
20	O & M Expense	\$ 154,378,310	\$ (120,507,940)	\$ 33,870,370
21	Depreciation and Amortization Expense	\$ 12,189,324	\$ (46,647)	\$ 12,142,677
22	Taxes Other than Income Taxes	\$ 6,058,244	\$ (1,984,527)	\$ 4,073,717
23	Deferred FIT Expense	\$ 4,355,136	\$ 6,396,504	\$ 10,751,640
24	Deferred SIT Expense	\$ (442,048)	\$ 3,369,267	\$ 2,927,219
25	Net ITC Adjustment	\$ (56,561)	\$ -	\$ (56,561)
26	Interest on Customer Deposits	\$ 7,035	\$ -	\$ 7,035
27	State Income Tax	\$ 1,969,269	\$ (3,564,579)	\$ (1,595,310)
28	Federal Income Tax	\$ (122,064)	\$ (5,737,491)	\$ (5,859,555)
29	Total Operating Expenses	\$ 178,336,645	\$ (122,075,414)	\$ 56,261,231
30				
31	Operating Income	\$ 7,634,706	\$ 7,345,162	\$ 14,979,868
32				
33	AFUDC	\$ 382,658	\$ -	\$ 382,658
34	Misc Earnings Items			
35	Earnings	\$ 8,017,364	\$ 7,345,162	\$ 15,362,526

Delmarva Power & Light Company

Gas Adjustments

6+6 Months Ending December 31, 2012

(000's)

(1) <u>Line</u>	(2) <u>Item</u>	(3) <u>Witness</u>	(4) <u>Earnings</u>	(5) <u>Rate Base</u>	(6) <u>ROR</u>	(7) <u>ROE</u>
1	Per Books - 6+6 months ending December 31, 2012	Ziminsky	\$15,466	\$250,048	6.19%	7.53%
2						
3	Adjustments					
4	1 Remove Employee Association	Ziminsky	\$18	\$0		
5	2 Regulatory Commission Exp Normalization	Ziminsky	(\$137)	\$250		
6	3 Wage and FICA Expense Adjustment	Ziminsky	(\$378)	\$0		
7	4 Removal of Executive Incentive Compensation	Ziminsky	\$425	\$0		
8	5 Remove Certain Executive Compensation	Ziminsky	\$14	\$0		
9	6 Uncollectible Expense Normalization	Ziminsky	(\$284)	\$0		
10	7 Injuries and Damages Exp Normalization	Ziminsky	\$17	\$0		
11	8 Benefits Expense Adjustment	Ziminsky	(\$183)	\$0		
12	9 Reflect Reliability Closings January 2013 - December 2013	Ziminsky/Collachi	(\$240)	\$18,029		
13	10 Remove Bloom-Related Incremental Rate Base	Ziminsky	\$1	(\$483)		
14	11 Reflect Gas AMI Net Plant Additions	Ziminsky/Collachi	(\$519)	\$4,245		
15	12 Normalize Meter Reading Expense	Ziminsky	(\$681)	\$0		
16	13 Amortization of Refinancings	Ziminsky	(\$125)	\$1,205		
17	14 Remove Post 1980 ITC Amortization	Ziminsky	(\$50)	\$0		
18	15 Recover Credit Facilities Expense	Ziminsky	(\$67)	\$190		
19	16 Reflect Taxes Related to Medicare Part D Subsidy	Ziminsky	(\$7)	\$14		
20	17 Annualization of Depreciation on Year-end Plant	Ziminsky	(\$321)	(\$321)		
21	18 Interest Synchronization	Ziminsky	\$362	\$0		
22	19 Cash Working Capital	Ziminsky	\$0	(\$9)		
23						
24	Adjusted Test Period		\$13,312	\$273,169	4.87%	4.84%

Delmarva Power & Light Company
Delaware Gas
6+6 Months Ending December 2012 Test Period
Determination of Revenue Requirements

(1) Line No.	(2) <u>Item</u>	(3) <u>Detail</u>
1	Adjusted Net Rate Base	\$ 273,168,940
2	Required Rate of Return	<u>7.51%</u>
3	Required Operating Income	\$ 20,514,987
4	Pro Forma Operating Income	<u>\$ 13,311,769</u>
5	Operating Income Deficiency	\$ 7,203,218
6	Revenue Conversion Factor	<u>1.69013</u>
7	Revenue Requirement	\$ 12,174,375

Schedule (JCZ)-3
Adjustment No. 1

Delmarva Power & Light
Employee Association Expenses - Gas
6+6 Months Ending December 31, 2012

(1) Line No.	(2) <u>Item</u>	(3) \$
1	Employee Association expenses - Total DPL	\$181,933
2		
3	Delmarva Power & Light Gas allocation	<u>17.07%</u>
4		
5	Employee Association expenses - Total DPL Gas	\$31,056
6		
7	Impact to Operating Expense	(\$31,056)
8		
9	Impact to SIT @ 8.7%	\$2,702
10		
11	Impact to FIT @ 35%	<u>\$9,924</u>
12		
13	Impact to Operating Income	<u><u>\$18,430</u></u>

Delmarva Power & Light
Regulatory Commission Expense - Gas
6+6 Months Ending December 31, 2012

(1) Line No.	(2) <u>Item</u>	(3) \$
1	<u>Earnings</u>	
2	Non-base case Regulatory Commission Expense (3 Year Average)	\$61,847 (1)
3		
4	Regulatory Commission Expense Included in Test Period	<u>\$41,932</u>
5		
6	Adjustment to Per Books Regulatory Commission Expense	\$19,914
7		
8	Cost of Current Case	\$632,600 (2)
9	Amortization of Current Case - 3 years	\$210,867
10		
11	Total Regulatory Commission Expense Adjustment	<u>\$230,781</u>
12		
13	Impact to SIT @ 8.7%	(\$20,078)
14		
15	Impact to FIT @ 35%	<u>(\$73,746)</u>
16		
17	Impact to Operating Income	<u><u>(\$136,957)</u></u>
18		
19	<u>Rate Base</u>	
20	Year-End Amortizable Balance	\$421,733
21	Deferred Tax Balance	<u>(\$171,456)</u>
22	Net Rate Base	\$250,278
23		
24		
25	(1) <u>3 Year Average</u>	
26	6+6 Months Ended 12/31/12	\$ 611,932 \$ 570,000 \$ 41,932
27	12 Months Ended 12/31/11	\$ 614,706 \$ 568,988 \$ 45,718
28	12 Months Ended 12/31/10	\$ 671,890 \$ 574,000 \$ 97,890
29	Average	\$ 61,847
30		
31	(2) <u>Cost of Current Case</u>	
32	Cost of Capital Consultant	\$92,600
33	External Legal	\$315,000
34	Court reporter, notice, etc.	\$25,000
35	DPSC	<u>\$200,000</u>
36	Total	\$632,600

Schedule (JCZ)-5
Adjustment No. 3

Delmarva Power & Light Company
Wage, Salary, and FICA Expense Adjustment - Gas
6+6 Months Ending December 31, 2012

(1) Line No.	(2) <u>Item</u>	(3) <u>Gas</u>
1	<u>Salary and Wage Adjustment</u>	
2	Gas O&M Expense Adjustment	\$604,300
3		
4	State Income Tax	(\$52,574)
5	Federal Income Tax	(\$193,104)
6	Total Expense	<u>\$358,622</u>
7		
8	Earnings	<u>(\$358,622)</u>
9		
10		
11		
12	<u>FICA Adjustment</u>	
13	Gas O&M Expense Adjustment	\$33,365
14		
15	State Income Tax	(\$2,903)
16	Federal Income Tax	(\$10,662)
17	Total Expense	<u>\$19,801</u>
18		
19	Earnings	<u>(\$19,801)</u>
20		
21		
22	Total Earnings Adjustment	(\$378,423)

Delmarva Power & Light Company
Removal of Executive Incentive Compensation - Gas
6+6 Months Ending December 31, 2012

(1) Line No.	(2) <u>Item</u>	(3) \$
1	Executive Incentives - Delaware Gas	(\$716,828)
2		
3	Income Taxes	
4	State Income Tax	\$62,364
5	Federal Income Tax	<u>\$229,062</u>
6	Total Income Taxes	\$291,426
7		
8	Earnings	<u><u>\$425,402</u></u>

Schedule (JCZ)-7
Adjustment No. 5

Delmarva Power & Light Company
Remove Certain Executive Compensation - Gas
6 +6 Months Ending December 31, 2012

(1) Line No.	(2) Description	(3) \$
1	Dividends Restricted Stock	\$ (261,882)
2	Company Match Deferred Compensation	(130,148)
3	Tax Preparation Fee	(12,500)
4	Financial Planning Fee	(43,280)
5	Executive Physical Fee	(1,600)
6	Club Dues	(5,066)
7	Spousal Travel	(7,877)
8		
9		
10	Total Compensation	\$ (462,353)
11		
12	DPL (as % of PHI)	30.36%
13	DPL Expense	(140,363)
14	DPL Gas (vs. Electric) %	17.07%
15	DPL Gas Expense	(23,960)
16		
17	State Income Tax Rate	8.700%
18	Effect on State income tax expense	\$ 2,085
19		
20	Federal Taxable	\$ (21,875)
21	Federal Income Tax Rate	35%
22	Effect on Federal income tax expense	\$ 7,656
23		
24	Total Expense	(14,219)
25		
26	Impact to Operating Income	\$ 14,219

Schedule (JCZ)-8
Adjustment No. 6

Delmarva Power & Light
Normalization of Uncollectible Expense - Gas
6+6 Months Ending December 31, 2012

(1) Line No.	(2) <u>Item</u>	(3) <u>\$</u>
1	3 Year Average	\$2,053,734
2		
3	6+6 Months Ending 12/31/12	<u>\$1,574,847</u>
4		
5	Adjustment	\$478,887
6		
7	Impact to SIT @ 8.7%	(\$41,663)
8		
9	Impact to FIT @ 35%	<u>(\$153,028)</u>
10		
11	Impact to Operating Income	<u>(\$284,196)</u>
12		
13	Account 904 12 Months Ended 12/31/10	\$2,161,566
14	12 Months Ended 12/31/11	\$2,424,790
15	6+6 Months Ended 12/31/12	<u>\$1,574,847</u>
16		
17	Average	<u>\$2,053,734</u>

Delmarva Power & Light
Normalization of Injuries & Damages Expense - Gas
6+6 Months Ending December 31, 2012

(1) Line No.	(2) <u>Item</u>	(3) \$
1	3 Year Average	\$349,692
2		
3	6+6 Months Ending 12/31/12	<u>\$377,928</u>
4		
5	Adjustment	(\$28,236)
6		
7	Impact to SIT @ 8.7%	\$2,457
8		
9	Impact to FIT @ 35%	<u>\$9,023</u>
10		
11	Impact to Operating Income	<u><u>\$16,756</u></u>
12		
13		
14	Account 925 12 Months Ended 12/31/10	\$409,044
15	12 Months Ended 12/31/11	\$262,105
16	6+6 Months Ended 12/31/12	<u>\$377,928</u>
17		
18	Average	<u><u>\$349,692</u></u>

Delmarva Power & Light
Medical/Dental/Vision Costs - Gas
6+6 Months Ending December 31, 2012

(1)	(2)	(3)	(4)	(5)
Line No.	Item	Per Books Amount	Benefit Rate Change	Rate Period Increase
1	Allocated to DPL			
2	Medical	9,444,656	8.0%	1,133,359
3	Dental	858,214	5.0%	64,366
4	Vision	<u>308,472</u>	5.0%	<u>23,135</u>
5	Total DPL Expense	10,611,342		1,220,860
6	Gas Allocation Factor			<u>17.07%</u>
7	DPL - Gas Medical/Dental/Vision Cost Increase			208,401
8				
9	Service Company employees allocated to DPL			
10	Medical	5,158,900	8.0%	619,068
11	Dental	468,068	5.0%	35,105
12	Vision	<u>168,092</u>	5.0%	<u>12,607</u>
13	Total allocated Service Company Costs	5,795,060		666,780
14	Expense allocator			<u>87.86%</u>
15	DPL - Expense			585,802
16	Gas Allocation Factor			<u>17.07%</u>
17	Service Company Allocated Medical/Dental/Vision Cost Increase - Gas			99,996
18				
19	Total Gas Medical/Dental/Vision Expense Increase for Rate Effective Period			<u><u>308,397</u></u>
20				
21	SIT			(26,831)
22	FIT			<u>(98,548)</u>
23	Total Expense			183,018
24				
25	Earnings			<u><u>(183,018)</u></u>

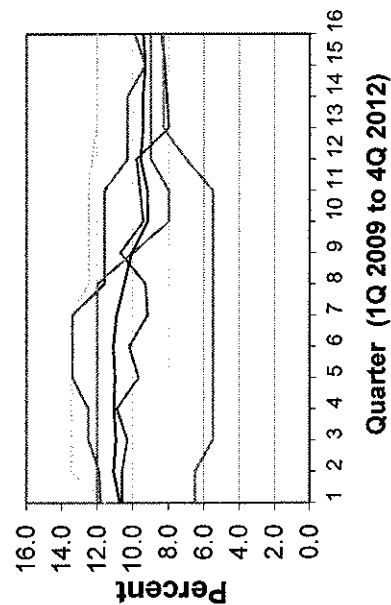
LAKE CONSULTING, INC. QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

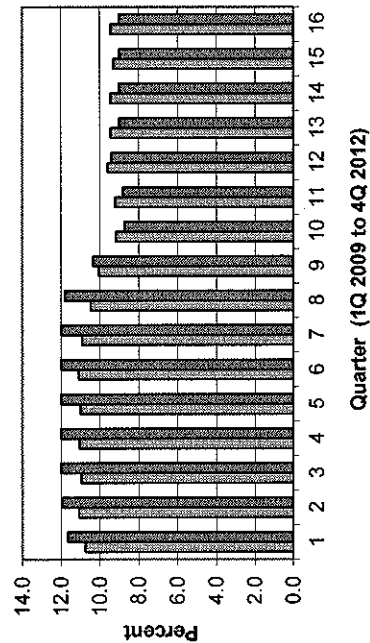
HMO Summary for 1Q 2009 to 4Q 2012

	Co. C	Co. F	Co. G	Co. J	Mean Ave	Median	Low	High
1 Q 2009	11.5	6.5	11.8	12.0	10.7	11.7	6.5	12.0
2 Q 2009	13.4	6.5	11.9	12.0	11.1	12.0	6.5	13.4
3 Q 2009	13.4	6.5	12.5	12.0	11.0	12.0	5.5	13.4
4 Q 2009	13.4	5.5	12.5	12.0	11.1	12.0	5.5	13.4
1 Q 2010	13.4	5.5	13.4	12.0	11.0	12.0	5.5	13.4
2 Q 2010	13.4	5.5	13.4	12.0	11.1	12.0	5.5	13.4
3 Q 2010	13.4	5.5	13.4	12.0	10.9	12.0	5.5	13.4
4 Q 2010	12.5	5.5	11.8	12.0	10.5	11.8	5.5	12.5
1 Q 2011	12.5	5.5	11.5	10.0	10.1	10.4	5.5	12.5
2 Q 2011	12.5	5.5	11.6	8.0	9.2	8.7	5.5	12.5
3 Q 2011	12.5	5.5	11.6	8.0	9.2	8.8	5.5	12.5
4 Q 2011	12.3	7.0	10.3	9.0	9.6	9.4	7.0	12.3
1 Q 2012	12.0	8.3	10.3	9.0	9.4	9.0	8.0	12.0
2 Q 2012	12.0	8.3	10.3	9.0	9.5	9.0	8.1	12.0
3 Q 2012	12.0	8.3	9.3	9.0	9.3	9.0	8.2	12.0
4 Q 2012	12.0	8.3	9.9	9.0	9.4	9.0	8.3	12.0

Company HMO Trends
1Q 2009 to 4Q 2012



HMO Mean & Median Trends
1Q 2009 to 4Q 2012



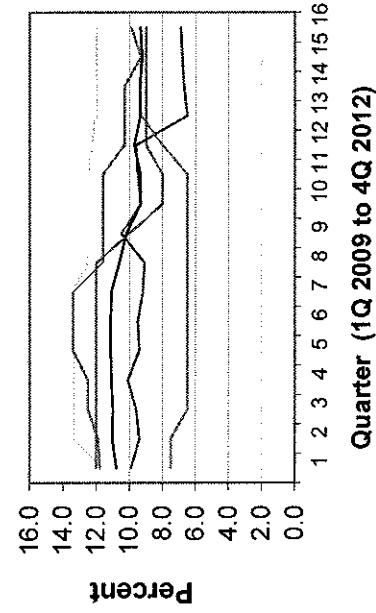
LAKE CONSULTING, INC. QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

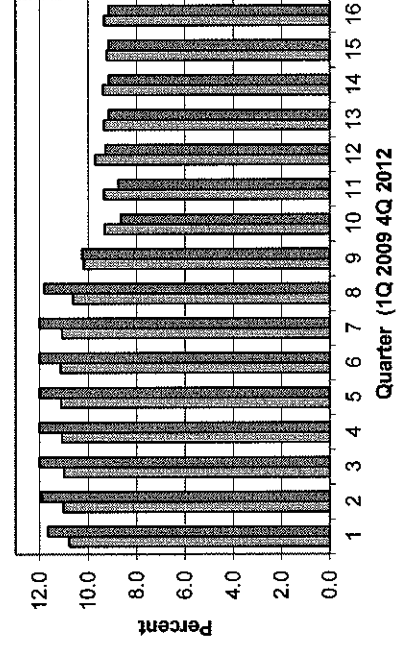
POS Summary for 1Q 2009 to 4Q 2012

	Co. C	Co. D	Co. E	Co. F	Co. G	Co. H	Mean Ave	Median	Range of Rates	
	Co. C	Co. D	Co. E	Co. F	Co. G	Co. H	Mean Ave	Median	Low	High
1 Q 2009	11.5	11.5	7.5	11.8	12.0	12.0	10.8	11.7	7.5	12.0
2 Q 2009	13.4	13.4	7.5	11.9	12.0	12.0	11.0	12.0	7.5	13.4
3 Q 2009	13.4	13.4	6.5	12.5	12.0	12.0	11.0	12.0	6.5	13.4
4 Q 2009	13.4	13.4	6.5	12.5	12.0	12.0	11.1	12.0	6.5	13.4
1 Q 2010	13.4	13.4	6.5	13.4	12.0	12.0	11.1	12.0	6.5	13.4
2 Q 2010	13.4	13.4	6.5	13.4	12.0	12.0	11.1	12.0	6.5	13.4
3 Q 2010	13.4	13.4	6.5	13.4	12.0	12.0	11.1	12.0	6.5	13.4
4 Q 2010	12.5	12.5	6.5	11.6	12.0	12.0	10.6	11.8	6.5	12.5
1 Q 2011	12.5	12.5	6.5	11.6	10.0	10.0	10.2	10.3	6.5	12.5
2 Q 2011	12.5	12.5	6.5	11.6	8.0	8.0	9.3	8.7	6.5	12.5
3 Q 2011	12.5	12.5	6.5	11.6	8.0	8.0	9.4	8.8	6.5	12.5
4 Q 2011	12.3	12.3	8.0	10.3	9.0	9.0	9.7	9.3	8.0	12.3
1 Q 2012	12.0	12.0	9.3	10.3	9.0	9.0	9.4	9.2	6.5	12.0
2 Q 2012	12.0	12.0	9.3	10.3	9.0	9.0	9.4	9.2	6.7	12.0
3 Q 2012	12.0	12.0	9.3	9.3	9.0	9.0	9.2	9.2	6.8	12.0
4 Q 2012	12.0	12.0	9.3	9.9	9.0	9.0	9.4	9.2	6.9	12.0

Company POS Trends
1Q 2009 to 4Q 2012



POS Mean & Median Trends
1Q 2009 to 4Q 2012



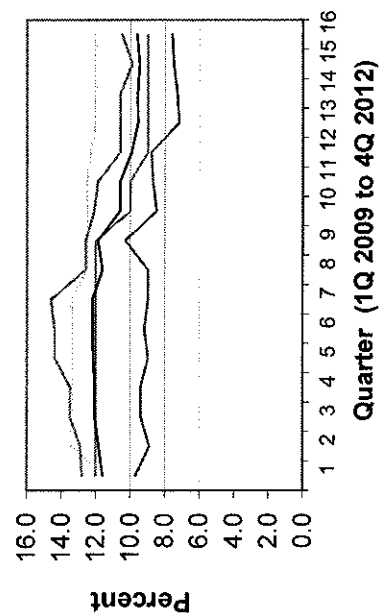
LAKE CONSULTING, INC. QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

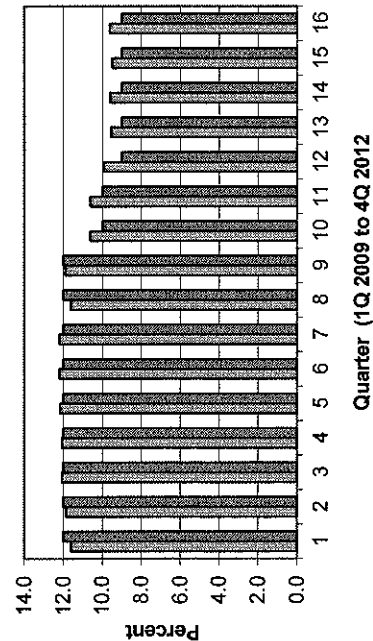
PPO Summary for 1Q 2009 to 4Q 2012

	Co. C	Co. D	Co. E	Co. F	Co. G	Co. I	Mean Ave	Median	Low	High
1 Q 2009	11.5				12.8	12.0	11.6	12.0	9.7	12.8
2 Q 2009	13.4				12.9	12.0	11.8	12.0	8.9	13.4
3 Q 2009	13.4				13.5	12.0	12.1	12.0	9.4	13.5
4 Q 2009	13.4				13.5	12.0	12.1	12.0	9.4	13.5
1 Q 2010	13.4				14.4	12.0	12.2	12.0	9.0	14.4
2 Q 2010	13.4				14.4	12.0	12.2	12.0	9.2	14.4
3 Q 2010	13.4				14.6	12.0	12.2	12.0	9.0	14.6
4 Q 2010	12.5				12.6	12.0	11.6	12.0	9.0	12.6
1 Q 2011	12.5				12.6	12.0	11.9	12.0	10.3	12.6
2 Q 2011	12.5				12.1	10.0	10.6	10.0	8.5	12.5
3 Q 2011	12.5				11.9	10.0	10.6	10.0	8.7	12.5
4 Q 2011	12.3				10.6	9.0	9.9	9.0	8.8	12.3
1 Q 2012	12.0				10.6	9.0	9.6	9.0	7.2	12.0
2 Q 2012	12.0				10.6	9.0	9.6	9.0	7.3	12.0
3 Q 2012	12.0				9.9	9.0	9.5	9.0	7.5	12.0
4 Q 2012	12.0				10.5	9.0	9.6	9.0	7.6	12.0

Company PPO Trends
1Q 2009 to 4Q 2012



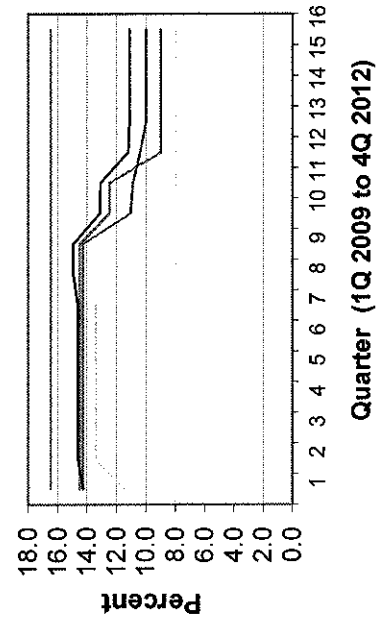
PPO Mean & Median Trends
1Q 2009 to 4Q 2012



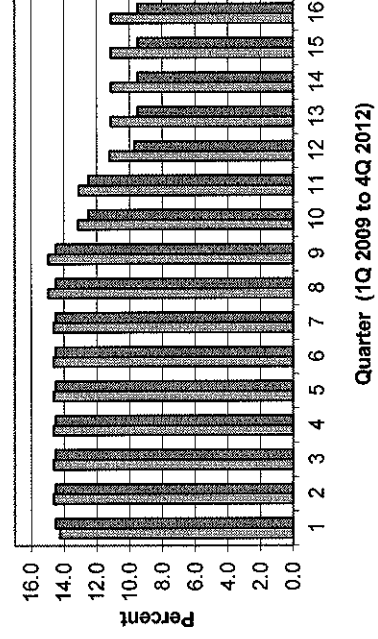
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY
 VA, MD, DC Area
 Indemnity Summary for 1Q 2009 to 4Q 2012

	Co. C	Co. A	Co. F	Co. G	Co. J	Mean Ave	Median	Range of Rates	
								Low	High
1 Q 2009	11.5	11.5	11.5	16.5	14.5	14.3	14.5	11.5	16.5
2 Q 2009	13.4	13.4	13.4	16.5	14.5	14.6	14.5	13.4	16.5
3 Q 2009	13.4	13.4	13.4	16.5	14.5	14.6	14.5	13.4	16.5
4 Q 2009	13.4	13.4	13.4	16.6	14.5	14.6	14.5	13.4	16.5
1 Q 2010	13.4	13.4	13.4	16.5	14.5	14.6	14.5	13.4	16.5
2 Q 2010	13.4	13.4	13.4	16.5	14.5	14.6	14.5	13.4	16.5
3 Q 2010	13.4	13.4	13.4	16.5	14.5	14.6	14.5	13.4	16.5
4 Q 2010	13.4	13.4	13.4	16.5	14.5	15.0	14.5	14.3	16.5
1 Q 2011				16.5	14.5	15.0	14.5	14.3	16.5
2 Q 2011				16.5	12.5	13.1	12.5	11.1	16.5
3 Q 2011				16.5	12.5	13.1	12.5	10.9	16.5
4 Q 2011				16.5	9.0	11.2	9.7	9.0	16.5
1 Q 2012				16.5	9.0	11.1	9.5	9.0	16.5
2 Q 2012				16.5	9.0	11.1	9.5	9.0	16.5
3 Q 2012				16.5	9.0	11.1	9.5	9.0	16.5
4 Q 2012				16.5	9.0	11.1	9.5	9.0	16.5

Company Indemnity Trends
 1Q 2009 to 4Q 2012



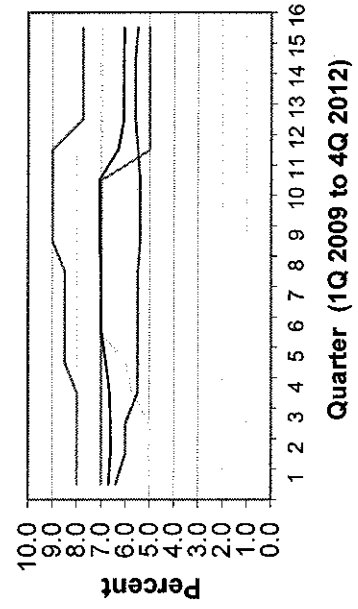
Indemnity Mean & Median Trends
 1Q 2009 to 4Q 2012



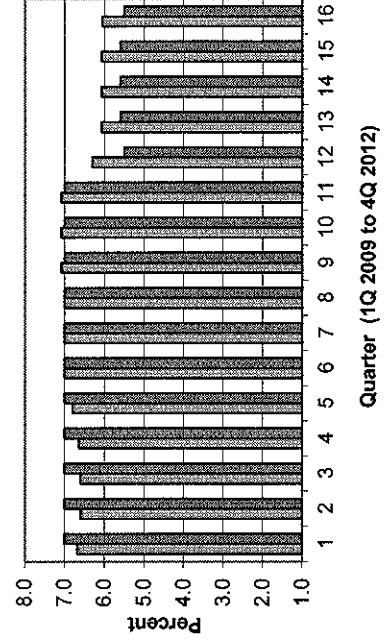
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY
 VA, MD, DC Area
 Dental Summary for 1Q 2009 to 4Q 2012

	Co. C	Co. F	Co. G	Co. J	Mean Ave	Median	Low	High
1 Q 2009	5.0		8.0	7.0	6.7	7.0	5.0	8.0
2 Q 2009	5.0		8.0	7.0	6.6	7.0	5.0	8.0
3 Q 2009	5.0		8.0	7.0	6.6	7.0	5.0	8.0
4 Q 2009	5.7		8.0	7.0	6.6	7.0	5.5	8.0
1 Q 2010	6.0		8.5	7.0	6.8	7.0	5.5	8.5
2 Q 2010	7.0		8.5	7.0	7.0	7.0	5.5	8.5
3 Q 2010	7.0		8.5	7.0	7.0	7.0	5.5	8.5
4 Q 2010	7.0		8.5	7.0	7.0	7.0	5.5	8.5
1 Q 2011	7.0		9.0	7.0	7.1	7.0	5.4	9.0
2 Q 2011	7.0		9.0	7.0	7.1	7.0	5.4	9.0
3 Q 2011	7.0		9.0	7.0	7.1	7.0	5.4	9.0
4 Q 2011	7.0		9.0	5.0	6.3	5.5	5.0	9.0
1 Q 2012	7.0		7.75	5.0	6.1	5.5	5.0	7.8
2 Q 2012	7.0		7.75	5.0	6.1	5.5	5.0	7.8
3 Q 2012	7.0		7.75	5.0	6.1	5.5	5.0	7.8
4 Q 2012	7.0		7.75	5.0	6.1	5.5	5.0	7.8

Company Dental Trends
 1Q 2009 to 4Q 2012

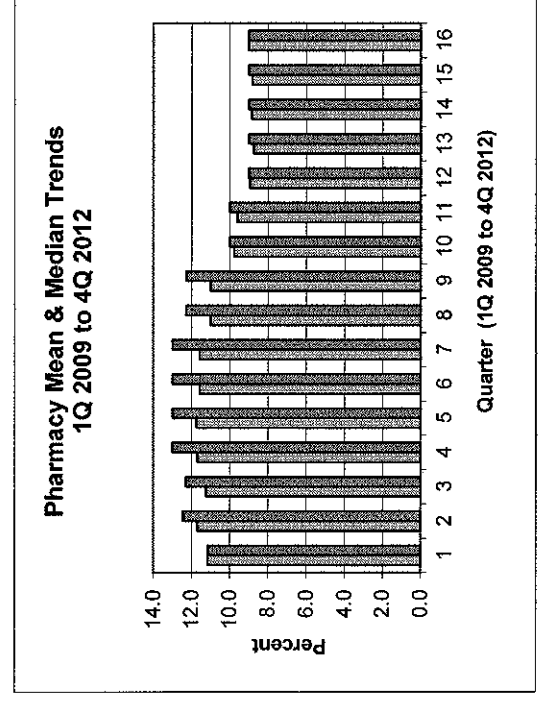
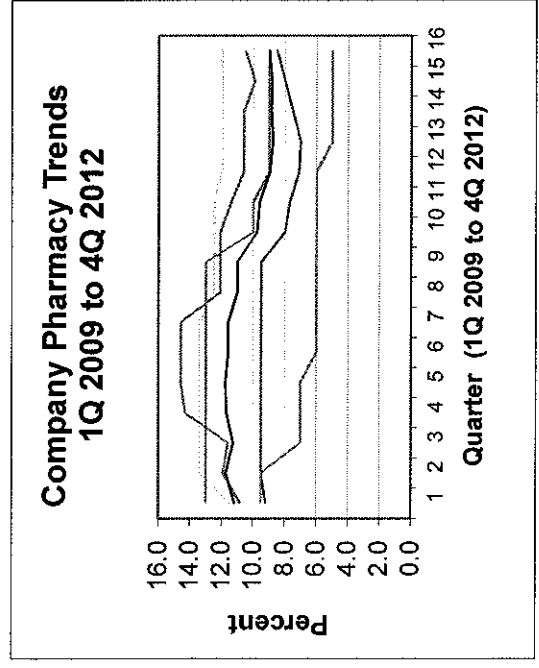


Dental Mean & Median Trends
 1Q 2009 to 4Q 2012



LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY
 VA, MD, DC Area
 Pharmacy Summary for 1Q 2009 to 4Q 2012

	Co. C	Co. D	Co. E	Co. F	Co. G	Co. H	Co. I	Mean Ave	Median	Range of Rates	
										Low	High
1 Q 2009	11.5	12.0	12.0	9.5	10.8	13.0	13.0	11.2	11.2	9.2	13.0
2 Q 2009	13.4	13.4	13.4	9.5	11.9	13.0	13.0	11.7	12.5	9.5	13.4
3 Q 2009	13.4	13.4	13.4	7.0	11.6	13.0	13.0	11.3	12.5	7.0	13.4
4 Q 2009	13.4	13.4	13.4	7.0	14.3	13.0	13.0	11.7	13.0	7.0	14.3
1 Q 2010	13.4	13.4	13.4	7.0	14.6	13.0	13.0	11.8	13.0	7.0	14.6
2 Q 2010	13.4	13.4	13.4	6.0	14.6	13.0	13.0	11.6	13.0	6.0	14.6
3 Q 2010	13.4	13.4	13.4	6.0	14.6	13.0	13.0	11.6	13.0	6.0	14.6
4 Q 2010	12.5	13.4	13.4	6.0	12.1	13.0	13.0	11.0	12.3	6.0	13.0
1 Q 2011	12.5	13.4	13.4	6.0	12.1	13.0	13.0	11.0	12.3	6.0	13.0
2 Q 2011	12.5	13.4	13.4	6.0	12.1	10.8	10.8	9.8	10.0	6.0	12.5
3 Q 2011	12.5	13.4	13.4	6.0	11.4	10.0	10.0	9.6	10.0	6.0	12.5
4 Q 2011	12.0	13.4	13.4	5.0	10.6	9.0	9.0	9.0	9.0	5.0	12.0
1 Q 2012	12.0	13.4	13.4	5.0	10.6	9.0	9.0	8.8	9.0	5.0	12.0
2 Q 2012	12.0	13.4	13.4	5.0	10.6	9.0	9.0	8.9	9.0	5.0	12.0
3 Q 2012	12.0	13.4	13.4	5.0	9.9	9.0	9.0	8.8	9.0	5.0	12.0
4 Q 2012	12.0	13.4	13.4	5.0	10.9	9.0	9.0	9.0	9.0	5.0	12.0



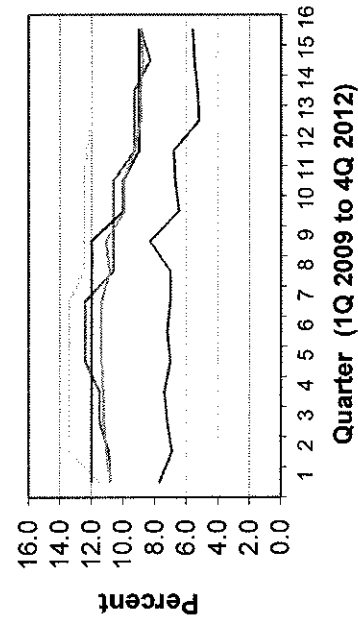
LAKE CONSULTING, INC. QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

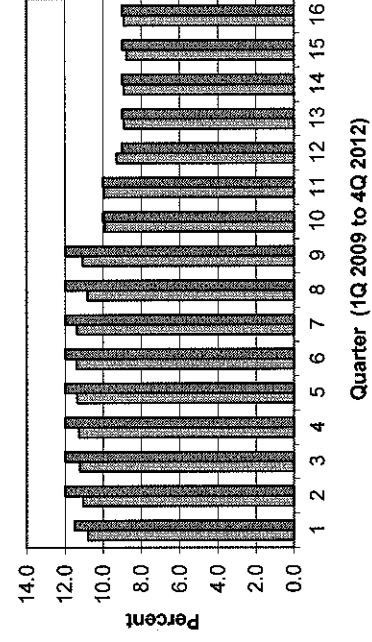
CDHP Summary for 1Q 2009 to 4Q 2012

	Co. C	Co. E	Co. F	Co. G	Co. I	Mean Ave	Median	Range of Rates	
								Low	High
1 Q 2009	11.5			10.8	12.0	10.8	11.5	7.7	12.0
2 Q 2009	13.4			10.9	12.0	11.0	12.0	6.9	13.4
3 Q 2009	13.4			11.5	12.0	11.2	12.0	7.2	13.4
4 Q 2009	13.4			11.5	12.0	11.3	12.0	7.4	13.4
1 Q 2010	13.4			12.4	12.0	11.4	12.0	7.0	13.4
2 Q 2010	13.4			12.4	12.0	11.4	12.0	7.2	13.4
3 Q 2010	13.4			12.4	12.0	11.4	12.0	7.0	13.4
4 Q 2010	12.5			10.6	12.0	10.8	12.0	7.0	12.5
1 Q 2011	12.5			10.6	12.0	11.1	12.0	8.3	12.5
2 Q 2011	12.5			10.6	10.0	9.9	10.0	6.5	12.5
3 Q 2011	12.5			10.6	10.0	10.0	10.0	6.7	12.5
4 Q 2011	12.3			9.3	9.0	9.3	9.0	6.8	12.3
1 Q 2012	12.0			9.3	9.0	8.9	9.0	5.2	12.0
2 Q 2012	12.0			8.3	9.0	8.9	9.0	5.3	12.0
3 Q 2012	12.0			8.3	9.0	8.8	9.0	5.5	12.0
4 Q 2012	12.0			8.9	9.0	8.9	9.0	5.6	12.0

Company CDHP Trends
1Q 2009 to 4Q 2012



CDHP Mean & Median Trends
1Q 2009 to 4Q 2012



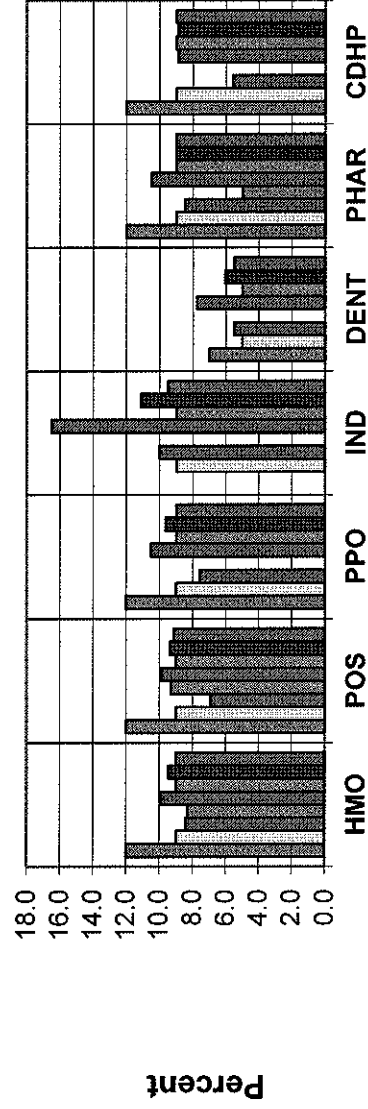
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

Annual Medical Trends Being Used for 4th Quarter 2012

	Company C	Company D	Company E	Company F	Company G	Company I	Mean Avg	Median	Range of Rates
									Low
HMO	12.0	9.0	8.4	8.3	9.9	9.0	9.4	9.0	8.3
POS	12.0	9.0	6.9	9.3	9.9	9.0	9.4	9.2	6.9
PPO	12.0	9.0	7.6		10.5	9.0	9.6	9.0	7.6
Indemnity		9.0	10.0		16.5	9.0	11.3	9.5	9.0
Dental	7.0	5.0	6.5		7.75	6.0	7.1	5.5	5.0
Pharmacy	12.0	9.0	8.5	5.0	10.5	9.0	9.0	9.0	5.0
CDHP	12.0	9.0	5.6		8.9	9.0	8.9	9.0	5.6

2012 Medical Trends as of 4Q 2012

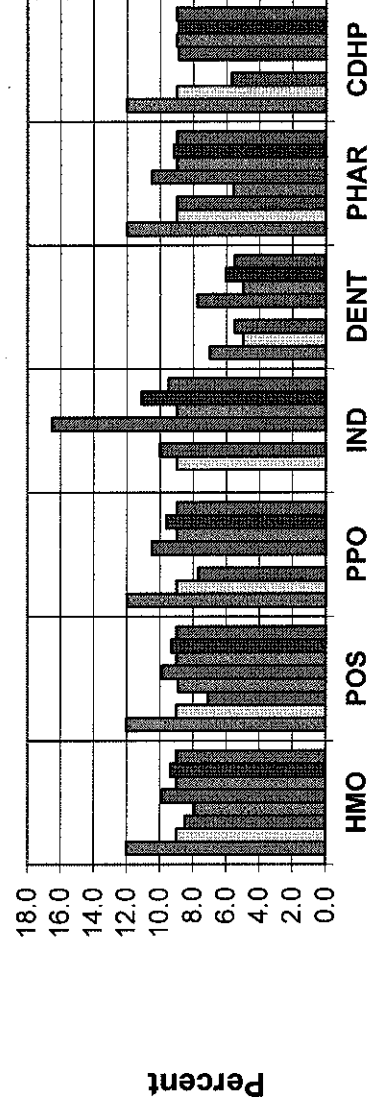


LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY
 VA, MD, DC Area

Annual Medical Trends Being Used for 2013 as of 4th Quarter 2012

	Company C	Company D	Company E	Company F	Company G	Company I	Market Avg	Median	Range of Rates
								Low	
HMO	12.0	9.0	8.5	7.9	9.9	9.0	8.9	9.0	7.9
POS	12.0	9.0	7.1	8.9	9.9	9.0	8.9	9.0	7.1
PPO	12.0	9.0	7.7		10.5	9.0	9.5	9.0	7.7
Indemnity		9.0	10.0		16.5	9.0	11.5	9.5	9.0
Dental	7.0	5.0	5.5		7.75	5.0	6.0	5.5	5.0
Pharmacy	12.0	9.0	9.0	5.5	10.5	9.0	10.2	9.0	5.5
CDHP	12.0	9.0	5.7		8.9	9.0	8.9	9.0	5.7

2013 Medical Trends as of 4Q 2012



Delmarva Power & Light
January 2013 to December 2013 Reliability Closings - Gas
6+6 Months Ending December 31, 2012

(1) Line No.	(2) <u>Item</u>	(3) \$
1	Rate Base	
2	Plant in Service	
3	Reliability closings January 2013 - December 2013	\$18,288,000
4	Retirements January 2013 - December 2013	<u>(\$3,600,000)</u>
5	Adjustment to Plant in Service	\$14,688,000
6		
7	Depreciation reserve	
8	Retirements January 2013 - December 2013	(\$3,600,000)
9	Depreciation expense	<u>\$202,005</u>
10	Adjustment to Depreciation Reserve	(\$3,397,995)
11		
12	Net Plant	\$18,085,995
13		
14	Deferred Taxes	(\$57,281)
15		
16	Total Rate Base	<u>\$18,028,714</u>
17		
18	Earnings	
19	Depreciation Expense	
20	Reliability closings January 2013 - December 2013	\$503,033
21	Retirements January 2013 - December 2013	<u>(\$99,022)</u>
22	Adjustment to Depreciation	\$404,010
23		
24	State Income Tax	(\$59,665)
25	Federal Income Tax	(\$219,147)
26	Deferred State Income Tax	\$24,516
27	Deferred Federal Income Tax	\$90,046
28		
29	Operating Expense	<u>\$239,760</u>
30		
31	Operating Income	<u>(\$239,760)</u>
32		
33	Total Earnings	<u>(\$239,760)</u>

Delmarva Power
Remove Bloom-Related Incremental Rate Base - Gas
6+6 Months Ending December 31, 2012

(1) Line No.	(2) <u>Item</u>	(3) <u>\$</u>
1	Rate Base	
2	Plant in Service	
3	Brookside Unit	(\$229,284)
4	Red Lion Unit	(\$302,000)
5	Adjustment to Plant in Service	(\$531,284)
6		
7	Depreciation reserve	
8	Brookside Unit	(\$2,138)
9	Red Lion Unit	(\$231)
10	Adjustment to Depreciation Reserve	(\$2,369)
11		
12	Net Plant	(\$528,915)
13		
14	Deferred Taxes	\$46,126
15		
16	Total Rate Base	(\$482,789)
17		
18	Earnings	
19	Depreciation Expense	
20	Brookside Unit	(\$2,138)
21	Red Lion Unit	(\$231)
22	Adjustment to Depreciation	(\$2,369)
23		
24	State Income Tax	\$19,948
25	Federal Income Tax	\$73,268
26	Deferred State Income Tax	(\$19,742)
27	Deferred Federal Income Tax	(\$72,511)
28		
29	Operating Expense	(\$1,406)
30		
31	Operating Income	\$1,406
32		
33	Total Earnings	\$1,406

Delmarva Power
AMI Net Plant Additions - Gas
6+6 Months Ending December 2012

(1) Line No.	(2) <u>Item</u>	(3) <u>\$</u>
1	Rate Base	
2	Proforma Plant in Service	
3	Delmarva Power - IMU	5,210,607
4	Delmarva Power - Communication Equipment	702,000
5	Service Company - IT Hardware and Software	<u>1,398,201</u>
6	Adjustment to Plant in Service	7,310,808
7		
8	Depreciation reserve	
9	Delmarva Power - IMU	178,676
10	Delmarva Power - Communication Equipment	6,179
11	Service Company - IT Hardware and Software	<u>205,942</u>
12	Adjustment to Depreciation Reserve	390,798
13		
14	Net Plant	<u>\$6,920,010</u>
15		
16	CWIP	(2,811,388)
17		
18	Deferred Taxes	\$136,105
19		
20	Total Rate Base	<u><u>\$4,244,726</u></u>
21		
22	Earnings	
23	Depreciation Expense	
24	Delmarva Power - IMU	391,984
25	Delmarva Power - Communication Equipment	33,429
26	Service Company - IT Hardware and Software	<u>439,544</u>
27	Adjustment to Depreciation	864,957
28		
29	State Income Tax	(\$17,000)
30	Federal Income Tax	(\$62,439)
31	Deferred State Income Tax	(\$58,252)
32	Deferred Federal Income Tax	(\$213,958)
33		
34	Operating Expense	<u>\$513,309</u>
35		
36	Operating Income	<u>(\$513,309)</u>
37		
38	AFUDC	(5,911)
39		
40	Total Earnings	<u><u>(\$519,220)</u></u>

Advanced Metering Business Case Including Demand Side Management Benefits

Report for Delaware

Before The Delaware Public Service Commission – Docket No. 07-28

August 29, 2007

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Executive Overview and Conclusion

Overview

The Delaware Public Service Commission (the "DPSC" or "the Commission") issued Order No. 7154 initiating this proceeding, Docket No. 07-28 on March 20, 2007. There have been several workshop meetings and discussions among the parties with the development and submission of this initial AMI business case as the next step in the process. As demonstrated in the following report, the AMI business case for Delmarva is justified by the operational benefits and the demand response benefits to the Company and our customers. Pepco Holdings, Inc. ("PHI"), the parent company of Delmarva Power & Light Company ("Delmarva" or "the Company"), Pepco and ACE has proposed their Blueprint for the Future (see February 6, 2007) that addresses two important local and national challenges: the rising cost of energy and the impact of energy use on the environment.

As regulated public utilities, we are uniquely positioned to play a leadership role in helping to meet both of these challenges. The Blueprint builds on the work we already have begun through Utility of the Future and other initiatives. In summary, Delmarva's Blueprint focuses on implementing advanced technologies and energy efficiency programs to improve service to our customers and enable them to manage their energy use and costs. If we can provide tools for our customers to control their energy use we can make a sizeable contribution to meeting the nation's energy and environmental challenges and at the same time help our customers keep their electric and natural gas bills as low as possible.

The Blueprint for the Future charts the course we believe we must follow to give our customers what they tell us they want: reasonable and stable energy costs; responsive customer service; power reliability; and environmental stewardship.

Delmarva is deploying a number of innovative technologies. Some, such as the automated distribution system, will help to improve reliability and workforce productivity, while others, including an Advanced Metering Infrastructure ("AMI"), will enable our customers to monitor and control their electricity use, reduce their energy costs and enable their participation in innovative rate options. Here are some examples of what's planned:

Demand Side Management (DSM) Programs

Delmarva plans on working closely with the SEU (Sustainable Energy Utility) to assure a portfolio of energy efficiency programs in the state that will work together to benefit our customers. Our primary focus will be on the demand response programs, as they are closely tied to the technology investments of the company. We will, however, in cooperation with the SEU develop appropriate energy efficiency programs to compliment, and supplement the SEU. A special effort with our consumer council will be taken to develop programs geared toward low-income customers who can also benefit from the advantage of this technology.

Automated Metering Infrastructure (AMI)

We will work collaboratively with the Commission to phase in the installation of an AMI system in the homes of Delmarva gas and electric customers. The AMI system will provide detailed usage data to our customers, our electricity suppliers and to the Company. The system will not only enable customers to track and modify their electric use, but it will also help us make improvements to customer reliability, outage management, and billing accuracy and timeliness.

Environmental Considerations

The deployment of an AMI System will support innovative customer rate options that help to support plug-in vehicles and small-scale renewable generators. The SEU has indicated that one of the primary benefits of this technology, to support their efforts, will be the ability to better pinpoint areas where distributed generation will provide overall system benefits. As part of PHI's multifaceted environmental initiatives, PHI is also laying the groundwork to transform its 2,000-vehicle fleet to more environmentally friendly technologies. We are already using Biodiesel at PHI fueling sites; we have replaced a number of our fleet vehicles with hybrid vehicles; and we are collaborating with the Electric Power Research Institute ("EPRI") on a project to demonstrate plug-in gasoline/electric vehicles.

In addition to these programs, the demand response efforts enabled by this technology will allow for reduced dependence on peaking sources of generation, while the technology will improve our access to greener sources of supply.

Delmarva's Blueprint for the Future Plan

Over the past several years the rising cost of energy across the nation has adversely affected Delmarva's customers, who are often left with limited ability to lower their energy use to reduce the added burden of higher energy costs. Delmarva has communicated with its customers and attempted to provide them with options to more efficiently manage their energy use. Last year PHI and Delmarva launched the "Energy Know How" campaign, which was recently re-introduced under the name of "My Account". PHI and Delmarva invested over \$1,000,000 to implement state of the art energy auditing software. This investment now enables Delmarva's residential customers to go on the internet and view data about their monthly bills to better understand how they use energy and what changes might reduce their overall costs. This was a good first step, but much more needs to be done to allow customers to further control their bills. The Blueprint is Delmarva's proposal to take Delaware customers into the future.

This filing is the next step in answering customer concerns by giving customers more robust energy efficiency tools to reduce electricity consumption and demand response programs that will help to change when customers use energy in an effort to reduce peak demands, driving total electricity costs down for the state. The data and communications capabilities inherent in the advanced metering proposal that Delmarva has set forth will provide a platform upon which to build a number of programs aimed at managing overall energy costs. Delmarva envisions that ultimately the new technology will even have customers' appliances receive and react to real time energy prices. Some of these technologies will take time and need to be tested, but many are ready to roll out immediately.

Components of Delmarva PHI AMI business case

The Business Case is comprised of four major components: Energy Delivery Benefits from AMI, Customer Savings from Reductions in Peak Loads, Cost to Deploy, and Accelerated Depreciation. The information contained in each of these components is further described below and detailed in the body of this report.

1 - Energy Delivery Benefits from AMI

Savings in operating costs captures O&M and capital savings expected to be realized once the AMI is implemented. These savings or benefits will include:

- Meter Related Benefits
- Customer Contact Benefits
- Asset Optimization Benefits
- Additional Benefits

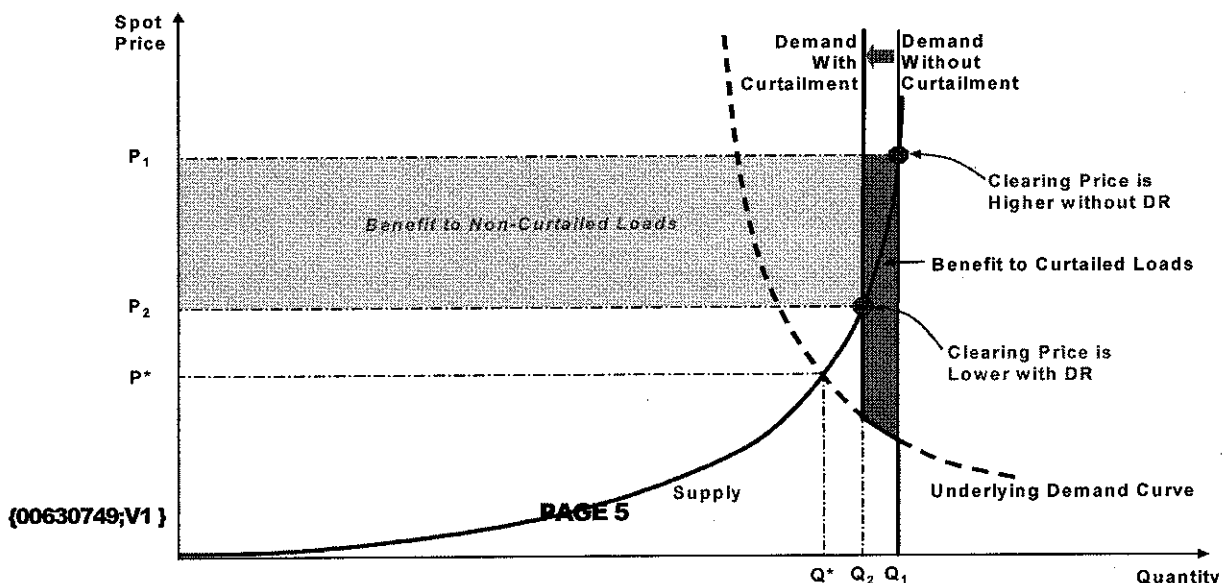
2 - Customer Savings from Reductions in Peak Loads

This analysis estimates the cost savings Delmarva's DSM programs are likely to achieve by (1) reducing the need for capacity, energy, and ancillary services (i.e., the "resource cost savings"); and (2) depressing market prices for energy and capacity by reducing demand. **The benefits are estimated consistently with the January, 2007 *Brattle Study*, "Quantifying Demand Response Benefits in PJM," sponsored by PJM and the Mid-Atlantic Distributed Resources Initiative (MADRI), with several additional analytical elements.**

The resource cost savings reflects the fact that every MW reduction in peak load lessens the need for physical capacity, which customers pay for through the load serving entities' payments. Similarly, every MWh reduction in consumption lessens the quantity of generation that customers must buy during peak periods with very high prices.

In general, the market price impacts reflect the fact that even a small reduction in demand during tight market conditions lowers the market price for energy, thus lowering the cost of energy for all customers (not just those curtailing load), as illustrated in Figure 1. Similarly, reducing the peak demand lowers the demand for capacity and thus reduces market prices for capacity, which affects all customers.

Figure 1: The *Brattle*-PJM-MADRI Study Showed How Even Small Changes in Demand Can Lead to Large Changes in Prices and Customer Benefits



3 - Cost to Deploy

Cost to Deploy includes the cost of the capital investments associated with building out the AMI system. Deployment costs included are; meters and installation, communications network infrastructure and installation and the associated information technology systems and integration, including the meter data management system (MDMS). Also included in the Cost to Deploy are the Incremental operating cost for the AMI system. Incremental operating costs include O&M expenses associated with operating the AMI. This includes; MDMS Software, Maintenance and license fees, AMI network management software maintenance and license fees, hardware lease expense for application and storage servers and expenses related to the communications network infrastructure.

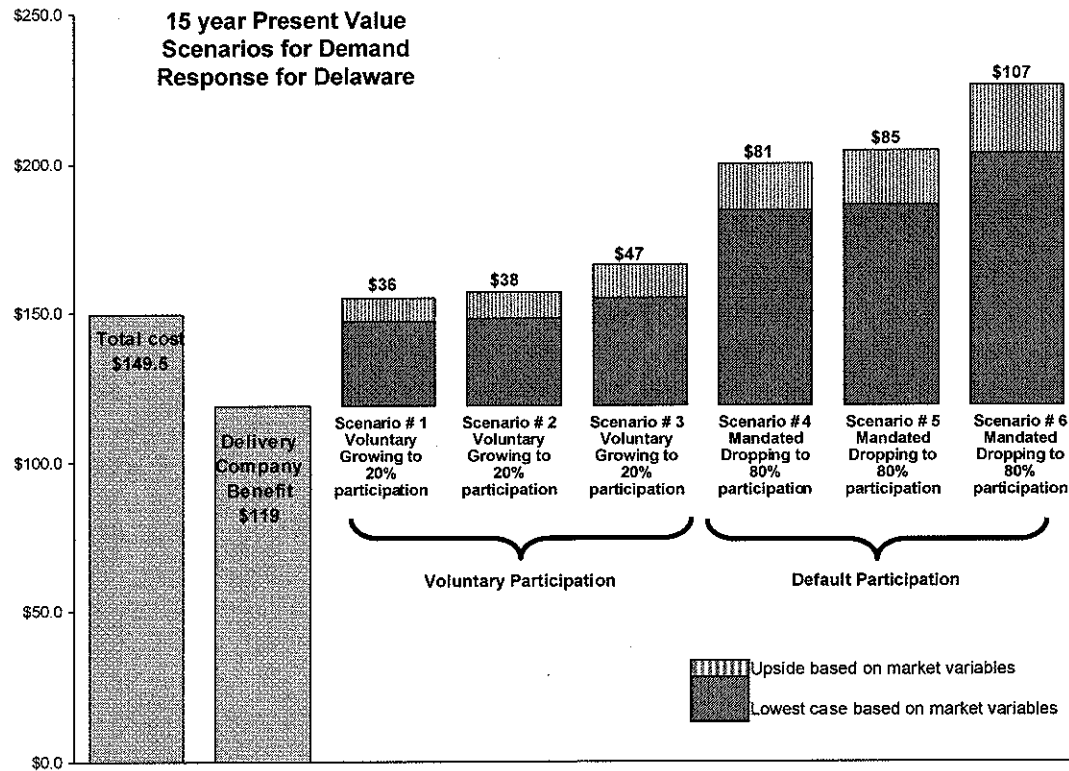
4 - Accelerated Depreciation

The deployment of AMI technology will require the removal and disposition of existing meters that are not fully depreciated and the replacement of, or significant modification to, existing meter reading, communications, and customer billing and information infrastructure. These impacts have been reflected in the analysis. Depreciation calculations may be updated due to pending Federal legislation.

Conclusions

The Delmarva AMI business case is justified by the operational benefits and the demand response benefits to the Company and our customers. The estimates for demand response benefits from the AMI deployment, over a 15 year period, is \$36 million estimated using the most conservative of scenarios. Coupled with operational savings of \$119 million, results in a positive \$5.5 million Present Value Revenue Requirement (PVRR) over the same period. Using the best case for Demand Response (DR) benefits, results in a positive \$76.5 PVRR.

Figure 2



In order to arrive at this conclusion, PHI contracted with the Brattle Group to develop six scenarios of customer and supplier response to AMI. Figure 2 above, shows the relationship of each of these six scenarios compared to the PVRR Cost and Benefit. The two cases, upside and low, for each scenario are the result of sensitivities associated with variations in market conditions. These conditions include possible fluctuations in fuel prices, and or high peak years (usually weather driven). Following PHI's example, if the other energy distributors in PJM deploy AMI, the benefit to Delaware customers is estimated to be as high as \$393.5 million.

The results of this analysis yields two key conclusions: (1) AMI is a net positive investment even in the lowest value scenario; (2) the benefits from AMI-enabled DR will be more than twice as large if dynamic pricing is the default rate structure than if it is merely an option that customers can elect.

Figure 3 below summarizes the PVRR for Delmarva Delaware.

Figure 3

Line		Initial Deployment Costs Only \$ in ('000s)		
		Electric	Gas	Combined
	AMI System Components			
1	Meters, including Installation Cost	\$ 42,783	\$ 9,195	\$ 51,978
2	Communications Network, including Installation Cost	\$ 21,616	\$ -	\$ 21,616
3	AMI Network Management System and Meter Data Management System	\$ 4,417	\$ 1,828	\$ 6,245
4	Contingency	\$ 4,680	\$ 1,543	\$ 6,223
	Total Capital Investment	\$ 73,496	\$ 12,566	\$ 86,062
		Annual Estimated Costs After Deployment \$ in ('000s)		
		Electric	Gas	Combined
	AMI System Incremental Cost to Operate			
5	MDMS Software Maintenance & License Fees	\$ 62	\$ 26	\$ 88
6	MDMS Hardware Leasing	\$ 168	\$ 70	\$ 238
7	AMI Network Management System O&M	\$ 196	\$ 81	\$ 277
8	Communications Network Infrastructure O&M	\$ 273	\$ -	\$ 273
	Total Incremental Cost to Operate	\$ 699	\$ 177	\$ 876

15 Year Revenue Requirement of Total Costs	\$149.5 million
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Line	Benefit Category	In Projected 2008 Dollars ('000s)		
		Electric	Gas	Combined
1	Eliminate Manual Meter Reading Costs	\$ 3,564	\$ 1,157	\$ 4,721
2	Implement Remote Turn-on/Turn-off Functionality	\$ 1,592	\$ -	\$ 1,592
3	Improve Billing Activities	\$ 484	\$ 186	\$ 670
4	Reduce Off-Cycle Meter Reading Labor Costs	\$ 372	\$ 57	\$ 429
5	Asset Optimization	\$ 219	\$ -	\$ 219
6	Reduce Expenses Related to Theft of Service	\$ 88	\$ 36	\$ 124
7	Eliminate Hardware, Software, Maintenance and Operations Cost	\$ 75	\$ 30	\$ 105
8	Reduce Volume of Customer Call Types Related to Metering	\$ 29	\$ 12	\$ 41
9	Reduced Complaint Handling	\$ 24	\$ 10	\$ 34
	Total Annual Operating Benefits	\$ 6,447	\$ 1,488	\$ 7,935

15 Year Revenue Requirement of Operating Benefits	\$119 million
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Summary of Cost and Benefits for Delmarva Delaware

Business Case Report Details

Organization of this Report

For the preparation of this report, PHI gathered information from both internal and external subject matter experts, including IBM and the Brattle Group, as well as from other utilities across the country. While this report represents the current state of thinking for AMI deployment, information within this report is still subject to change. Therefore this report should be considered a living document that will be consistently updated as additional information becomes available. Specific points to remember are:

- AMI Capital Costs reflected in this report are estimates. Once PHI secures an AMI Vendor(s), the final Capital Cost numbers will be updated.
- This Business Case considers the deployment of an AMI system throughout all PHI jurisdictions.
- Cost and Benefit estimates are realistic yet conservative in order to assure a high probability of achievement.
- While many benefits are immediately available as the AMI System is deployed, timing of the full benefits associated with an AMI system is assumed to begin following the complete deployment.
- Business Case Financial Assumptions:
 - 15 year Present Value Revenue Requirement model, with multiple jurisdictions modeled
 - Meter Deployment assumed 100% of Delmarva DE meters in 2009:
 - Meter growth is assumed to be 1% per year
 - 3% labor and expense annual escalation rate
 - Cost of Capital
 - Delmarva-DE Elec: 6.23%
 - Delmarva-DE Gas: 6.55%
 - Tax rate 40.4% for all jurisdictions
 - Depreciation:

- New meter and meter communications equipment - 15 yrs
- Existing meter and equipment – 5 years
- IT Capital Cost - 5 years

Energy Delivery Benefits from AMI

This section of the report describes the estimated benefits¹ that could be realized by Delmarva's electric and gas delivery businesses through deployment of the advanced metering infrastructure system and the associated meter data management system. Typically, the full value realized from the benefits is expected to occur after full deployment of the AMI system. The Company proposes to use these quantified benefits to help offset the costs associated with AMI and MDMS in the proposed AMI Adjustment Mechanism as described in the Appendix to the February 6, 2007 Blueprint for the Future filing with the Delaware Public Service Commission. Figure 4 below summarizes the annualized benefits and under the Figure are more detailed descriptions of each benefit.

Figure 4 (In \$ Millions)

Line	Benefit Category	In Projected 2008 Dollars			Benefit Dollars as a % of Total		
		Delmarva DE-Elec	Delmarva DE-Gas	Delmarva Combined	Delmarva DE-Elec	Delmarva DE-Gas	Delmarva Combined
1	Eliminate Manual Meter Reading Costs	\$ 3,564	\$ 1,157	\$ 4,721	55.3%	77.8%	59.5%
2	Implement Remote Turn-on/Turn-off Functionality	\$ 1,592	\$ -	\$ 1,592	24.7%	0.0%	20.1%
3	Improve Billing Activities	\$ 484	\$ 186	\$ 670	7.5%	12.5%	8.4%
4	Reduce Off-Cycle Meter Reading Labor Costs	\$ 372	\$ 57	\$ 429	5.8%	3.8%	5.4%
5	Asset Optimization	\$ 219	\$ -	\$ 219	3.4%	0.0%	2.8%
6	Reduce Expenses Related to Theft of Service	\$ 88	\$ 36	\$ 124	1.4%	2.4%	1.6%
7	Eliminate Hardware, Software, Maintenance and Operations Cost	\$ 75	\$ 30	\$ 105	1.2%	2.0%	1.3%
8	Reduce Volume of Customer Calls Related to Metering	\$ 29	\$ 12	\$ 41	0.4%	0.8%	0.5%
9	Reduced Complaint Handling	\$ 24	\$ 10	\$ 34	0.4%	0.7%	0.4%
10	Total	\$ 6,447	\$ 1,488	\$ 7,935	100.0%	100.0%	100.0%

1) Eliminate Manual Meter Reading Costs

This is the largest operational benefit expected to be realized after full deployment of the AMI system. As of June 2007, Delmarva employed a total of 55 meter readers and supervisory personnel in Delaware, all of which would no longer be needed to perform their present functions with full deployment of AMI. As of the date of this report, which is prior to

¹The quantification of these benefits will change as Delmarva conducts the procurement phase of its AMI project and evaluates the capabilities of the various AMI systems available in the market today. In addition, the quantifications will also change due to changing labor rates, payroll loading rates, inflation and other possible changes in the underlying assumptions used to derive the estimated value of the benefits.

development of the request for proposal for the procurement of the AMI system, the Company expects to design and configure its AMI such that all Delaware customers will have meters that are reachable by the AMI's communications network infrastructure. The elimination of the need to manually read meters would result in annualized O&M expense savings of \$4.7 million (expressed in projected 2008 dollars). The O&M expense savings estimate is based on the actual 2007 salaries of the 55 people with the applicable loading for payroll taxes and benefits such as medical coverage, dental coverage, pension and other post retirement benefits. The savings also include 2007 budgeted overtime, vehicle and miscellaneous expenses associated with the manual meter reading.

The savings were allocated between electric and gas service using a three step approach. First, the meter reading personnel working in the Delaware portions of Delmarva's New Castle and Bay regions were specifically identified with the Bay region costs assigned completely to the electric service. The New Castle region costs were then allocated between electric and gas service using the allocation factor the Company currently uses in its accounting practices to allocate the meter reading costs between electric and gas service. This allocation factor was updated in late 2006 and is presented in the Figure below. Finally, the portion of the New Castle region's expenses allocated to the electric service were added to the specifically identified Bay region expenses in order to derive the total electric savings for Delaware.

Figure 5 below is the allocation factor for New Castle region's meter reading in the Christiana operating center, which is entirely in the state of Delaware:

Figure 5

Meter Reading Analysis :

Description	Source	Number	% of Total	Gas %	Gas % of Total
Accounts read in Christiana Region	November 2006 Report BCR074 [C3]	341,757		50.0%	23.9%
Combined Gas& Electric Premise	DB2 Extract from C3 November 2006	110,489	47.8%		
Total Premises Visited	Total less combined	231,268			
Gas customer accounts	Monthly SAP 661 - November 2006	120,781		100.0%	4.5%
Combined Gas& Electric Premise	DB2 Extract from C3 November 2006	110,489			
Gas Only Premise	Gas cust less G&E combined	10,292	4.5%		
Electric Christiana Customer accounts	Total Accounts less Gas Accounts	220,976		0.0%	0.0%
Combined Gas& Electric Premise	B. Dodge - C3 November 2006	110,489			
Electric Only Premise	Chris. Elec. Cust less G&E comb	110,487	47.8%		
Gas Delivery Meter Reading %					28.3%

The initial year was assumed to be 2008 therefore the 2007 O&M expense savings as described above were escalated three percent (3%) to account for expected wage and inflation increases. The three percent

escalation factor was also used to grow the estimated annualized savings in the remaining years of the revenue requirements schedule

2) Implement Remote Turn-on/Turn-off Functionality

Delmarva's current assumption is that a switch will be available inside the meters that will permit the Company to remotely connect and disconnect 200 AMP and less electric service. This assumption is consistent with AMI recent experiences and plans of other utilities and requirements of other state public service commissions. This type of switch would not be used for the gas type of service therefore gas connections and disconnections would continue to be done using the existing work processes.

The estimated savings associated with this benefit is comprised of two components. First, there would be savings from avoiding field visits to customers' premises conducted at the customers' requests to turn-on or turn-off electric service. Based on a review of 2006 data from Delmarva's accounting system, there were approximately 12,000 labor hours used for residential turn-on and turn-off orders. This translates into approximately seven to eight (7 to 8) Full Time Equivalents (FTE). The Full Time Equivalent employee concept was used instead of specific personnel since a mix of employees does this type of work. The savings were computed by multiplying the FTEs by a 2007 fully loaded annual labor cost per FTE which took into account the cost mix of employees doing the work. The fully loaded annual labor costs included the same costs that were described in the meter reading benefit, as described above. This portion of the savings amounted to an estimated annualized \$0.8 million (expressed in projected 2008 dollars).

The second component of the savings would come from avoiding field visits to customers' premises for collection reasons, both the initial cut/collect field visit and the reconnection field visit, if such a reconnection visit was requested by the customer. Based in a review of 2006 data from the Company's accounting system, there were approximately 10,000 labor hours used for residential field collection and reconnection visits. This translates into approximately six to seven (6 to 7) full time equivalents (FTE). Full time equivalents were used instead of specific personnel since a mix of employees does this type of work. The savings were computed by multiplying the FTEs by a 2007 fully loaded annual labor cost per FTE which took into account the cost mix of employees doing the work. The fully loaded annual labor costs included the same costs that were described in the meter reading benefit, as described above. This portion of the savings amounted to an estimated annualized \$0.7 million (expressed in projected 2008 dollars).

Remote turn on/turn off capability will benefit all customers, especially those subject to disconnection for non-payment. Currently the Delaware tariff specifies that if a disconnected customer requests to be reconnected, then a charge of \$75.00 to \$175.00 is required (depending on the time of day). With AMI's remote connection and disconnection functionality, this charge could be significantly reduced (estimated in the range of \$5 to \$10). The reconnection could be accomplished remotely from Delmarva's offices, after the customer calls the Company to verify payment, rather than dispatching a person to the customer's premise. This reduces the financial burden on those having difficulty paying their bills. This method is also safer for employees who perform this type of work.

3) Improve Billing Activities

With the deployment of AMI, the Company expects to significantly reduce the volume of exceptions that it currently addresses in its billing department. These exceptions include such transactions as estimated bills, consecutive estimations, high/low consumption and other checks. Delmarva and Atlantic City Electric Company (ACE) operate their billing department on an integrated basis using the same customer information system (CIS). As of June 2007, Delmarva and ACE employed a total of 28 billing analyst and supervisory personnel to handle the exceptions work volume. For this benefit, Delmarva assumed 90% of the work performed by these personnel would be eliminated with full deployment of AMI which translates into the elimination of the cost of 25 full time equivalents. The savings were computed by multiplying the FTEs by a 2007 fully loaded annual labor cost per FTE which took into account the cost mix of employees (analysts and supervisors) doing the work. The fully loaded annual labor costs included the same costs that were described in the meter reading benefit, as described above. This portion of the savings amounted to an estimated annualized \$1.9 million (expressed in projected 2008 dollars) for all of Delmarva and ACE combined. Note that if less than 90% of the exception volume is ultimately realized, then the savings estimate will be adjusted accordingly.

The savings were allocated between the Company's electric and gas types of service, Delmarva's Maryland jurisdiction and ACE using a 2007 average budgeted customer counts as the allocation factor. This allocation factor is presented in the Figure below.

Figure 6

Allocation based on 2007 Budgeted Customer Counts			
ACE	543,437	47%	\$ 849,577
Delmarva-DE-Electric	296,159	26%	\$ 469,979
Delmarva-DE-Gas	119,403	10%	\$ 180,761
Delmarva-MD	200,350	17%	\$ 307,294
Combined	1,159,350	100%	\$ 1,807,611

The 2007 dollars in Figure 6 above were escalated by three percent (3%) to account for 2008 estimated wage increases which increases the dollars in Figure 6 from \$1.8 million to \$1.9 million.

4) Reduce Off-Cycle Meter Reading Labor Costs

Delmarva typically uses meter readers, meter technicians, service persons and trouble persons to obtain meter readings outside of the normally scheduled meter reading routes for a variety of reasons. These reasons include when a customer moves out of a premise and a new customer moves in shortly thereafter and asks the billing department or the call center to check a reading in the field. With the full deployment of AMI, these "check reads" can be obtained remotely from Delmarva's offices eliminating the need for a field visit. When computing the estimated savings associated with this benefit, any costs from meter readers were excluded. Those savings are included in meter reading benefit described above.

Based on a review of 2006 data from the Company's accounting system, there were approximately 4,700 labor hours used for electric meter "check reads" and about 700 labor hours used for gas meter "check reads". This translates into approximately three to four (3 to 4) full time equivalents (FTE) for electric meters and approximately one half of a FTE for gas meters. Full time equivalents were used instead of specific personnel since a mix of employees does this type of work. The savings were computed by multiplying the FTEs by a 2007 fully loaded annual labor cost per FTE which took into account the cost mix of employees doing the work. The fully loaded annual labor costs included the same costs that were described in the meter reading benefit above. This portion of the savings amounted to an estimated annualized \$0.4 million (expressed in projected 2008 dollars).

5) Asset Optimization

AMI deployment will improve the quality of customer outage status and hence will reduce the field restoration efforts associated with "false" power

outages. Delmarva-DE experiences approximately 1000 power outage calls annually where upon arrival at the customer locations, the emergency response team finds that there is no electric service problem from Delmarva but the problem is on the customer side of the meter or in the house. Similarly, during storms, the Company responds to 500 to 600 outage requests annually which have been already restored previously but not recorded in the Company outage management system. AMI capabilities will eliminate these unproductive trips as well as reduce the number of Call Center calls and will result in estimated savings of \$179,000. AMI deployment also will improve Delmarva's asset management program and will result in accurate sizing of transformers and fuses. This will result in reduced outages and is expected to reduce number of field trips by 250 annually. It will also reduce field trips associated with special load readings at substations. The savings associated with this benefit is \$ 40,000 annually.

6) Reduce Expenses Related to Theft of Service

Delmarva currently uses an outside firm to analyze commercial account data to provide internal field investigators with selected accounts that may be experiencing tampering, energy diversion or some sort of metering problem. Based on discussions with MDMS vendors, it appears that with data coming from the AMI system coupled with analytical capabilities of the MDMS, Delmarva will be better equipped to conduct these types of analyses on its own and could therefore eliminate this contractual relationship. The savings were allocated between the Delmarva electric and gas service, Delmarva's Maryland jurisdiction and ACE using a 2007 average budgeted customer counts as the allocation factor.

7) Eliminate Hardware, Software, Maintenance and Operations Cost

PHI currently pays maintenance fees on its existing hand held metering reading devices and also employs two employees to operate and maintain the devices and associated data. With the deployment of AMI, these costs would be eliminated. The O&M expense savings for the two employees is based on the actual 2007 salaries of the two people with the applicable loading for payroll taxes and benefits such as medical coverage, dental coverage, pension and other post retirement benefits. The costs and savings were allocated between the Delmarva's electric and gas service, Delmarva's Maryland jurisdiction and ACE using a 2007 average budgeted customer counts as the allocation factor.

8) Reduce Volume of Call Types Related to Metering

PHI operates its call centers for Delmarva and ACE on an integrated basis using the same customer information system (CIS). In 2005 and 2006,

PHI received about 40,000 customer calls related to metering. If this associated call volume were reduced after the full deployment, the call center could save two full time equivalents. The O&M expense savings for the FTEs is based on the actual salary for a customer service representative with the applicable loading for payroll taxes and benefits such as medical coverage, dental coverage, pension and other post retirement benefits multiplied by two FTEs. The costs and savings were allocated between Delmarva's electric and gas service in Delaware, Delmarva's Maryland jurisdiction and ACE using a 2007 average budgeted customer counts as the allocation factor.

9) Reduced Complaint Handling

PHI operates its complaint handling group for Delmarva and ACE on an integrated basis using the same customer information system (CIS). For this benefit, PHI is assuming the data from AMI will, over time, contribute to fewer complaints and that the company representatives may be able to more quickly resolve complaints. The current assumption is that the complaint handling group may be able to reduce one full time equivalent. The O&M expense savings for the one FTE is based on the actual salary for a company representative with the applicable loading for payroll taxes and benefits such as medical coverage, dental coverage, pension and other post retirement benefits. The costs and savings were allocated between Delmarva's electric and gas service in Delaware, Delmarva's Maryland jurisdiction and ACE using a 2007 average budgeted customer counts as the allocation factor.

Customer Savings from Reductions in Peak Loads

The Brattle Group was retained by PHI to estimate the value to customers of load reductions resulting from PHI's proposed investments in demand-side management (DSM) initiatives, including energy efficiency, direct load control, and deployment of advanced metering infrastructure. *Brattle's* analysis involves two major components: first, determining the magnitude of load reductions that are likely to be achieved; and second, estimating the customer value of such load reductions.

1) Estimated Load Reductions

Load reductions associated with PHI's proposed programs involving energy efficiency and AMI-enabled direct load control are taken directly from PHI's most recent Blueprint Filing for its DSM programs. Load reductions associated with AMI-enabled critical peak pricing (CPP) programs were estimated using the PRISM model, which is based on

empirical data from the California Statewide Pricing Pilot and is calibrated to the load characteristics of residential and small C&I customers in Delmarva Delaware. Assuming a CPP program similar to PEPCO DC's current CPP pilot becomes the default rate structure with 80% of eligible customers participating, the resulting load reductions would likely be quite substantial, as shown in Figure 7a. The load reductions would be less substantial if participation were voluntary, as shown in Figure 7b.

Figure 7a - Estimated Peak Load Reductions for Delaware from PHI's Initiatives, Assuming CPP is the Default Rate Structure (MW)

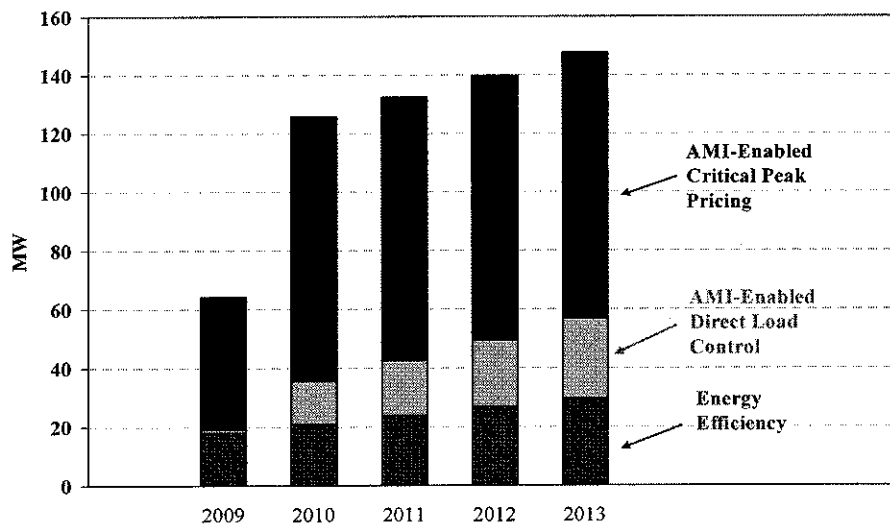
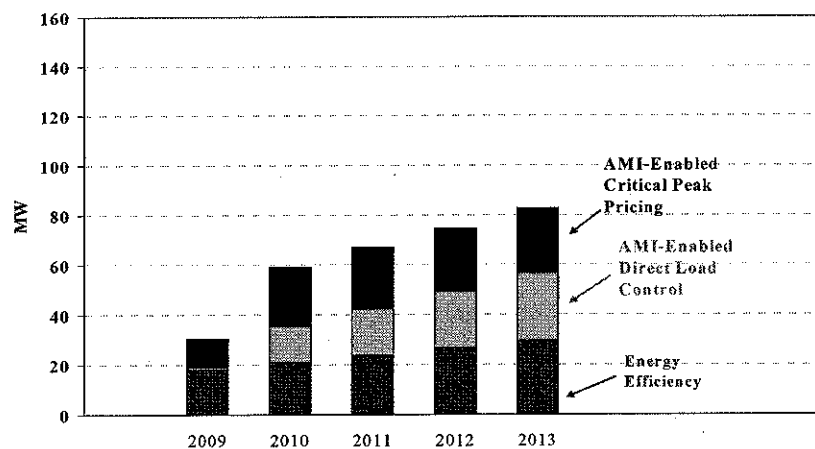


Figure 7b - Estimated Peak Load Reductions from PHI's Initiatives, Assuming CPP is a Voluntary Rate Structure (MW)



2) Analysis of Customer Benefits from Load Reductions

Savings to the customer relates to those benefits that will reduce the customer's bill, but not impact the cost of energy delivery. Most significantly, AMI-enabled innovative rate options (e.g., critical peak pricing, time of use rates, real-time pricing, etc.) will allow the customer to better manage consumption and thus reduce demand during peak periods. Reductions in peak consumption will produce savings by (1) reducing the need for supply-side capacity, energy, and ancillary services (i.e., the "resource cost savings"); (2) depressing market prices for energy and capacity by reducing demand; (3) reducing transmission losses; (4) improving reliability; (5) reducing rate volatility; (6) enhancing market competitiveness; (7) improving environmental quality or reducing energy prices by lowering the costs of environmental compliance; and (8) potentially obviating or delaying the need for investments in transmission and distribution.

The customer benefits detailed in this report focus on items one and two above. The other categories of benefits have not been quantified because the economic methodologies involved are not well developed or standardized. Therefore, the total benefits of reducing load could be substantially larger than the limited set of benefits reported in this Business Case.

The Brattle Group has estimated the benefits to Delaware customers from resource cost savings and market price impacts consistent with its January, 2007 study, "Quantifying Demand Response Benefits in PJM," sponsored by PJM and the Mid-Atlantic Distributed Resources Initiative (MADRI), but with several additional analytical elements.

Resource Cost Savings

Capacity savings reflect the fact that DR lowers the load forecast, which lessens the amount of capacity that load-serving entities must purchase from generation suppliers through contracts or through PJM's capacity market. Alternatively, load that is controlled directly by the utility can provide capacity, thus offsetting the need for physical capacity. The value of either approach – reducing the capacity requirement or contributing capacity – can be evaluated using a projected price of capacity. *Brattle* estimated the future capacity price using the Net Cost of New Entry (Net CONE) that PJM uses in its definition of capacity market parameters. Net CONE is a conservative proxy because the capacity price has been higher than Net CONE in recent auctions for the 2007/08 and 2008/09 delivery years. Net CONE is also less than the avoided capacity cost often used in

DSM plans, which often does not net out the marginal value (i.e., operating margins) that new generation would provide by selling energy and ancillary services.

Generation savings depends on the particular type of generation that is being avoided, which could come from a combination of new capacity not constructed and old capacity retired or not dispatched. The value of reduced generation is also partially offset by the value the customer forgoes by not consuming as much power. Assessing the forgone value to the customer is difficult to assess and depends on whether the customer shifts load to lower-priced periods. These issues were addressed in the *Brattle-PJM-MADRI* study, in which generation savings amounted to an additional 12-36 percent on top of the capacity savings. Brattle's analysis of AMI-enabled DR in Delmarva simply adopts these figures by adding 12-36 percent of the estimated capacity savings.

Some DR could provide spinning reserves or other ancillary services (A/S), which would reduce the need for reserves from supply-side resources, the marginal value of which is given by the market price for spinning reserves. However, ancillary service value is somewhat speculative because currently none of PHI's DSM programs plan to enable ancillary services, although other DR does provide small amounts of A/S in PJM and ISO-NE².

Short-Term Price Impacts

Short-term energy price reductions are estimated by adapting the results of the *Brattle-PJM-MADRI* study (January, 2007) to reflect the load reductions expected from PHI's programs. As in the *Brattle-PJM-MADRI* study, the "benefit" is given by the product of the estimated price reduction and the load exposed to market prices. Benefits are partially offset by an associated reduction in the value of Financial Transmission Rights ("FTRs") (about a 15% offset). To the extent that PHI's load reductions differ from the load reductions simulated in the *Brattle-PJM-MADRI* study, *Brattle* linearly extrapolated the price impacts (e.g., twice the amount of load reductions would lead to twice the price impact).

While the *Brattle-PJM-MADRI* study assumed that all non-curtailed load was exposed to market prices, the present analysis assumes conservatively that only a fraction of load is exposed to market prices. The remainder is unaffected because it is covered by pre-existing contracts that were priced without anticipating the effects of DSM. Roughly

²*Brattle* assumed conservatively that AMI could eventually enable 100 MW of spinning reserves from loads that can be curtailed within less than 30 minutes of notification and stay offline for as much as 4 hours, such as electric arc furnaces or chillers in supermarkets. Hence potential ancillary service value is estimated by multiplying a conservative quantity of spinning reserves by the historical average price of spinning reserves (2004-06) of \$8.5/MWh and by the number of hours in a year.

corresponding to the contract lengths and schedules by which standard offer service is procured in DC, DE, and MD and basic generation service in New Jersey, *Brattle* assumed that in any given year 50% of load-serving obligations are supplied by pre-existing wholesale contracts, and 50% are supplied by new contracts. This assumption results in discounted customer benefits relative to the *Brattle*-PJM-MADRI study – a 50% discount in the “Fast” Supply Response scenario and a 17% discount in the “Slower” scenario discussed below.

A second difference from the *Brattle*-PJM-MADRI study is the quantification of real-time DR benefits. The *Brattle*-PJM-MADRI study quantified benefits for only day-ahead DR and discussed qualitatively the potential additional value from DR that is dispatchable in real-time and thereby able to mitigate the effects of real-time surprises in supply and demand. In its present analysis of DSM in Delmarva, *Brattle* assumed that loads under direct load control were dispatchable in real time, and estimated the premium using the ratio of historical super-peak RT prices to super-peak DA prices. *Brattle* also estimated the additional value if dynamic pricing could designate peak periods on the day-of rather than day-ahead.

A third difference is that *Brattle*'s present analysis includes an estimate of the capacity price impact from DR, whereas capacity price impacts were outside the scope of the *Brattle*-PJM-MADRI. Participation of DR in capacity markets is an important element of PJM's newly instituted Reliability Pricing Model (RPM). While only the subset of load reductions, those that are under direct control (by the utility, other retail providers, curtailment service providers or the RTO), can participate as supply in capacity markets (Smart thermostat), the expected effect of dynamic pricing programs would also impact capacity prices by reducing the load forecast and thus the administratively-determined demand for capacity. Given this new market reality, *Brattle* has estimated capacity price impacts as follows: in the “Fast” and “Slower” Supply scenarios (defined below), the market was assumed to be in supply/demand balance with the expected 3-year forward capacity price set by Net CONE, irrespective of the level of load reductions achieved. Hence, the capacity price impact was conservatively set at zero in these scenarios. In the “Inadequate” Supply scenario, capacity price impacts were estimated by intersecting supply and demand curves for capacity in the Eastern MACC Locational Delivery Area both with and without DR. The demand curve was constructed using PJM's load forecast and the other parameters it uses to determine the administratively-determined demand curve. The supply curve was constructed by adding projected new supply (from the generation interconnection queue) to the supply curve available from the most recent capacity auction.

Scenario Definition

A key insight is that the resource cost savings from reducing peak loads persist over time, whereas the market price impacts can be expected to diminish as suppliers respond to depressed prices by delaying the construction of new generation or accelerating the retirement of existing plants. The magnitude and duration of the price impact depends on the rate at which suppliers respond to changes in market conditions and on the tightness of the market over the next several years. Price impacts are the largest and the longest-lasting in a scarcity situation; they are the smallest and shortest-lived in a surplus market or in a balanced market in which suppliers react quickly to DSM's successes (and associated price impacts) by delaying construction of new capacity or accelerating the retirement of existing plants. Hence, Brattle analyzed a range of plausible market conditions by constructing three supplier scenarios in which the longevity of price impacts is varied:

- In the "Fast" scenario, the market is in supply-demand equilibrium, and suppliers react quickly to changes in fundamentals. Short-term energy price impacts, as derived from the Brattle-PJM-MADRI study which used a short-term equilibrium model in which supply is static, benefits last for only one year before suppliers fully respond to DSM. One year after the introduction of new DR, suppliers have accelerated enough retirements and/or delayed enough new construction to completely offset the price impact of DR. Hence, if PHI's deployment schedule produces a 200 MW of total peak load reduction in year n and 300 MW in year $n+1$, then only 100 MW of load reductions has a price impact in year $n+1$. This scenario is consistent with the observation that suppliers in PJM's recent RPM Base Residual Capacity Auction for the 2008/09 delivery year changed their plans relative to the prior auction (in this case delaying retirements), presumably in response to high prices in the prior auction.
- The "Slower" scenario is similar to the "Fast" scenario except that short-term price impacts persist for three years before suppliers respond. The three-year response time corresponds to a three-year lead time for new construction.
- In the "Inadequate" scenario, suppliers do not build any capacity that is not currently in PJM's queue until 2015, and the market becomes very short on capacity. In such a shortage situation, suppliers are not responsive to the introduction of DR because they have no new capacity to delay and retiring existing plants early is unlikely, hence all load reductions achieved by PHI's DSM initiatives creates price impacts until 2015. This scenario reflects

the possibility that suppliers are reluctant to build in the current uncertain environment with the threats of reregulation, high gas prices, climate change policies, and siting difficulties.

Finally, each supplier response scenario is analyzed assuming high rates of customer participation in dynamic pricing programs and, alternatively, low customer participation rates. Customer participation rates depend primarily on whether critical peak pricing becomes the default rate structure or merely an option that customers can elect. In the "CPP Default Rate Structure" scenario, 100% of customers would be enrolled in a critical peak pricing rate initially, and some 20% would eventually switch to a non-CPP rate structure, leaving 80% participation in year two and beyond. In the "CPP Elective" scenario, 0% of customers would sign up initially, ramping up to 20% in two years and beyond. (These rates are based on the experience from the California Statewide Pricing Pilot and other pilots.)

3) Conclusions Regarding Customer Benefits from Load Reductions

Figure 8 shows the benefits to Delaware customers (including municipal and cooperative utilities contained within the PHI zones) if Delmarva's proposed DSM programs are implemented in Delmarva-Delaware according to its proposed deployment schedule.

The following conclusions can be drawn from this analysis:

- For the Default CPP Case, the quantified benefits of load reductions would be significant in a supply-adequate market in which suppliers are highly responsive to the introduction of DSM (\$65-81 million for all of Delaware), but they are be much greater in the Inadequate Supply Response scenario (\$84-107 million for all of Delaware).
- For the Voluntary CPP Case, the quantified benefits of load reductions would be significant in a supply-adequate market in which suppliers are highly responsive to the introduction of DSM (\$28-36 million for all of Delaware), but they are be much greater in the Inadequate Supply Response scenario (\$36-47 million for all of Delaware).
- The short-term savings to all customers, including customers outside of PHI's zones, would be much larger than the benefits to just Delaware customers due to the fact that PHI's load reductions would have a market-wide impact on energy and capacity prices.

Figure 8. Benefits to Delaware Customers from AMI-Enabled Dynamic Pricing and Direct Load Control Programs in Delmarva Delaware for both Voluntary and Default Cases.

Benefits to Delaware Customers from AMI-Enabled CPP and DLC in Delmarva DE
Net Present Value of Benefits through 2024 (million 2007 \$'s)

Rate Structure Scenario Supplier Responsiveness Scenario*	CPP is a Voluntary Rate			CPP is the Default Rate		
	Fast	Slower	Inadequate	Fast	Slower	Inadequate
RESOURCE COST SAVINGS						
Avoided Capacity Costs	\$25	\$25	\$25	\$57	\$57	\$57
Avoided Energy Costs	\$3 - \$9	\$3 - \$9	\$3 - \$9	\$7 - \$20	\$7 - \$20	\$7 - \$20
Avoided Ancillary Services Costs	\$0.7 - \$2	\$0.7 - \$2	\$0.7 - \$2	\$0.9 - \$2.5	\$0.9 - \$2.5	\$0.9 - \$2.5
SHORT-TERM MARKET PRICE IMPACTS						
Energy Price Benefit	\$0.2 - \$0.5	\$0.9 - \$2	\$2 - \$5	\$0.4 - \$1.1	\$2 - \$6	\$5 - \$13
Potential Additional Real-Time Benefit	\$0.1 - \$0.2	\$0.2 - \$0.4	\$0.3 - \$0.5	\$0.3 - \$0.7	\$0.6 - \$1.2	\$0.9 - \$1.5
Capacity Price Benefit	\$0	\$0	\$6	\$0	\$0	\$15
TOTAL QUANTIFIED BENEFITS ***	\$28 - \$36	\$29 - \$38	\$36 - \$47	\$65 - \$81	\$67 - \$85	\$84 - \$107
UNQUANTIFIED BENEFITS						
Enhanced Reliability			Large***			Very Large***
Enhanced Market Competitiveness						
Reduced Rate Volatility						
Environmental Benefits						
Reduced Transmission Losses						
Avoided Transmission and Distribution Costs						

* Fast response: short-term benefits last for 1 year; Slower response: short-term benefits last for 3 years;

Inadequate response: no generic entry and short-term benefits last until 2015.

** Excludes potential real-time benefits.

*** A PHI-wide implementation of AMI and energy efficiency would increase reserve margins in Eastern MAAC from 18.1% to 18.9% in 2010, and from 11.5% to 12.9% in 2013 if CPP is the Default Rate Structure and from 18.1% to 18.6% in 2010, and from 11.5% to 12.3% in 2013 if CPP is a Voluntary Rate Structure

- The savings to Delaware customers would be as much as two times larger if all utilities in PJM-East followed PHI's lead in deploying DSM programs and achieved similar load reductions, with the aggregate load reductions creating a much greater impact on energy and capacity prices.
- The savings to Delaware customers would be less than half as large if critical peak pricing were not the default rate structure, requiring customers to take initiative in order to sign up for the program. This finding is based on the assumption that a voluntary program would achieve only 20% participation by residential and small commercial and industrial customers, whereas making CPP the default rate structure with an option to switch to a fixed rate would achieve 80% participation. (This assumption is consistent with participation rates in California's Statewide Pricing Pilot.) However, even at a pessimistic

20% participation rate, the total benefits of AMI/DSM exceed the total costs.

- Although critical peak pricing programs typically designate peak periods on a day-ahead basis, making the programs callable on a real-time basis would enable customers to mitigate the impacts of real-time surprises in load or supply outages. This could add an additional \$300,000 to \$1.5 million in value.
- In the Inadequate Supply Response scenario, implementation of DSM programs like PHI's throughout PJM-East would increase reserve margins in Southwest MACC from 15.2% to 18.3% in 2010, and from 5.8% to 14.4% in 2013; in Eastern MAAC from 18.1% to 21% in 2010 and from 11.5 to 19.9% in 2013. Hence, DSM initiatives would provide substantial value as an insurance against intolerably low reserve margins.

These savings estimates do not include potential additional customer benefits from reducing transmission losses, improving reliability, reducing rate volatility, enhancing market competitiveness, improving environmental quality, reducing energy prices by lowering the costs of environmental compliance, or potentially obviating or delaying the need for investments in transmission and distribution. These categories of benefits have not been quantified because the economic methodologies involved are not as well developed or standardized. Therefore, the total customer benefits of AMI could be substantially larger than the limited set of benefits reported in this Business Case.

Additional Benefits

Customer Benefits

Delmarva utilizes a market research model developed by Market Strategies Inc ("MSI") to assist the company in identifying the key drivers of customer satisfaction. The energy delivery benefits associated with AMI related to billing, customer service, energy information and reliability contribute positively to Delmarva's customer satisfaction performance once the full Blueprint plan is implemented. Additional customer benefits include:

- Improved website capabilities which will provide interval usage data to enable customers to understand when and how they are consuming energy at their homes and businesses.

- Individual customer load profile data can be useful in enabling the utility to target specific conservation programs or messaging to those customers who would achieve the maximum benefit. Delmarva's "My Account" software has the capability to provide "Energy Grams" to customers which would offer customized energy conservation information based on how they are currently using energy.
- AMI would enable Delmarva to provide for a "point of purchase" notification or understanding by consumers. Delmarva's "My Account" software has the capability of providing AMI metered customers with "My bill to date" which enables customers to see how much they have spent so far in any given month. The "My bill to date" feature also enables the utility to perform outbound notifications to customers letting them know when energy consumption or spending has reached customer prescribed levels. These notifications will raise awareness of energy use and contribute to changing consumer behavior towards conservation and environmental stewardship.
- AMI allows Delmarva to potentially offer "On-Request" meter reading services whereby a customer could request a specific meter reading which would show consumption information for a period of time (1 hour for example). This type of reading would be able to let customers see a "before and after" view of energy use which enables them to see the benefits of conservation.
- AMI will enable Delmarva to provide on-line assistance with rate evaluations. Customers would benefit from having an Interactive Rate Comparison program available on line to examine the cost savings potential of various rate options in a manner which is customized based on their actual historic load profile. Users would select among options and calculate the energy costs for each option automatically. Users could then print out a summary of the analysis to be used for making rate decisions.
- AMI provides improved customer service due to the ability to remotely verify or determine that a particular meter is currently in service or out of service. This helps to alert the customer that the problem may be on the customer side of the meter.
- With AMI, it would be possible to offer customers an option of changing their monthly billing due date. This could conceivably provide some cash flow and payment flexibility benefit for customers.
- AMI information will benefit our Customer Contact Centers by enabling Customer Service Representatives ("CSR's") to quickly identify the time of high customer usage. This would enable the CSR to offer

enhanced levels of customer educations by explaining exactly when periods of high usage are occurring at the customer's home or business.

- AMI allows the Company to be less intrusive to customers by not having meter reading personnel in or near the customer's home or business.

Theft of Service

Delmarva expects to improve the detection of lost revenue due to energy theft and other metering issues and to ultimately reduce it by using the capabilities of the AMI system. The AMI system is expected to enhance Delmarva's ability to identify and recover lost revenue in three ways. First, by visiting all of Delmarva's meter locations during the initial AMI meter deployment, we anticipate that some percentage of the meters currently affected by tampering, diversion or other problem will be found and remedied. Second, once the AMI system is installed, Delmarva anticipates that additional data will be available to indicate the status of the meter as well as provide electronic notification of possible tampering. This functionality will permit more timely identification, investigation and remediation of possible theft events. Finally, by using the interval data from the AMI system coupled with the analytical capabilities provided by the MDMS, Delmarva expects to develop the capability to analyze usage and other patterns to discern possible theft cases, particularly with commercial accounts. According to the Edison Electric Institute ("EEI"), electric utilities typically estimate approximately one to three percent of their annual revenue is lost due to energy theft. If the expected AMI capabilities enable Delmarva to improve its energy theft recovery by 0.5% of its annual kilowatt hour sales, we estimate that the recovered volume would be about 47 million kilowatt hours or about \$6.5 million per year, assuming a combined residential distribution and standard offer service rate of 13.75 cents per kilowatt hour. Customers might experience a small reduction in rates due to reduced losses from the electrical system as the costs of the diverted electricity are paid for by the actual responsible parties. This benefit, however, would represent a shift in cost responsibility among customers, rather than a reduction in total revenue requirement recovered from all customers and was not included in this analysis.

Costs to Deploy

This section of the report provides the initial cost estimates for the deployment of the AMI system and the associated meter data management system ("MDMS") by Delmarva's electric and gas delivery businesses. The costs will change as the Company conducts the procurement phase of its AMI project and evaluates the capabilities of the various AMI systems available in the market today. In addition, the quantifications will also change due to changing labor rates, payroll loading rates, inflation and other possible changes in the underlying assumptions used to derive the estimated cost values. Below is Figure 9 summarizing total capital expenditures needed for the initial deployment of the AMI system and annualized O&M costs expected in the first full year after deployment, followed by a more detailed description of each cost category.

Figure 9

Line		Initial Deployment Costs Only \$ in ('000s)		
		Electric	Gas	Combined
	AMI System Components			
1	Meters, including Installation Cost	\$ 42,783	\$ 9,195	\$ 51,978
2	Communications Network, including Installation Cost	\$ 21,616	\$ -	\$ 21,616
3	AMI Network Management System and Meter Data Management Sy	\$ 4,417	\$ 1,828	\$ 6,245
4	Contingency	\$ 4,680	\$ 1,543	\$ 6,223
	Total Capital Investment	\$ 73,496	\$ 12,566	\$ 86,062
		Annual Estimated Costs After Deployment \$ in ('000s)		
		Electric	Gas	Combined
	AMI System Incremental Cost to Operate			
5	MDMS Software Maintenance & License Fees	\$ 62	\$ 26	\$ 88
6	MDMS Hardware Leasing	\$ 168	\$ 70	\$ 238
7	AMI Network Management System O&M	\$ 196	\$ 81	\$ 277
8	Communications Network Infrastructure O&M	\$ 273	\$ -	\$ 273
	Total Incremental Cost to Operate	\$ 699	\$ 177	\$ 876

Note that the costs in the figure above exclude certain one time costs described in number 9 below.

1) Meters and Installation Labor

Costs include new AMI meters that contain certain equipment "under glass" such a remote connect/disconnect switch for certain meters, communications modules where applicable and the associated installation labor. Prices for AMI equipment are estimated using filings from other utilities as well as initial quotes from a few vendors and the calculated estimates consider differences in commercial and residential equipment requirements. A value of \$85.00 is used for the AMI base cost for residential electric meters and a \$194.00 value is used for commercial electric meters. Additionally 98% of residential electric meters will require a \$25.00 remote connect/disconnect switch, which is not required for the commercial electric meter. All existing gas meters will be retrofitted with an AMI communications module, estimated at \$60 per module. Labor cost for installations/ retrofits is estimated at \$16.50 per electric meter and \$20.00 per gas meter. This brings the estimated cost for meters with the associated installation labor to about \$52 million for Delmarva's electric and gas customers in Delaware.

2) Communications Network Infrastructure and Installation Labor

The communications network infrastructure solution is assumed to leverage Delmarva's already existing network. There will be no separate communications network for gas meters; instead the gas meter's communication modules will utilize the communications network deployed for electric meters. The cost of this component of the AMI system is more variable than the other components (i.e., meters and the network

management IT system), given the different ways AMI vendors configure and price their communications networks combined with the variability of terrain, meter density and meter locations in Delaware. For purposes of this cost estimate, \$70.00 per electric meter, including installation costs, was used. The total estimated costs for communications network infrastructure and the associated installation is about \$22 million for Delmarva's electric and gas customers in Delaware.

3) AMI Network Management System and Meter Data Management System

This cost category captures the estimated costs associated with software applications, systems integration and computer hardware necessary to support AMI. System costs include categories for

- MDMS – software license, servers, storage, operating system, database management system, clustering software, and system design, configuration and integration
- Customer Presentment – servers, storage, and system design, configuration and integration
- PHI Integration – CIS and other IT systems integration.

The total estimated costs for the AMI Network Management System and the Meter Data Management System are about \$6 million for Delmarva's electric and gas customers in Delaware.

4) Contingency

We determined that a contingency should be applied to the start-up and installation activities as a way to help manage the current uncertainty around the AMI cost estimate. A contingency amount comprising 7% of the capital investment for Delmarva, representing an amount of about \$6 million is included to cover unexpected increases in equipment costs, labor costs or materials prices.

5 and 6) MDMS Software Maintenance, License Fees and Hardware Leasing

The MDMS will require software maintenance and license fee contracts with the system's vendor for system support, upgrades and the like. The operating costs for the hardware for the MDMS system include the hardware leasing costs for the servers, the data warehouse system and data storage capacity.

7) AMI Network Management IT System O&M

The AMI Network Management IT System has costs similar in nature to the MDMS with regard to software and hardware. Three additional FTEs are estimated to be required after AMI deployment to operate and maintain the AMI system for PHI.

8) Communication Network Infrastructure O&M

These costs include the estimated ongoing maintenance of the communications equipment needed to transmit the data back and forth between the meters on the customers' premises and the Company's offices. This cost is dependent on the mix of communication technologies Delmarva ultimately obtains through its procurement process.

9) Labor Related Costs

The reduction in certain types of work would be phased in after the 2008 deployment, with labor related costs being incurred over a three year period (2010 through 2012). These costs would include reassignment and retraining of Delmarva employees. The estimated cost of this one time expense is \$1.1 million for the electric service and \$0.4 million for the gas service.

Accelerated Depreciation

As stated in PHI's February 6, 2007 Blueprint for the Future filing and in the 2007 NARUC³ Resolution to Remove Barriers to the Broad Implementation of Advanced Metering Infrastructure, the deployment of AMI technology will require the removal and disposition of existing meters that are not fully depreciated and the replacement of, or significant modification to, existing meter reading, communications, and customer billing and information infrastructure. To encourage the implementation of this new technology the Commission should adopt ratemaking policies that remove a utility's disincentive toward demand-side resources that reduce throughput; provide for timely cost recovery of prudently incurred AMI expenditures, including accelerated recovery of investment in existing metering infrastructure, in order to provide cash flow to help finance new AMI deployment; and provide depreciation lives for AMI that take into account the speed and nature of change in metering technology.

The business case reflects depreciation lives for AMI that take into the account the speed and nature of the change in metering technology. The

³ See NARUC Resolution Attached in Appendix 2



A PPL Company

SCHEDULE (JCZ)-13.1

business case reflects a recovery period of fifteen years for the AMI investment and five years for the recovery of the remaining costs associated with the existing metering system. As of December 31, 2006, Delmarva's existing electric metering system had a remaining net book value of about \$26 million and the existing gas metering system's communication modules had a remaining net book value of about \$3 million. At this time, Delmarva expects to be able to retrofit the existing gas meters with an AMI ready communications module and not replace the existing meters. In certain cases, Delmarva has gas meters with existing communications modules installed in customers' premises. These modules would not be compatible with the communication system needed for the AMI system and therefore accelerated recovery treatment similar to the existing electric metering system is appropriate. Depreciation calculations in the business case may need to be updated due to pending federal legislation.

Appendix 1

Developments in other jurisdictions

Congress with the passage of the Energy Policy Act of 2005 recognized the importance of advanced metering for growth in the development of electric demand response programs across the United States. To advance the development of such programs, Congress directed the Federal Energy Regulatory Commission ("FERC") to assess demand response resources currently in existence in the electric power industry. FERC conducted a survey where they requested information from every state on the number and uses of advanced metering, existing demand response and time-based rate programs within their state. As a result of this survey, states were required to consider the adoption of a smart metering standard for each of their state regulated utilities.

Many states took the FERC survey results and determined methods for confronting the rising energy costs within their particular states with Advanced Metering Infrastructure and Demand Response Programs. The following identifies several utilities which have obtained approval from their individual state regulatory commissions and are beginning implementation of intelligent meter technology, demand response and time-based rate programs within their operating jurisdictions. California and Texas utility companies have led the way in implementation of AMI and Demand Response Programs.

CALIFORNIA

The California Public Utilities Commission ("CPUC") in 2004, directed each of the state's regulated utilities to explore the option and feasibility of upgrading their home and small-business electric meters to digital intelligent meters, similar to the types used to measure energy usage by larger commercial customers. The CPUC's goal was for its state regulated utilities to significantly ease California's constrained energy resources by providing some form of demand response during periods of peak demand. The need for a smart metering standard was essential in California due to the increased growth in population and per-person energy use in the state. California's state energy policies require utilities to commit large amounts of resources to fund and implement energy efficiency programs.

Pacific Gas & Electric ("PG&E")

Pacific Gas & Electric in 2006 obtained approval from the CPUC for the universal deployment of an AMI system which required the installation of

5.2 million electric meters and 4.1 million gas meters throughout its operating territory. PG&E immediately began an AMI pilot program in Bakersfield, California to test the accuracy and performance of SmartMeter™ after winning approval from the CPUC. Mass deployment of PG&E's SmartMeter™ Program is expected to begin in late 2007.

Southern California Edison (SCE)

Southern California Edison obtained approval from the CPUC to replace its existing 5.1 million electric meters with "next generation" electronic intelligent meter technology beginning in 2009. Edison SmartConnect™ is Southern California Edison's AMI Program which aims to improve overall customer service by allowing customers to proactively manage their energy use and also save money through participation in programs with time-differentiated rates and demand response options. The Edison SmartConnect™ program is the first overhaul of SCE's metering system since 1949.

San Diego Gas & Electric ("SDG&E")

San Diego Gas & Electric obtained approval from the CPUC in April 2007 to begin implementation of "smart meter" technology for its estimated 1.4 million electric meters and retrofitting approximately 900,000 gas meters throughout its service territory beginning in 2008. SDG&E's approval also includes an agreement with the CPUC's Division of Ratepayer Advocates ("DRA") and the Utility Consumers' Action Network ("UCAN") to become a leader in emerging energy technologies through the use of a smarter electric distribution grid.

TEXAS

With the passage of House Bill 2129, the Texas Public Utility Commission was required to study the benefit to be derived by electric utilities in Texas from advanced metering. Because of the retail choice environment of the Texas retail market, the challenge exists for implementing advanced metering in a way that will maximize the benefits for the utility company, retail providers and customers. The Texas Commission has also initiated a separate project to evaluate potential demand response programs for the Texas utilities market.

Centerpoint Energy

Centerpoint obtained approval from the Texas Public Utility Commission in 2006 for implementation of smart meter technology for its more than three million electric and natural gas customers in the Houston area. Implementation of smart electricity meters began in November 2006 in selected areas of Houston.

TXU Electric Delivery

TXU Electric Delivery plans to have its 3 million automated meters by 2011, complementing an advanced grid intelligent enough to monitor electric service real-time. By year's end, TXU Electric Delivery expects to have 370,000 automated meters system-wide, including 10,000 BPL-enabled meters. The BPL-enabled network will serve approximately 2 million residential and commercial customers in Texas.

OTHER JURISDICTIONS

Several utility companies in other jurisdictions have either filed applications or have obtained approval for implementing advanced metering and demand response programs. A sampling of these utilities companies are outlined below.

- *Detroit Edison ("DTE")* – The Michigan Commission approved DTE's plan to replace 3 million electric meters. DTE is investing \$330 million for implementation of this over the next six years. DTE has also created a Home Energy Saver audit tool on their website (mydteenergy.com) to help customers manage their energy use and obtain conservation tips.
- *Pennsylvania Power & Light Company ("PPL")* – PPL completed the installation of 1.3 million electric meters in 2004. PPL has created sections on its website dedicated to energy conservation efforts, including an energy calculator, detailed information about smart meters, safety concerns and an energy library for customers to learn more about energy usage in their homes.
- *Baltimore Gas & Electric Company* – BGE filed for approval by the Maryland Public Service Commission in early 2007 of its plan to deploy an AMI system and Demand Side Management Programs.
- *Southern Company* – Southern Company obtained Commission approval to replace 4.5 million electric meters in their four-state operating territory.
- *Portland General Electric ("PGE")* – PGE has filed an application with the Public Utility Commission of Oregon to install 843,000 smart meters for both residential and small non-residential customers throughout PGE's operating territory.

Business Case Summaries from Other Utilities

Summaries based on publicly available information from filings for PG&E Southern California Edison and San Diego Gas and Electric are included below. The summaries demonstrate the similarities in approach and results with PHI's AMI business case analysis.

Pacific Gas and Electric Company

The AMI business case filed by PG&E with the California Public Utilities Commission shows that AMI can largely be justified by the operational benefits and savings to the utility. The operational "gap" between the costs and benefits for a full AMI deployment case is \$234 million on a present value revenue requirement (PVR) basis. Adopting a benefit calculation* for Demand Response of \$338 million which is more conservative than a Base Case* of \$510 million still results in finding that the project is cost-effective.

The field and metering services benefits include the reduction/elimination of the labor and non-labor costs required for regular meter reading and change of party/special reads and remote Turn-On/Shut-Off. Other operational benefits include improvement in Electric & Gas Transmission and Distribution restoration after significant outages, reduced customer calls and duration of calls related to billing and power outages, and reduced employee-related costs.

The major categories of deployment costs for AMI include meter and module equipment and installation costs, network equipment and install costs, and IT costs that include interval billing system, interface and integration costs. Operational and maintenance costs include AMI operation costs, meter operation costs, marketing and communications costs, and customer acquisition costs

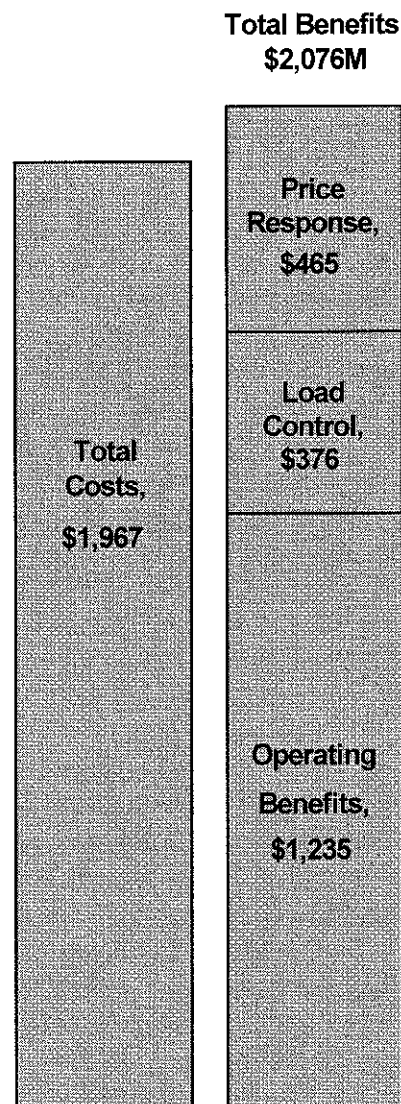
Total Costs	Total Benefits
\$2258M	\$2362M
Operations & Maintenance \$409M	Demand Response \$338M
Deployment \$1849M	Other Operational Benefits \$848M
	Field & Metering Services \$1176M

Southern California Edison

The AMI business case filed by SCE with the California Public Utilities Commission shows that AMI is justified by the Operational, Load Control, and Price Response Benefits to the utility. The operational "gap" between the costs and benefits for a full AMI deployment case is \$356 million on a present value revenue requirement (PVRR) basis. The new functionality of the Edison SmartConnect™ technology not only increases the ways in which customers can use demand response; it also results in SCE going from a negative \$951 million Present Value Revenue Requirement (PVRR) in 2005,* to a positive \$109 million PVRR in 2007 for full AMI deployment.

Through its AMI System Design and Use Case Process, SCE will integrate Edison SmartConnect™ into its operating systems to ensure that the expected benefits accrue in the areas of customer service, billing, outage management, and operations and maintenance.

Operational savings are forecast to cover approximately 63 percent of the related costs. Participation by residential and <200kW business customers in dynamic pricing and demand response programs is expected to provide sufficient additional benefits to justify the Edison SmartConnect™ project. The cost-benefit analysis is summarized in the Figure below.



* Source: EDISON SMARTCONNECT™ DEPLOYMENT

FUNDING AND COST RECOVERY

Volume 1 –Policy July 31, 2007 - Before the Public Utilities Commission of the State of California

WHEREAS, Sound AMI planning and deployment requires the identification and consideration of tangible and intangible costs and benefits to a utility system and its customers; *and*

WHEREAS, Cost-effective AMI may be a critical component of the intelligent grid of the future that will provide many benefits to utilities and consumers; *and*

WHEREAS, It is important that AMI allow the free and unimpeded flow and exchange of data and communications to empower the greatest range of technology and customer options to be deployed; *and*

WHEREAS, The deployment of cost-effective AMI technology may require the removal and disposition of existing meters that are not fully depreciated and may require replacement of, or significant modification to, existing meter reading, communications, and customer billing and information infrastructure; *and*

WHEREAS, Regulated utilities may be discouraged from pursuing demand response opportunities by the prospect of diminished sales and revenues; *now, therefore, be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its February 2007 Winter Meetings in Washington, D.C., recommends that commissions seeking to facilitate deployment of cost-effective AMI technologies consider the following regulatory options:

- pursue an AMI business case analysis, in conjunction with each regulated utility, in order to identify an optimal, cost-effective strategy for deployment of AMI that takes into account both tangible and intangible benefits;
- adopt ratemaking policies that provide utilities with appropriate incentives for reliance upon demand-side resources;
- provide for timely cost recovery of prudently incurred AMI expenditures, including accelerated recovery of investment in existing metering infrastructure, in order to provide cash flow to help finance new AMI deployment; *and*,
- provide depreciation lives for AMI that take into account the speed and nature of change in metering technology; *and be it further*

RESOLVED, That the Federal tax code with regard to depreciable lives for AMI investments should be amended to reflect the speed and nature of change in metering technology; *and be it further*

RESOLVED, That NARUC supports movement toward an appropriate level of open architecture and interoperability of AMI to enable cost-effective investments, avoid obsolescence, and increase innovations in technology products.

*Sponsored by the Committee on Energy Resources and Environment
Adopted by NARUC Board of Directors February 21, 2007*

Appendix 2 NARUC Resolution

Resolution to Remove Regulatory Barriers To the Broad Implementation of Advanced Metering Infrastructure

WHEREAS, The Energy Policy Act of 2005 amended the State ratemaking provisions of the Public Utilities Regulatory Policies Act of 1978 (PURPA) to require every State regulatory commission to consider and determine whether to adopt a new standard with regard to advanced metering infrastructure (AMI); *and*

WHEREAS, Advanced metering, as defined by Federal Energy Regulatory Commission (FERC), refers to a metering system that records customer consumption hourly or more frequently and that provides daily or more frequent transmittal of measurements over a communication network to a central collection point; *and*

WHEREAS, The implementation of dynamic pricing, which is facilitated by AMI, can afford consumers the opportunity to better manage their energy consumption and electricity costs through the practice of demand response strategies; *and*

WHEREAS, Effective price-responsive demand requires not only deployment of AMI to a material portion of a utility's load, but also implementation of dynamic price structures that reveal to consumers the value of controlling their consumption at specific times; *and*

WHEREAS, AMI deployment offers numerous potential benefits to consumers, both participants and non-participants, including:

- greater customer control over consumption and electric bills;
- improved metering accuracy and customer service;
- potential for reduced prices during peak periods for all consumers;
- reduced price volatility;
- reduced outage duration; and,
- expedited service initiation and restoration; *and*

WHEREAS, The use of AMI may afford significant utility operational cost savings and other benefits, including:

- automation of meter reading;
- outage detection;
- remote connection/disconnection;
- reduced energy theft;
- improved outage restoration;
- improved load research;
- more optimal transformer sizing;
- reduced demand during times of system stress;
- decreased T&D system congestion; and,
- reduced reliance on inefficient peaking generators; *and*

Schedule (JCZ)-14
Adjustment No. 12

Delmarva Power & Light Company
Normalize Meter Reading Expense- Gas
6 + 6 Months Ending December 31, 2012

(1) Line No.	(2) <u>Item</u>	(3) <u>Amount</u>
1	Remove Meter Reading Expense - SSN Credit	
2	Delaware Gas	\$1,147,546
3		
4	Income Taxes	
5	State Income Tax	(\$99,837)
6	Federal Income Tax	<u>(\$366,698)</u>
7	Total Income Taxes	(\$466,535)
8		
9	Earnings	(\$681,011)

(1) Line No.	(2) Item	(3) First Mortgage Bonds Demand Rate Bonds Tax Exempt Bonds Tax Exempt Bonds					(6) Tax Exempt Bonds	
		Amount	Aug-93	Nov-93	Sep-00	Sep-00	Sep-00	Sep-00
1	Total Company	\$32,558,769	\$702,894	\$348,751	\$576,741	\$1,438,608		
2	Gas Amount Refinanced	\$3,940,339	\$42,174	\$20,925	\$45,216	\$112,787		
3	Deferred SIT	(\$342,809)	(\$3,669)	(\$1,820)	(\$3,934)	(\$9,812)		
4	Deferred FIT	(\$1,259,135)	(\$13,477)	(\$6,687)	(\$14,449)	(\$36,041)		
5								
6	Earnings							
7	Amortization	\$209,897	\$1,745	\$996	\$3,014	\$5,784		
8	DSIT	(\$18,261)	(\$152)	(\$87)	(\$262)	(\$503)		
9	DFIT	(\$67,073)	(\$558)	(\$318)	(\$963)	(\$1,848)		
10	Total Expense	\$124,563	\$1,036	\$591	\$1,789	\$3,432		
11	Earnings	(\$124,563)	(\$1,036)	(\$591)	(\$1,789)	(\$3,432)		
12								
13	Rate Base							
14	Amortizable Balance - 12/31/11	\$2,095,980	\$10,034	\$2,823	\$11,053	\$47,236		
15	Amortizable Balance - 12/31/12	\$2,031,341	\$8,289	\$1,827	\$8,038	\$41,452		
16	Average Balance	\$2,063,660	\$9,162	\$2,325	\$9,546	\$44,344		
17								
18	Deferred SIT - 12/31/11	(\$182,350)	(\$873)	(\$246)	(\$962)	(\$4,109)		
19	Deferred SIT - 12/31/12	(\$176,727)	(\$721)	(\$159)	(\$699)	(\$3,606)		
20	Average Balance	(\$179,538)	(\$797)	(\$202)	(\$830)	(\$3,858)		
21								
22	Deferred FIT - 12/31/11	(\$669,771)	(\$3,206)	(\$902)	(\$3,532)	(\$15,094)		
23	Deferred FIT - 12/31/12	(\$649,115)	(\$2,649)	(\$584)	(\$2,569)	(\$13,246)		
24	Average Balance	(\$659,443)	(\$2,928)	(\$743)	(\$3,050)	(\$14,170)		
25								
26	Net Year End Balance	\$1,205,499	\$4,919	\$1,084	\$4,770	\$24,599		
27								
28	Amortization begin date (a)		August-93	November-93	September-00	September-00		
29	Amortization period (months)		290	252	180	234		
30	Amortization as of 12/31/11		221	218	136	136		
31	Amortization as of 12/31/12		233	230	148	148		

(a) rounded to nearest full month

(1) Line No.	(2) Item	Tax Exempt Bonds					First Mortgage Bonds				
		(3) Sep-00	(4) Oct-00	(5) Jul-01	(6) Jul-01	(7) Jul-01					
1	Total Company	\$558,772	\$235,481	\$490,000	\$690,000	\$3,762,881					
2	Gas Amount Refinanced	\$43,808	\$18,462	\$38,416	\$54,096	\$295,010					
3	Deferred SIT	(\$3,811)	(\$1,606)	(\$3,342)	(\$4,706)	(\$25,666)					
4	Deferred FIT	(\$13,999)	(\$5,899)	(\$12,276)	(\$17,286)	(\$94,270)					
5											
6	Earnings										
7	Amortization	\$3,245	\$1,086	\$1,921	\$3,182	\$20,702					
8	DSIT	(\$282)	(\$94)	(\$167)	(\$277)	(\$1,801)					
9	DFIT	(\$1,037)	(\$347)	(\$614)	(\$1,017)	(\$6,615)					
10	Total Expense	\$1,926	\$644	\$1,140	\$1,888	\$12,286					
11	Earnings	(\$1,926)	(\$644)	(\$1,140)	(\$1,888)	(\$12,286)					
12											
13	Rate Base										
14	Amortizable Balance - 12/31/11	\$7,031	\$6,154	\$18,248	\$20,684	\$77,634					
15	Amortizable Balance - 12/31/12	\$3,786	\$5,068	\$16,327	\$17,502	\$56,932					
16	Average Balance	\$5,408	\$5,611	\$17,287	\$19,093	\$67,283					
17											
18	Deferred SIT - 12/31/11	(\$612)	(\$535)	(\$1,588)	(\$1,799)	(\$6,754)					
19	Deferred SIT - 12/31/12	(\$329)	(\$441)	(\$1,420)	(\$1,523)	(\$4,953)					
20	Average Balance	(\$471)	(\$488)	(\$1,504)	(\$1,661)	(\$5,854)					
21											
22	Deferred FIT - 12/31/11	(\$2,247)	(\$1,966)	(\$5,831)	(\$6,609)	(\$24,808)					
23	Deferred FIT - 12/31/12	(\$1,210)	(\$1,619)	(\$5,217)	(\$5,593)	(\$18,193)					
24	Average Balance	(\$1,728)	(\$1,793)	(\$5,524)	(\$6,101)	(\$21,500)					
25											
26	Net Year End Balance	\$2,247	\$3,008	\$9,689	\$10,386	\$33,786					
27											
28	Amortization begin date (a)	September-00	October-00	July-01	July-01	July-01					
29	Amortization period (months)	162	204	240	204	171					
30	Amortization as of 12/31/11	136	136	126	126	126					
31	Amortization as of 12/31/12	148	148	138	138	138					

(a) rounded to nearest full month

(1) Line No.	(2) Item	(3) Medium Term Notes - First Mortgage Bonds			(5) Medium Term Notes		
		Jul-01	Jul-01	Jul-01	Jul-01	Jul-01	Jul-01
1	Total Company	\$3,058,389	\$1,634,283	\$1,073,753			(\$595,660)
2	Gas Amount Refinanced	\$239,778	\$128,128	\$84,182			(\$46,700)
3	Deferred SIT	(\$20,861)	(\$11,147)	(\$7,324)			\$4,063
4	Deferred FIT	(\$76,621)	(\$40,943)	(\$26,900)			\$14,923
5							
6	Earnings						
7	Amortization	\$12,349	\$6,225	\$5,402			(\$2,816)
8	DSIT	(\$1,074)	(\$542)	(\$470)			\$245
9	DFIT	(\$3,946)	(\$1,989)	(\$1,726)			\$900
10	Total Expense	\$7,329	\$3,694	\$3,206			(\$1,671)
11	Earnings	(\$7,329)	(\$3,694)	(\$3,206)			\$1,671
12							
13	Rate Base						
14	Amortizable Balance - 12/31/11	\$110,113	\$62,767	\$27,461			(\$17,131)
15	Amortizable Balance - 12/31/12	\$97,763	\$56,542	\$22,058			(\$14,315)
16	Average Balance	\$103,938	\$59,655	\$24,759			(\$15,723)
17							
18	Deferred SIT - 12/31/11	(\$9,580)	(\$5,461)	(\$2,389)			\$1,490
19	Deferred SIT - 12/31/12	(\$8,505)	(\$4,919)	(\$1,919)			\$1,245
20	Average Balance	(\$9,043)	(\$5,190)	(\$2,154)			\$1,368
21							
22	Deferred FIT - 12/31/11	(\$35,186)	(\$20,057)	(\$8,775)			\$5,474
23	Deferred FIT - 12/31/12	(\$31,240)	(\$18,068)	(\$7,049)			\$4,574
24	Average Balance	(\$33,213)	(\$19,063)	(\$7,912)			\$5,024
25							
26	Net Year End Balance	\$58,018	\$33,555	\$13,091			(\$8,495)
27							
28	Amortization begin date (a)	July-01	July-01	July-01			July-01
29	Amortization period (months)	233	247	187			199
30	Amortization as of 12/31/11	126	126	126			126
31	Amortization as of 12/31/12	138	138	138			138

(a) rounded to nearest full month

(1) Line No.	(2) Item	(3) Medium Term Notes First Mortgage Bonds				(5) Tax Exempt Bonds				(6) Tax Exempt Bonds			
		Jul-01		Feb-02		Jun-02		Jun-02		Jun-02		Jun-02	
1	Total Company	\$1,340,233		\$1,388,233		\$944,292		\$1,313,393					
2	Gas Amount Refinanced	\$105,074		\$222,117		\$151,087		\$210,143					
3	Deferred SIT	(\$9,141)		(\$19,324)		(\$13,145)		(\$18,282)					
4	Deferred FIT	(\$33,576)		(\$70,978)		(\$48,280)		(\$67,151)					
5													
6	Earnings												
7	Amortization	\$4,107		\$11,060		\$7,523		\$12,301					
8	DSIT	(\$357)		(\$962)		(\$655)		(\$1,070)					
9	DFIT	(\$1,312)		(\$3,534)		(\$2,404)		(\$3,931)					
10	Total Expense	\$2,437		\$6,563		\$4,465		\$7,300					
11	Earnings	(\$2,437)		(\$6,563)		(\$4,465)		(\$7,300)					
12													
13	Rate Base												
14	Amortizable Balance - 12/31/11	\$61,949		\$112,441		\$78,991		\$92,258					
15	Amortizable Balance - 12/31/12	\$57,842		\$101,381		\$71,468		\$79,957					
16	Average Balance	\$59,896		\$106,911		\$75,230		\$86,107					
17													
18	Deferred SIT - 12/31/11	(\$5,390)		(\$9,782)		(\$6,872)		(\$8,026)					
19	Deferred SIT - 12/31/12	(\$5,032)		(\$8,820)		(\$6,218)		(\$6,956)					
20	Average Balance	(\$5,211)		(\$9,301)		(\$6,545)		(\$7,491)					
21													
22	Deferred FIT - 12/31/11	(\$19,796)		(\$35,931)		(\$25,242)		(\$29,481)					
23	Deferred FIT - 12/31/12	(\$18,483)		(\$32,396)		(\$22,838)		(\$25,550)					
24	Average Balance	(\$19,140)		(\$34,163)		(\$24,040)		(\$27,516)					
25													
26	Net Year End Balance	\$34,326		\$60,165		\$42,413		\$47,450					
27													
28	Amortization begin date (a)	July-01		February-02		June-02		June-02					
29	Amortization period (months)	307		241		241		205					
30	Amortization as of 12/31/11	126		119		115		115					
31	Amortization as of 12/31/12	138		131		127		127					

(a) rounded to nearest full month

(1) Line No.	(2) Item	(3) First Mortgage Bonds				(4) Tax Exempt Bonds		(5) Trust Preferred		(6) First Mortgage Bonds	
		May-03		Aug-03		May-04		May-04		Jun-05	
1	Total Company	\$1,298,560		\$1,347,719		\$1,943,173		\$1,943,173		\$4,497,500	
2	Gas Amount Refinanced	\$207,770		\$215,635		\$310,908		\$310,908		\$719,600	
3	Deferred SIT	(\$18,076)		(\$18,760)		(\$27,049)		(\$27,049)		(\$62,605)	
4	Deferred FIT	(\$66,393)		(\$68,906)		(\$99,351)		(\$99,351)		(\$229,948)	
5											
6	Earnings										
7	Amortization	\$16,733		\$8,086		\$9,591		\$9,591		\$35,980	
8	DSIT	(\$1,456)		(\$704)		(\$834)		(\$834)		(\$3,130)	
9	DFIT	(\$5,347)		(\$2,584)		(\$3,065)		(\$3,065)		(\$11,497)	
10	Total Expense	\$9,930		\$4,799		\$5,692		\$5,692		\$21,352	
11	Earnings	(\$9,930)		(\$4,799)		(\$5,692)		(\$5,692)		(\$21,352)	
12											
13	Rate Base										
14	Amortizable Balance - 12/31/11	\$62,749		\$147,575		\$237,377		\$237,377		\$482,732	
15	Amortizable Balance - 12/31/12	\$46,016		\$139,489		\$227,786		\$227,786		\$446,752	
16	Average Balance	\$54,383		\$143,532		\$232,581		\$232,581		\$464,742	
17											
18	Deferred SIT - 12/31/11	(\$5,459)		(\$12,839)		(\$20,652)		(\$20,652)		(\$41,998)	
19	Deferred SIT - 12/31/12	(\$4,003)		(\$12,136)		(\$19,817)		(\$19,817)		(\$38,867)	
20	Average Balance	(\$4,731)		(\$12,487)		(\$20,235)		(\$20,235)		(\$40,433)	
21											
22	Deferred FIT - 12/31/11	(\$20,052)		(\$47,158)		(\$75,854)		(\$75,854)		(\$154,257)	
23	Deferred FIT - 12/31/12	(\$14,704)		(\$44,574)		(\$72,789)		(\$72,789)		(\$142,759)	
24	Average Balance	(\$17,378)		(\$45,866)		(\$74,321)		(\$74,321)		(\$148,508)	
25											
26	Net Year End Balance	\$27,308		\$82,780		\$135,180		\$135,180		\$265,125	
27											
28	Amortization begin date (a)										
29	Amortization period (months)	May-03	Aug-03	May-04	Jun-05						
30	Amortization as of 12/31/11	149	320	389	240						
31	Amortization as of 12/31/12	104	101	92	79						
		116	113	104	91						

(a) rounded to nearest full month

(1) Line No.	(2) Item	(3) Preferred Stock Jan-07		(4) Tax Exempt Bonds Mar-08		(5) Tax Exempt Bonds Mar-08		(6) Tax Exempt Bonds Mar-08	
1	Total Company	\$740,468		\$439,979		\$668,515		\$790,973	
2	Gas Amount Refinanced	\$118,475		\$70,397		\$106,962		\$126,556	
3	Deferred SIT	(\$10,307)		(\$6,125)		(\$9,306)		(\$11,010)	
4	Deferred FIT	(\$37,859)		(\$22,495)		(\$34,180)		(\$40,441)	
5									
6	Earnings								
7	Amortization	\$11,847		\$3,140		\$4,411		\$4,149	
8	DSIT	(\$1,031)		(\$273)		(\$384)		(\$361)	
9	DFIT	(\$3,786)		(\$1,004)		(\$1,409)		(\$1,326)	
10	Total Expense	\$7,031		\$1,864		\$2,618		\$2,462	
11	Earnings	(\$7,031)		(\$1,864)		(\$2,618)		(\$2,462)	
12									
13	Rate Base								
14	Amortizable Balance - 12/31/11	\$59,237		\$58,359		\$90,054		\$110,650	
15	Amortizable Balance - 12/31/12	\$47,390		\$55,218		\$85,643		\$106,500	
16	Average Balance	\$53,314		\$56,788		\$87,849		\$108,575	
17									
18	Deferred SIT - 12/31/11	(\$5,154)		(\$5,077)		(\$7,835)		(\$9,627)	
19	Deferred SIT - 12/31/12	(\$4,123)		(\$4,804)		(\$7,451)		(\$9,266)	
20	Average Balance	(\$4,638)		(\$4,941)		(\$7,643)		(\$9,446)	
21									
22	Deferred FIT - 12/31/11	(\$18,929)		(\$18,648)		(\$28,777)		(\$35,358)	
23	Deferred FIT - 12/31/12	(\$15,143)		(\$17,645)		(\$27,367)		(\$34,032)	
24	Average Balance	(\$17,036)		(\$18,147)		(\$28,072)		(\$34,695)	
25									
26	Net Year End Balance	\$28,124		\$32,769		\$50,825		\$63,203	
27									
28	Amortization begin date (a)	Jan-07		Mar-08		Mar-08		Mar-08	
29	Amortization period (months)	120		269		291		366	
30	Amortization as of 12/31/11	60		46		46		46	
31	Amortization as of 12/31/12	72		58		58		58	

(a) rounded to nearest full month

(1) Line No.	(2) Item	(3) Tax Exempt Bonds Apr-08	(4) Tax Exempt Bonds Apr-08	(5) Tax Exempt Bonds Nov-08	(6) Tax Exempt Bonds Dec-10
1	Total Company	\$176,784	\$655,565	\$84,228	\$148,731
2	Gas Amount Refinanced	\$28,285	\$104,890	\$13,476	\$23,797
3	Deferred SIT	(\$2,461)	(\$9,125)	(\$1,172)	(\$2,070)
4	Deferred FIT	(\$9,039)	(\$33,518)	(\$4,306)	(\$7,604)
5					
6	Earnings				
7	Amortization	\$1,267	\$4,528	\$2,344	\$1,632
8	DSIT	(\$110)	(\$394)	(\$204)	(\$142)
9	DFIT	(\$405)	(\$1,447)	(\$749)	(\$521)
10	Total Expense	\$752	\$2,687	\$1,391	\$968
11	Earnings	(\$752)	(\$2,687)	(\$1,391)	(\$968)
12					
13	Rate Base				
14	Amortizable Balance - 12/31/11	\$23,536	\$87,912	\$6,055	\$0
15	Amortizable Balance - 12/31/12	\$22,270	\$83,384	\$3,711	\$20,397
16	Average Balance	\$22,903	\$85,648	\$4,883	\$10,199
17					
18	Deferred SIT - 12/31/11	(\$2,048)	(\$7,648)	(\$527)	\$0
19	Deferred SIT - 12/31/12	(\$1,937)	(\$7,254)	(\$323)	(\$1,775)
20	Average Balance	(\$1,993)	(\$7,451)	(\$425)	(\$887)
21					
22	Deferred FIT - 12/31/11	(\$7,521)	(\$28,092)	(\$1,935)	\$0
23	Deferred FIT - 12/31/12	(\$7,116)	(\$26,645)	(\$1,186)	(\$6,518)
24	Average Balance	(\$7,319)	(\$27,369)	(\$1,560)	(\$3,259)
25					
26	Net Year End Balance	\$13,216	\$49,484	\$2,202	\$12,105
27					
28	Amortization begin date (a)	Apr-08	Apr-08	Nov-08	Dec-10
29	Amortization period (months)	268	278	69	175
30	Amortization as of 12/31/11	45	45	38	13
31	Amortization as of 12/31/12	57	57	50	25

(a) rounded to nearest full month

(1) Line No.	(2) Item	(3) Tax Exempt Bonds Dec-10		(4) Tax Exempt Bonds Jun-11		(5) Total
1	Total Company	\$171,299		\$634,231		\$32,558,769
2	Gas Amount Refinanced	\$27,408		\$101,477		\$3,940,339
3	Deferred SIT	(\$2,384)		(\$8,829)		(\$342,809)
4	Deferred FIT	(\$8,758)		(\$32,427)		(\$1,259,135)
5						
6	Earnings					
7	Amortization	\$1,559		\$6,803		\$209,897
8	DSIT	(\$136)		(\$592)		(\$18,261)
9	DFIT	(\$498)		(\$2,174)		(\$67,073)
10	Total Expense	\$925		\$4,037		\$124,563
11	Earnings	(\$925)		(\$4,037)		(\$124,563)
12						
13	Rate Base					
14	Amortizable Balance - 12/31/11	\$0		\$0		\$2,095,980
15	Amortizable Balance - 12/31/12	\$24,160		\$90,706		\$2,031,341
16	Average Balance	\$12,080		\$45,353		\$2,063,660
17						
18	Deferred SIT - 12/31/11	\$0		\$0		(\$182,350)
19	Deferred SIT - 12/31/12	(\$2,102)		(\$7,891)		(\$176,727)
20	Average Balance	(\$1,051)		(\$3,946)		(\$179,538)
21						
22	Deferred FIT - 12/31/11	\$0		\$0		(\$669,771)
23	Deferred FIT - 12/31/12	(\$7,720)		(\$28,985)		(\$649,115)
24	Average Balance	(\$3,860)		(\$14,493)		(\$659,443)
25						
26	Net Year End Balance	\$14,338		\$53,829		\$1,205,499
27						
28	Amortization begin date (a)	Dec-10		Jun-11		
29	Amortization period (months)	211		179		
30	Amortization as of 12/31/11	13		7		
31	Amortization as of 12/31/12	25		19		

(a) rounded to nearest full month

Delmarva Power & Light Company
Investment Tax Credit - Gas
6+6 Months Ending December 31, 2012

(1) Line No.	(2) Item	(3) Balance December 2011	(4) Pre 1981 Amortization	(5) Post 1980 Amortization	(6) Total Amortization	(7) Balance December 2012	(8) Average Balance
1	Gas Investment Tax Credit						
2	Transmission	(23,469)	(313)	(3,302)	(3,615)	(19,854)	(21,661)
3							
4	Distribution - DE	(472,596)	(5,076)	(34,498)	(39,573)	(433,022)	(452,809)
5							
6	General	(12,864)	(61)	(2,048)	(2,109)	(10,755)	(11,810)
7							
8	Common	(36,856)	(642)	(10,622)	(11,264)	(25,592)	(31,224)
9							
10	Total Gas	(545,785)	(6,092)	(50,470)	(56,561)	(489,224)	(517,504)
11							
12	<u>Adjustment to Remove Post 1980 Vintage ITC Amortization</u>						
13							
14	Expense			50,470			
15							
16	Earnings			<u>(50,470)</u>			

Schedule (JCZ)-17
Adjustment No. 15

Delmarva Power & Light Company
Reflect Credit Facilities Cost - Gas
6+6 Months Ending December 31, 2012

(1) Line No.	(2) <u>Item</u>	(3) <u>Gas</u>
1	<u>Earnings</u>	
2	Expense - Rate Effective Period	\$ 113,005 (1)
3		
4	State Income Tax	\$ (9,831)
5	Federal Income Tax	\$ (36,111)
6	Total Expenses	<u>\$ 67,063</u>
7		
8	Earnings	\$ (67,063)
9		
10	<u>Rate Base</u>	
11	Year End Amortizable Balance	\$ 189,974 (2)
12		
13		
14	(1) Annual amortization of start-up costs	\$ 259,058
15	Annual cost of maintaining credit facility	<u>\$ 447,222</u>
16	Total DPL expense	<u>\$ 706,280</u>
17		
18	DPL Gas	\$ 113,005
19		
20	(2) DPL 12/31/12 Amortizable Balance	\$ 1,187,340
21	Gas %	<u>16%</u>
22	DPL Gas	<u>\$ 189,974</u>

Delmarva Power & Light Company
Recovery of Tax on OPEB Medicare Tax Subsidy - Gas
6+6 Months Ending December 2012

(1) Line No.	(2) <u>Item</u>	(3) DE <u>Distribution</u>
1	<u>Earnings</u>	
2	Amortization	\$11,907 (1)
3		
4	State Income Tax	(\$1,036)
5	Federal Income Tax	(\$3,805)
6	Total Expenses	<u>\$7,066</u>
7		
8	Earnings	(\$7,066)
9		
10	<u>Rate Base</u>	
11	Year-End Amortizable Balance	\$23,815 (2)
12		
13	Deferred State Income Tax	(\$2,072)
14	Deferred Federal Income Tax	(\$7,610)
15	Net Rate Base	<u>\$14,133</u>
	(1) DPL Total	\$223,263
	DPL Gas %	16.0000%
	DP&L Delaware	<u>\$35,722</u>
	Amortization period - years	3
	Annual amortization amount	<u>\$11,907</u>
	<u>DPL Gas</u>	
	(2) Beg. Balance	\$35,722
	End. Balance	<u>\$23,815</u>
	Avg. Balance	\$29,768

Delmarva Power & Light
Annualization of Depreciation on Year-end Plant
6+6 Months Ending December 31, 2012

(1)	(2)	(3)	(4)	(5)
Line No.	Plant Category	Annualized Depreciation Exp	6+6 ME Dec 2012 Depreciation Exp	Adjustment
1	Other Storage	\$ 380,707	\$310,674	\$70,033
2				
3	Transmission	\$ 689,112	\$684,445	\$4,667
4				
5	Distribution	\$ 10,888,773	\$10,472,509	\$416,264
6				
7	General	\$ 168,724	\$119,051	\$49,673
8				
9	Total	\$12,127,316	\$11,586,679	\$540,637
10				
11				
12			DSIT @ 8.7%	(\$47,035)
13			DFIT @ 35%	(\$172,760)
14			Total Expense	\$320,841
15				
16			Earnings	(\$320,841)
17				
18			Rate Base	(\$320,841)

(1) Line No.	(2) Item	(3) Revenue	(4) O & M	(5) Depn/Amort	(6) Other Taxes	(7) SII	(8) EIT	(9) Def Tax/ITC/AEC	(10) Total Expenses	(11) Interest	(12) Earnings
1	Remove Employee Association	\$0	(\$31,056)	\$0	\$0	\$2,702	\$9,924	\$0	\$0		\$18,430
2	Regulatory Commission Exp Normalization	\$0	\$230,781	\$0	\$0	(\$20,078)	(\$73,746)	\$0	\$0		(\$136,957)
3	Wage and FICA Expense Adjustment	\$0	\$504,300	\$0	\$33,365	(\$55,477)	(\$203,766)	\$0	\$0		(\$378,423)
4	Removal of Certain Executive Compensation	\$0	(\$716,826)	\$0	\$0	\$62,364	\$228,082	\$0	\$0		\$425,402
5	Officer Compensation	\$0	(23,960)	\$0	\$0	\$2,085	\$7,656	\$0	\$0		\$14,219
6	Uncollectible Expense Normalization	\$0	\$478,867	\$0	\$0	(\$41,863)	(\$153,028)	\$0	\$0		(\$284,196)
7	Injuries and Damages Exp Normalization	\$0	(\$28,236)	\$0	\$0	\$2,457	\$9,023	\$0	\$0		\$16,756
8	Benefits Expense Adjustment	\$0	\$308,397	\$0	\$0	(\$26,831)	(\$98,546)	\$0	\$0		(\$183,018)
9	Reflect forecasted reliability closings January 2013 - December 2013	\$0	\$0	\$404,010	\$0	(\$35,149)	(\$129,102)	\$0	\$0		(\$239,760)
10	Remove Bloom-Related Incremental Rate Base	\$0	\$0	\$0	\$0	\$206	\$757	\$0	\$0		\$1,406
11	Reflect Gas AMI Net Plant Additions	\$0	\$0	\$964,957	\$0	(\$75,251)	(\$276,397)	\$0	\$0	(\$5,811)	(\$519,220)
12	Remove Meter Reading Expense Silver Spring Network Credit	\$0	\$1,147,546	\$0	\$0	(\$99,837)	(\$366,686)	\$0	\$0		(\$681,011)
13	Amortization of Refinancings	\$0	\$0	\$209,897	\$0	\$0	\$0	(\$85,334)	\$0		(\$124,963)
14	Remove Post 1980 ITC Amortization	\$0	\$0	\$0	\$0	(\$9,831)	(\$36,111)	\$0	\$0		(\$50,470)
15	Recover Credit Facilities Expense	\$0	\$113,005	\$0	\$0	(\$1,036)	(\$3,805)	\$0	\$0		\$67,063
16	Reflect Taxes Related to Medicare Part D Subsidy	\$0	\$0	\$11,907	\$0	\$0	\$0	\$0	\$0		(\$7,066)
17	Annualization of Depreciation on Year-end Plant	\$0	\$0	\$540,637	\$0	(\$47,035)	(\$172,760)	\$0	\$0		(\$320,841)
18	Total	\$0	\$2,082,837	\$2,029,036	\$33,365	(\$342,375)	(\$1,257,539)	(\$34,864)	\$2,510,463	(\$5,811)	(\$2,516,374)
19									Int. Exp		
20	Rate		0.0773	0.0000	0.1402	0.2206	0.0116		(0.0741)	(0.32686)	\$11,397
21	Working Capital		\$160,920	\$0	\$4,677	(\$75,511)	(\$14,636)		(\$65,964)	\$1,932	
22											
23	Interest Synch 1										
24	Working Capital		\$160,920	\$0	\$4,677	(\$419,804)	(\$1,541,936)		(\$66,005)	\$1,932	(\$9,011)
25											
26	Interest Synch 2										
27	Working Capital		\$160,920	\$0	\$4,677	(\$419,829)	(\$1,542,027)		(\$65,967)	\$1,932	(\$8,980)
28											
29	Interest Synch 3										
30	Working Capital		\$160,920	\$0	\$4,677	(\$419,784)	(\$1,541,863)		(\$65,967)	\$1,932	(\$8,968)
31											
32											
33	Interest Synchronization										
34	Per Books Interest	\$5,970,942	\$5,970,942	\$5,970,942	\$5,970,942	\$5,970,942	\$5,970,942	\$5,970,942	\$5,970,942	\$5,970,942	\$5,970,942
35	Adjusted Rate Base	\$273,177,908 (1)	\$273,189,395	\$273,186,867	\$273,186,867	\$273,186,867	\$273,186,867	\$273,186,867	\$273,186,867	\$273,186,867	\$273,186,867
36	Wtd COD - Proforma Cap Str	0.0251	0.0251	0.0251	0.0251	0.0251	0.0251	0.0251	0.0251	0.0251	0.0251
37	Proforma Interest	\$6,856,765	\$6,857,052	\$6,856,539	\$6,856,539	\$6,856,539	\$6,856,539	\$6,856,539	\$6,856,539	\$6,856,539	\$6,856,539
38	IOCD	\$4,166	\$4,166	\$4,166	\$4,166	\$4,166	\$4,166	\$4,166	\$4,166	\$4,166	\$4,166
39	Total Proforma Interest	\$6,860,931	\$6,861,218	\$6,860,705	\$6,860,705	\$6,860,705	\$6,860,705	\$6,860,705	\$6,860,705	\$6,860,705	\$6,860,705
40	Difference	\$898,990	\$890,276	\$898,764	\$899,764	\$899,764	\$899,764	\$899,764	\$899,764	\$899,764	\$899,764
41	SIT @ 8.7 %	(\$77,429)	(\$77,454)	(\$77,409)	(\$77,409)	(\$77,409)	(\$77,409)	(\$77,409)	(\$77,409)	(\$77,409)	(\$77,409)
42	Fit @ 35 %	(\$284,396)	(\$284,485)	(\$284,324)	(\$284,324)	(\$284,324)	(\$284,324)	(\$284,324)	(\$284,324)	(\$284,324)	(\$284,324)
43											
44	Earnings	\$361,825	\$361,942	\$361,733	\$361,734	\$361,734	\$361,734	\$361,734	\$361,734	\$361,734	\$361,734
45											
46	(1) Without working capital adjustment										