December 21, 2015

Ms. Donna Nickerson, Secretary
Delaware Public Service Commission
861 Silver Lake Boulevard
Cannon Building, Suite 100
Dover, Delaware 19904

Re: Delaware Division of Chesapeake Utilities Corporation Rate Increase Application

Dear Ms. Nickerson:

Enclosed for filing is an electronic copy of the application of Chesapeake Utilities Corporation ("Chesapeake" or the "Company") for a general increase in its natural gas rates and for certain other changes to its natural gas tariff. Included in the application are the proposed delivery service rates and rate design that would achieve the requested annual revenue. Also included in the application are delivery service rates which the Company is seeking to put into effect on an interim basis under bond in the event the Delaware Public Service Commission suspends the full proposed increase in rates.

As indicated in the Company's Notice of Intent to the Delaware Public Service Commission dated December 8, 2015, the general rate increase application support data is based upon a test year comprised of the twelve months ended June 30, 2015 and a test period consisting of the twelve months ending March 31, 2016.

Also, enclosed is the Delaware Public Service Commission's "Filing Cover Sheet" along with the application fee of $100. Should you have any questions with regard to this filing, please contact me at 302.736.7635.

Sincerely,

William O'Brien
Associate General Counsel

Enclosures

Cc: Brian M. Quinn
David L. Bonar, Public Advocate

For PSC Use Only:
Docket No. __________
Filing Date: __________
Reviewer: ___________
Given to: ______ _____

DELAWARE PUBLIC SERVICE COMMISSION
FILING COVER SHEET

1. NAME OF APPLICANT: Chesapeake Utilities Corporation
2. TYPE OF FILING:
   - RATE CHANGE X
   - FUEL ADJUSTMENT __
   - ADMINISTRATIVE __
   - CPCN __
   - NEW SERVICE OFFERING __
   - OTHER __

   IF A TELECOMMUNICATIONS FILING, WHAT TYPE OF SERVICE IS IMPACTED? (PLEASE CHECK)

   BASIC____ COMPETITIVE____ DISCRETIONARY

3. PROPOSED EFFECTIVE DATE: February 19, 2016

   IS EXPEDITED TREATMENT REQUESTED? YES __ NO X

4. SHORT SYNOPSIS OF FILING: Chesapeake Utilities Corporation proposes a general increase in its natural gas rates and approval of certain other changes to its natural gas tariff.

5. DOES THIS FILING RELATE TO PENDING DOCKETS? YES__ NO X

   IF SO, PLEASE LIST DOCKET(S) NO(S):

6. IS PUBLIC NOTICE REQUIRED? YES X NO
   IF YES, PLEASE ATTACH COPY OF PROPOSED PUBLIC NOTICE.

7. APPLICANT'S CONTACT PERSON:
   (NAME) William O'Brien
   (TITLE) Associate General Counsel
   (EMAIL) bobrien@chpk.com
   (TELE. NO.) 302.736.7635

8. DID YOU PROVIDE A COMPLETE COPY OF THE FILING TO THE PUBLIC ADVOCATE?

   YES X NO ___ IF SO, WHEN? December 21, 2015

9. FILING FEE ENCLOSED: $100.00
   (AMOUNT)

NOTE: House Bill 681, enacted into law 7/13/98, authorizes the Commission to recover the cost of time spent by in-house staff to process all filings initiated after the date of enactment. You may be required to reimburse the Commission for staff time.

BEFORE THE
PUBLIC SERVICE COMMISSION
OF DELAWARE

IN THE MATTER OF THE APPLICATION OF	*	
CHESAPEAKE UTILITIES CORPORATION	*	
FOR A GENERAL INCREASE IN ITS	*	
NATURAL GAS RATES AND FOR	*	**PSC DOCKET NO. _______**
APPROVAL OF CERTAIN OTHER	*	
CHANGES TO ITS NATURAL GAS TARIFF	*	
(Filed December 21, 2015)	*	

* * * * * * * * * * * * *

APPLICATION OF CHESAPEAKE UTILITIES CORPORATION FOR A GENERAL INCREASE IN ITS NATURAL GAS RATES AND FOR APPROVAL OF CERTAIN OTHER CHANGES TO ITS NATURAL GAS TARIFF

Chesapeake Utilities Corporation ("Chesapeake") hereby files this application ("Application") with the Public Service Commission of the State of Delaware ("Commission") seeking a change in natural gas base rates, and other miscellaneous changes to its tariff, pursuant to 26 Del. C. §§201, 301, 304, 306, 315, 1500 and other applicable authorities. In support of this Application, Chesapeake submits the following:

<u>Applicant</u>

1. Chesapeake is a Delaware corporation duly authorized by its articles of incorporation to engage in the business of transporting, distributing and selling natural gas in the State of Delaware.[1] Under 26 Del. C. §102, Chesapeake is a "public utility" and is authorized to sell and distribute natural gas in portions of New Castle County and throughout Kent County and Sussex County, Delaware. Chesapeake, through its Delaware Division, serves approximately 47,000

[1] The voting stock of Chesapeake is publicly owned. Shares of common stock, 15,242,967 of which were outstanding as of June 30, 2015, are the only voting securities of Chesapeake.

natural gas customers in Delaware pursuant to rates heretofore approved by the Commission. [2]

2. All communications and correspondence concerning this matter should be sent to the following persons at the addresses stated below:

William O'Brien (bobrien@chpk.com)
Associate General Counsel
Chesapeake Utilities Corporation, Inc.
909 Silver Lake Boulevard
Dover, Delaware 19904

Brian M. Quinn[3] (bquinn@venable.com)
Venable LLP
750 E. Pratt Street, Suite 900
Baltimore, Maryland 21202

C. James Moore, Vice President (jmoore@chpk.com)
Chesapeake Utilities Corporation
350 South Queen Street
Dover, Delaware 19904

Need for Rate Change

3. For the first time in over eight years, Chesapeake is seeking an adjustment to its volumetric delivery rates. [4] Not surprisingly, costs have risen since 2007 to a point where Chesapeake is falling well short of its authorized return on utility investment.[5] In addition, natural gas consumption on a per customer basis has declined since 2007, which has decreased the volumes over which to allocate fixed costs. Furthermore, since its 2007 rate case, Chesapeake has invested nearly $11 million in pipeline replacement, primarily to remove unprotected bare steel

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[2] Chesapeake is a diversified energy company engaged in natural gas gathering, transmission, distribution and marketing; electric distribution; propane distribution and wholesale marketing; and other related businesses. Chesapeake operates natural gas distribution entities in Maryland, Delaware and Florida that serve a total of approximately 141,000 customers. Each natural gas entity is separately subject to the regulatory jurisdiction of the public utility commission in each of those three states.

[3] Chesapeake is separately filing a motion for admission of Mr. Quinn, *pro hac vice*, to represent Chesapeake in this matter.

[4] On June 25, 2012, in order to facilitate natural gas expansion in southeastern Sussex County, Chesapeake requested increases to its fixed monthly customer charges for new customers in certain rate classes located within a defined Expansion Area. In November of 2013, the Commission authorized new Expansion Area rate classes with higher customer charges than those charged under the corresponding rate classes applicable outside of the Expansion Area. *See* Order No. 8479 (Nov.5, 2013), Docket No. 12-292. In this Application, Chesapeake does not seek changes to the customer charges approved in Docket No. 12-292 for the Expansion Area rate classes.

[5] Chesapeake filed its last base rate case on July 6, 2007, in Docket No. 07-186. At the conclusion of that case, the Commission adopted a proposed settlement agreement that increased rates by $325,000, or less than 1 percent of total operating revenues. *See* Order No. 7434 (Sept. 2, 2008).

pipe that was installed prior to 1970. Although bare steel replacement improves system reliability, it does not generate incremental revenue to support the substantial investment required. Chesapeake seeks an adjustment to its rates therefore to reflect accurately the current level of sales and the current level of costs that Chesapeake is incurring to provide safe and reliable service to its customers.

Summary of Application

4. By this Application, Chesapeake seeks approval of an increase in delivery service rates of $4,741,823 or 9.96% percent of total operating revenues. Under the proposed rate design, an average residential heating customer using 120 Ccfs during a winter month will experience an increase of $13.36 per month, or 10.68 percent. An average residential non-heating customer using 18 Ccfs per month will experience an increase of $5.41 per month, or 15.17 percent. The proposed rates are based on a historic test year of the twelve-month period ending June 30, 2015, and a test period of the twelve-month period ending March 31, 2016.

5. Applicant is filing revised natural gas tariff pages along with this Application that incorporate the proposed changes for base rates to be effective February 19, 2016. Should the Commission exercise its discretion to suspend the proposed adjustment to base rates, Chesapeake requests that the Commission permit interim rates to go into effect on February 19, 2016, subject to refund. With respect to rate design and rate structure, Chesapeake is submitting herewith a complete cost of service study and certain rate design proposals. The proposed percentage increases in revenue from the various existing rate classifications under the proposed interim rates and the full proposed rates are included as Exhibit A. A proposed form of public notice is attached to this Application.

6. Chesapeake's current Commission-approved rate of return is 8.91 percent, which

includes a return on equity of 10.25 percent. Chesapeake's current *actual* rate of return on an adjusted rate base for the test period (without rate relief) is 4.61 percent, including a 4.46 percent return on equity. Chesapeake has determined that its cost of capital, which is the overall rate of return required to attract capital at a reasonable cost, is 8.55 percent, which includes a return on equity of 11.0 percent. Because Chesapeake's actual rate of return of 4.61 percent is less than its 8.55 percent cost of capital, Chesapeake's present rates are not just and reasonable and do not provide an opportunity for it to earn a reasonable return on the fair value of its property devoted to natural gas service.

7. In addition to the proposed rate changes, Chesapeake seeks approval of certain new service offerings further described in the testimony and revised tariff pages submitted herewith. Proposed new offerings include: (a) a Multi-Family Housing Program, under which Chesapeake will provide a financial contribution to offset the costs associated with gas piping and venting to builders that select natural gas for multi-family housing -- while protecting existing customers from subsidizing such expansion; (b) a Natural Gas Compression Service, under which Chesapeake will construct, own and maintain compression facilities for commercial customers who require enhanced pressure for their operations; (c) a Municipal Natural Gas Infrastructure Expansion Program, under which Chesapeake may offer incorporated towns an advance that would fund the construction of natural gas infrastructure in the town and which the town would pay back within six years; (d) a Temporary Gas Storage Tank Program for those instances when new construction has been completed prior to Chesapeake completing its natural gas main extension to the project and the customers require a temporary gas service until they can connect to the natural gas main, (e) a Poultry House Transportation offering, which will permit poultry companies to aggregate usage from their poultry houses for purposes of meeting the minimum consumption

requirement for transportation service, and (f) natural gas service to owners or operators of compressed natural gas ("CNG") facilities or to CNG transportation providers, who compress and/or transport CNG to third parties. Chesapeake also proposes a Revenue Normalization Adjustment ("RNA") for residential and smaller commercial customers similar to the RNA contained in its Maryland Division tariff since 2006, as well as several other miscellaneous changes to its tariff.

8. In addition, Chesapeake is requesting Commission approval of deferral accounting treatment for: (a) expenses relating to the set-up and implementation of new technologies, including a new billing system and (b) expenses associated with Chesapeake's pension, deferred compensation and other post-retirement benefits. A deferred accounting order is no guaranty of future cost recovery but the Commission in the past has required pre-approval of deferred treatment prior to a company's request for recovery of such expenses. *See* PSC Order No. 8589 (Aug. 5, 2014) at ¶ 118, 119; PSC Order No. 7838 (Sept. 21, 2010).

9. The justification for the proposed rate changes, new service offerings, and deferred accounting approvals is set forth in the accompanying Minimum Filing Requirements schedules and the supporting direct testimony of the following witnesses:

> i. C. James Moore, Vice President – overview of the Application and the need for rate relief;
>
> ii. Sarah Hardy, Regulatory Analyst III – sales and revenues, cost of service internal cost studies, and proposed tariff changes;
>
> iii. Matthew Everngam, Regulatory Analyst III – rate base;
>
> iv. Jeffrey Weiss, Regulatory Analyst II – operations and maintenance ("O&M") expenses and aggregated economic results from expansion projects since the last rate case;
>
> v. Matthew Dewey, Director of Accounting Shared Services – corporate O&M

expenditure adjustments and cost allocation procedures;

vi. Lisa Elder, Director of Financial Reporting and Tax – income taxes;

vii. Christopher Redd, Director of Gas Operations and Engineering – capital spending;

viii. Autumn Chalabala, Manager, Financial Analysis and Services – actual O&M expenses;

ix. Shane Breakie, Director of Energy Services – proposed new services;

x. Kathy McVay, independent consultant – proposal on pension plan;

xi. John Taylor, Project Manager, Black & Veatch Corporation – cost of service study;

xii. Ronald Amen, Director, Black & Veatch Corporation – rate design and proposed RNA; and

xiii. Paul Moul, Managing Consultant, P. Moul & Associates – return on equity and overall rate of return.

Copies of Chesapeake's proposed rate schedules and revised tariff pages as well as the Minimum Filing Requirements schedules are being submitted simultaneously with the filing of this Application.

Interim Rate Relief

10. In accordance with 26 Del. C. §306, Chesapeake's revised rates and schedules are submitted with a proposed effective date of February 19, 2016, which is 60 days after the filing. Should the Commission exercise its discretion to suspend the proposed adjustment, Chesapeake requests interim rates, effective February 19, 2016, designed to contribute $2,500,000 annually, as permitted under 26 Del. C. §306(c). Chesapeake proposes to recover the $2,500,000 interim

adjustment as an equal increase to all firm volumetric delivery service rates and fixed monthly customer charges (other than the customer charges contained in its Expansion Area rate schedules), as set forth in the tariff pages included with this filing.

11. Chesapeake respectfully requests that the Commission waive the surety bond requirement of 26 Del. C. §306(b) for interim rates. Chesapeake is strong financially and has access to sufficient financial resources to provide a refund, if so ordered by the Commission. As described in Mr. Moul's testimony, Chesapeake has the highest credit rating available from the National Association of Insurance Commissioners for long term debt and has financing arrangements in place with Prudential Investment Management and a group of five banks for a total of $300 million. Chesapeake agrees to abide by any Commission order that would require a refund of amounts collected through the use of interim rates. Chesapeake notes that the Commission recently has granted similar waiver requests to Artesian Water Company, Inc. in Docket No. 14-132 and to Delmarva Power & Light Company in Docket No. 13-115.[6]

12. The testimony and schedules filed herewith in support of this Application demonstrate that the proposed rate increase is essential, cost-justified and the minimum required to assure continued adequate service and to achieve the minimum rate of return needed to attract capital at reasonable costs.

WHEREFORE, Chesapeake respectfully requests that the Commission:

A. Find the accompanying revised rate schedules for retail gas service to be just and reasonable and authorize the rates and charges specified therein to become effective on February 19, 2016;

B. Should the Commission suspend the proposed adjustments to base rates, issue an order

[6] *See* PSC Order No. 8558 (May 13, 2014) and Order No. 8337 (April 9, 2013), respectively.

permitting the interim rates requested herein to go into effect on February 19, 2016, subject to refund;

C. Waive the surety bonding requirement for interim rates;

D. Approve the new service offerings and associated tariff changes proposed herein, including a Revenue Normalization Adjustment; and

E. Grant deferred accounting treatment for certain expenses relating to new technologies and for certain expenses relating to its pension plan, as requested herein.

Respectfully submitted,

William O'Brien
Associate General Counsel
Chesapeake Utilities Corporation

December 21, 2015

DATED: DECEMBER 21, 2015

STATE OF DELAWARE)
)
COUNTY OF KENT)

BE IT REMEMBERED that on this 21st day of December, 2015, personally appeared before me, a notary public for the State and County aforesaid, C. James Moore, who being by me duly sworn, did depose and say that he is Vice President for Chesapeake Utilities Corporation, a Delaware corporation and insofar as the Application of Chesapeake Utilities Corporation states facts, said facts are true and correct, and insofar as those facts are not within his personal knowledge, he believes them to be true, and that the schedules accompanying this application and attached hereto are true and correct copies of the originals of the aforesaid schedules, and that he has executed this Application on behalf of the Company.

C. James Moore
C. James Moore
Vice President

SWORN TO AND SUBSCRIBED before me the day and year above written.

Rebecca K. Grier
Notary Public
My Commission Expires: 7.17.18

REBECCA K. GRIER
NOTARY
PUBLIC
MY COMMISSION
EXPIRES ON
07-17-18
STATE OF DELAWARE

CERTIFICATE OF SERVICE

I, William F. O'Brien, do hereby certify that on December 21, 2015, a copy of Chesapeake Utilities Corporation's application for a general increase in its natural gas rates and services and for approval of certain other changes to its Delaware natural gas tariff was issued to the following persons in the manner indicated:

VIA E-FILING

Donna Nickerson, Secretary
Delaware Public Service Commission
Suite 100, Cannon Building
861 Silver Lake Blvd.
Dover, Delaware 19904

VIA E-MAIL

David L. Bonar, Public Advocate
Division of the Public Advocate
David.Bonar@state.de.us

Regina A. Iorii, Deputy Attorney General
Division of the Public Advocate
Regina.Iorii@state.de.us

Will O'Brien

William O'Brien
Associate General Counsel

Chesapeake Utilities Corporation
Delaware Division
Application for an Increase in Base Rates
and Other Changes to the Tariff
PSC Docket No. 15-

Impact of Proposed Interim Rates

Schedule	Rate Classification	% Increase
RS-1	Residential Service - 1	7.90%
ERS-1	Residential Service - 1 Expansion	2.38%
RS-2	Residential Service - 2	5.02%
ERS-2	Residential Service - 2 Expansion	2.06%
GS	General Service	4.93%
EGS	General Service Expansion	1.77%
MVS	Medium Volume Service	3.16%
EMVS	Medium Volume Service Expansion	2.86%
LVS	Large Volume Service	5.34%
HLFS	High Load Factor Service	10.05%
NGV	Natural Gas Vehicle Service	no change
GLR	Gas Lighting Service	no change
NCR	Negotiated Contract Rate	0.74%
ITS	Interruptible Transportation Service	flexible rate

Chesapeake Utilities Corporation
Delaware Division
Application for an Increase in Base Rates
and Other Changes to the Tariff
PSC Docket No. 15-

Impact of Full Proposed Rates

Schedule	Rate Classification	% Increase
RS-1	Residential Service - 1	30.68%
ERS-1	Residential Service - 1 Expansion	11.25%
RS-2	Residential Service - 2	12.33%
ERS-2	Residential Service - 2 Expansion	4.96%
GS	General Service	13.32%
EGS	General Service Expansion	2.70%
MVS	Medium Volume Service	4.38%
EMVS	Medium Volume Service Expansion	3.86%
LVS	Large Volume Service	-0.06%
HLFS	High Load Factor Service	-0.11%
NGV	Natural Gas Vehicle Service	no change
GLR	Gas Lighting Service	33.67%
NCR	Negotiated Contract Rate	4.67%
ITS	Interruptible Transportation Service	flexible rate

“DRAFT”

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF CHESAPEAKE UTILITIES CORPORATION FOR A GENERAL INCREASE IN ITS NATURAL GAS RATES AND FOR APPROVAL OF CERTAIN OTHER CHANGES TO ITS NATURAL GAS TARIFF (Filed December 21, 2015)	)))))))	PSC DOCKET NO. 15-

P U B L I C   N O T I C E

TO: ALL NATURAL GAS CUSTOMERS OF CHESAPEAKE UTILTIES CORPORATION AND OTHER INTERESTED PERSONS

On December 21, 2015, the Delaware Division of Chesapeake Utilities Corporation ("Chesapeake") filed with the Delaware Public Service Commission an application for an increase in natural gas rates and other proposed changes to its currently effective tariff. The new rates are proposed to be effective with service rendered on and after February 19, 2016, and are designed to produce an annual increase of approximately $4,741,823 or 9.96% of existing revenues based on a test period ending March 31, 2016. The full proposed rates would increase the bill of the average residential natural gas heating customer using 120 Ccf (hundred cubic feet) during a winter month by approximately $13.36 per month, and by $5.41 per month for the average non-heating gas customer using 18 Ccf per month.

The Commission has suspended the proposed effective date of the proposed new rates; however, pursuant to 26 Del. C. §306(c), Chesapeake has placed interim rates into effect, subject to refund. The interim rates would increase the bill of the average residential natural gas heating customer using 120 Ccf during a winter month by approximately

$4.83 per month, and by $2.71 per month for the average non-heating gas customer using 18 Ccf per month.

In addition to the proposed rate changes, Chesapeake seeks approval of certain new service offerings. Proposed new offerings include: (a) a Multi-Family Housing Program, under which Chesapeake will provide a financial contribution to offset the costs associated with gas piping and venting to builders that select natural gas for multi-family housing -- while protecting existing customers from subsidizing such expansion; (b) a Natural Gas Compression Service, under which Chesapeake will construct, own and maintain compression facilities for commercial customers who require enhanced pressure for their operations; (c) a Municipal Natural Gas Infrastructure Expansion Program, under which Chesapeake may offer incorporated towns an advance that would fund the construction of natural gas infrastructure in the town and which the town would pay back within six years; (d) a Temporary Gas Storage Tank Program for those instances when new construction has been completed prior to Chesapeake completing its natural gas main extension to the project and the customers require a temporary gas service until they can connect to the natural gas main, and (e) a Poultry House Transportation offering, which will permit poultry companies to aggregate usage from their poultry houses for purposes of meeting the minimum consumption requirement for transportation service. Chesapeake also proposes a Revenue Normalization Adjustment (“RNA”) for residential and smaller commercial customers similar to the RNA contained in its Maryland Division tariff since 2006, as well as several other miscellaneous changes to its tariff.

The Commission will conduct evidentiary hearings, to be scheduled at a later date, concerning this Application. The Commission's final decision will be based on the evidence presented at such hearings.

If you wish to formally participate as a party in this matter, with the right to present evidence and be represented by counsel, you must file with the Commission a written petition asking for leave to intervene in accordance with the requirements of the Commission's Rules of Practice and Procedure (26 *Del. Admin. C.* §1001-2.9) ***on or before* ________________________________*.*** All such petitions should be e-filed according to the Commission's Rules (26 *Del. Admin. C.* §1001-1.6.4). Petitions filed after the deadline of __________________________________, will not be considered except for good cause shown.

You are invited to review Chesapeake's application and supporting documents to determine how your interests may be affected by going to DelaFile (http://delafile.delaware.gov), the Commission's file management system, and by searching for Docket No. 15-________.

If you would like to review documents at the Commission's offices, please contact Donna Nickerson at (302) 736-7500 or by sending an email addressed to donna.nickerson@state.de.us. You may also review copies of Chesapeake's Application and supporting documents at the office of the Division of the Public Advocate located at either 820 North French Street, 4th Floor, Wilmington, Delaware 19801 or 29 South State Street, Dover, DE 19901. Please call either (302) 577-5077 (Wilmington) or (302) 241-2555 (Dover) to arrange for a time to review the documents at either of those locations.

If you wish to request copies of documents in this matter, please submit a Freedom of Information Act Request Form. The link to this form can be found on the Commission's website, http://depsc.delaware.gov, or by visiting this web address: https://delafile.delaware.gov/Complaints/FOIA.aspx. The Commission will respond to your request in accordance with the Delaware Freedom of Information Act, 29 *Del. C. ch*. 100.

If you have a disability and wish to participate or to review the materials in this matter, please contact the Commission to discuss any auxiliary aids or services you might need to help you. You may contact the Commission in person, by writing, by telephone (including text telephone), by Internet e-mail, or other means. If you have questions about this matter, you may call the Commission at 1-800-282-8574 (toll-free in Delaware) or (302) 736-7500 (voice and text telephone). You may also send questions regarding this matter by Internet e-mail addressed to jason.r.smith@state.de.us.

CHESAPEAKE UTILITIES CORPORATION
DELAWARE DIVISION BASE RATE APPLICATION
Briefing Sheet
PSC Docket No. 15-
Filed December 21, 2015

Subject:

Chesapeake Utilities Corporation – Delaware Division filed an application with the Delaware Public Service Commission ("Commission") on Monday, December 21, 2015, for a general increase in its natural gas base tariff rates and for approval for certain other changes to its natural gas tariff.

Increase Sought:

Proposed base rate increase of $4,741,837 or 9.96% of existing revenues based on the test period ending March 31, 2016. In the event the Commission suspends the increase in base rates pending the evidentiary hearing process, the Company proposes to increase rates on an interim basis subject to refund by $2,500,000 which represents a 5.25% increase of existing revenues, or 52.7% of the overall requested increase.

Test Year: Twelve-months ended June 30, 2015

Test Period: Twelve-months ending March 31, 2016

Primary Reasons For Filing:

Chesapeake Utilities Corporation – Delaware Division has been unable to earn its allowed rate of return for the twelve months ended June 30, 2015. Natural gas consumption on a per customer basis has declined since 2007, which has decreased the volumes over which to allocate fixed costs. Also, since its last rate case, Chesapeake has invested nearly $11 million in pipeline replacement, primarily to remove unprotected bare steel pipe that was installed prior to 1970. Although bare steel replacement improves system reliability, it does not generate incremental revenue to support the investment it requires. The Company's last base rate filing was submitted to the Delaware Public Service Commission on July 6, 2007, and the Commission approved a $325,000 general increase in base rates in that docket.

Effective Date:

The Company is requesting that the full proposed base rate increase become effective February 19, 2016. In the event the full proposed rates and services are suspended beyond 60 days from the date of the application, the Company proposes to place interim rates in effect as of February 19, 2016.

CHESAPEAKE UTILITIES CORPORATION
DELAWARE DIVISION BASE RATE APPLICATION
Briefing Sheet
PSC Docket No. 15-
Filed December 21, 2015

Rate Design and Structure:

The proposed interim base rates have been designed based on the Company's current rate structure and current customer classes. The $2,500,000 interim rate increase as stated above has been spread to all firm customer classes equally based on their non-fuel or delivery service margin, other than the customer charges contained in the Expansion Area rate schedules.

The Company is not proposing any changes in its rate structure and design for its full proposed rates. The Company is proposing a revenue normalization adjustment mechanism for customers in all Residential Service and General Service rate classes.

Rate Base:

Included in this filing is a calculation of the Company's average rate base for the twelve months ending March 31, 2016, which is $70,938,749.

New Service Offering:

In addition to the proposed rate changes, Chesapeake seeks approval of certain new service offerings. Proposed new offerings include:

(a) a Multi-Family Housing Program, under which Chesapeake will provide a financial contribution to offset the costs associated with gas piping and venting to builders that select natural gas for multi-family housing -- while protecting existing customers from subsidizing such expansion;

(b) a Natural Gas Compression Service, under which Chesapeake will construct, own and maintain compression facilities for commercial customers who require enhanced pressure for their operations;

(c) a Municipal Natural Gas Infrastructure Expansion Program, under which Chesapeake may offer incorporated towns an advance that would fund the construction of natural gas infrastructure in the town and which the town would pay back within six years;

(d) a Temporary Gas Storage Tank Program for those instances when new construction has been completed prior to Chesapeake completing its natural gas main extension to the project and the customers require a temporary gas service until they can connect to the natural gas main;

(e) a Poultry House Transportation offering, which will permit poultry companies to aggregate usage from their poultry houses for purposes of meeting the minimum consumption requirement for transportation service; and
(f) natural gas service to owners or operators of compressed natural gas ("CNG") facilities or to CNG transportation providers, who compress and/or transport CNG to third parties.

Other Tariff Changes:

Chesapeake also proposes several other tariff changes, such as:

(a) a Revenue Normalization Adjustment ("RNA") for residential and smaller commercial customers similar to the RNA contained in its Maryland Division tariff since 2006;
(b) proposed modifications to the curtailment policy;
(c) a proposed extension in the bill payment due date from ten (10) days to twenty (20) days;
(d) a proposed modification to the interest rate on customer deposits; and
(e) general formatting and clarification changes.

Rate of Return:

Proposed overall rate of return of 8.55% on rate base with a proposed 11.00% on common equity.

Capital Structure:

Line No.	Type of Capital	Proportion of Total	Cost of Each Type of Capital	Cost Component
1	Long-Term Debt	39.61%	4.82%	1.91%
2	Common Equity	60.39%	11.00%	6.64%
3	Total	100.00%		8.55%

CHESAPEAKE UTILITIES CORPORATION
DELAWARE DIVISION BASE RATE APPLICATION
Briefing Sheet
PSC Docket No. 15-
Filed December 21, 2015

Summary of Rate Increase:

	Test Period Amount ($000's)
Rate Base	$70,939
Net Operating Income	$3,267
Earned Rate of Return	4.61%
Proposed Fair Rate of Return	9.68%
Required Operating Income	$6,065
Operating Income Deficiency	$2,798
Revenue Deficiency	$4,741
Revenue Increase Requested	9.96%

Details of Preceding Rate Case: (Docket No. 07-186)

- Filed July 6, 2007; decided September 2, 2008; final rates effective September 3, 2008.
- Increase of $325,000 granted.
- 8.91% overall rate of return granted.
- 10.25% return on equity granted.

Impact on Existing Rate Classes:

Rate Classification	Test Period Average Customers	Interim Proposed Increase Dollar	Interim Proposed Increase %
Residential – 1	4,147	$92,502	7.90%
Residential – 1 (Exp)	106	1,057	2.37%
Residential – 2	38,500	1,544,161	5.02%
Residential – 2 (Exp)	465	9,736	2.06%
General Svc	2,851	162,218	4.93%
General Svc (Exp)	15	362	1.77%
Medium Volume	484	88,980	3.16%
Medium Volume (Exp)	3	302	2.86%
Large Volume	205	198,123	5.34%
High Load Factor	310	399,507	10.05%
Other Firm	15	1,104	1.69%
Interruptible	2	0	0.00%
Natural Gas Vehicles	5	0	0.00%
Total	47,108	$2,498,052	5.25%

CHESAPEAKE UTILITIES CORPORATION
DELAWARE DIVISION BASE RATE APPLICATION
Briefing Sheet
PSC Docket No. 15-
Filed December 21, 2015

Existing and Proposed Typical Residential Rates (Non-Expansion Area):

	Existing Rate	Proposed Interim Rate	Full Proposed Rate (RS-2)
Customer Charge	$13.00	$14.50	$17.00
First 20 Ccf	$0.578	$0.645	$0.656
Next 30 Ccf	$0.319	$0.355	$0.397
Over 50 Ccf	$0.132	$0.145	$0.210

Existing and Proposed Typical Residential Rates (Expansion Area):

	Existing Rate	Proposed Interim Rate	Full Proposed Rate (ERS-2)
Customer Charge	$31.75	$31.75	$31.75
First 20 Ccf	$0.578	$0.645	$0.656
Next 30 Ccf	$0.319	$0.355	$0.397
Over 50 Ccf	$0.132	$0.145	$0.210

Impact on Average Residential Heating Customer Using 645 Ccf per Year:
(As compared to Current Rates)

Proposed Interim $3.44 per month or 5.15%

Full Proposed $8.19 per month or 12.24%

CHESAPEAKE UTILITIES CORPORATION
DELAWARE DIVISION BASE RATE APPLICATION
Briefing Sheet
PSC Docket No. 15-
Filed December 21, 2015

<u>Impact on Average Residential Heating Customer Using 120 Ccf per Winter Month</u>:
(As compared to Current Rates)

Proposed Interim	$4.83 per winter month or 3.86%
Full Proposed	$13.36 per winter month or 10.68%

<u>Impact on Average Residential Non-Heating Customer Using 18 Ccf per Month</u>:
(As compared to Current Rates)

Proposed Interim	$2.71 per month or 7.60%
Full Proposed	$5.41 per month or 15.17%

RATE SCHEDULE "RS - 1"

RESIDENTIAL SERVICE - 1

AVAILABILITY

This rate schedule is available to any individually metered customer using gas in a residential dwelling or unit for space heating, cooking, water heating, or other domestic purpose with an annual consumption of 240 Ccf or less. The Company will annually review those customers receiving service under this rate schedule in order to determine the appropriate firm residential rate schedule should their annual consumption warrant such a change. This annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer Charge:	$11.75 per month
First 20 Ccf	$0.675 per Ccf
Next 30 Ccf	$0.310 per Ccf
Over 50 Ccf	$0.190 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers served under this rate schedule are subject to the gas cost rate applicable to Rate Schedule "RS-1" provided on Sheet No. 42.

PAYMENT TERMS

Bills are due within ten (10) days of their date.

MINIMUM BILL

The minimum monthly bill under this rate schedule is the customer charge.

Issue Date: December 21, 2015
Effective Date: For Service Rendered on and after February 19, 2016
Authorization:

RATE SCHEDULE "RS - 2"

RESIDENTIAL SERVICE – 2

AVAILABILITY

This rate schedule is available to any individually metered customer using gas in a residential dwelling or unit for space heating, cooking, water heating, or other domestic purpose with annual consumption of greater than 240 Ccf. The Company will annually review those customers receiving service under this rate schedule in order to determine the appropriate firm residential rate schedule should their annual consumption warrant such a change. A Customer on RS-1 Service will be moved to this rate schedule with annual consumption equal to or greater than 264 Ccf. A Customer on this rate schedule will be moved to RS-1 Service with annual consumption less than 216 Ccf. This annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer Charge:	$14.50 per month
First 20 Ccf	$0.645 per Ccf
Next 30 Ccf	$0.355 per Ccf
Over 50 Ccf	$0.145 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers served under this rate schedule are subject to the gas cost rate applicable to Rate Schedule "RS-2" provided on Sheet No. 42.

PAYMENT TERMS

Bills are due within ten (10) days of their date.

MINIMUM BILL

The minimum monthly bill under this rate schedule is the customer charge.

RATE SCHEDULE "ERS-1"

EXPANSION AREA RESIDENTIAL SERVICE – 1

AVAILABILITY

This rate schedule is available to any individually metered customer within the southeastern Sussex County, Delaware, expansion area using gas in a residential dwelling or unit for space heating, cooking, water heating, or other domestic purpose with an annual consumption of 240 Ccf or less. The southeastern Sussex County, Delaware, expansion area is defined as the area east of Chesapeake's district regulator station located on Route 9 in Lewes, Delaware, that is connected to Chesapeake's distribution main and any area that is connected to Chesapeake's distribution main behind the three Eastern Shore Natural Gas transmission pipeline City Gates located in Dagsboro, Frankford, and Selbyville, Delaware. The Company will annually review those customers receiving service under this rate schedule in order to determine the appropriate firm residential rate schedule should their annual consumption warrant such a change. This annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer Charge:	$16.50 per month
First 20 Ccf	$0.675 per Ccf
Next 30 Ccf	$0.310 per Ccf
Over 50 Ccf	$0.190 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers served under this rate schedule are subject to the gas cost rate applicable to Rate Schedule "RS" provided on Sheet No. 42.

PAYMENT TERMS

Bills are due within ten (10) days of their date.

RATE SCHEDULE "ERS-2"

EXPANSION AREA RESIDENTIAL SERVICE – 2

AVAILABILITY

This rate schedule is available to any individually metered customer within the southeastern Sussex County, Delaware, expansion area using gas in a residential dwelling or unit for space heating, cooking, water heating, or other domestic purpose with annual consumption of greater than 240 Ccf. The southeastern Sussex County, Delaware, expansion area is defined as the area east of Chesapeake's district regulator station located on Route 9 in Lewes, Delaware, that is connected to Chesapeake's distribution main and any area that is connected to Chesapeake's distribution main behind the three Eastern Shore Natural Gas transmission pipeline City Gates located in Dagsboro, Frankford, and Selbyville, Delaware. The Company will annually review those customers receiving service under this rate schedule in order to determine the appropriate firm residential rate schedule should their annual consumptions warrant such a change. A Customer on ERS-1 Service will be moved to this rate schedule with annual consumption equal to or greater than 264 Ccf. A Customer on this rate schedule will be moved to ERS-1 Service with annual consumption less than 216 Ccf. This annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer Charge:	$31.75 per month
First 20 Ccf	$0.645 per Ccf
Next 30 Ccf	$0.355 per Ccf
Over 50 Ccf	$0.145 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers served under this rate schedule are subject to the gas cost rate applicable to Rate Schedule "RS" provided on Sheet No. 42.

PAYMENT TERMS

Bills are due within ten (10) days of their date.

RATE SCHEDULE "GS"

GENERAL SERVICE

AVAILABILITY

This rate schedule is available to any customer using gas for commercial and/or industrial purposes with an annual consumption of less than 4,000 Ccf. The Company will annually review those customers receiving service under this rate schedule in order to determine the appropriate firm commercial and/or industrial rate schedule should their annual consumption warrant such a change. This annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer Charge:	$28.95 per month
First 20 Ccf	$0.495 per Ccf
Next 30 Ccf	$0.310 per Ccf
Over 50 Ccf	$0.155 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "GS" provided on Sheet No. 42.

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial customers with annual consumption through one or more contiguous meters in a specific geographic location equal to, or greater than, 30,000 Ccf per year that choose to have their own gas transported through the Company's distribution system. Customers purchasing natural gas from a supplier, other than the Company, must have the natural gas delivered to the Company's city gate in accordance with the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the customer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate: **$0.081** per Ccf of gas consumed

Issue Date: **December 21, 2015**
Effective Date: **For Service Rendered on and after February 19, 2016**
Authorization:

RATE SCHEDULE "EGS"

EXPANSION AREA GENERAL SERVICE

AVAILABILITY

This rate schedule is available to any customer within the southeastern Sussex County, Delaware, expansion area using gas for commercial and/or industrial purposes with an annual consumption of less than 4,000 Ccf. The southeastern Sussex County, Delaware, expansion area is defined as the area east of Chesapeake's district regulator station located on Route 9 in Lewes, Delaware, that is connected to Chesapeake's distribution main and any area that is connected to Chesapeake's distribution main behind the three Eastern Shore Natural Gas transmission pipeline City Gates located in Dagsboro, Frankford, and Selbyville, Delaware. The Company will annually review those customers receiving service under this rate schedule in order to determine the appropriate firm commercial and/or industrial rate schedule should their annual consumption warrant such a change. This annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer Charge:	$56.00 per month
First 20 Ccf	$0.5000 per Ccf
Next 30 Ccf	$0.310 per Ccf
Over 50 Ccf	$0.160 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "GS" provided on Sheet No. 42.

RATE SCHEDULE "MVS"
MEDIUM VOLUME SERVICE

AVAILABILITY

This rate schedule is available to any customer using gas for commercial and/or industrial purposes with an annual consumption generally equal to or greater than 4,000 Ccf and less than 15,000 Ccf. The Company will annually review those Customers receiving service under this rate schedule in order to determine the appropriate firm commercial and/or industrial rate schedule should their annual consumption warrant such a change. A Customer on General Service will be moved to this rate schedule with annual consumption equal to or greater than 4,400 Ccf. A Customer on this rate schedule will be moved to General Service with annual consumption less than 3,600 Ccf. The annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer Charge:	$72.40 per month
First 200 Ccf	$0.250 per Ccf
Over 200 Ccf	$0.125 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "MVS" provided on Sheet No. 42.

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial customers with annual consumption through one or more contiguous meters in a specific geographic location equal to, or greater than, 30,000 Ccf per year that choose to have their own gas transported through the Company's distribution system. Customers purchasing natural gas from a supplier, other than the Company, must have the natural gas delivered to the Company's city gate in accordance with the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the customer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate: $0.091 per Ccf of gas consumed

RATE SCHEDULE "EMVS"

EXPANSION AREA MEDIUM VOLUME SERVICE

AVAILABILITY

This rate schedule is available to any customer within the southeastern Sussex County, Delaware, expansion area using gas for commercial and/or industrial purposes with an annual consumption generally equal to or greater than 4,000 Ccf and less than 15,000 Ccf. The southeastern Sussex County, Delaware, expansion area is defined as the area east of Chesapeake's district regulator station located on Route 9 in Lewes, Delaware, that is connected to Chesapeake's distribution main and any area that is connected to Chesapeake's distribution main behind the three Eastern Shore Natural Gas transmission pipeline City Gates located in Dagsboro, Frankford, and Selbyville, Delaware. The Company will annually review those Customers receiving service under this rate schedule in order to determine the appropriate firm commercial and/or industrial rate schedule should their annual consumption warrant such a change. A Customer on Rate Schedule EGS will be moved to this rate schedule with annual consumption equal to or greater than 4,400 Ccf. A Customer on this rate schedule will be moved to rate schedule EGS with annual consumption less than 3,600 Ccf. The annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer Charge:	$158.75 per month
First 200 Ccf	$0.250 per Ccf
Over 200 Ccf	$0.125 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "MVS" provided on Sheet No. 42.

RATE SCHEDULE "LVS"

LARGE VOLUME SERVICE

AVAILABILITY

This rate schedule is available to any customer using gas for commercial and/or industrial purposes with an annual consumption generally equal to or greater than 15,000 Ccf. The Company will annually review those customers receiving service under this rate schedule in order to determine the appropriate firm commercial and/or industrial rate schedule should their annual consumption warrant such a change. A Customer on Medium Volume Service will be moved to this rate schedule with annual consumption equal to or greater than 16,500 Ccf. A Customer on this rate schedule will be moved to Medium Volume Service with annual consumption less than 13,500 Ccf. The annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer charge:	$139.25 per month
First 1000 Ccf	$0.360 per Ccf
Over 1000 Ccf	$0.090 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "LVS" provided on Sheet No. 42.

RATE SCHEDULE "HLFS"

HIGH LOAD FACTOR SERVICE

AVAILABILITY

This rate schedule is available to any customer using gas for commercial and/or industrial purposes that would otherwise qualify for Medium Volume Service or Large Volume Service and with winter months' consumption, defined as the months of January through March, being less than thirty-five percent (35%) of their annual consumption. In addition, the customer must use natural gas in at least eleven of the twelve months under review and usage must be fairly evenly distributed throughout the review period. The Company will annually review those Customers receiving service under this rate schedule in order to determine the appropriate firm commercial and/or industrial rate schedule should their annual consumption or winter months consumption warrant such a change. A Customer will remain on this rate schedule as long as winter months' consumption is less than thirty-seven percent (37%) of their annual consumption and the Customer qualifies for Medium Volume Service or Large Volume Service. The annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption or winter months' consumption other than after the annual review.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer Charge:	$83.55 per month
All gas consumed	$0.100 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "HLFS" provided on Sheet No. 42.

RATE SCHEDULE "RS - 1"

RESIDENTIAL SERVICE - 1

AVAILABILITY

This rate schedule is available to any individually metered customer using gas in a residential dwelling or unit for space heating, cooking, water heating, or other domestic purpose with an annual consumption of 240 Ccf or less. The Company will annually review those customers receiving service under this rate schedule in order to determine the appropriate firm residential rate schedule should their annual consumption warrant such a change. This annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer Charge:	$11.75~~10.50~~ per month
First 20 Ccf	$0.675~~0.607~~ per Ccf
Next 30 Ccf	$0.310~~0.280~~ per Ccf
Over 50 Ccf	$0.190~~0.170~~ per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers served under this rate schedule are subject to the gas cost rate applicable to Rate Schedule "RS-1" provided on Sheet No. 42.

PAYMENT TERMS

Bills are due within ten (10) days of their date.

MINIMUM BILL

The minimum monthly bill under this rate schedule is the customer charge.

RATE SCHEDULE "RS - 2"

RESIDENTIAL SERVICE – 2

AVAILABILITY

This rate schedule is available to any individually metered customer using gas in a residential dwelling or unit for space heating, cooking, water heating, or other domestic purpose with annual consumption of greater than 240 Ccf. The Company will annually review those customers receiving service under this rate schedule in order to determine the appropriate firm residential rate schedule should their annual consumption warrant such a change. A Customer on RS-1 Service will be moved to this rate schedule with annual consumption equal to or greater than 264 Ccf. A Customer on this rate schedule will be moved to RS-1 Service with annual consumption less than 216 Ccf. This annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer Charge:	$14.50~~13.00~~ per month
First 20 Ccf	$0.645~~0.578~~ per Ccf
Next 30 Ccf	$0.355~~0.319~~ per Ccf
Over 50 Ccf	$0.145~~0.132~~ per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers served under this rate schedule are subject to the gas cost rate applicable to Rate Schedule "RS-2" provided on Sheet No. 42.

PAYMENT TERMS

Bills are due within ten (10) days of their date.

MINIMUM BILL

The minimum monthly bill under this rate schedule is the customer charge.

RATE SCHEDULE "ERS-1"

EXPANSION AREA RESIDENTIAL SERVICE – 1

AVAILABILITY

This rate schedule is available to any individually metered customer within the southeastern Sussex County, Delaware, expansion area using gas in a residential dwelling or unit for space heating, cooking, water heating, or other domestic purpose with an annual consumption of 240 Ccf or less. The southeastern Sussex County, Delaware, expansion area is defined as the area east of Chesapeake's district regulator station located on Route 9 in Lewes, Delaware, that is connected to Chesapeake's distribution main and any area that is connected to Chesapeake's distribution main behind the three Eastern Shore Natural Gas transmission pipeline City Gates located in Dagsboro, Frankford, and Selbyville, Delaware. The Company will annually review those customers receiving service under this rate schedule in order to determine the appropriate firm residential rate schedule should their annual consumption warrant such a change. This annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer Charge:	$16.50 per month
First 20 Ccf	$0.675~~0.607~~ per Ccf
Next 30 Ccf	$0.310~~0.280~~ per Ccf
Over 50 Ccf	$0.190~~0.170~~ per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers served under this rate schedule are subject to the gas cost rate applicable to Rate Schedule "RS" provided on Sheet No. 42.

PAYMENT TERMS

Bills are due within ten (10) days of their date.

RATE SCHEDULE "ERS-2"

EXPANSION AREA RESIDENTIAL SERVICE – 2

AVAILABILITY

This rate schedule is available to any individually metered customer within the southeastern Sussex County, Delaware, expansion area using gas in a residential dwelling or unit for space heating, cooking, water heating, or other domestic purpose with annual consumption of greater than 240 Ccf. The southeastern Sussex County, Delaware, expansion area is defined as the area east of Chesapeake's district regulator station located on Route 9 in Lewes, Delaware, that is connected to Chesapeake's distribution main and any area that is connected to Chesapeake's distribution main behind the three Eastern Shore Natural Gas transmission pipeline City Gates located in Dagsboro, Frankford, and Selbyville, Delaware. The Company will annually review those customers receiving service under this rate schedule in order to determine the appropriate firm residential rate schedule should their annual consumptions warrant such a change. A Customer on ERS-1 Service will be moved to this rate schedule with annual consumption equal to or greater than 264 Ccf. A Customer on this rate schedule will be moved to ERS-1 Service with annual consumption less than 216 Ccf. This annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer Charge:	$31.75 per month
First 20 Ccf	$0.645~~0.578~~ per Ccf
Next 30 Ccf	$0.355~~0.319~~ per Ccf
Over 50 Ccf	$0.145~~0.132~~ per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers served under this rate schedule are subject to the gas cost rate applicable to Rate Schedule "RS" provided on Sheet No. 42.

PAYMENT TERMS

Bills are due within ten (10) days of their date.

RATE SCHEDULE "GS"

GENERAL SERVICE

AVAILABILITY

This rate schedule is available to any customer using gas for commercial and/or industrial purposes with an annual consumption of less than 4,000 Ccf. The Company will annually review those customers receiving service under this rate schedule in order to determine the appropriate firm commercial and/or industrial rate schedule should their annual consumption warrant such a change. This annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer Charge:	$28.95~~26.00~~ per month
First 20 Ccf	$0.495~~0.447~~ per Ccf
Next 30 Ccf	$0.310~~0.278~~ per Ccf
Over 50 Ccf	$0.155~~0.140~~ per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "GS" provided on Sheet No. 42.

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial customers with annual consumption through one or more contiguous meters in a specific geographic location equal to, or greater than, 30,000 Ccf per year that choose to have their own gas transported through the Company's distribution system. Customers purchasing natural gas from a supplier, other than the Company, must have the natural gas delivered to the Company's city gate in accordance with the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the customer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate: **$0.081** per Ccf of gas consumed

Issue Date: **December 21, 2015~~September 1, 2015~~**
Effective Date: For Service Rendered on and after February 19, 2016~~November 1, 2015 – Temporary Basis~~
Authorization: ~~Order No. 8792 in PSC Docket No. 15-1362 dated September 22, 2015~~

RATE SCHEDULE "EGS"

EXPANSION AREA GENERAL SERVICE

AVAILABILITY

This rate schedule is available to any customer within the southeastern Sussex County, Delaware, expansion area using gas for commercial and/or industrial purposes with an annual consumption of less than 4,000 Ccf. The southeastern Sussex County, Delaware, expansion area is defined as the area east of Chesapeake's district regulator station located on Route 9 in Lewes, Delaware, that is connected to Chesapeake's distribution main and any area that is connected to Chesapeake's distribution main behind the three Eastern Shore Natural Gas transmission pipeline City Gates located in Dagsboro, Frankford, and Selbyville, Delaware. The Company will annually review those customers receiving service under this rate schedule in order to determine the appropriate firm commercial and/or industrial rate schedule should their annual consumption warrant such a change. This annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer Charge:	$56.00 per month
First 20 Ccf	$0.5000~~0.447~~ per Ccf
Next 30 Ccf	$0.3100~~0.278~~ per Ccf
Over 50 Ccf	$0.1600~~0.140~~ per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "GS" provided on Sheet No. 42.

RATE SCHEDULE "MVS"
MEDIUM VOLUME SERVICE

AVAILABILITY

This rate schedule is available to any customer using gas for commercial and/or industrial purposes with an annual consumption generally equal to or greater than 4,000 Ccf and less than 15,000 Ccf. The Company will annually review those Customers receiving service under this rate schedule in order to determine the appropriate firm commercial and/or industrial rate schedule should their annual consumption warrant such a change. A Customer on General Service will be moved to this rate schedule with annual consumption equal to or greater than 4,400 Ccf. A Customer on this rate schedule will be moved to General Service with annual consumption less than 3,600 Ccf. The annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer Charge:	$72.40~~65.00~~ per month
First 200 Ccf	$0.250~~0.227~~ per Ccf
Over 200 Ccf	$0.125~~0.115~~ per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "MVS" provided on Sheet No. 42.

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial customers with annual consumption through one or more contiguous meters in a specific geographic location equal to, or greater than, 30,000 Ccf per year that choose to have their own gas transported through the Company's distribution system. Customers purchasing natural gas from a supplier, other than the Company, must have the natural gas delivered to the Company's city gate in accordance with the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the customer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate: $0.091 per Ccf of gas consumed

RATE SCHEDULE "EMVS"

EXPANSION AREA MEDIUM VOLUME SERVICE

AVAILABILITY

This rate schedule is available to any customer within the southeastern Sussex County, Delaware, expansion area using gas for commercial and/or industrial purposes with an annual consumption generally equal to or greater than 4,000 Ccf and less than 15,000 Ccf. The southeastern Sussex County, Delaware, expansion area is defined as the area east of Chesapeake's district regulator station located on Route 9 in Lewes, Delaware, that is connected to Chesapeake's distribution main and any area that is connected to Chesapeake's distribution main behind the three Eastern Shore Natural Gas transmission pipeline City Gates located in Dagsboro, Frankford, and Selbyville, Delaware. The Company will annually review those Customers receiving service under this rate schedule in order to determine the appropriate firm commercial and/or industrial rate schedule should their annual consumption warrant such a change. A Customer on Rate Schedule EGS will be moved to this rate schedule with annual consumption equal to or greater than 4,400 Ccf. A Customer on this rate schedule will be moved to rate schedule EGS with annual consumption less than 3,600 Ccf. The annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer Charge:	$158.75 per month
First 200 Ccf	$0.250~~0.227~~ per Ccf
Over 200 Ccf	$0.125~~0.115~~ per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "MVS" provided on Sheet No. 42.

Issue Date: **December 21, 2015~~July 21, 2015~~**
Effective Date: **For Service~~Bills~~ Rendered on and after February 19, 2016~~September 1, 2015~~**
Authorization: **~~Order 8752 in PSC Docket No. 13-383 dated July 21, 2015~~**

RATE SCHEDULE "LVS"

LARGE VOLUME SERVICE

AVAILABILITY

This rate schedule is available to any customer using gas for commercial and/or industrial purposes with an annual consumption generally equal to or greater than 15,000 Ccf. The Company will annually review those customers receiving service under this rate schedule in order to determine the appropriate firm commercial and/or industrial rate schedule should their annual consumption warrant such a change. A Customer on Medium Volume Service will be moved to this rate schedule with annual consumption equal to or greater than 16,500 Ccf. A Customer on this rate schedule will be moved to Medium Volume Service with annual consumption less than 13,500 Ccf. The annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer charge:	$139.25~~125.00~~ per month
First 1000 Ccf	$0.3600~~.326~~ per Ccf
Over 1000 Ccf	$0.0900~~.083~~ per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "LVS" provided on Sheet No. 42.

RATE SCHEDULE "HLFS"

HIGH LOAD FACTOR SERVICE

AVAILABILITY

This rate schedule is available to any customer using gas for commercial and/or industrial purposes that would otherwise qualify for Medium Volume Service or Large Volume Service and with winter months' consumption, defined as the months of January through March, being less than thirty-five percent (35%) of their annual consumption. In addition, the customer must use natural gas in at least eleven of the twelve months under review and usage must be fairly evenly distributed throughout the review period. The Company will annually review those Customers receiving service under this rate schedule in order to determine the appropriate firm commercial and/or industrial rate schedule should their annual consumption or winter months consumption warrant such a change. A Customer will remain on this rate schedule as long as winter months' consumption is less than thirty-seven percent (37%) of their annual consumption and the Customer qualifies for Medium Volume Service or Large Volume Service. The annual review process will be based on the twelve months ended August. Customers will not be shifted between rate schedules due to changes in annual consumption or winter months' consumption other than after the annual review.

DELIVERY SERVICE RATES

The following rates for delivering gas to the customer's location apply to all customers served under this rate schedule.

Customer Charge:	$83.55~~75.000~~	per month
All gas consumed	$0.1000~~.087~~	per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "HLFS" provided on Sheet No. 42.

Issue Date: December 21, 2015~~September 2, 2008~~
Effective Date: For Service~~Bills~~ Rendered on and after February 19, 2016~~September 3, 2008~~
Authorization: ~~Order No. 7434 dated September 2, 2008 in PSC Docket No. 07-186~~

CHESAPEAKE UTILITIES

DELAWARE DIVISION

RULES AND REGULATIONS

GOVERNING THE DISTRIBUTION

AND SALE OF GAS

OF

CHESAPEAKE UTILITIES CORPORATION

IN

NEW CASTLE, KENT & SUSSEX COUNTIES, DELAWARE

CHESAPEAKE UTILITIES CORPORATION
DELAWARE DIVISION

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RULES AND REGULATIONS **SHEET NO.**

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CHESAPEAKE UTILITIES CORPORATION
DELAWARE DIVISION

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RULES AND REGULATIONS

SECTION I - GENERAL

1.1 FILING AND POSTING

A copy of this Tariff, which is the rates, rules and regulations under which gas service will be supplied by Chesapeake Utilities Corporation to its Customers, is on file with the Public Service Commission of Delaware, and is posted and open for inspection at the offices of the Company. The Tariff is supplementary to any Regulations of that Commission.

1.2 REVISIONS

This Tariff may be revised, amended, supplemented and otherwise changed from time to time in accordance with the Public Service Commission Law of Delaware, and such changes, when effective, shall have the same force and effect as the present Tariff.

1.3 APPLICATION OF TARIFF

The Tariff provisions apply to any party or parties receiving gas service from the Company, or to its successors and assigns, under the rates set forth therein, and the receipt of gas shall constitute the receiver a Customer of the Company as the term is used herein.

1.4 RULES AND REGULATIONS

The Rules and Regulations, filed as a part of this Tariff, are a part of every contract or agreement for service, whether written, oral or implied, made by the Company and govern all classes of service where applicable. Subject to the approval of the Commission, the Company shall have the right to interpret and determine the applicability of such rules and regulations.

1.5 STATEMENT OF AGENTS

No agent or employee of the Company has authority to make any promise, agreement or representation inconsistent with the provisions of this Tariff.

RULES AND REGULATIONS

SECTION II - CURTAILMENT

2.1 GENERAL

In the event that the Company determines that there is insufficient gas supply to meet the demands of the Customers on its distribution system, the Company may, at its sole discretion, curtail service to Customers. Curtailments will be made to maintain supply to its firm sales customers in the priorities set forth below. When curtailment is necessary, sufficient gas will be available to maintain a temperature which will keep the building pipes from freezing and other plant protection use, if possible. Prior to, or in conjunction with curtailment the Company may call for voluntary usage reductions on the part of all Customers.

2.2 DEFINITIONS

Essential Human Needs: Includes residences, apartments, hotels, motels, dormitories, hospitals, nursing homes, police and other institutions essential to the public welfare.

Plant protection use: Minimum volumes of natural gas required to prevent physical harm to the plant facilities' processes or danger to plant personnel when such protection cannot be afforded through the use of an alternative fuel. Plant protection requirements include volumes necessary for the protection of such material in process as would otherwise be destroyed, but does not include deliveries required to maintain production.

2.3 CURTAILMENT PRIORITIES

Curtailment to the extent necessary as determined by the Company, up to and including complete curtailment shall be done in accordance with the following list of priorities, starting with the lowest priority, priority 6.

RULES AND REGULATIONS
SECTION II
(Continued)

2.3 CURTAILMENT PRIORITIES (continued)

Priority 1: Essential humans needs Customers.

Priority 2: All other customers other than Priority 1 Customers will be curtailed to the extent necessary as determined by the Company.

Priority 3: Firm commercial and industrial Customers using above 4,000 Ccf per year.

Priority 4: Firm commercial and industrial Customers using above 15,000 Ccf per year.

Priority 5: Firm commercial and industrial Customers using above 100,000 Ccf per year.

Priority 6: All interruptible transportation and IBE Customers.

2.4 CURTAILMENT OF CUSTOMER-OWNED GAS

If adequate supply to priority essential human needs Customers is threatened in the Company's judgment, Customer-owned transportation gas may be curtailed in addition to system supply and in the same order of priorities. In the event that Customer-owned gas is diverted for use by higher priority Customers, the Company will reimburse the Customer by paying the cost of the Customers alternative fuel or, if the Customer has no alternative fuel, reimbursement will be at a rate equal to the higher of the Company's weighted average cost of gas (the total cost of natural gas delivered to the Company for system supply divided by the volume delivered) or the Customer's total acquisition cost of gas (including pipeline transportation charges). In the event of a supply shortage which causes the Company to purchase the Customer's gas, the Customer shall make available a copy of its contract for natural gas supply upon request; or in lieu thereof, the Customer shall supply a sworn affidavit specifying Customer's total acquisition cost of gas. In lieu of this provision, the Company may enter into contractual or informal arrangements with transportation Customers or any other parties to obtain supplies to avoid curtailments.

2.5 LIABILITY

The Company shall not be liable for any damages, loss of product, or other business losses suffered by Customers as a result of curtailed gas service, other than the compensation provided in Section 2.4 above. The Company shall not be liable for curtailment as a result of any action by any governmental agency with jurisdiction to regulate, allocate, or control gas supplies or the rendition of service, and regardless of any defect in such law, regulation, or order.

RULES AND REGULATIONS

SECTION II
(Continued)

2.6 ADDITIONAL LOADS

In the event that additional gas supply becomes limited for any reason, the Company reserves the right to defer supplying gas for new loads in such manner as to cause the least hardship to present or prospective Customers, taking into consideration the volume of natural gas available and the capacities of local mains and facilities. In each of the listed classes, present Customers will be allowed to increase loads before new Customers will be allowed to begin service.

During any period when gas supply is expected to be limited the Company will maintain a Register of New Loads applied for, but not already being served by the Company, in order to assist the Company in forecasting peak demands for its service, and to afford a basis of priority in supplying additional loads to existing as well as to new or prospective Customers.

During any period of restricted gas supply the Company will not supply gas for any equipment unless application for such load was registered with the Company prior to the connection of such equipment, and approval thereof was given by the Company.

The priority in which additional loads will be accepted is:

	DESCRIPTION	TYPE
(1)	Non-space heating load Peak day less than 1,000 cu. ft.	Residential
(2)	Non-space heating load Peak day less than 1,000 cu. ft	Commercial Industrial
(3)	Space heating load Peak day less than 2,000 cu. ft.	Residential Commercial Industrial
(4)	Dwelling Units - Home or Apartments Individually Billed Not to exceed 25 units at one location.	Residential

RULES AND REGULATIONS

SECTION II
(Continued)

2.6 ADDITIONAL LOADS (continued)

	DESCRIPTION	TYPE
(5)	Dwelling Units - Home or Apartments Master Metered Not to exceed 25 units at one location	Commercial
(6)	Non-space heating load Peak day not to exceed 10,000 cu ft	Commercial Industrial
(7)	Space Heating Load Peak day less than 10,000 cu. ft.	Commercial Industrial
(8)	Same as (4) above except in increments of 26 to 100 units at one location.	
(9)	Same as (5) above except in increments of 26 to 100 units at one location.	
(10)	Same as (4) above except in increments of over 100 units at one location.	
(11)	Same as (5) above except in increments of over 100 units at one location.	
(12)	All other commercial and industrial loads.	

The Company reserves the right to establish priority of loads in accordance with volume within each category above.

The Company reserves the right to allocate gas to various priority categories listed above based on estimated gas sales and gas supply and to make adjustments as actual figures vary from the estimate.

RULES AND REGULATIONS

SECTION II
(Continued)

2.6 ADDITIONAL LOADS (continued)

When anticipated gas supplies are not sufficient to service all new loads applied for in one of the above categories, priority will be given in the order in which application was registered with the Company, provided the new load is connected within a reasonable time after notice from the Company that it may be served.

When the evidence available to the Company reasonably indicates that a Customer has connected additional load without registering same or in violation of the Company's notice that it may not be connected, the Company will discontinue all service to such Customer, upon ten (10) days’ written notice, until such additional load has been disconnected.

RULES AND REGULATIONS

SECTION III - APPLICATION FOR SERVICE

3.1 APPLICATION

Application for gas service may be made through the local office of the Company or authorized agent, by:

(a) Verbal or telephonic request to a business office of the Company, or
(b) Electronic request to the Company's web site (www.chpkgas.com), or
(c) if required by the Company, by submission to the Company a completed Gas Delivery Service Application (certain Applicants may be required to execute a Transportation Service Agreement).

The Company reserves the right to require the Applicant before any gas is delivered, to execute an application at the local office with proper identification. The application does not constitute a commitment by the Company to serve the Applicant.

3.2 RIGHT TO REJECT

The Company may place limitations on the amount or character of service it will supply, or may reject applications for any of the following reasons:

(a) Until the Customer has complied with the state and municipal regulations governing gas service.

(b) If the Company does not have adequate facilities to render the service desired.

(c) If such service is of a character that it is likely to unfavorably affect service to other Customers.

(d) If, in the judgment of the Company, the Applicant's installation of piping or gas equipment is hazardous, or of such a character that satisfactory and safe service cannot be rendered.

(e) If an extension of street main, except as set forth under Section 6 - Extensions, is required to furnish such service.

RULES AND REGULATIONS

SECTION III
(Continued)

3.2 RIGHT TO REJECT (Continued)

(f) When it is necessary to conserve the supply of gas (See Section 2.3 Curtailment Priorities and 2.6 Additional Loads.)

(g) Customer's failure to provide a deposit to insure payment of bills, where requested by the Company under the provisions of Section 13.2.

(h) Customer's failure to make such payment as may be required under Section 6 as a condition of extension of supply facilities.

(i) Customer’s failure to pay the Connection Charge, Reconnection Charge or Seasonal Customer Charge.

(i) Service at new location will be rendered only when all bills for gas service to the Customer at any other locations have been paid.

(j) Non-compliance with provisions of this Tariff.

3.3 ACCEPTANCE

Acceptance of gas service by the Customer shall constitute an agreement to accept service under these Rules, Regulations and Rates as amended from time to time, the Orders or Rules of the Public Service Commission of Delaware, the Laws of the State of Delaware and the Laws of the United States of America.

RULES AND REGULATIONS

SECTION III
(Continued)

3.4 CUSTOMER TO SPECIFY TIME WHEN SERVICE IS CONNECTED

A Customer shall give two (2) business days' notice to the Company for gas service to be connected during normal business hours, under normal operating conditions. Business days shall mean Monday through Friday excluding Federal Banking Holidays. As a safety precaution, the Customer, or an authorized representative of the Customer of at least eighteen (18) years of age, shall be present at the premises for gas service to be connected. If, due to unforeseen or emergency circumstances, the Company is not able to meet the two (2) business day connection schedule, the Customer shall be informed, and a new arrangement made. .The Connection Charge provided on Sheet No. 46 (Miscellaneous Customer Charges) shall apply to all gas service connections. If necessary for the Customer's convenience that the connection be made after normal working hours, the After Hours Connection Charge provided on Sheet No. 46 (Miscellaneous Customer Charges) shall apply.

3.5 POINT OF DELIVERY

(a) The point of delivery of gas to a Customer shall be at the outlet side of the meter connection, Title to Company owned gas shall pass to the Customer at this point. The use of Service on two or more separate meters will not be combined for billing purposes.

(b) (Exception) Combined billings for registrations of multiple meters installed on a customer's premises is permitted only where such multiple meters are installed for the convenience of the Company.

3.6 CHARACTER OF GAS

The gas to be served will be natural gas with a specific gravity of approximately .60, a minimum value per cubic foot of one thousand (1,000) BTU, and that is in conformance with the quality specifications of transporters delivering such gas to the Company's Receipt Points, or such other gas as may be approved by the Public Service Commission of Delaware. The Company shall have the right to supply stand-by or peak shaving gas of similar characteristics when necessary.

RULES AND REGULATIONS

SECTION IV – CUSTOMER'S INSTALLATIONS

4.1 INFORMATION FROM CUSTOMER

Anyone desiring to equip their premises for the use of gas shall communicate with the Company personally, or through their contractor or other authorized agent, giving the exact location of the premises and details of all gas consuming equipment to be installed.

4.2 POINT OF CONNECTION

The Company will designate the point where the applicant would, if served, be required to terminate their piping for connection to the lines of the Company. The furnishing of such information does not constitute an agreement, or obligation, on the part of the Company to render service.

4.3 METER SPACE

The applicant shall provide, free of expense to the Company, a space satisfactory to the Company for meters, regulators or other equipment of the Company which is necessary for the rendering of adequate and safe service. The Company reserves the right to establish the standard as to the location of such space in accordance with pressure conditions, volumes, and other pertinent factors.

4.4 METER LOCATION

The Company shall have the right to determine the location of its meters, which must be placed where they will be easily accessible, and the Customer or owner of the building shall provide at all times, free of expense to the Company, proper space for the Company's meters. Likewise, the Customer shall not permit materials of any character to be piled up or heaped around the meter location. The Customer shall reimburse the Company for the loss of, or any damage to, its meters and meter connections, or other property of the Company while located on the Customer's premises, arising out of or caused by the Customer's negligence, carelessness; or that of the Customer's agents, employees, members of the Customer's household, or any person upon the Customer's premises under or by authority of the Customer's consent or sufferance.

RULES AND REGULATIONS

SECTION IV
(Continued)

4.5 METER CONNECTIONS

The Company will own, furnish, and maintain the meter, regulator, meter connection, electronics, remote reading device, if any, and all other appurtenant equipment required to measure the gas supplied to the Customer, and will supply gas only through a meter furnished and owned by the Company. The Company must be notified when the Customer desires to have the meter installed, changed or removed.

4.6 TEMPORARY SERVICE

The Customer shall pay the cost for all material, labor and all other necessary expense incurred by the Company in supplying gas service to the Customer for any temporary purpose or use, and shall pay the cost of removing material after service is discontinued, in addition to the regular payments for gas used. The Company will credit the Customer with the reasonable salvage value of any material recovered.

4.7 SERVICE LINES

The Company will own and maintain at its expense, the service line to the point of connection designated by the Company. (See Section 6.1 Service Connections).

4.8 HOUSE PIPING

Prior to the installation of house piping by the Customer in new or altered premises, inquiry should be made of the Company to determine the requirements, sizes of pipe, quality and other specifications.

Customer’s installation shall be installed at the Customer’s expense and shall be maintained by the Customer in compliance with applicable codes.

RULES AND REGULATIONS

SECTION IV
(Continued)

4.9 INTERFERENCE WITH COMPANY FACILITIES

The Customer shall not open, tamper or interfere with, in any manner, the service line, regulators, or safety appliances installed in connection with service provided to the Customer. The Company's main, service line, service cock, curb box and meter shall not be tampered or interfered with at any time. In the event of the Company's meters or other property being tampered or interfered with, the Customer being supplied through such equipment shall pay the amount which may be reasonably estimated to be due for service used but not registered on the Company's meter, and for any repairs, replacements or changes in facilities required, as well as for costs of inspections, investigations and protective installations.

4.10 RESPONSIBILITY OF CUSTOMER

This Company's ownership and responsibility terminates at the meter outlet. The Customer is warned of the risk of damage to property and the possibility of fire or personal injury resulting from improper house piping and manner of attachment or use and maintenance of gas appliances, fixtures, and apparatus, and is advised to permit no one except experienced and capable pipe fitters to install or to make any changes, alterations, additions or repairs to any part of the Customer's installation. The Company will not be liable for any injury or damage or loss of gas caused by reason of defects in any portion whereof.

RULES AND REGULATIONS

SECTION V - TESTING AND INSPECTION OF CUSTOMER'S PIPING

5.1 REQUIREMENT

Prior to providing gas service, the Customer's facilities and appliances must be in accordance with the national and local code requirements.

5.2 COMPANY'S RIGHT TO INSPECT

The Company shall have the right, but shall not be obliged, to inspect any installation before gas is introduced or at any later time, and reserves the right to reject any piping or appliances not in accordance with the Company's standard requirements, or with any national and local code requirements; but such inspection, or failure to inspect, or to reject, shall not render the Company liable or responsible for any loss or damage, resulting from defects in the Customer's installation, piping or appliances, or from violation of the Company rules, or from accidents which may occur upon the premises of the Customer.

RULES AND REGULATIONS

SECTION VI – SERVICE INSTALLATIONS AND MAIN EXTENSIONS

6.1 SERVICE INSTALLATIONS

The Company will install the service line from its existing distribution main to the Customer's meter location at its expense. However, if the service line exceeds seventy-five (75) feet in length, the Company's initial investment in the entire service installation shall be limited to six (6) times the related estimated annual base tariff revenue excluding all fuel costs ("net revenue") from the Customer. The amount of the investment that exceeds the six (6) times net revenue test for the service installation shall be paid by the Customer in accordance with the terms of Section 6.3.

Service Installations, as used in this section for purposes of the six (6) times net revenue test, refers to the costs associated with the service line piping, meter installation and associated materials from the tap on the Company's gas distribution main system up to and including the Customer's meter.

6.2 MAIN EXTENSIONS

Main extensions to the Company's gas system shall be provided, owned and maintained under the terms and conditions stated herein. Main extensions, as used in this section for purposes of the economic evaluation criteria, refers to the cost of gas distribution mains and associated materials that must be constructed along public streets, roads and highways, or on private property from the Company's existing gas distribution main system to the initiation of the service line. Main extensions are limited to the extent of new investment warranted by the anticipated revenues as stated in this Section VI.

<u>New Residential Development</u>

The economic evaluation criteria for installing natural gas service to the new residential development will be based on an Internal Rate of Return Model ("IRRM") with certain predetermined conditions and guidelines. The applicable procedures and guidelines in the implementation of the IRRM are on file with and have been approved by the Public Service Commission of Delaware. The procedure used to determine whether a financial guarantee will be required from a Customer(s) is part of the IRRM methodology on file with the Commission.

RULES AND REGULATIONS

SECTION VI – SERVICE INSTALLATIONS AND MAIN EXTENSIONS (Continued)

6.2 MAIN EXTENSIONS (Continued)

When evaluating potential multi-family housing projects, if the IRRM demonstrates that the anticipated revenues warrant an investment greater than the cost of the main extension and service connection, then the Company may, at its sole discretion, provide a contribution to the Customer to offset costs incurred for the installation of gas piping and venting in the premise. The contribution provided by the Company may not exceed the amount that is warranted by the anticipated revenues and, in any event, may not exceed the actual cost for installation of gas pipe and venting in the premise. A project will be determined to be a multi-family project if there are at least four (4) individually metered dwelling units in one premise. When providing a contribution to offset costs related to the installation of gas piping and venting, the Customer bears all responsibility for proper installation and maintenance of all pipe beyond the Company's meter.

Existing Residential Developments

The economic evaluation criteria for installing natural gas service to an existing residential development will be based on an Internal Rate of Return Model ("IRRM") with certain predetermined conditions and guidelines. The applicable procedures and guidelines in the implementation of the IRRM are on file with and have been approved by the Public Service Commission of Delaware. The procedure used to determine whether a financial guarantee will be required from a Customer(s) is part of the IRRM methodology on file with the Commission.

Commercial and Industrial Main Extensions

The economic evaluation criteria for installing natural gas service to commercial and industrial Customers, including transportation and non-firm Customers, will be the six (6) times net revenue test based on the commercial and industrial Customers' estimated level of annual non-fuel revenue. The estimated annual non-fuel revenue is defined as the estimated annual base Tariff revenue or delivery service revenue excluding all fuel related costs for the respective Customer. If the estimated investment in the facilities necessary to provide gas service exceeds six (6) times the related annual non-fuel revenue from the respective Customer(s), the Customer(s) shall provide a financial guarantee in accordance with the terms of Section 6.3.
The economic evaluation criteria for negotiated contracts for compression services will be the IRRM and will include the Company's cost of installing Company-owned and maintained compression facilities to meet the pressure demands specified by the Customer.

RULES AND REGULATIONS

SECTION VI – SERVICE INSTALLATIONS AND MAIN EXTENSIONS (Continued)

6.3 FINANCIAL GUARANTEES

Financial guarantees may be made by a Contribution in Aid of Construction ("CIAC"), a Customer Advance, a Letter of Credit, or other financial guarantee at the Company's discretion.

Should the Customer provide a Customer Advance, the Company will provide, in a written agreement with the Customer, for refunds (without interest) of all, or part, of the monies advanced by the Customer in connection with the extension and the applicable economic evaluation criteria. Refunds to the Customer shall extend over a term of years, not to exceed six (6) years, upon such basis or conditions as may be mutually agreeable to the Company and the Customer, and specified in the written agreement. In no case shall the total refund be greater than the Customer's deposit. Any portion of the deposit remaining after the expiration of the term as specified in the written agreement shall be retained by the Company and credited as a Contribution In Aid of Construction.

Should the Customer provide a Letter of Credit or other financial guarantee, the estimated revenue attributable to the extension shall be examined prior to the expiration of the Letter of Credit or other financial guarantee. The Company may either draw on the Letter of Credit or other financial guarantee or require that it be renewed, where a continued financial guarantee is still required.

6.4 RIGHT TO DETERMINATION

In each and every situation where the Company and the prospective Customer cannot agree as to the necessity for a financial guarantee to be borne by the prospective Customer, the prospective Customer will be advised by the Company of the right to have the matter determined by the Public Service Commission of Delaware under 26 Del Code, Section 203.

RULES AND REGULATIONS

SECTION VI – SERVICE INSTALLATIONS AND MAIN EXTENSIONS (Continued)

6.5 OWNERSHIP AND MAINTENANCE

The Company shall own, maintain and renew all its equipment, between the main and the outlet side of the meter connection.

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RULES AND REGULATIONS

SECTION VII - RIGHTS-OF-WAY/OR EASEMENTS

7.1 RIGHTS-OF-WAY AND/OR EASEMENTS

The Applicant(s) requesting service shall furnish, without expense to the Company, and to the Company's satisfaction, rights-of-way and/or easements necessary for the supply of service or shall agree to reimburse the Company for expense incurred in the procurement of the necessary rights-of-way and/or easements. The Company shall first exercise reasonable efforts to procure any necessary rights-of-way and/or easements from the land owner for nominal consideration or without charge to the Company and the Applicant(s) requesting service.

7.2 TERM AND RENTALS

When, to serve a Customer, it is necessary to extend the Company's facilities over the property of another, the Customer shall accept service for such term as is provided in the permit or agreement covering the location and maintenance of such facilities on the land or property of others. The Customer may be required to reimburse the Company for any and all special, or rental, charges that may be made for such rights by said permit or agreement.

7.3 GRADING

Rights-of-way, easements and service routes must be cleared and graded to within six (6) inches of final grade by the Applicant including certification by the Applicant that such grade has been achieved before the Company will commence construction. Such clearing and grading must be maintained by the Applicant during construction by the Company.

7.4 CHANGE IN GRADE

If subsequent to any agreement to construct by the Company, the clearance or grade is changed in such a manner as to require relocation of pipelines or other facilities, the cost of such relocation shall be borne by the Applicant, or the Applicant’s executor, administrator, heir or successor.

7.5 DELAYS

Application for service from an extension to be constructed where a right-of-way and/or easement is not owned by the Company, will only be accepted subject to delays incident to obtaining a satisfactory right-of-way and/or easement.

RULES AND REGULATIONS

SECTION VIII - COMPANY EQUIPMENT ON CUSTOMER'S PREMISES

8.1 MAINTENANCE

The Company shall keep in repair and maintain its own property installed on the premises of the Customer.

8.2 RESPONSIBILITY OF CUSTOMER

The Customer shall not cause damage to the equipment of the Company on the Customer’s premises, and shall not permit any person, except a Company employee having proper Company identification, to break any seals upon, or do any work on any meter, service pipe or other equipment of the Company located on the Customer's premises.

8.3 TAMPERING

In the event of the Company's meters or other property being tampered or interfered with, the Customer being supplied through such equipment shall pay the amount which may be reasonably estimated to be due for service used but not registered on the Company's meter, and for any repairs, replacements or changes in facilities required, as well as for costs of inspections, investigations and protective installations.

8.4 ACCESS TO PREMISES

The Company, or its authorized agents, shall have access at all reasonable times to the property or premises in or on which gas is used to determine if the gas is being carried, distributed and burned in a proper and safe manner and in accordance with these Rules and Regulations, or to read, inspect and test the meter or house lines and other appliances, equipment or facilities. Refusal on the part of the Customer to allow access to the Customer’s premises shall constitute sufficient cause for turning off the gas supply to such premises. (See Section 14.1).

8.5 RELOCATION OR ALTERATION OF COMPANY-OWNED FACILITIES

Any relocation or alteration of Company-owned facilities to furnish gas service to Customers for the convenience and benefit of the Company shall be paid for by the Company; however, any such changes occasioned or necessitated by any action of the Customer, or owner of the property if the Customer is a lessee, may be made only after prior approval of the Company, and shall be at the expense of the Customer or owner.

Issue Date:
Effective Date:
Authorization:

RULES AND REGULATIONS

SECTION IX - SERVICE CONTINUITY

9.1 REGULARITY OF SUPPLY

The Company will use reasonable diligence to provide a continuous, regular and uninterrupted supply of gas service; but does not and cannot guarantee a constant supply and should the supply be interrupted by the Company for the reasons set forth in Section II, entitled "Curtailment" or for the purpose of making repairs, changes, or improvements, in any part of its system for the general good of the service or the safety of the public, or should the supply of service be interrupted, or fail, by reason of accident, strike, legal process, State or Municipal interference, lack of sufficient gas supply, mechanical failure, or any cause whatsoever, beyond its control, the Company shall not be liable for damages, direct or consequential, resulting from such interruption or failure.

9.2 NOTICE OF TROUBLE

The Customer shall notify the Company, immediately, should the service be unsatisfactory for any reason, or should there be any defects, leaks, trouble, or accident, affecting or resulting from the supply of gas.

9.3 PREARRANGED INTERRUPTION OF SERVICE

Whenever it is necessary to interrupt service for work on mains or other equipment, such work shall be done, as far as practicable, at a time that will cause the least inconvenience to the Customer. The Customer(s) to be affected by such interruption shall, if practicable, be notified in advance.

RULES AND REGULATIONS

SECTION X - CUSTOMER'S USE OF SERVICE

10.1 PRECAUTIONS TO BE TAKEN BY CUSTOMER

The responsibility of detection of defects and leaks on the Customer's premises is upon the Customer; defects among other things, shall mean failure or deficiency of gas, irregular supply, leakage and excessive pressure. In case of detection of a leak within the Customer's premises, the Customer should

- Leave the home or building immediately and go upwind of the suspected leak.
- Immediately call the Company's local emergency telephone number or 911 from a cellular phone outside the home or building, or from a neighboring location, to report the suspected gas leak.
- Not use their home telephone, turn on or off any electrical switches, light a match or do anything that might create a spark or flame.
- Not re-enter the building where the suspected leak is until emergency officials give the okay.

. When gas has been shut off because of a leak in the house lines or fixtures or other hazardous conditions of service, it shall not be turned on again until such leak or other hazardous conditions have been repaired and made safe either by a competent plumber or gas fitter. In the event of failure or deficiency of gas or excessive pressure, the Customer shall notify the Company and be governed by instructions or assistance received from the Company.

10.2 PRUDENT USES OF GAS

A Customer should always make prudent use of gas.

Upon notice by the Customer, the Company will investigate reports of suspected gas leakage and improper functioning of gas appliances.

In the event that gas passes through the meter as a result of the Customer's negligence or malfunctioning of the Customer's piping or appliances, no credit will be issued, unless such use is a result of fault or neglect of agents of the Company.

10.3 SALES OF GAS BY CUSTOMER

The Customer shall not directly or indirectly sell, sublet, assign or otherwise dispose of the gas or any part thereof. Purchase of gas for use by tenants located on the Customer's property, when the cost to the tenant of such gas is included in the normal rental charge for occupancy of the premises, shall not be considered as resale.

RULES AND REGULATIONS

SECTION X
(Continued)

10.4 SERVICE TO CUSTOMER'S APPLIANCES

The Company shall investigate complaints of gas leaks or odors at any time without charge. The Company shall have the right, but shall not be obliged, to inspect any installation before gas is introduced or at any later time, and reserves the right to reject any piping or appliances not in accordance with the Company’s standard requirements, or with any national and local code requirements; but such inspection, or failure to inspect, or to reject, shall not render the Company liable or responsible for any loss or damage, resulting from defects in the Customer’s installation, piping or appliances, or from violation of the Company rules, or from accidents which may occur upon the premises of the Customer.

10.5 FLUCTUATIONS

Gas service must not be used in such a manner as to cause unusual fluctuations or disturbances in the Company's supply system, and in the case of a violation of this rule, the Company may discontinue service, or require the Customer to modify their installation and/or equip it with approved controlling devices.

10.6 LIABILITY FOR DAMAGES

The Company shall not be liable for any injury to persons or damage to property arising or occurring in any manner whatsoever from the misuse of gas.

RULES AND REGULATIONS

SECTION XI - MEASUREMENT

11.1 DEFINITION OF A CUBIC FOOT

a. Low Pressure Sales - Standard delivery to the Customer is at low pressure, and for those meters not having temperature correcting devices which correct to a temperature of sixty (60) degrees Fahrenheit, a cubic foot of gas shall be that amount of gas which occupies a volume of one cubic foot at the time metered and under the conditions existing at the Customer's meter.

b. Other Than Low Pressure Sales As Under (a) Above - When at the discretion of the Company, gas is supplied at higher than standard delivery pressure, measurement may be by a meter equipped with a base pressure corrector and the metering is continuously, automatically, and uniformly corrected from the absolute delivery pressure (14.73 atmospheric pressure) in pounds per square inch, to a pressure base of 14.95 lbs. per square inch, at the temperature existing at the meter. Meters may be equipped with a base pressure and temperature corrector and the metering is continuously, automatically and uniformly corrected from the absolute delivery pressure of 14.73 absolute pressure in pounds per square inch to a pressure base of 14.95 lbs. per square inch, and to a temperature of sixty (60) degrees Fahrenheit.

11.2 MEASUREMENT OF GAS

Except as herein otherwise provided, the measurement of gas service shall be by meters furnished and installed by the Company. The Company will furnish each Customer with a meter of such size and type as the Company may determine will adequately serve the Customer's service requirements, and may from time to time, change or alter the equipment to provide for accurate measurement.

Each meter shall be calibrated to serve gas within the tolerance as specified by the Public Service Commission of Delaware. Registration shall be in cubic feet or multiples thereof depending on service classification.

If any correction factor is applied to any meter, this factor shall be marked on such meter.

RULES AND REGULATIONS

SECTION XI MEASUREMENT
(Continued)

11.2 MEASUREMENT OF GAS (Continued)

The Company shall install, at the Company's expense, a remote reading device on all Customer's served under the LVH, HLFS or Interruptible Transportation Service Rate Schedules with annual consumption of at least one hundred thousand (100,000) Ccf annually. All remote reading devices shall be owned, installed and maintained by the Company. When requested by a Customer below the annual consumption level above, and approved by the Company, a remote reading device may be installed at a cost payable by the Customer. In all cases the Customer shall, at the Customer's expense, provide and maintain electrical power and telephone service to the remote reading device location.

A periodic verification reading shall be taken on the meter and the remote reading device. The Company shall notify the Customer when the periodic verification is required. The Company shall determine the frequency of such verification based on the technical characteristics of the installed equipment and its in-service performance.

In cases of a measurement dispute related to the remote reading device, the Company's meter may be used as the final determinant in measuring consumption.

11.3 METERS NOT AVAILABLE

In cases where meters are not available due to circumstances beyond the control of the Company, and the necessity for rendering gas service to the Customer is urgent, the Company may, after proper authorization by the Commission and by written agreement with the Customer, commence service and render bills temporarily on the basis of estimated gas consumption.

11.4 METER READING INTERVALS

The Company will endeavor to make its regular meter reading and/or estimated meter reading as nearly as reasonably possible at scheduled monthly intervals.

RULES AND REGULATIONS

SECTION XI MEASUREMENT
(Continued)

11.5 ESTIMATED USAGE

The Company may render estimated bills when (1) no meter is installed, as provided above, or (2) when a meter is installed but the scheduled meter reading cannot be obtained due to the inability of the Company's agent or representative to gain access to the meter location at the time scheduled, or (3) in case any meter or measuring device for any reason fails to register for any period of time the full consumption by a Customer, (See Section XII Meter Tests), or (4) the Company is unable to obtain a meter reading for causes beyond its control.

Estimated readings shall be based upon prior consumption at the particular location for a similar period of time and may be adjusted for current conditions. The Customer shall be obligated to pay the bill based on the estimated consumption as though the same was based on an actual meter reading, and failure to so pay shall subject the Customer and the Customer's service to the penalties herein provided. Bills based on estimated readings shall be subject to adjustment for any unusual circumstances found to have affected the quantity of gas used, or for obvious errors in estimates, which adjustments shall be made not later than the next subsequent bill rendered the Customer, or that period of time when an actual reading can be obtained.

The Company will cooperate with the Customer to schedule meter readings; however, in those instances where the Company's agent or representative is unable to gain access to the Customer's premises, during the regular scheduled working hours, to obtain a meter reading, the number of estimated readings shall be limited to three (3) consecutive months, and the Customer's service thereafter, is subject to discontinuance.

RULES AND REGULATIONS

SECTION XII - METER TESTS

12.1 METER TESTS

All meters shall be tested periodically by the Company in compliance with the Rules of the Commission and at the Company's expense.

12.2 ACCURACY OF GAS METERS

When any test of a meter by the Company or by the Commission shows such meter to have an average error of more than two percent (2%), and no meter tampering has occurred, the following provisions for the adjustment of bills shall be observed:

Fast Meters

Unless the date of the beginning of inaccuracy shall be known, it shall be assumed that the over-registration existed for a period of three (3) years or a period equal to one-half (1/2) of the time since the meter was last tested, whichever is less.

If the meter is found to be over-registering, the Company shall make a refund to the last Customer of record receiving service through the meter for the amount which shall have been charged in excess of that which would have been charged had the meter registered with one hundred percent (100%) accuracy, provided the refund exceeds one dollar ($1). The refund will be computed upon the assumption that the meter was registering one hundred percent (100%) accurately prior to the beginning of the period of inaccuracy or the period of adjustment defined in the preceding paragraph. The refund shall be for the period that the last Customer received service through the meter, but for not more than the periods referred to in this Section 12.2.

Slow Meters

If the meter is found to under-register, or is slow, the Company may bill the Customer one-half (1/2) of the unbilled undercharge for a period of twelve (12) months, unless the meter has been tested within that twelve (12) month period, in which event the Company may bill the Customer one-half (1/2) of the unbilled undercharge for the period since the meter was last tested. If the amount of under-registration is less than five dollars ($5), the bill will not be adjusted. Installment payments will be arranged equal to the number of months the account was billed in error in the event additional charges are due the Company, and the installment payments are due and payable in addition to the Customer’s regular monthly natural gas service bill.

RULES AND REGULATIONS

SECTION XII
(Continued)

12.2 ACCURACY OF GAS METERS (Continued)

Non-Registering Meters

If the meter is found to be not registering, or is stopped, the Company may estimate, and bill the Customer the proper charge for the unregistered service by reference to the Customer's consumption during similar periods. Except in the case of tampering, theft, or unauthorized use, the estimate shall cover a period of not more than six (6) months. Installment payments will be arranged equal to the number of months the account was billed in error in the event additional charges are due the Company, and the installment payments are due and payable in addition to the Customer’s regular monthly natural gas service bill.

12.3 REQUEST TESTS

Upon request by a Customer and at no charge the Company shall make a test of the accuracy of registration of the meter serving that Customer, providing that such tests need not be made more frequently than once in eighteen (18) months.

RULES AND REGULATIONS

SECTION XIII - PAYMENT TERMS

13.1 INITIAL RATE SCHEDULE ASSIGNMENT

Subsequent to receiving an application for Gas Delivery Service and prior to activating such service, the Company shall estimate the annual usage of the Customer (based upon the connected gas consuming appliances or equipment) for the purpose of the initial assignment of a Rate Schedule. Where selection of the most favorable schedule is difficult to predetermine, the Company shall, at the request of the Customer, assist the Customer in selecting a Rate Schedule. Subsequent to service activation, the Customer shall be given reasonable opportunity to change to another Rate Schedule, but the Company shall not be required to make refunds for any previous billing under any Rate Schedules selected by the Customer prior to the time of receipt of a written notice from the Customer requesting to change to another Rate Schedule.

13.2 ESTABLISHMENT OF CUSTOMER CREDIT

The Company may require a prospective Customer to satisfactorily establish credit before Gas Delivery Service will be initiated. Such establishment of credit shall not relieve the prospective Customer from complying with the Company's provisions herein for prompt payment of bills. Credit will be deemed so established, and no deposit required, if any one of the following criteria is satisfied:

(a) The Customer has been a Customer of the Company or other similar Delaware utility in the past two (2) years and;
  (1) paid the final bill when due, and
  (2) did not on more than two (2) occasions during the last twelve (12) consecutive months have a bill unpaid after a reasonable period of time after the due date, and
  (3) did not have service discontinued for non-payment, and
  (4) can provide the Company with a letter from the last utility substantiating a good payment history; or

(b) The Customer owns or is purchasing the residence for which the gas service is requested; or,

(c) The Customer can provide a guarantor satisfactory to the Company. This guarantee shall be in writing and must continue in full force and effect for one (1) year from installation date of the service or until Customer's credit is otherwise established, or

(d) The Non-residential Customer possesses and maintains an Experian Intelliscore of sixty (60) or above, or

RULES AND REGULATIONS

SECTION XIII
(Continued)

13.2 ESTABLISHMENT OF CUSTOMER CREDIT (Continued)

(e) The Non-residential Customer possesses and maintains at least an investment grade bond/long-term debt rating from either Standard and Poor's or Moody's. Comparable ratings may be considered from other nationally recognized rating organizations acceptable to the Company. In the event a Customer, whose annual gas consumption exceeds one hundred thousand (100,000) Ccf, does not possess a debt rating or the rating is below investment grade, credit may be established, at the sole discretion of the Company, by the Customer's demonstration of adequate financial strength and stability. The Company may evaluate the Customer's creditworthiness by review of at least two (2) years audited financial statements, accompanied by the opinion of an independent certified public accountant or chartered accountants of recognized national or regional standing, and such other known or discovered factors relating to the Customer's creditworthiness.

(f) The Customers for which credit is established pursuant to this Section 13.2 are subject to periodic review by the Company to assure that no material changes adversely affecting the Customer's creditworthiness have occurred. In the event a material change has occurred, or the Customer has paid its account with a check dishonored by a bank, the Company may request that credit be established by (i) cash deposit, or (ii) irrevocable letter of credit from a bank, or (iii) surety bond.

(g) Notwithstanding anything stated herein to the contrary, a security deposit shall be required if the Customer has been disconnected by the Company for non-payment within the nine (9) months prior to the Customer's application for service.

When none of the above conditions are met or service has been discontinued (see Section 14.1-b) the Customer shall make a deposit with the Company subject to the following:

(a) Amount of deposit required may not be more than two-twelfths (2/12) of the estimated charges for the ensuing twelve (12) months, nor less than five dollars ($5). Residential deposits in excess of one hundred dollars ($100) may be made with an initial deposit of one hundred dollars ($100) with the remainder to be paid over the ensuing four (4) week period.

(b) Interest on a deposit shall be simple interest at an annual rate equal to the average of the percent yields of the 1-year Treasury constant maturities for September, October, and November of the preceding year. Interest will be paid at the time the deposit is returned. The deposit ceases to draw interest on the date service is terminated, or in the case of good credit, the date the deposit is processed for refund. No interest will be paid on deposits held less than ninety (90) days.

RULES AND REGULATIONS

SECTION XIII
(Continued)

13.2 ESTABLISHMENT OF CUSTOMER CREDIT (Continued)

(c) Deposits will be refunded to residential Customers following payment of twelve (12) consecutive bills without arrears.

(d) Refund of deposit upon discontinuance of service will occur promptly and automatically for the deposit and accrued interest less the Customer's final outstanding balance. A transfer of service from one premises to another within the service area may not be deemed a discontinuance of service.

(e) At the option of the Company a deposit plus accrued interest may be refunded in whole or in part, at any time earlier than the times prescribed in this Tariff.

(f) Commercial deposits will be returned when, in the Company's judgement, such deposit is no longer required.

13.3 BILLING PERIOD

Rates are stated on a monthly basis and bills are rendered monthly following the supply of service based on meter readings to the nearest one hundred (100) or one thousand (1,000) cubic feet, depending on the applicable Rate Schedule, scheduled at approximate monthly intervals of twenty-eight (28) to thirty-four (34) days.

An initial period of less than ten (10) days is included in the next month's billing. If the period is more than ten (10) days, a bill is rendered at the regular billing date. A final period, consisting of the number of days from the most recent meter reading to turn off, will be billed as one (1) month. The Customer is liable for service taken after notice to terminate their service until the meter is read and gas shut off. The final bill for service is due and payable upon presentation. Credit balances in a final bill that are five dollars ($5) or more will be refunded to the Customer.

13.4 PAYMENT PERIOD

. The rates are contingent upon prompt payment. The final date for payment will not fall on any Saturday, Sunday or holiday, and will be due within twenty (20) days of the bill date. Failure to receive the bill will not excuse the Customer from payment obligations, and payments must be made without regard to any counter claims whatsoever.

RULES AND REGULATIONS

SECTION XIII
(Continued)

13.5 BUDGET PLAN

The Budget Plan is designed for the Customers under Rate Schedules RS-1, ERS-1, RS-2, ERS-2, GS, and EGS, with their account in good standing, and at least twelve (12) months of consumption history. Seasonal heating bills are spread over the Budget Plan period (September through May) with equal monthly payments. The Customer’s higher monthly bills during the winter heating season are distributed over a nine-(9) month period, with any under or over billing for the season appearing on and being due with the June bill.

If a RS-1, ERS-1, RS-2, ERS-2, GS, or EGS Customer elects to use the Budget Plan, the estimated bills for the Budget Plan period will be based upon prior consumption at the particular location for a similar period of time, corrected for current conditions. The estimated total bill for the period is divided by the respective number of months to produce the approximate budget payment, which will then be rounded off to the nearest dollar. Subsequent adjustments to the monthly budget payment amount will be made by the Company to compensate for temperature and/or rate changes during the Budget Plan period, with the Customer receiving immediate notification of their new Budget Plan payment amount.

The Company

To remain on the Budget Plan, a Customer must pay the current budget payment by the due date each month and pay all balances due as they appear on the bill at the end of the Budget Plan period.

The Company will normally require that the Customer begin the Budget pPan in September of each year.

13.6 DISPUTED BILLS

Upon receipt of the Customer's initial complaint prior to due date, the Company will extend to the Customer an additional five (5) days to allow for investigation and review of complaint. During time allotted for investigation and review of the complaint, the Company will not discontinue service or require the Customer to provide a security deposit. The final date when payment is due after settlement of complaint shall be ten (10) days.

Issue Date:
Effective Date:
Authorization:

RULES AND REGULATIONS

SECTION XIII
(Continued)

13.7 UNAUTHORIZED USE

The use of service obtained from the Company without authority may be terminated by the Company without notice. The use of service without notifying the Company and enabling it to read its meter, will render the user liable for any amount due for service supplied to the premises from the time of the last reading of the meter, immediately preceding user's occupancy, as shown by the books of the Company.

13.8 RETURNED PAYMENTS

Payment for services provided under this Tariff, Customer deposits, or other Tariff charges which are returned unpaid by the Customer's bank or other financial institution shall result in an additional twenty dollar ($20) Returned Payment Charge per occurrence and will be charged against the Customer's account. After the second returned payment the Company reserves the right to notify the Customer that an alternate payment method will be required for future payments.

Failure to pay the full amount of the bill including the Returned Payment Charge will result in a discontinuance of the Customer's service. The Company may discontinue service without prior notice if an invalid payment is used to restore service or satisfy a disconnect notice.

13.9 ADJUSTMENTS FOR INCORRECT BILLINGS

Incorrect billings resulting from clerical error or improper service classifications shall be corrected immediately upon discovery and correct billings rendered to the Customer; however, in no case may additional charges due from the Customer be collected for more than three (3) years prior to the month of discovery. In the event a Customer is overcharged, the overbilling will be refunded to the date the error was made, not to exceed five (5) years, such refund shall be paid to the Customer within sixty (60) days after the error is discovered. Installment payments will be arranged equal to the number of months the account was billed in error in the event additional charges are due the Company, and the installment payments are due and payable in addition to the Customer's regular monthly natural gas service bill.

RULES AND REGULATIONS
SECTION XIV - DISCONNECTION BY THE COMPANY

14.1 DISCONNECTION BY THE COMPANY

The Company may discontinue service and remove its property without being liable to the Customer, or to tenants or occupants of the premises served, for any loss, cost, damage or expense occasioned by such refusal, discontinuance or removal, for any of the following reasons:

(a) Customer's failure to comply with any of the provisions of the contract, or any applicable regulations of the Commission, or any of the Company's applicable rules or practices currently in effect.

(b) Customer's non-payment of bill at present or former location. A written notice shall set forth the date service will be discontinued, which shall not be less than five (5) days from the date of mailing of such notice.

(c) Customer's failure to provide a deposit to insure payment of bills, when requested by the Company under the provisions of Section 13.2.

(d) After a reasonable request for access to its meter or meters is refused, or if access thereto is obstructed or hazardous.

(e) The Customer's failure to maintain their equipment in safe condition, in the judgment of the Company.

(f) The Customer's abuse, fraud, or tampering with the connections, meters or other equipment of the Company.

(g) The Customer's equipment or use thereof might injuriously affect the equipment of the Company, or the Company's service to other Customers.

The notice provided for in this Section shall consist of five (5) days' written notice sent by first class prepaid mail deposited in a United States mailbox and addressed to the Customer at the Customer’s last known mailing address appearing on the records of the Company.

The Company may discontinue service without notice for reasons (e), (f), or (g) above; but, except in emergency situations, in no event shall such termination occur between 12:00 noon on any Friday and 12:00 noon on the succeeding Monday. Should Friday be a legal, state or national holiday, the last preceding business day shall be substituted for Friday. Should Monday be a state or national, legal holiday, the next succeeding business day shall be substituted for Monday. Except in cases of safety or in emergency situations, in no event shall termination occur on a day when the temperature is thirty-two (32) degrees Fahrenheit or below at 8:00 a.m.

RULES AND REGULATIONS

SECTION XIV
(Continued)

14.1 DISCONNECTION BY THE COMPANY (Continued)

The Company may discontinue service without prior notice if an invalid check is used to restore service or to satisfy a disconnect notice.

The Company will comply with the Commission rules regarding weather conditions or medical conditions for disconnections. Except in case of emergency situations, in no event shall termination occur for non-payment if any occupant of any dwelling unit shall be so ill that the termination of such sale or service shall adversely affect their health or recovery, which has been so certified by a signed statement from any duly licensed physician, physician assistant or advanced nurse practitioner, of this State or of a state with similar accreditation and received by an authorized agent of the Company. Signed statements from a licensed physician, physician assistant or advanced nurse practitioner, obtained pursuant to this section are effective for one hundred twenty (120) days. Signed statements may be renewed by means of a new signed statement to prevent termination only if a customer makes a good faith effort to make payments towards the utility service being provided..

14.2 SEASONAL RECONNECTION AND RECONNECTION CHARGES

Whenever a residential Customer's gas is turned off or a Customer’s meter is disconnected by the Company at the Customer's request, and the account placed on inactive status, and such account is reactivated by the same Customer no less than thirty (30) days and not more than one hundred eighty (180) days from the date of the disconnect, a Seasonal Reconnection Charge equal to the monthly Customer Charge in the Customer’s applicable Rate Schedule for each month the account was inactive, plus the Reconnection Charge shall be paid. Such payment, along with other satisfactory arrangements for reconnection, shall be made with the Company for reconnection by the end of the next business day. Details of the charges are contained on Sheet No. 46 (Miscellaneous Customer Charges).

Whenever a Customer's gas shall be turned off or such Customer’s meter disconnected by reason of non- compliance with these Rules and Regulations or orders of the Public Service Commission of Delaware, a reconnection charge must be paid and other satisfactory arrangements made with the Company prior to 3:00 p.m. of a normal business day before the gas will be turned on again. Details of the charge are contained on Sheet No. 46 (Miscellaneous Customer Charges).

RULES AND REGULATIONS

SECTION XIV
(Continued)

If the Customer desires that the initial gas service connection or gas service reconnection following disconnection by the Company for any reason, be completed on the same day as the request is received by the Company or outside the Company's normal business hours, such After Hours Reconnection may be performed, subject to the availability of Company personnel. The After Hours Connection or Reconnection Charge must be paid. Details of the charges are contained on Sheet No. 46 (Miscellaneous Customer Charges).

Service interruptions may be avoided by paying the overdue amount prior to the past due date of the gas bill, or by paying the overdue amount plus a collection fee to the Company or an authorized agent of the Company. Details of the charge are contained on Sheet No. 46 (Miscellaneous Customer Charges).

14.3 NON-COMPLIANCE BY COMPANY

Failure on part of the Company to enforce any of its rights at any time shall not be deemed a waiver of any of its rights.

RULES AND REGULATIONS

SECTION XV - TERMINATION OF SERVICE

15.1 TERMINATION BY COMPANY

The Company's obligation to serve a particular premise shall, at the option of the Company cease and terminate (1) in case the property served is vacated or a change of occupancy occurs; (2) in case of an assignment for the benefit of creditors; (3) in case of the illegal use of gas.

15.2 TERMINATION BY CUSTOMER

A Customer who intends to vacate a premises, discontinue the use of Gas, or terminate the liability to pay for gas delivered to the premises, shall give at least five (5) days notice to the Company prior to the date of service termination. The Company shall take its final read of the terminating Customer's meter, within normal business hours, on the date designated by the Customer as the termination date, but shall have no obligation to read the meter before the fifth (5^{th}) day following receipt of the Customer's termination notice. If such notice is not given, the Customer shall be liable for gas registered by the meter until the meter is read by the Company and the account terminated. Receipt of a notice to discontinue gas service from a Customer with a contract term of service shall not relieve such Customer from any minimum or guaranteed payment under such contract.

15.3 FINAL BILL

The Customer is liable for service taken after notice to terminate their service until the meter is read and gas shut off. The final bill for service is due and payable upon presentation. Credit balances on a final bill that are five dollars ($5) or more will be refunded to the Customer.

RULES AND REGULATIONS

SECTION XVI - APPLICATION OF RATES

16.1 DEFINITION OF THE TERM “CUSTOMER”

For the purpose of applying rate schedules in this Tariff, the term “Customer” is defined as any individual, firm, or organization purchasing natural gas delivery service and gas sales service or transportation and balancing service in any one (1) month at one (1) location for one (1) classification of service through one (1) meter. Each individual Customer shall be properly accounted for and identified in the Company’s billing system through the combination of a Customer Account number and a Service Identification and Extension number. The schedule of rates is based on delivering and billing service to the end user for retail service only and does not permit resale or redistribution, unless otherwise specified in the Tariff.

A “month” does not refer to a calendar month, but shall mean the period between any two scheduled consecutive readings of the meters by the Company.

In those cases where, at the Company’s election, two (2) or more meters are installed at a single metering location on the same premises for the same Customer for the same class of service, the amount of gas supplied through all such meters will be combined in arriving at the total charge, and the customer charge will be the same as though one (1) meter was installed.

Where a single commercial, industrial, or institutional Customer occupies more than one (1) unit of space in the conduct of the same business, each separate unit will be metered separately and considered a distinct Customer, unless the Customer makes the necessary provisions to permit metering of all gas used for each class of service in the various units at a single metering location. This rule shall apply only where the units are located on contiguous property with no intervening public property or private property controlled by others. Only one (1) service connection will be provided for each class of service furnished, and the metering location shall be as close as possible to the point of service entrance.

RATE SCHEDULE "RS - 1"

RESIDENTIAL SERVICE - 1

AVAILABILITY

This Rate Schedule is available to any individually metered Customer using gas in a residential dwelling or unit for space heating, cooking, water heating, or other domestic purpose with an annual consumption of two hundred forty (240) Ccf or less. The Company will annually review those Customers receiving service under this Rate Schedule in order to determine the appropriate firm residential Rate Schedule should their annual consumption warrant such a change. A Customer on RS-1 Service will be moved to Rate Schedule with annual consumption equal to or greater than two hundred sixty-four (264) Ccf. This annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between Rate Schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the Customer's location apply to all Customers served under this Rate Schedule.

Customer Charge:	$15.00 per month
First 20 Ccf	$0.852 per Ccf
Next 30 Ccf	$0.525 per Ccf
Over 50 Ccf	$0.415 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, Customers served under this Rate Schedule are subject to the gas cost rate applicable to Rate Schedule "RS-1" provided on Sheet No. 42.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others.

(3) In addition to the above Delivery Service rates, Customers served under this Rate Schedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

REVENUE NORMALIZATION ADJUSTMENT (“RNA”):

The Delivery Service Revenue for Customers under this Rate Schedule is adjusted quarterly via a separate line item on the bill titled “Revenue Normalization Adjustment.” The RNA is calculated to reflect a targeted annual average margin per customer for this Rate Schedule as established in PSC Docket No. 15-____, specifically $278 per Customer. The RNA is determined under the guidelines approved on Sheet No. 42.5.

RATE SCHEDULE "RS - 2"

RESIDENTIAL SERVICE – 2

AVAILABILITY

This Rate Schedule is available to any individually metered Customer using gas in a residential dwelling or unit for space heating, cooking, water heating, or other domestic purpose with annual consumption of greater than two hundred forty (240) Ccf. The Company will annually review those Customers receiving service under this Rate Schedule in order to determine the appropriate firm residential Rate Schedule should their annual consumption warrant such a change. A Customer on RS-1 Service will be moved to this Rate Schedule with annual consumption equal to or greater than two hundred sixty-four (264) Ccf. A Customer on this Rate Schedule will be moved to RS-1 Service with annual consumption less than two hundred sixteen (216) Ccf. This annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between Rate Schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the Customer's location apply to all Customers served under this Rate Schedule.

Customer Charge:	$17.00 per month
First 20 Ccf	$0.656 per Ccf
Next 30 Ccf	$0.397 per Ccf
Over 50 Ccf	$0.210 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, Customers served under this Rate Schedule are subject to the gas cost rate applicable to Rate Schedule "RS-2" provided on Sheet No. 42.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others.

(3) In addition to the above Delivery Service rates, Customers served under this Rate Schedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

REVENUE NORMALIZATION ADJUSTMENT ("RNA"):

The Delivery Service revenue for Customers under this Rate Schedule is adjusted quarterly via a separate line item on the bill titled "Revenue Normalization Adjustment." The RNA is calculated to reflect a targeted annual average margin per customer for this Rate Schedule as established in PSC Docket No. 15-____, specifically $453 per Customer. The RNA is determined under the guidelines approved on Sheet No. 42.5.

Issue Date:
Effective Date:
Authorization:

RATE SCHEDULE "ERS-1"

EXPANSION AREA RESIDENTIAL SERVICE – 1

AVAILABILITY

This Rate Schedule is available to any individually metered Customer within the southeastern Sussex County, Delaware, expansion area using gas in a residential dwelling or unit for space heating, cooking, water heating, or other domestic purpose with an annual consumption of two hundred forty (240) Ccf or less. The southeastern Sussex County, Delaware, expansion area is defined as the area east of Chesapeake's district regulator station located on Route 9 in Lewes, Delaware, that is connected to Chesapeake's distribution main and any area that is connected to Chesapeake's distribution main behind the three (3) Eastern Shore Natural Gas transmission pipeline City Gates located in Dagsboro, Frankford, and Selbyville, Delaware. The Company will annually review those Customers receiving service under this Rate Schedule in order to determine the appropriate firm residential Rate Schedule should their annual consumption warrant such a change. A Customer on ERS-1 Service will be moved to Rate Schedule ERS-2 with annual consumption equal to or greater than two hundred sixty-four (264) Ccf. This annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between Rate Schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the Customer's location apply to all Customers served under this Rate Schedule.

Customer Charge:	$16.50 per month
First 20 Ccf	$0.852 per Ccf
Next 30 Ccf	$0.525 per Ccf
Over 50 Ccf	$0.415 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, Customers served under this Rate Schedule are subject to the gas cost rate applicable to Rate Schedule "ERS" provided on Sheet No. 42.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

RATE SCHEDULE "ERS-1"

EXPANSION AREA RESIDENTIAL SERVICE – 1
(Continued)

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others.

(3) In addition to the above Delivery Service rates, Customers served under this Rate Schedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

REVENUE NORMALIZATION ADJUSTMENT (“RNA”):

The Delivery Service revenue for Customers under this Rate Schedule is adjusted quarterly via a separate line item on the bill titled “Revenue Normalization Adjustment.” The RNA is calculated to reflect a targeted annual average margin per customer for this Rate Schedule as established in PSC Docket No. 15-____, specifically $335 per Customer. The RNA is determined under the guidelines approved on Sheet No. 42.5.

RATE SCHEDULE "ERS-2"

EXPANSION AREA RESIDENTIAL SERVICE – 2

AVAILABILITY

This Rate Schedule is available to any individually metered Customer within the southeastern Sussex County, Delaware, expansion area using gas in a residential dwelling or unit for space heating, cooking, water heating, or other domestic purpose with annual consumption of greater than two hundred forty (240) Ccf. The southeastern Sussex County, Delaware, expansion area is defined as the area east of Chesapeake's district regulator station located on Route 9 in Lewes, Delaware, that is connected to Chesapeake's distribution main and any area that is connected to Chesapeake's distribution main behind the three (3) Eastern Shore Natural Gas transmission pipeline City Gates located in Dagsboro, Frankford, and Selbyville, Delaware. The Company will annually review those Customers receiving service under this Rate Schedule in order to determine the appropriate firm residential Rate Schedule should their annual consumptions warrant such a change. A Customer on ERS-1 Service will be moved to this Rate Schedule with annual consumption equal to or greater than two hundred sixty-four (264) Ccf. A Customer on this Rate Schedule will be moved to ERS-1 Service with annual consumption less than two hundred sixteen (216) Ccf. This annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between Rate Schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the Customer's location apply to all Customers served under this Rate Schedule.

Customer Charge:	$31.75 per month
First 20 Ccf	$0.656 per Ccf
Next 30 Ccf	$0.397 per Ccf
Over 50 Ccf	$0.210 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, Customers served under this Rate Schedule are subject to the gas cost rate applicable to Rate Schedule "ERS" provided on Sheet No. 42.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

RATE SCHEDULE "ERS-2"

EXPANSION AREA `RESIDENTIAL SERVICE – 2
(Continued)

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others.

(3) In addition to the above Delivery Service rates, Customers served under this Rate Schedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

REVENUE NORMALIZATION ADJUSTMENT ("RNA"):

The Delivery Service revenue for Customers under this Rate Schedule is adjusted quarterly via a separate line item on the bill titled "Revenue Normalization Adjustment." The RNA is calculated to reflect a targeted annual average margin per customer for this Rate Schedule as established in PSC Docket No. 15-____, specifically $620 per Customer. The RNA is determined under the guidelines approved on Sheet No. 42.5.

RATE SCHEDULE "GS"
GENERAL SERVICE

AVAILABILITY

This Rate Schedule is available to any Customer using gas for commercial and/or industrial purposes with an annual consumption of less than four thousand (4,000) Ccf. The Company will annually review those Customers receiving service under this Rate Schedule in order to determine the appropriate firm commercial and/or industrial Rate Schedule should their annual consumption warrant such a change. A Customer on General Service will be moved to Rate Schedule MVS with annual consumption equal to or greater than four thousand four hundred (4,400) Ccf. This annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between Rate Schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the Customer's location apply to all Customers served under this Rate Schedule.

Customer Charge:	$34.00 per month
First 20 Ccf	$0.506 per Ccf
Next 30 Ccf	$0.337 per Ccf
Over 50 Ccf	$0.199 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, Customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "GS" provided on Sheet No. 42.

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial Customers on this Rate Schedule who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service Rate applied to all gas consumption.

Firm Balancing Service Rate: **$0.081** per Ccf of gas consumed

RATE SCHEDULE "GS"

GENERAL SERVICE
(Continued)

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of compressed natural gas ("CNG") to third parties.

(3) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service, as authorized under the Company's Tariff, may be required to pay a transition charge in the future to prevent the remaining firm Gas Sales Service Customers from having to absorb stranded fixed gas supply costs which would otherwise be collected from the firm Gas Sales Service Customers switching to Transportation and Balancing Service.

(4) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service or to Interruptible Sales Service, as authorized under the Company's Tariff, will be billed for or receive credit for any under or over collection of gas costs from prior periods.

(5) In addition to the above Delivery Service rates, Customers served under this Rate Schedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

RATE SCHEDULE "GS"

GENERAL SERVICE

(Continued)

REVENUE NORMALIZATION ADJUSTMENT (“RNA”):

The Delivery Service revenue for Customers under this Rate Schedule is adjusted quarterly via a separate line item on the bill titled “Revenue Normalization Adjustment.” The RNA is calculated to reflect a targeted annual average margin per customer for this Rate Schedule as established in PSC Docket No. 15-____, specifically $663 per Customer. The RNA is determined under the guidelines approved on Sheet No. 42.5.

RATE SCHEDULE "EGS"

EXPANSION AREA GENERAL SERVICE

AVAILABILITY

This Rate Schedule is available to any Customer within the southeastern Sussex County, Delaware, expansion area using gas for commercial and/or industrial purposes with an annual consumption of less than four thousand (4,000) Ccf. The southeastern Sussex County, Delaware, expansion area is defined as the area east of Chesapeake's district regulator station located on Route 9 in Lewes, Delaware, that is connected to Chesapeake's distribution main and any area that is connected to Chesapeake's distribution main behind the three (3) Eastern Shore Natural Gas transmission pipeline City Gates located in Dagsboro, Frankford, and Selbyville, Delaware. The Company will annually review those Customers receiving service under this Rate Schedule in order to determine the appropriate firm commercial and/or industrial rate schedule should their annual consumption warrant such a change. A Customer on Rate Schedule EGS will be moved to Rate Schedule EMVS with annual consumption equal to or greater than four thousand four hundred (4,400) Ccf This annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between Rate Schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the Customer's location apply to all Customers served under this Rate Schedule.

Customer Charge:	$56.00 per month
First 20 Ccf	$0.506 per Ccf
Next 30 Ccf	$0.337 per Ccf
Over 50 Ccf	$0.199 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, Customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "EGS" provided on Sheet No. 42.

Issue Date:
Effective Date:
Authorization:

RATE SCHEDULE "EGS"

EXPANSION AREA GENERAL SERVICE
(Continued)

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial Customers on this Rate Schedulee who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate: $0.081 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

RATE SCHEDULE "EGS"

EXPANSION AREA GENERAL SERVICE
(Continued)

SPECIAL TERMS AND CONDITIONS OF SERVICE (Continued)

(3) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service, as authorized under the Company's Tariff, may be required to pay a transition charge in the future to prevent the remaining firm Gas Sales Service Customers from having to absorb stranded fixed gas supply costs which would otherwise be collected from the firm Gas Sales Service Customers switching to Transportation and Balancing Service.

(4) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service or to Interruptible Sales Service, as authorized under the Company's Tariff, will be billed for or receive credit for any under or over collection of gas costs from prior periods.

(5) In addition to the above Delivery Service rates, Customers served under this Rate Schedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

REVENUE NORMALIZATION ADJUSTMENT ("RNA"):

The Delivery Service revenue for Customers under this Rate Schedule is adjusted quarterly via a separate line item on the bill titled "Revenue Normalization Adjustment." The RNA is calculated to reflect a targeted annual average margin per customer for this Rate Schedule as established in PSC Docket No. 15-____, specifically $897 per Customer. The RNA is determined under the guidelines approved on Sheet No. 42.5.

Authorization:

RATE SCHEDULE "MVS"
MEDIUM VOLUME SERVICE

AVAILABILITY

This Rate Schedule is available to any Customer using gas for commercial and/or industrial purposes with an annual consumption generally equal to or greater than four thousand (4,000) Ccf and less than fifteen thousand (15,000) Ccf. The Company will annually review those Customers receiving service under this Rate Schedule in order to determine the appropriate firm commercial and/or industrial Rate Schedule should their annual consumption warrant such a change. A Customer on General Service will be moved to this Rate Schedule with annual consumption equal to or greater than four thousand four hundred (4,400) Ccf. A Customer on this Rate Schedule will be moved to General Service with annual consumption less than three thousand six hundred (3,600) Ccf. The annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between Rate Schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the Customer's location apply to all Customers served under this Rate Schedule.

Customer Charge:	$80.00 per month
First 200 Ccf	$0.237 per Ccf
Over 200 Ccf	$0.125 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, Customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "MVS" provided on Sheet No. 42.

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial Customers on this Rate who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the customer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate: $0.091 per Ccf of gas consumed

Issue Date:
Effective Date:
Authorization:

RATE SCHEDULE “MVS”

MEDIUM VOLUME SERVICE

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

(3) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service, as authorized under the Company’s Tariff, may be required to pay a transition charge in the future to prevent the remaining firm Gas Sales Service Customers from having to absorb stranded fixed gas supply costs which would otherwise be collected from the firm Gas Sales Service Customers switching to Transportation and Balancing Service.

(4) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service or Interruptible Sales Service, as authorized under the Company’s Tariff, will be billed for or receive credit for any under or over collection of gas costs from prior periods.

(5) In addition to the above Delivery Service rates, Customers served under this Rate Schedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

RATE SCHEDULE "EMVS"

EXPANSION AREA MEDIUM VOLUME SERVICE

AVAILABILITY

This Rate Schedule is available to any Customer within the southeastern Sussex County, Delaware, expansion area using gas for commercial and/or industrial purposes with an annual consumption generally equal to or greater than four thousand (4,000) Ccf and less than fifteen thousand (15,000) Ccf. The southeastern Sussex County, Delaware, expansion area is defined as the area east of Chesapeake's district regulator station located on Route 9 in Lewes, Delaware, that is connected to Chesapeake's distribution main and any area that is connected to Chesapeake's distribution main behind the three (3) Eastern Shore Natural Gas transmission pipeline City Gates located in Dagsboro, Frankford, and Selbyville, Delaware. The Company will annually review those Customers receiving service under this Rate Schedule in order to determine the appropriate firm commercial and/or industrial Rate Schedule should their annual consumption warrant such a change. A Customer on Rate Schedule EGS will be moved to this Rate Schedule with annual consumption equal to or greater than four thousand four hundred (4,400) Ccf. A Customer on this Rate Schedule will be moved to Rate Schedule EGS with annual consumption less than three thousand six hundred (3,600) Ccf. The annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between Rate Schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the Customer's location apply to all Customers served under this Rate Schedule.

Customer Charge:	$158.75 per month
First 200 Ccf	$0.237 per Ccf
Over 200 Ccf	$0.125 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, Customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "EMVS" provided on Sheet No. 42.

RATE SCHEDULE "EMVS"

EXPANSION AREA MEDIUM VOLUME SERVICE
(Continued)

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial Customers on this Rate who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate: $0.091 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

RATE SCHEDULE "EMVS"

EXPANSION AREA MEDIUM VOLUME SERVICE
(Continued)

SPECIAL TERMS AND CONDITIONS OF SERVICE (Continued)

(3) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service, as authorized under the Company's Tariff, may be required to pay a transition charge in the future to prevent the remaining firm Gas Sales Service Customers from having to absorb stranded fixed gas supply costs which would otherwise be collected from the firm Gas Sales Service Customers switching to Transportation and Balancing Service.

(4) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service or Interruptible Sales Service, as authorized under the Company's Tariff, will be billed for or receive credit for any under or over collection of gas costs from prior periods.

(5) In addition to the above Delivery Service rates, Customers served under this Rate Schedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

RATE SCHEDULE "LVS"

LARGE VOLUME SERVICE

AVAILABILITY

This Rate Schedule is available to any Customer using gas for commercial and/or industrial purposes with an annual consumption generally equal to or greater than fifteen thousand (15,000) Ccf. The Company will annually review those Customers receiving service under this Rate Schedule in order to determine the appropriate firm commercial and/or industrial Rate Schedule should their annual consumption warrant such a change. A Customer on Medium Volume Service will be moved to this Rate Schedule with annual consumption equal to or greater than sixteen thousand five hundred (16,500) Ccf. A Customer on this Rate Schedule will be moved to Medium Volume Service with annual consumption less than thirteen thousand five hundred (13,500) Ccf. The annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between Rate Schedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the Customer's location apply to all Customers served under this Rate Schedule.

Customer charge:	$175.00 per month
First 1000 Ccf	$0.218 per Ccf
Over 1000 Ccf	$0.088 per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, Customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "LVS" provided on Sheet No. 42.

RATE SCHEDULE "LVS"

LARGE VOLUME SERVICE
(Continued)

TRANSPORTATION AND BALANCING SERVICE

Transportation service is available to commercial and industrial Customers on this Rate Schedule who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service rate applied to all gas consumption.

Firm Balancing Service Rate: $0.073 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

RATE SCHEDULE "LVS"

LARGE VOLUME SERVICE
(Continued)

SPECIAL TERMS AND CONDITIONS OF SERVICE (Continued)

(3) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service, as authorized under the Company's Tariff, may be required to pay a transition charge in the future to prevent the remaining firm Gas Sales Service Customers from having to absorb stranded fixed gas supply costs which would otherwise be collected from the firm Gas Sales Service Customers switching to Transportation and Balancing Service.

(4) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service or to Interruptible Sales Service, as authorized under the Company's Tariff, will be billed for or receive credit for any under or over collection of gas costs from prior periods.

(5) In addition to the above Delivery Service rates, Customers served under this Rate Schedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

RATE SCHEDULE "HLFS"
HIGH LOAD FACTOR SERVICE

AVAILABILITY

This Rate Schedule is available to any Customer using gas for commercial and/or industrial purposes that would otherwise qualify for Medium Volume Service or Large Volume Service and with winter months' consumption, defined as the months of January through March, being less than thirty-five percent (35%) of their annual consumption. In addition, the Customer must use natural gas in at least eleven (11) of the twelve (12) months under review and usage must be fairly evenly distributed throughout the review period. The Company will annually review those Customers receiving service under this Rate Schedule in order to determine the appropriate firm commercial and/or industrial Rate Schedule should their annual consumption or winter months consumption warrant such a change. A Customer will remain on this Rate Schedule as long as winter months' consumption is less than thirty-seven percent (37%) of their annual consumption and the Customer qualifies for Medium Volume Service or Large Volume Service. The annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between Rate Schedules due to changes in annual consumption or winter months' consumption other than after the annual review.

DELIVERY SERVICE RATES

The following rates for delivering gas to the Customer's location apply to all Customers served under this Rate Schedule.

Customer Charge:	$125.00	per month
All gas consumed	$0.080	per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, Customers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "HLFS" provided on Sheet No. 42.

Issue Date:
Effective Date:
Authorization:

RATE SCHEDULE "HLFS"
HIGH LOAD FACTOR SERVICE
(Continued)

TRANSPORTATION AND BALANCING SERVICE

Transportation service is available to commercial and industrial Customers on this Rate who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service rate applied to all gas consumption

Firm Balancing Service Rate: $0.024 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

RATE SCHEDULE "HLFS"

HIGH LOAD FACTOR SERVICE
(Continued)

SPECIAL TERMS AND CONDITIONS OF SERVICE (Continued)

(3) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service, as authorized under the Company's Tariff, may be required to pay a transition charge in the future to prevent the remaining firm Gas Sales Service Customers from having to absorb stranded fixed gas supply costs which would otherwise be collected from the firm Gas Sales Service Customers switching to Transportation and Balancing Service.

(4) A firm Customer that transfers from Gas Sales Service to Transportation and Balancing Service or to Interruptible Sales Service, as authorized under the Company's Tariff, will be billed for or receive credit for any under or over collection of gas costs from prior periods.

(5) In addition to the above Delivery Service rates, Customers served under this Rate Schedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

RATE SCHEDULE "NGV"

NATURAL GAS VEHICLE

SERVICE AVAILABILITY

This Rate Schedule is available to any Customer operating a motor vehicle that is capable of using compressed natural gas ("CNG") as a fuel if the equipment installed on the vehicle meets industry recognized standards and if the operator is authorized by the Company to fuel a motor vehicle with the CNG as the result of completing the Company's training program or a program determined by the Company, in its sole discretion, to be an equivalent training program.

This gas service will be available at Chesapeake Utilities Corporation, 350 South Queen Street, Dover, Delaware 19904. Service hereunder is subject to availability of the Company's gas supply, adequate distribution system capabilities and other resources available to and as determined by the Company.

This gas service is subject to interruption, at the Company's option, at any time during the year without notice and for an indefinite period of time. The Company has no obligation whatsoever to make CNG available to any Customer and may interrupt service at any time without notice.

TERM

Service under this contract will terminate, with ninety (90) days' notice, at the discretion of the Company or the Commission. This notice shall be given by registered letter.

COMMODITY CHARGE (Posted Price)

The price per Ccf of CNG will be posted at the CNG Station on the first (1^{st}) day of each month and will be set at the average price for CNG for the central Atlantic region as published by the U.S. Department of Energy in its most recent Clean Cities Alternative Fuel Price Report or its successor publication, plus any applicable tax imposed by any governmental entity on natural gas sales or CNG sales.

The price charged to any Customer will be reduced from the posted price to the extent the posted price includes a tax or taxes imposed by any governmental entity on natural gas sales or CNG sales and the Customer is exempt from such tax or taxes.

If the Customer is exempt from federal or state taxes imposed with respect to sales of CNG for motor vehicle use, the price charged to the Customer will be reduced from the posted price by the tax or taxes on CNG from which the Customer is exempt.

In no event will CNG be sold if the price as determined above is below the price level established for Company-Use Gas.

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RATE SCHEDULE "GLR"

GAS LIGHTING SERVICE

AVAILABILITY

This Rate Schedule is available for unmetered residential outdoor gas lights as herein specified where the Company's existing distribution mains and services are suitable to supply such service.

DELIVERY SERVICE RATE

The following rate for delivering gas to the Customer’s location applies to all Customers served under this Rate Schedule.

Each 2 cu. ft./hr. or less $16.72 per month.

GAS SALES SERVICE

In addition to the above Delivery Service rates, Customers served under this Rate Schedule are subject to the gas cost rate applicable to Rate Schedule “GLR” provided on Sheet No. 42.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) The Customer shall install and own the lighting devices.

(3) In addition to the above Delivery Service rates, Customers served under this Rate Schedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

RATE SCHEDULE "GLO"

GAS LIGHTING SERVICE

AVAILABILITY

This Rate Schedule is available for unmetered outdoor gas lights for other than residential use as herein specified where the Company's existing distribution mains and services are suitable to supply such service.

DELIVERY SERVICE RATE

The following rate for delivering gas to the Customer's location applies to all Customers served under this Rate Schedule.

Each 2 cu. ft./hr. or less $16.72 per month.

GAS SALES SERVICE

In addition to the above Delivery Service rates, Customers served under this Rate Schedule are subject to the gas cost rate applicable to Rate Schedule "GLO" provided on Sheet No. 42.

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20 days of their date.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) The Customer shall install and own the lighting devices.

(3) In addition to the above Delivery Service rates, Customers served under this Rate Schedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

RATE SCHEDULE "NCR"

NEGOTIATED CONTRACT RATE

AVAILABILITY

This negotiated contract Tariff provision enables the Company to respond to Customers' competitive options in the energy services market. The Company shall use this negotiated contract Tariff to compete with alternate pricing situations resulting from, but not limited to, fuel switching, facility relocation or expansion, partial or complete plant production shifting, potential physical bypass, or other options available to the Customer. The Company shall use the provisions of this Tariff only after a determination by the Company and the Customer that other existing Tariff options will not meet the Customer's needs.

ELIGIBILITY

This contract Tariff is available to any qualifying Customer as specified herein. Customer qualification shall be based upon meeting each of the following criteria as determined solely by the Company:

(1) The Customer has an economic competitive alternative to full or partial service from the Company's standard Tariff rates, as determined by the Company;

(2) The Customer is likely to select said alternative if the Company does not provide a negotiated contract rate; and

(3) The price to the Customer will provide net revenues above the incremental costs to provide service under this negotiated contract rate; and

(4) The Customer desires fixed pricing for a term of one (1) year or more which requires a gas supply tailored to the specified term and pricing conditions.

The Company shall determine eligibility on a case-by-case basis based upon information supplied by the Customer and in accordance with the Company's internal pricing guidelines. The Company's decision on the application shall consider the economics of the competitive alternative, as well as the practical aspects of securing that alternative (e.g., ability to secure environmental permitting, feasibility studies, switching ability, ability to secure required capital).

RATE SCHEDULE "NCR"

NEGOTIATED CONTRACT RATE
(Continued)

SERVICE OPTIONS

If the Company concludes that the Customer meets all the eligibility requirements listed above, the Company shall enter into negotiations with the Customer for the purpose of offering such services as are believed to meet the Customer's requirements. Competitive offers may be made in a manner which provides the Customer with numerous choices for service. A menu of service options differentiated by contract term, quantity, pricing options, and service attributes may be made available to the qualifying Customer.

RATE

Pricing for delivery service only, a combination of delivery service and gas supply, and balancing service shall be determined on a case-by-case basis according to the nature of the competitive situation. The final arrangements between the Company and the Customer shall be included in the contract.

PUBLIC UTILITES TAX

All rates and charges under this Rate Schedule, including gas cost if applicable, are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

CONTRACT TERM

The contract term shall be specified in a contract between the Customer and the Company. The minimum term of any contract will be one (1) year and the maximum term will be five (5) years.

SPECIAL TERMS AND PROVISIONS

(1) Upon agreement on service options, the Customer and the Company shall enter into a contract which specifies the services and the terms and conditions of providing the services. The Customer must sign the contract prior to commencement of this service and any investment by the Company. Service under the contractual agreement will commence on the date specified in the contract.

RATE SCHEDULE "NCR"

NEGOTIATED CONTRACT RATE
(Continued)

SPECIAL TERMS AND PROVISIONS (Continued)

(2) The contract shall be considered a confidential document between the Company and the Customer. By signing the contract, the Customer and the Company agree not to share the contract or information contained within the contract with anyone except the parties to the contract, the Public Service Commission of Delaware and the Office of the Public Advocate, unless given written consent from the other party. Violations by the Customer of the confidentiality agreement shall permit the Company to immediately terminate the contract with the Customer and serve the Customer under another rate schedule for which the Customer qualifies. The Customer shall also be responsible for the penalty provision described below and additional damages or prejudices to any other existing or potential contracts resulting from the breach of confidentiality.

(3) The contract between the Company and the Customer shall include penalty provisions for early contract cancellation. If at any time prior to the end of the contract term the Customer elects to terminate the contractual agreement with the Company without exercising a re-contracting option for continuing service, the Customer shall be obligated to the terms for cancellation as specified within the contract.

(4) The Company may offer value-added services in conjunction with the contract. All service attributes agreed to between the Company and the Customer shall be included in the contract.

(5) The Company shall file all required information with the Public Service Commission of Delaware within thirty (30) days of the executed Contract.

RATE SCHEDULE "ITS"

INTERRUPTIBLE TRANSPORTATION SERVICE

AVAILABILITY

This Rate Schedule is available to any non-residential Customer with annual consumption of at least one hundred thousand (100,000) Ccf with facilities in operating condition capable of utilizing an alternative fuel due to the fact gas service provided is subject to complete interruption at any time during the year at the Company's option. The definition of an alternative fuel under this rate schedule shall be propane, fuel oil, or electricity. When applying for service under this Rate Schedule, the Customer is required to provide the Company, in writing, with the type and specific grade of alternative fuel utilized by the Customer. The Customer shall submit, within thirty (30) days of any change in operations, written notification when such change affects its alternate fuel capability. The Customer must also purchase all of its gas from or through a qualified supplier of natural gas as set forth in Rate Schedule SUP.

DELIVERY SERVICE RATE

Customer charge:	$935.00	per month

The rate per Ccf of consumption shall be determined on an individual Customer basis according to the nature of the interruptible service to be provided. This rate can be adjusted upon one (1) day's notice to the Customer.

TRANSPORTATION AND BALANCING SERVICE

Customers must have the natural gas delivered to the Company's city gate in accordance with the Transportation and Balancing Rider General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rate, the Customer is subject to the following Interruptible Balancing Service rate applied to all gas consumption.

Interruptible Balancing Service Rate:	$0.014	per Ccf of gas consumed

RATE SCHEDULE "ITS"

INTERRUPTIBLE TRANSPORTATION SERVICE
(Continued)

PUBLIC UTILITIES TAX

The Delivery Service, Interruptible Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

MINIMUM BILL

The minimum monthly bill under this Rate Schedule is the Customer charge.

CONTRACT TERMS

The contract term shall be specified in a contract between the Customer and the Company. The minimum term of any contract will be one (1) year.

SERVICE INTERRUPTION

The Company will endeavor to provide as much notice as possible to Customers prior to any interruption or curtailment of gas delivery service. Customer agrees to accept complete interruption of service upon at least four (4) hours advance notice from any hour of the day. If the Customer fails to interrupt service, the Customer shall pay a Penalty Rate of five dollars ($5) per Ccf in addition to the currently effective rate. The Penalty Rate, which shall be credited to firm Customers through the GSR mechanism, shall remain in effect until such time as the Company, in its sole discretion, determines that normal service can be restored. The Customer agrees to hold the Company harmless from any loss, cost or damage occasioned by the interruption of service resulting from the Company's enforcement of this provision. In the event the Customer has an emergency that would cause the Customer great hardship if gas service is interrupted, the Company may, at its sole discretion based on available gas supply, waive interruption for a specified period of time. If the Customer fails to interrupt by the end of the specified period, the Customer shall pay the penalty shown above.

RATE SCHEDULE "ITS"

INTERRUPTIBLE TRANSPORTATION SERVICE
(Continued)

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Service purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others.

(3) Service hereunder will be interrupted at the sole discretion of the Company.

(4) Service hereunder will not be supplied from the Company's peaking facilities unless the Company waives the interruption of service due to an emergency.

(5) In addition to the above Delivery Service rates, Customers served under this Rate Schedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

RATE SCHEDULE "IBE"

INTERRUPTIBLE BEST EFFORTS SALES SERVICE

AVAILABILITY

This Rate Schedule is available to any commercial or industrial transportation Customer or Supplier for use as an interruptible gas supply for deliveries to or upstream of the distribution system or to any entity for off-system deliveries to replace third-party gas for any reason or to serve incremental loads. This service is available only on a best efforts basis subject to the ability of the Company to obtain gas supply and subject to interruption for any reason determined by the Company. Service under this Rate Schedule must be scheduled no later than 7:00 a.m. of the day before service is to begin. Transportation Customers that have a third-party supply interrupted will be subject to any applicable penalties that accrue before this service is scheduled.

DELIVERY SERVICE RATE

The rate for delivering gas to the Customer's location through the Company's distribution system will be at the Delivery Service rate set forth in the Rate Schedule under which the Customer normally receives service.

GAS SERVICE RATE

The gas rate for natural gas service shall be a negotiated, market-based rate. Any margins received under this rate shall be credited eighty percent (80%) to the firm customers through the GSR mechanism with twenty percent (20%) being retained by the Company.

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty (20) days of their date.

CONTRACT TERMS

The contract term shall be specified in a contract between the Customer and the Company. The minimum term of any contract is one (1) day.

RATE SCHEDULE "IBE"

INTERRUPTIBLE BEST EFFORTS SALES SERVICE
(Continued)

SERVICE INTERRUPTION

The Customer agrees to accept complete interruption of service upon at least four (4) hour advance notice from any hour of the day. If the customer fails to interrupt service, the Customer shall pay a Penalty Rate of five dollars ($5) per Ccf in addition to the currently effective rates. The Penalty Rate, which shall be credited to firm Customers through the GSR mechanism, shall remain in effect until such time as the Company, in its sole discretion, determines that normal service can be restored. The Customer agrees to hold the Company harmless from any loss, cost or damage occasioned by the interruption of service resulting from the Company's enforcement of this provision. In the event the Customer has an emergency that would cause the Customer great hardship if gas service is interrupted, the Company may, at its sole discretion based on available gas supply, waive interruption for a specified period of time. If the Customer fails to interrupt by the end of the specified period, the Customer shall pay the penalty shown above.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this Rate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Service purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others.

(3) Service hereunder will be interrupted at the sole discretion of the Company.

(4) Service hereunder will not be supplied from the Company's peaking facilities unless the Company waives the interruption of service due to an emergency.

RATE SCHEDULE "GSR"

GAS SALES SERVICE RATES

FIRM SALES RATE SCHEDULES

The Gas Sales Service Rates applicable to the respective firm Rate Schedules, as listed below, will be applied to all Customers served on that schedule based on a volumetric charge per Ccf (100 cubic feet). The Gas Sales Service Rates only apply to the respective firm Rate Schedules listed below and do not apply to the Interruptible Transportation Service, Transportation Service, Negotiated Contract Rate, and Interruptible Best Efforts Sales Service. The Gas Sales Service Rates will be calculated to the nearest tenth of a cent (.1¢).

The following lists the applicable Gas Sales Service Rates for the respective firm Rate Schedules as defined in this Tariff:

RATE SCHEDULE	GAS SALES SERVICE RATES
RS, ERS, GS, EGS, MVS, EMVS LVS	$0.681 per Ccf
HLFS	$0.488 per Ccf
GLR and GLO	$0.218 per Ccf

These rates are subject to change based on actual and estimated gas costs. The The Company will file with the Commission a copy of these Gas Sales Service Rates at least sixty (60) days prior to the regularly scheduled adjustment date, which shall be each November 1.

The November 1 rates will be based on a projected twelve (12) month period of November through October (projected period). The rates computed under this Rate Schedule shall remain in effect for the projected period provided the latest estimated over collection does not exceed 4½% or the latest estimated under collection does not exceed 6% of the actual firm gas costs incurred to date along with the Company’s latest firm gas cost estimates for the remainder of the over/under collection period (over/under period). The twelve (12) month period used for the calculation of the over/under period will be based on the actual nine (9) months ended July 31 of each year and the projected three (3) months ended October 31 of each year. If it appears that the use of these rates for the twelve (12) month over/under period will result in an over or under collection exceeding these limits, the Company shall apply to the Commission for revised rates to be effective until the next annual adjustment in the rates.

RATE SCHEDULE "GSR"
GAS SALES SERVICE RATES
(Continued)

OVERALL METHODOLOGY

The overall projected firm gas costs for the twelve (12) month projected period shall include:

(1) Natural gas purchased from any Supplier; plus

(2) Liquefied petroleum gas (LPG); plus

(3) Liquefied natural gas (LNG); plus

(4) Other hydrocarbons distributed to Customers or used as feedstock for production of substitute natural gas (SNG); plus

(5) Storage, transportation, and any other gas related costs, including costs related to the gas supply department; plus

(6) Charges paid to the Company's Suppliers for past periods unless disallowed by the Public Service Commission of Delaware; less

(7) The projected commodity gas costs for Interruptible Service; less

(8) The demand and commodity gas costs for Negotiated Contract Rate Customers who are not charged the gas sales service rate associated with a firm Rate Schedule; less

(9) The commodity gas costs for Interruptible Best Efforts Sales Service; less

(10) All demand and commodity Supplier refunds received from the Company's Suppliers; less

(11) The firm sales Customers receipt of one hundred percent (100%) of the firm and interruptible transportation balancing service margins which will be a demand related gas cost; less or plus

(12) The over or under collection for the prior over/under period of the actual nine (9) months ended July 31 and the projected three (3) months ended October 31. Interest will be calculated on the actual monthly over or under collection balances net of deferred income taxes at the rate of one-twelfth (1/12th) the annual refund interest rate issued by the Federal Energy Regulatory Commission on a quarterly basis; less or plus

(13) Any other applicable gas cost adjustments

RATE SCHEDULE "GSR"

GAS SALES SERVICE RATES
(Continued)

OVERALL METHODOLOGY (Continued)

A Demand Rate will be determined by dividing the total firm fixed cost components by the firm peak day capacity requirements. A Commodity Rate will be determined by dividing the total firm commodity cost components by total firm consumption for the respective determination period.

ALLOCATION TO RESPECTIVE FIRM RATE SCHEDULES

Rate Schedule HLFS – High Load Factor Service will be charged a single gas cost rate per Ccf based on the combination of a weighted average Demand and Commodity Rate developed on an overall seventy-one and fifty-seven one hundredths percent (71.57%) load factor for the customer class with the overall system weighted average gas cost rate. The purchased gas costs will be allocated to this Rate Schedule based on its annual consumption for the projected period.

Rate Schedule GLO, GLR – The Gas Lighting Services will be charged the weighted average Demand and Commodity Rates through a single gas cost rate per Ccf based on a one hundred percent (100%) load factor. The purchased gas costs will be allocated to this Rate Schedule based on its annual consumption for the projected period.

Rate Schedule RS-1, ERS-1, RS-2, ERS-2, GS, EGS, MVS, EMVS, LVS – These rate schedules will be assigned the remaining firm purchased gas costs after the firm purchased gas costs have been allocated to the above mentioned Rate Schedules less the portion of any shared margins resulting from capacity release, or off-system sales. These Rate Schedules will be charged a single gas cost rate per Ccf. This rate will reflect the sum of the projected demand and commodity costs for these classes divided by the sum of their annual consumption for the projected period.

MARGIN SHARING

Margins as used herein for off system sales means revenues less: (a) associated gas costs and (b) any applicable taxes based on gross receipts. Margins as used herein for capacity release means revenues less any applicable taxes based on gross receipts. As used in this Tariff, the term "Shared Margins" means off system sales margins, and upstream capacity release margins.

RATE SCHEDULE “GSR”

GAS SALES SERVICE RATES
(Continued)

MARGIN SHARING (Continued)

During the over/under period, the Company shall retain twenty percent (20%) and the firm customers, as described above, will receive eighty percent (80%) of all Shared Margins resulting from off-system sales. Additionally, during the over/under period, the Company shall retain ten percent (10%) and the firm customers, as described above, will receive ninety percent (90%) of all Shared Margins resulting from upstream capacity release transactions.

UNACCOUNTED FOR GAS INCENTIVE MECHANISM

The Unaccounted For Gas Incentive Mechanism was originally approved by the Commission on an experimental basis for the following three (3) consecutive twelve (12) month ending periods: August 31, 1993, 1994 and 1995. The Commission reviewed the Incentive Mechanism and determined it should be continued beyond the initial three (3) year period by Order No. 4189 in PSC Docket No. 95-206F.

DEFINITIONS

The terms utilized in the Unaccounted For Gas Incentive Mechanism shall have the following meanings:

1. Unaccounted For Gas shall be defined as the difference between total gas sales, billed and unbilled, and total gas send-out, exclusive of Company-use gas and pressure compensated gas volumes.

2. The Unaccounted For Gas Target (UFG-T) shall be three and two tenths percent (3.20%) of total gas sendout or total gas requirements.

3. The Dead Band shall mean +/- one-half percent (0.5%) around the three and two tenths percent (3.20%) UFG-T. Unaccounted For Gas volumes which are within two and seven tenths percent (2.70%) to three and seven tenths percent (3.70%) of total gas sendout will be considered to be within the "dead band". Unaccounted For Gas volumes within the dead band will be regarded as meeting the objectives of this mechanism.

RATE SCHEDULE "GSR"

GAS SALES SERVICE RATES
(Continued)

PROCESS

The Company, as part of its annual Gas Sales Service Rate filing in September, will provide the actual Unaccounted For Gas volumes and total gas sendout for the preceding twelve (12) month period, ended July 31, in order that the Unaccounted For Gas can be expressed as a percentage of total gas sendout. This percentage will be compared to the target percentage of three and two tenths percent (3.20%) with a range of plus or minus one-half percent (+/-0.5%) by the Public Service Commission of Delaware Staff. The Staff will review the actual Unaccounted For Gas volumes on an annual basis and review the Delaware Division's performance under this mechanism in the next base rate proceeding.

RATE SCHEDULE "RNA"

REVENUE NORMALIZATION ADJUSTMENT

FIRM SALES RATE SCHEDULES

The Revenue Normalization Adjustment (RNA) will be applicable to Customers on Rate Schedules RS-1, ERS-1, RS-2, ERS-2, GS, and EGS.

OVERALL METHODOLOGY

Delivery Service revenues for Customers under the Rate Schedules described above are adjusted quarterly via a separate line item on the bill titled "Revenue Normalization Adjustment." The RNA is calculated to reflect a targeted annual average margin per Customer for each Rate Schedule as established in PSC Docket No. ______. The RNA is determined from the following series of calculations:

(1) Actual Margin per Customer for month and Rate Schedule **-** Targeted Normalized Margin per Customer for month and Rate Schedule **=** the Difference per Customer for month and Rate Schedule;

(2) Difference per Customer for month and Rate Schedule **x** the Customer count for month and Rate Schedule **=** the Over or Under Collection for month and Rate Schedule;

(3) Total Over or Under Collection for quarter **=** Sum of the Over or Under Collection for all Rate Schedules subject to the RNA for three months of the quarter;

(4) Current Quarter RNA Adjustment **=** Over or Under Collection for the quarter ÷ Projected Sales Volume over the next twelve (12) months for all Rate Schedules subject to the RNA;

(5) Total RNA Adjustment **=** the Current Quarter RNA Adjustment **+** the previous three (3) Quarter RNA Adjustments **+** the Annual True-Up.

(6) Annual True-Up = difference between the Projected RNA Collection and Actual RNA Collection for the previous twelve (12) months ÷ by the Projected Sales Volume over the previous twelve (12) moths for all Rate Schedules subject to the RNA.

TRANSPORTATION AND BALANCING RIDER
GENERAL TERMS AND CONDITIONS

1 GENERAL

1.1 Transportation service is available to commercial and industrial Customers having consumption equal to, or greater than, 30,000 CCF per year. For purposes of meeting the 30,000 CCF threshold, a Customer may aggregate consumption from accounts it holds for meters located on contiguous properties; or in the case of poultry houses, the properties need not be contiguous but must be set up under a common name for billing purposes to qualify for aggregation to meet the threshold. This service provides the Customer with the ability to purchase their own Gas supply (Customer-owned Gas) and transport, or have transported, such Gas to the Company's distribution system. Transportation service consists of the following components with associated charges: (a) the transportation of the Customer-owned Gas through pipeline systems upstream of the Company, including the interstate pipeline system of Eastern Shore Natural Gas Company (ESNG), (b) the transportation of the Customer-owned Gas through the Company's distribution system to the Company's installed meter, (c) balancing the difference between the Volume of Gas provided by the Customer and the Volume of Gas actually consumed by the Customer on a daily basis, and (d) the resolution of imbalances created by the difference between the Volume of Gas the Customer provided and the Volume of Gas the Customer consumed which may exist at the end of a billing Month. Customers utilizing transportation service will be billed for delivery service, balancing service, Capacity, a one-time transition charge (or credit) for under (or over) collection of gas costs from prior periods, and other charges applicable for the rate schedule under which they are served.

1.2 Once approved for transportation service it is necessary for the Customer to execute a firm contract(s) with a Qualified Supplier of Natural Gas and other entities, if necessary, to ensure the firm transportation of such Gas to the Point(s) of Receipt. The Customer is required to notify the Company of the name of its Qualified Supplier prior to the fifteenth (15th) calendar day of the Month preceding the Month for which transportation will commence.

2 DEFINITIONS

Agent: An entity authorized to act on behalf of the Customer, more specifically defined in Section 10 of this Transportation and Balancing Rider.

British Thermal Unit: The amount of heat required to raise the temperature of one (1) pound of water one (1) degree Fahrenheit at 60 degrees Fahrenheit.

Broker: An entity or individual that acts as an intermediary in the sale and purchase of Gas but does not take title to Gas. A Broker can be an Agent.

Capacity: The physical space, in dekatherms (DTs), provided by a pipeline for a fixed monthly reservation charge which gives a shipper the right to transport up to a maximum daily Quantity of Gas between defined points on the pipeline's system.

CCF: One hundred (100) cubic feet of Gas.
CCT: Central Clock Time, which includes the recognition of Daylight Savings Time.

Customer: For the purposes of this Transportation and Balancing Rider, Customer shall mean an individual Customer as defined in the Section 16.1 of the Rules and Regulations of this tariff or the aggregation of Customer accounts of one or more contiguous meters in a specific geographic location for the purpose of transporting their own Gas through the Company's distribution system.

Customer-owned Gas: Gas to which the Customer has title clear of any liens and encumbrances.

Daily Contract Quantity (DCQ): The monthly Quantity of Gas scheduled by the Customer to be delivered to the Company's distribution system each Day of the Month, which has been adjusted to account for the Shrinkage Factor.

Flowing Gas: Gas flowing through a pipeline or distribution system excluding Gas taken out of storage.

Gas or Natural Gas: Processed or unprocessed natural gas, vaporized liquid natural gas, synthetic gas, gas from coal seams or any mixture of these gases.

Gas Day or Day: A period of twenty-four (24) consecutive hours, beginning at nine o'clock (9:00) a.m. Central Clock Time (CCT).

Imbalance: Any difference between the Volume of Gas provided by the Customer and the Volume of Gas consumed by the Customer. Nominations are adjusted for thermal content and shrinkage to determine the Volume of Gas provided by the Customer.

Marketer: An entity that purchases and takes title to Gas as an intermediary for sale to a Customer. A Marketer can be an Agent.

MCF: One thousand (1,000) cubic feet of gas.

Month: The period beginning at nine o'clock (9:00) a.m. CCT or the hour otherwise agreed upon by the Customer and the Company on the first Day of the calendar month and ending at the same hour on the first Day of the next succeeding calendar month.

Nomination: The Quantity of Gas, adjusted by the Shrinkage Factor, that the Customer is delivering, or having delivered on its behalf, to a Point(s) of Receipt in the electronic format as provided by the Company.

Point(s) of Delivery: The point(s) at the connection at which the Gas leaves the facilities of the Company and enters the downstream facilities of the Customer.

Point(s) of Receipt: The point(s) at the connection at which the Gas enters the facilities of the Company and leaves the facilities of ESNG.

Qualified Supplier: An entity that has met all qualification requirements as stated in Rate Schedule "SUP", and is deemed capable of holding title to the Gas, and causing it to be delivered to the upstream pipeline interconnect on behalf of the customer.

Quantity of Gas: The Volume of Gas adjusted by the Thermal Factor and expressed in dekatherms, unless otherwise specified.

Replacement Shipper: An entity that takes title to Capacity upstream of the Company's distribution system under the terms of the interstate pipeline's tariff.

Shrinkage Factor: A percentage applied to a Nomination to adjust for Gas lost and unaccounted-for within the Company's distribution system. The Shrinkage Factor shall be determined annually and will be the five-year average.

Summer Peaking Customer: A Customer whose lowest DCQ from November to March does not exceed ten percent (10%) of its highest DCQ for the Year.

Thermal Factor: The amount of British Thermal Units in one MCF of Natural Gas divided by one million. The thermal factor for converting between DT and MCF shall be 1.035 unless otherwise specified by the Company.

Volume of Gas: The number of units of Gas expressed in cubic feet, unless otherwise specified.

Year: A period of three hundred sixty-five (365) consecutive Days; provided, however, that any such Year which contains a date of February 29th shall consist of three hundred sixty-six
(366) consecutive Days.

3 REQUEST FOR TRANSPORTATION SERVICE

Each prospective transportation Customer, or existing transportation Customer seeking enrollment of a new meter, must submit a completed application on the standard form provided by the Company no later than the first (1^{st}) calendar day of the Month preceding the Month in which the transportation service will commence. Service will be provided by the Company based upon the established criteria referenced within the Customer's applicable rate schedule, available capacity and the Customer providing suitable Gas to the Point(s) of Receipt.

4 CONTRACT FOR SERVICE

A Service Agreement with an initial term of one Year must be executed by each Applicant as a condition of receiving transportation service. The Service Agreement shall specify the date on which service is to begin, Point(s) of Receipt and Point(s) of Delivery, the rate schedule(s) under which service is to be provided and other conditions of receipt by the Company and delivery to the Customer. Transportation of Gas will not begin until a fully executed Service Agreement is completed. Service Agreements must be renewed annually, and received by the Company no later than the fifteenth (15^{th}) calendar day of the Month preceding the Month of renewal in order for the customer to continue participating in the transportation program without an interruption of service. The Company may waive the annual renewal requirement at its discretion.

5 GAS TO BE TRANSPORTED BY THE COMPANY

The Customer is responsible for making all arrangements necessary for transporting the Gas to a Point(s) of Receipt in compliance with pressure requirements established by the Company or any upstream pipeline for such Point(s) of Receipt. Gas received for one Customer will be commingled with the Gas of other customers and suppliers. Gas transported by the Company shall be and remain the property of the Customer.

6 QUALITY OF GAS

Gas received by the Company for the account of the Customer shall be Natural Gas conforming to the quality specifications as provided for in the General Terms and Conditions of the tariff of the pipeline that is interconnected to the Company's distribution system. Any Gas entering the Company's system at a Point(s) of Receipt that is not an interconnection with an interstate pipeline must also meet the "pipeline quality" standard set forth above.

7 TITLE TO GAS

The Customer must have good title to all the Gas that enters the Company's distribution system for transportation to a Point(s) of Delivery. Such title shall be free and clear of all liens, encumbrances, and claims whatsoever. The Customer agrees to indemnify and hold the Company harmless against any loss or cost incurred by the Company on account of liens, encumbrances or claims resulting from any possession or transportation by the Company.

8 LIABILITY

The Company shall not be liable for any loss to the Customer arising from or out of transportation service under any rate schedule, including loss of gas in the possession of the Company. The Company makes no guarantee against and assumes no liability for interruptions of service.

9 METERING AND ASSOCIATED EQUIPMENT

Transportation service of Customer-owned Gas to the Point(s) of Delivery is not expected to require any special metering or communication equipment in excess of what would be needed to provide regular delivery and standard Gas sales service. However, there may be situations which will require knowledge of daily usage by transportation Customers that will require additional equipment. If any additional metering or communication equipment is required to provide transportation service, the Customer will reimburse the Company for such equipment and its installation. The Customer shall provide any electrical supply or phone line needed for the operation of any additional equipment. As referenced in Section 11.2 of the Rules and Regulations of this Tariff, remote reading will be utilized for customers with consumption greater than 100,000 annual CCF.

10 AGENTS ACTING ON BEHALF OF THE CUSTOMER

A Customer may use the services of an Agent to act on its behalf for the delivery of Gas to the Company's distribution system. An Agent can be a Broker, Marketer or a Qualified Supplier. All Customers are required to have a Qualified Supplier on record. If a Customer engages the use of an Agent, it is the responsibility of the Customer to notify the Company, using the standard form provided by the Company, of their designation of such Agent to conduct business on their behalf. A Customer may choose to designate an Agent in addition to their Qualified Supplier. Any notices provided to a Customer's Agent shall be deemed to have been provided to the Customer and the Company shall be held harmless from any actions taken by the Agent.

11 COMPANY AS AGENT

The Company may act as Agent for a Customer in securing and transporting Gas supply to a Point(s) of Receipt. The Company shall not be responsible for charges incurred on behalf of the Customer, nor for the performance, non-performance or continued availability of any pipeline or other services. The charges for this service shall be determined by negotiation between the Company and the Customer.

12 DETERMINATION OF DAILY CONTRACT QUANTITY

12.1 A Daily Contract Quantity (DCQ) for each Month for the following twelve (12) month period shall be calculated annually by the Company based on usage during the previous three Years, if available. Previous usage shall be adjusted for normal weather in a matter determined by the Company. The Customer will be obligated to have the DCQ delivered each Day of the Month to the agreed upon Point(s) of Receipt.

12.2 The Company may approve adjustments to the Monthly DCQs on an ongoing basis due to changes in a Customer's Gas equipment, pattern of usage, or any other information affecting demand that is deemed reliable by the Company. To be considered, such information must be provided to the Company in writing from the Customer or the Customer's Agent.

12.3 The Company considers DCQ information to be confidential and proprietary data for the Customer. The Company will only provide usage data to the Customer or the Customer's Agent. If a Customer wishes to authorize a third party to have access to such data the Company must receive a written letter of authorization, on the Customer's official letterhead, and signed by the authority referenced as a contact under the Customer's account information.

12.4 The Company will not provide DCQ information to multiple third parties simultaneously. If multiple parties are requesting DCQ information for the same Customer, the Company will provide that data directly to the Customer or to one Agent for such Customer.

13 NOMINATIONS AND SCHEDULING

13.1 A Customer's DCQ will be considered their daily Nomination. The Company shall require from either the Customer or the Customer's Agent on record a signed DCQ Nomination form. The Nomination form must be received by the Company via mail, electronic mail, or facsimile transmission no later than the fifteenth (15^{th}) calendar day of the Month prior to the first Day of the Month in which transportation service begins, and annually on that date thereafter. If the nomination cannot be confirmed with the delivering pipeline(s) or other source(s), the nomination will be rejected.

13.2 Upon receipt of a completed and properly executed DCQ Nomination form by the Company, the Company will release upstream ESNG transportation Capacity to the Customer, or the Customer's Agent on record, to facilitate the transportation of Gas to the Point(s) of Receipt.

a. The Customer, or Customer's Agent on record, as the recipient of released Capacity becomes the Replacement Shipper with respect to ESNG.
b. For all Customers other than Summer Peaking Customers, the amount of ESNG Capacity to be released will be equal to the highest DCQ within the twelve (12) Months of DCQs calculated.
c. For Summer Peaking Customers, the amount of ESNG Capacity to be released will be equal to the monthly calculated DCQ.
d. ESNG will invoice the Replacement Shipper for all pipeline Capacity and commodity charges associated with the released Capacity.

13.3 Upon the release of Capacity, the Customer, or their Agent on record, shall be responsible for scheduling their DCQ Nomination Quantity on ESNG for the ultimate delivery to the designated Point(s) of Receipt.

13.4 Any variance between the Nomination Quantity and the approved DCQ will be subject to a balancing penalty of $30.00 per DT. Such penalty shall be paid by the Customer in addition to the cost of Gas supply used to serve the customer.

13.5 In the event that changes to existing DCQ's, as referenced in section 12.2, are approved, the Customer is required to resubmit their DCQ nomination sheet by the deadline stated in section 13.1.

14 FIRM BALANCING SERVICE

14.1 Balancing the difference between the Customer's nominated DCQ and the Volume of Gas consumed by the Customer is performed daily by the Company on a firm basis. The Company will charge a Firm Balancing Service Rate pursuant to the applicable rate schedule under which service is provided.

14.2 Any Imbalance for a billing month will be reconciled (*i.e.*, "cashed-in" or "cashed-out") at the Company's weighted average cost at the city gate for Flowing Gas for the calendar month in which most of the billing month occurs. Estimated costs will be used based on nominations made by the Company when the applicable calendar month is not completed before billing the Customer.

14.3 For the purposes of Company invoicing, nominated Quantities of Gas shall be converted to CCF using the Thermal Factor and reduced by the Shrinkage Factor to determine the volume actually delivered to the Point(s) of Delivery.

15 INTERRUPTIBLE BALANCING SERVICE

15.1 Balancing between the Customer's DCQ and the Volume of Gas consumed by the Customer is performed daily by the Company on an interruptible basis. Imbalances between the Volume of Gas provided by the Customer and the Volume of Gas consumed by the Customer for a billing Month will be cashed-in or cashed-out at the Company's weighted average cost at the city gate for Flowing Gas for the calendar Month in which most of the billing month occurs. Estimated costs will be used based on Nominations made by the Company when the applicable calendar month is not completed before billing the Customer.

15.2 The Customer is expected to cease using Gas if the Customer's supply is interrupted. When a supply interruption occurs the Customer must notify the Company immediately upon interruption and upon resumption of supply. During the interruption period the Customer's DCQ will be set to zero for purposes of calculating daily shortfalls and monthly imbalances. Using Gas during a period of supply interruption will subject the Customer to the same penalty rate specified in the interruptible rate schedule for failure to interrupt service unless the Company is not interrupting customers and has Gas supply available. In the later case, the fee specified in 15.3, below, will apply to Gas used during the Customer's supply interruption unless the Customer schedules another service from the Company.

15.3 If the Customer, or the Customer's Qualified Supplier, fails to supply the DCQ on any Gas day the Customer shall be billed a fee of $30.00 per DT for the difference between the DCQ Nomination, which is in DTs, and the Volume actually supplied by the Customer. Such penalty is in addition to any cash-in or cash-out price paid by the Customer for monthly imbalances.

15.4 On a daily basis, the Company, in its sole discretion, may limit Customer usage to the Volume of Customer-owned Gas that is delivered to the Company's distribution system.

15.5 When the Company interrupts the delivery of Customer-owned Gas to an Interruptible Transportation Customer for distribution system reasons any monthly imbalance up to the total DCQ Volumes delivered to the Company's distribution system by such Interruptible Transportation Customer during the period of interruption will be purchased by the Company at the Customer's cost or the otherwise effective cash-in or cash-out price, whichever is greater.

16 OPERATIONAL FLOW ORDER

At any time that Customer-owned Gas, in the sole judgment of the Company, adversely impacts the Company's distribution system or its ability to serve firm Customers, the Company may issue an Operational Flow Order and refuse to accept Customer-owned Gas at the Point(s) of Receipt or require the Customer to adjust its Nominations up or down. Operational Flow Orders will be issued by the Company eight (8) hours in advance of implementation, unless exigent circumstances dictate a shorter notice period.

RATE SCHEDULE "SUP"

GAS SUPPLIER REQUIREMENTS

AVAILABILITY

The requirements under this Schedule apply to Qualified Suppliers that contract with a Customer to deliver the Customer's Daily Contract Quantity (DCQ) to the Point(s) of Receipt under the General Terms and Conditions of the Transportation and Balancing Rider. To become a Qualified Supplier, a supplier must submit a completed application on the Company's standard form to provide service to Customers under this Schedule and must satisfy the Company's credit requirements set forth below.

RESPONSIBILITY FOR GAS DELIVERY

The Qualified Supplier shall provide the necessary Gas supply to facilitate Nomination and delivery of the Customer's DCQ in accordance with the General Terms and Conditions of the Transportation and Balancing Rider. If the Qualified Supplier has more than one Customer, and has become a Replacement Shipper on behalf of the Customer(s), a Nomination which is the sum for more than one Customer will be made on interstate pipelines upstream of the Company's distribution system but the Quantity of Gas for each Customer must be identified on the Nomination to the Company. Failure to deliver the required Quantity of Gas will make the Qualified Supplier subject to penalties as stated in the General Terms and Conditions of the Transportation and Balancing Rider. If the Qualified Supplier fails to pay any penalties, the Customer for whom the Qualified Supplier is delivering Gas shall be responsible for payment of such penalties.

CREDITWORTHINESS

To become a Qualified Supplier, the supplier must demonstrate to the Company's satisfaction that it has met and continues to meet the creditworthiness criteria of at least one non-affiliated interstate pipeline that delivers Natural Gas to the Company's city gate or to an interstate pipeline that is connected to Eastern Shore Natural Gas. Upon notification by the Company that the supplier no longer satisfies the credit criteria or has failed to timely pay any bill rendered under this Schedule, the supplier is disqualified until such time as satisfactory evidence is provided by the supplier that the supplier's overall financial condition again meets the Company's credit criteria or an acceptable credit enhancement, including but not limited to a cash deposit, letters of credit or surety bonds, is furnished to the Company.

Issue Date: **July 21, 2015**
Effective Date: For Bills Rendered on and after September 1, 2015
Authorization: Order 8752 in PSC Docket No. 13-383 dated July 21, 2015

TAXES

Any applicable taxes including, but not limited to, the Public Utilities Tax will be added to all charges.

PAYMENT TERMS

Bills are due within twenty (20) calendar days of their date.

LIABILITY LIMITS

The Company shall not be liable for any loss, cost, damage or expense occasioned by the calculation of the DCQ. The Qualified Supplier shall warrant that, at the time of delivery of Gas to the Point(s) of Receipt, it will have good title to deliver all Gas Quantities. The Company shall have no liability with respect to any Gas prior to its delivery to the Point(s) of Receipt or after its delivery to the Point(s) of Delivery.

RATE SCHEDULE "ER"

ENVIRONMENTAL RIDER

PURPOSE

The purpose of this rider is to recover reasonable environmental costs associated with cleaning up former manufactured gas plants (MGP). Applicable environmental costs are those incurred as a result of, but not limited to, investigation, testing, monitoring, remediation (including remediation of the groundwater), land acquisition, and legal costs relating to former MGP sites, disposal sites, or sites to which material may have migrated as a result of the earlier operation and/or decommissioning of MGPs. Environmental costs expended will be offset by any payments related to these costs received by the Company from insurance proceeds or from another party. Environmental costs shall not include expenses incurred in connection with litigation by third parties claiming personal injury or by third parties claiming damage to their property as a result of the operation or decommissioning of MGPs or as a result of the migration of materials from MGP sites.

APPLICABILITY

The environmental rider will be applicable to all firm Delivery Service customers.

OPERATION OF THE RIDER

The Company will file with the Commission a copy of the environmental rider computation at least 30 days prior to the proposed effective date, which will be each December 1.

The calculation filed will be supported by all bills and receipts relating to the amount of any environmental costs incurred in the preceding Environmental Cost Year for which the Company seeks to begin recovery. In the same filing, the Company shall include similar material and information to support any expenses and/or recoveries resulting from Third Party claims. The Company shall also submit in its annual filing a projection of environmental costs for the following Environmental Cost Year based on the best information available at the time of filing.

RATE

The rate for the rider effective December 1, 2015 is $0.0001 per Ccf.

RATE SCHEDULE "ER"

ENVIRONMENTAL RIDER
(Continued)

DETERMINATION OF RATE

The rider shall be comprised of an amortization factor and a reconciliation factor as follows:

(1) Amortization Factor: Recovery of net environmental costs incurred during an Environmental Cost Year will be accomplished through a five (5) year amortization, offset by the tax benefit associated with those environmental costs as defined below. A net annual amortization amount will be calculated for each of the five (5) years of amortization scheduled for the Environmental Cost Year. The amortization factor for any year will be comprised of the total net annual amount scheduled for that year.

(2) Reconciliation Factor: The reconciliation factor shall be equal to the over/under collection of the environmental cost rider. Over/under collection is the accumulated experienced net over or under recovery of the environmental costs during the twelve (12) month period ending with the month of August immediately preceding the beginning of the next Recovery Year.

(3) Rider Rate: The rider rate shall be equal to the sum of the amortization and reconciliation factors divided by projected firm sales over the next recovery period of December 1 through November 30. The rate shall be rounded to four (4) decimal places per Ccf.

DEFINITIONS

(1) Environmental Cost Year is the time period over which environmental costs are incurred and any payments from other parties are netted against the costs. For purposes of this rider, the Environmental Cost Year will be from October 1 through September 30. The Environmental Cost Year will include actual data recorded for the year. Recovery of environmental costs for an Environmental Cost Year will begin with the Recovery Year that starts immediately following the end of the Environmental Cost Year.

(2) Recovery Year is each December 1 through November 30 and is the time period over which the annually calculated environmental rider rate will be billed to firm customers.

RATE SCHEDULE “ER”

ENVIRONMENTAL RIDER
(Continued)

DEFINITIONS (Continued)

(3) Tax benefit (TB) associated with environmental expenditures shall be calculated as follows:

Tbn	=	AECn * [5-x)/5] * .1306 * .39742

where:

AECn	=	Actual Environmental Costs incurred in Environmental Cost Year "n"
x	=	The number of years that the Actual Environmental Costs (AEC) incurred in Year "n" have been subject to amortization (x = 1, 2, 3, and 4)
.1306	=	Before Tax Cost Rate
.39742	=	Effective Combined Federal and State Income Tax Rate.

The Before Tax Cost Rate of .1306 and the Effective Combined Federal and State Income Tax Rate of .39742 are the rates at the time of implementation of this rider and are subject to change. Any change in the Before Tax Cost Rate will be implemented starting when the next Rider Rate is calculated for the next Recovery Year. Any change in the Effective Combined Federal and State Income Tax Rate will be implemented starting with the recovery calculation for next Environmental Cost Year that ends after the rate changes.

MISCELLANEOUS CUSTOMER CHARGES

1 CONNECTION CHARGE

Each Applicant for gas service shall pay to the Company a Connection Charge of thirty-five dollars ($35) before gas service is activated by the Company at the Customer's premises. Such Connection Charge shall not be collected from builders or other contractors activating gas service during the construction of a premises prior to occupation by the Company's customer of record.

2 RECONNECTION CHARGE

Whenever a Customer's gas is turned off at Customer's request, or Customer's meter disconnected by reason of non-compliance with these Rules and Regulations or orders of the Public Service Commission of Delaware, a Reconnection Charge of thirty five dollars ($35) must be paid and other satisfactory arrangements made with the Company prior to 3:00p.m. of a normal business day before the account is reactivated and gas service reconnected by the end of the next business day.

3 AFTER HOURS SERVICE CONNECTION OR RECONNECTION CHARGE

If the Customer desires that the initial gas service connection or gas service reconnection following disconnection by the Company for any reason, be completed on the same day as the request is received by Company or outside the Company's normal business hours, such After Hours Reconnection may be performed, subject to the availability of Company personnel. The After Hours Connection or Reconnection Charge shall be sixty dollars ($60).

4 SEASONAL RECONNECTION CHARGE

Whenever a residential Customer's gas is turned off or Customer's meter disconnected by the Company at Customer's request and the account placed on inactive status, and such account is reactivated by the same Customer no less than thirty (30) days and no more than one hundred eighty (180) days from the date of the disconnect, a Seasonal Reconnection Charge equal to the monthly Customer Charge in the Customer's applicable Rate Schedule for each month the account was inactive, plus the Reconnection Charge provided in 2 (above), shall be paid. Such payment, along with other satisfactory arrangements for reconnection, shall be made with the Company for reconnection the following normal business day.

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Issue Date:
Effective Date:
Authorization:

MISCELLANEOUS CUSTOMER CHARGES (Continued)

5 FIELD COLLECTION CHARGE

Service interruptions may be avoided by paying the overdue amount prior to the past due date of the gas bill, or by paying the overdue amount plus a collection fee of seventeen dollars ($17) to the Company or an authorized agent of the Company.

6 RETURNED PAYMENT CHARGE

Payment for Services provided under this Tariff, Customer deposits, or other Tariff charges which are returned unpaid by the Customer's bank or other financial institution shall result in an additional charge of twenty dollars ($20) per occurrence, and will be charged against the Customer's account. Failure to pay the full amount of the bill including the Returned Payment Charge may result in discontinuance of the Customer's service. After the second returned payment the Company reserves the right to notify the Customer that an alternate payment method (other than a personal check or bank debit) will be required for payment of the Company's bill statements.

7 CHANGE OF ACCOUNT CHARGE

If the change of occupants in a premise with existing gas service occurs without a physical service disconnection, a Change of Account may occur. The Company shall bill to the applicant a Change of Account Charge in the amount of seventeen dollars ($17).

8 FAILED TRIP CHARGE

In the event a Customer, or other entity, requesting service from the Company that requires a field visit to a premise, fails to keep a scheduled appointment with the Company's employee at said premises to provide a service requested by the Customer, the Customer shall pay a Failed Trip Charge of thirty-five dollars ($35).

RATE SCHEDULE "TSFF"

TOWN OF SMYRNA FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the Town of Smyrna franchise fee, from all customers within the limits of the Town of Smyrna in accordance with the Franchise Agreement between the Company and the Town of Smyrna. This franchise fee will be in effect until December 31, 2029.

APPLICABILITY

The Town of Smyrna Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the Town of Smyrna.

RATE

The rate applicable to all Delivery Service throughput is $.0181 per Ccf.

RATE SCHEDULE "CMFF"

CITY OF MILFORD FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the City of Milford franchise fee, from all customers within the limits of the City of Milford in accordance with the Franchise Agreement between the Company and the City of Milford. This franchise fee will be in effect until June 27, 2019.

APPLICABILITY

The City of Milford Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the City of Milford, excluding those customers from whom the Company is prohibited by law from collecting said surcharge.

RATE

The rate applicable to all Delivery Service throughput is $0.010 per Ccf.

RATE SCHEDULE "TGFF"

TOWN OF GEORGETOWN FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the Town of Georgetown franchise fee, from all customers within the limits of the Town of Georgetown in accordance with the Franchise Agreement between the Company and the Town of Georgetown. This franchise fee will be in effect until June 27, 2021.

APPLICABILITY

The Town of Georgetown Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the Town of Georgetown, excluding those customers from whom the Company is prohibited by law from collecting said surcharge.

RATE

The rate applicable to all Delivery Service throughput is $0.010 per Ccf.

RATE SCHEDULE "MBFF"

TOWN OF MILLSBORO FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the Town of Millsboro franchise fee, from all customers within the limits of the Town of Millsboro in accordance with the Franchise Agreement between the Company and the Town of Millsboro. This franchise fee will be in effect until September 4, 2021.

APPLICABILITY

The Town of Millsboro Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the Town of Millsboro, excluding those customers from whom the Company is prohibited by law from collecting said surcharge.

RATE

The rate applicable to all Delivery Service throughput is $0.0181 per Ccf.

RATE SCHEDULE "MTFF"

TOWN OF MILTON FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the Town of Milton franchise fee, from all customers within the limits of the Town of Milton in accordance with the Franchise Agreement between the Company and the Town of Milton. This franchise fee will be in effect until January 7, 2032.

APPLICABILITY

The Town of Milton Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the Town of Milton, excluding those customers from whom the Company is prohibited by law from collecting said surcharge.

RATE

The rate applicable to all Delivery Service throughput is $0.0181 per Ccf.

RATE SCHEDULE "SFFF"

CITY OF SEAFORD FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the City of Seaford franchise fee, from all customers within the limits of the City of Seaford in accordance with the Franchise Agreement between the Company and the City of Seaford. This franchise fee will be in effect until June 23, 2033.

APPLICABILITY

The City of Seaford Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the City of Seaford, excluding those customers from whom the Company is prohibited by law from collecting said surcharge.

RATE

The rate applicable to all Delivery Service throughput is $0.0181 per Ccf.

RATE SCHEDULE "DBFF"

TOWN OF DAGSBORO FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the Town of Dagsboro franchise fee, from all customers within the limits of the Town of Dagsboro in accordance with the Franchise Agreement between the Company and the Town of Dagsboro. This franchise fee will be in effect until December 20, 2022.

APPLICABILITY

The Town of Dagsboro Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the Town of Dagsboro, excluding those customers from whom the Company is prohibited by law from collecting said surcharge.

RATE

The rate applicable to all Delivery Service throughput is $0.0181 per Ccf.

RATE SCHEDULE "CLFF"

CITY OF LEWES FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the City of Lewes franchise fee, from all customers within the limits of the City of Lewes in accordance with the Franchise Agreement between the Company and the City of Lewes. This franchise fee will be in effect until September 11, 2031.

APPLICABILITY

The City of Lewes Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the City of Lewes, excluding those customers from whom the Company is prohibited by law from collecting said surcharge.

RATE

The rate applicable to all Delivery Service throughput is $0.0181 per Ccf.

RATE SCHEDULE "SBFF"

TOWN OF SELBYVILLE FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the Town of Selbyville franchise fee, from all customers within the limits of the Town of Selbyville in accordance with the Franchise Agreement between the Company and the Town of Selbyville. This franchise fee will be in effect until June 11, 2027.

APPLICABILITY

The Town of Selbyville Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the Town of Selbyville, excluding those customers from whom the Company is prohibited by law from collecting said surcharge.

RATE

The rate applicable to all Delivery Service throughput is $0.0181 per Ccf.

RATE SCHEDULE "TFFF"

TOWN OF FREDERICA FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the Town of Frederica franchise fee, from all customers within the limits of the Town of Frederica in accordance with the Franchise Agreement between the Company and the Town of Frederica.

APPLICABILITY

The Town of Frederica Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the Town of Frederica, excluding those customers from whom the Company is prohibited by law from collecting said surcharge.

RATE

The rate applicable to all Delivery Service throughput is $0.010 per Ccf.

P.S.C. DEL. NO. 4

CHESAPEAKE UTILITIES

DELAWARE DIVISION

RULES AND REGULATIONS

GOVERNING THE DISTRIBUTION

AND SALE OF GAS

OF

CHESAPEAKE UTILITIES CORPORATION

IN

NEW CASTLE, KENT & SUSSEX COUNTIES, DELAWARE

Issue Date: ~~September 2, 2008~~
Effective Date: ~~For Bills Rendered on and after September 3, 2008~~
Authorization: ~~Order No. 7434 dated September 2, 2008 in PSC Docket No. 07-186~~

CHESAPEAKE UTILITIES CORPORATION
DELAWARE DIVISION

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CHESAPEAKE UTILITIES CORPORATION DELAWARE DIVISION

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Issue Date: ~~November 5, 2013~~
Effective Date: ~~For Bills Rendered on and after December 1, 2013~~
Authorization: ~~Order No. 8479 in PSC Docket No. 12-292 dated November 5, 2013~~

CHESAPEAKE UTILITIES CORPORATION
DELAWARE DIVISION

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(Continued)

RULES AND REGULATIONS

SECTION I - GENERAL

1.1 FILING AND POSTING

A copy of this Tariff, which is the rates, rules and regulations under which gas service will be supplied by Chesapeake Utilities Corporation to its Customers, is on file with the Public Service Commission of Delaware, and is posted and open for inspection at the offices of the Company. The Tariff is supplementary to any Regulations of that Commission.

1.2 REVISIONS

This Tariff may be revised, amended, supplemented and otherwise changed from time to time in accordance with the Public Service Commission Law of Delaware, and such changes, when effective, shall have the same force and effect as the present Tariff.

1.3 APPLICATION OF TARIFF

The Tariff provisions apply to any party or parties receiving gas service from the Company, or to its successors and assigns, under the rates set forth therein, and the receipt of gas shall constitute the receiver a Customer of the Company as the term is used herein.

1.4 RULES AND REGULATIONS

The Rules and Regulations, filed as a part of this Tariff, are a part of every contract or agreement for service, whether written, oral or implied, made by the Company and govern all classes of service where applicable. Subject to the approval of the Commission, the Company shall have the right to interpret and determine the applicability of such rules and regulations.

1.5 STATEMENT OF AGENTS

No agent or employee of the Company has authority to make any promise, agreement or representation inconsistent with the provisions of this Tariff.

RULES AND REGULATIONS

SECTION II - CURTAILMENT

2.1 GENERAL

In the event that the Company determines that there is insufficient gas supply to meet the demands of the Customers on its distribution system, the Company may, at its sole discretion, curtail service to Customers. Curtailments will be made to maintain supply to its firm sales customers in the priorities set forth below. When curtailment is necessary, sufficient gas will be available to maintain a temperature which will keep the building pipes from freezing and other plant protection use, if possible. Prior to, or in conjunction with curtailment the Company may call for voluntary usage reductions on the part of all C~~c~~ustomers.

2.2 DEFINITIONS

Essential Human Needs: Includes residences, apartments, hotels, motels, dormitories, hospitals, nursing homes, police and other institutions essential to the public welfare.

Plant protection use: Minimum volumes of natural gas required to prevent physical harm to the plant facilities' processes or danger to plant personnel when such protection cannot be afforded through the use of an alternative fuel. Plant protection requirements include volumes necessary for the protection of such material in process as would otherwise be destroyed, but does not include deliveries required to maintain production.

2.3 CURTAILMENT PRIORITIES

Curtailment to the extent necessary as determined by the Company, up to and including complete curtailment shall be done in accordance with the following list of priorities, starting with the lowest priority, priority 6.

RULES AND REGULATIONS
SECTION II
(Continued)

2.3 CURTAILMENT PRIORITIES (continued)

Priority 1: Essential humans needs C~~c~~ustomers.

Priority 2: All other customers other than P~~p~~riority 1 C~~c~~ustomers will be curtailed to the extent necessary as determined by the Company.

Priority 3: Firm commercial and industrial C~~c~~ustomers using above 4,000 Ccf per year.

Priority 4: Firm commercial and industrial C~~c~~ustomers using above 15,000 Ccf per year.

Priority 5: Firm commercial and industrial C~~c~~ustomers using above 100,000 Ccf per year.

Priority 6: All interruptible transportation and IBE C~~c~~ustomers.

2.4 CURTAILMENT OF CUSTOMER-OWNED GAS

If adequate supply to priority essential human needs C~~c~~ustomers is threatened in the Company's judgment, Customer-owned transportation gas may be curtailed in addition to system supply and in the same order of priorities. In the event that Customer-owned gas is diverted for use by higher priority C~~c~~ustomers, the Company will reimburse the Customer by paying the cost of the Customers alternative fuel or, if the Customer has no alternative fuel, reimbursement will be at a ~~price equivalent to No. 2 fuel oil.~~ rate equal to the higher of the Company's weighted average cost of gas (the total cost of natural gas delivered to the Company for system supply divided by the volume delivered) or the Customer's total acquisition cost of gas (including pipeline transportation charges). In the event of a supply shortage which causes the Company to purchase the Customer's gas, the Customer shall make available a copy of its contract for natural gas supply upon request; or in lieu thereof, the Customer shall supply a sworn affidavit specifying Customer's total acquisition cost of gas. In lieu of this provision, the Company may enter into contractual or informal arrangements with transportation Customers or any other parties to obtain supplies to avoid curtailments.

2.5 LIABILITY

The Company shall not be liable for any damages, loss of product, or other business losses suffered by Customers as a result of curtailed gas service, other than the compensation provided in ~~paragraph~~ Section 2.4 above. The Company shall not be liable for curtailment as a result of any action by any governmental agency with jurisdiction to regulate, allocate, or control gas supplies or the rendition of service, and regardless of any defect in such law, regulation, or order.

RULES AND REGULATIONS

SECTION II
(Continued)

2.6 ADDITIONAL LOADS

In the event that additional gas supply becomes limited for any reason, the Company reserves the right to defer supplying gas for new loads in such manner as to cause the least hardship to present or prospective C~~c~~ustomers, taking into consideration the volume of natural gas available and the capacities of local mains and facilities. In each of the listed classes, present C~~c~~ustomers will be allowed to increase loads before new C~~c~~ustomers will be allowed to begin service.

During any period when gas supply is expected to be limited the Company will maintain a Register of New Loads applied for, but not already being served by the Company, in order to assist the Company in forecasting peak demands for its service, and to afford a basis of priority in supplying additional loads to existing as well as to new or prospective C~~c~~ustomers.

During any period of restricted gas supply the Company will not supply gas for any equipment unless application for such load was registered with the Company prior to the connection of such equipment, and approval thereof was given by the Company.

The priority in which additional loads will be accepted is:

	DESCRIPTION	TYPE
(1)	Non-space heating load Peak day less than 1,000 cu. ft.	Residential
(2)	Non-space heating load Peak day less than 1,000 cu. ft	Commercial Industrial
(3)	Space heating load Peak day less than 2,000 cu. ft.	Residential Commercial Industrial
(4)	Dwelling Units - Home or Apartments Individually Billed Not to exceed 25 units at one location.	Residential

RULES AND REGULATIONS

SECTION II
(Continued)

2.6 ADDITIONAL LOADS (continued)

	DESCRIPTION	TYPE
(5)	Dwelling Units - Home or Apartments Master Metered Not to exceed 25 units at one location	Commercial
(6)	Non-space heating load Peak day not to exceed 10,000 cu ft	Commercial Industrial
(7)	Space Heating Load Peak day less than 10,000 cu. ft.	Commercial Industrial
(8)	Same as (4) above except in increments of 26 to 100 units at one location.	
(9)	Same as (5) above except in increments of 26 to 100 units at one location.	
(10)	Same as (4) above except in increments of over 100 units at one location.	
(11)	Same as (5) above except in increments of over 100 units at one location.	
(12)	All other commercial and industrial loads.	

The Company reserves the right to establish priority of loads in accordance with volume within each category above.

The Company reserves the right to allocate gas to various priority categories listed above based on estimated gas sales and gas supply and to make adjustments as actual figures vary from the estimate.

RULES AND REGULATIONS

SECTION II
(Continued)

2.6 ADDITIONAL LOADS (continued)

When anticipated gas supplies are not sufficient to service all new loads applied for in one of the above categories, priority will be given in the order in which application was registered with the Company, provided the new load is connected within a reasonable time after notice from the Company that it may be served.

When the evidence available to the Company reasonably indicates that a C~~c~~ustomer has connected additional load without registering same or in violation of the Company's notice that it may not be connected, the Company will discontinue all service to such C~~c~~ustomer, upon ten (10) days' written notice, until such additional load has been disconnected.

Issue Date: ~~**September 2, 2008**~~
Effective Date: ~~**For Bills Rendered on and after September 3, 2008**~~
Authorization: ~~**Order No. 7434 dated September 2, 2008 in PSC Docket No. 07-186**~~

RULES AND REGULATIONS

SECTION III - APPLICATION FOR SERVICE

3.1 APPLICATION

Application for gas service may be made through the local office of the Company or authorized agent, by:

(a) Verbal or telephonic request to a business office of the Company, or
(b) Electronic request to the Company's web site (www.chpkgas.com), or
(c) if required by the Company, by submission to the Company a completed Gas Delivery Service Application (certain Applicants may be required to execute a Transportation Service Agreement).

The Company reserves the right to require the A~~a~~pplicant before any gas is delivered, to execute an application at the local office with proper identification. The application does not constitute a commitment by the Company to serve the A~~a~~pplicant.

3.2 RIGHT TO REJECT

The Company may place limitations on the amount or character of service it will supply, or may reject applications for any of the following reasons:

(a) Until the Customer has complied with the state and municipal regulations governing gas service.

(b) If the Company does not have adequate facilities to render the service desired.

(c) If such service is of a character that it is likely to unfavorably affect service to other Customers.

(d) If, in the judgment of the Company, the A~~a~~pplicant's installation of piping or gas equipment is hazardous, or of such a character that satisfactory and safe service cannot be rendered.

(e) If an extension of street main, except as set forth under Section 6 - Extensions, is required to furnish such service.

RULES AND REGULATIONS

SECTION III
(Continued)

3.2 RIGHT TO REJECT (Continued)

(f) When it is necessary to conserve the supply of gas (See Section ~~II~~ 2.3 Curtailment Priorities and 2.6 Additional Loads.)

(g) Customer's failure to provide a deposit to insure payment of bills, where requested by the Company under the provisions of Section 13.2.

(h) Customer's failure to make such payment as may be required under Section 6 as a condition of extension of supply facilities.

(i) Customer's failure to pay the Connection Charge, Reconnection Charge or Seasonal Customer Charge.

(i) Service at new location will be rendered only when all bills for gas service to the Customer at any other locations have been paid.

(j) Non-compliance with provisions of this T~~t~~ariff.

3.3 ACCEPTANCE

Acceptance of gas service by the Customer shall constitute an agreement to accept service under these Rules, Regulations and Rates as amended from time to time, the Orders or Rules of the Public Service Commission of Delaware, the Laws of the State of Delaware and the Laws of the United States of America.

RULES AND REGULATIONS

SECTION III
(Continued)

3.4 CUSTOMER TO SPECIFY TIME WHEN SERVICE IS CONNECTED

A Customer shall give two (2) business days' notice to the Company for gas service to be connected during normal business hours, under normal operating conditions. Business days shall mean Monday through Friday excluding Federal Banking Holidays. As a safety precaution, the Customer, or an ~~adult~~ authorized representative of the Customer of at least eighteen (18) years of age, shall be present at the premises for gas service to be connected. If, due to unforeseen or emergency circumstances, the Company is not able to meet the two (2) business day connection schedule, the Customer shall be informed, and a new arrangement made. .The Connection Charge provided on Sheet No. 46 (Miscellaneous Customer Charges) shall apply to all gas service connections. If necessary for the Customer's convenience~~, and if he so directs,~~ that the connection be made after normal working hours, the After Hours Connection Charge provided on Sheet No. 46 (Miscellaneous Customer Charges) shall apply.

3.5 POINT OF DELIVERY

(a) The point of delivery of gas to a Customer shall be at the outlet side of the meter connection, ~~at which point~~ T~~t~~itle to ~~the~~ Company owned gas shall pass to the Customer at this point. The use of Service on two or more separate meters will not be combined for billing purposes.

(b) (Exception) Combined billings for registrations of multiple meters installed on a customer's premises is permitted only where such multiple meters are installed for the convenience of the Company.

3.6 CHARACTER OF GAS

The gas to be served will be natural gas with a specific gravity of approximately .60, a minimum value per cubic foot of one thousand (1,000) BTU, and that is in conformance with the quality specifications of transporters delivering such gas to the Company's ~~Delivery~~ Receipt Points, or such other gas as may be approved by the Public Service Commission of Delaware. The Company shall have the right to supply stand-by or peak shaving gas of similar characteristics when necessary.

RULES AND REGULATIONS

SECTION IV – CUSTOMER'S INSTALLATIONS

4.1 INFORMATION FROM CUSTOMER

Anyone desiring to equip ~~his~~ their premises for the use of gas shall communicate with the Company personally, or through ~~his~~ their contractor or other authorized agent, giving the exact location of the premises and details of all gas consuming equipment to be installed.

4.2 POINT OF CONNECTION

The Company will designate the point where the a~~A~~pplicant would, if served, be required to terminate ~~his~~ their piping for connection to the lines of the Company. The furnishing of such information does not constitute an agreement, or obligation, on the part of the Company to render service.

4.3 METER SPACE

The a~~A~~pplicant shall provide, free of expense to the Company, a space satisfactory to the Company for meters, regulators or other equipment of the Company which is necessary for the rendering of adequate and safe service. The Company reserves the right to establish the standard as to the location of such space in accordance with pressure conditions, volumes, and other pertinent factors.

4.4 METER LOCATION

The Company shall have the right to determine the location of its meters, which must be placed where they will be easily accessible, and the Customer or o~~O~~wner of the building shall provide at all times, ~~maintain~~ free of expense to ~~this~~ the Company, proper space for ~~this~~ the Company's meters. Likewise, the Customer ~~is warned~~shall not ~~to~~ permit materials of any character to be piled up or heaped around the meter location. The Customer shall reimburse ~~this~~ the Company for the loss of, or any damage to, its meters and meter connections, or other property of the Company while located on the Customer's premises, arising out of or caused by the Customer's negligence, carelessness; or that of ~~his servants,~~the Customer's agents, employees, members of ~~his~~ the Customer's household, or any person upon ~~his~~ the Customer's premises under or by authority of ~~his~~ the Customer's consent or sufferance.

RULES AND REGULATIONS

SECTION IV
(Continued)

4.5 METER CONNECTIONS

~~This~~ The Company will own, furnish, and maintain the meter, regulator, meter connection, electronics, remote reading device, if any, and all other appurtenant equipment required to measure the gas supplied to the Customer, and will supply gas only through a meter furnished and owned by the Company. ~~This~~ The Company must be notified when the Customer desires to have the meter installed, changed or removed.

4.6 TEMPORARY SERVICE

The Customer shall pay the cost for all material, labor and all other necessary expense incurred by the Company in supplying gas service to the Customer for any temporary purpose or use, and shall pay the cost of removing material after service is discontinued, in addition to the regular payments for gas used. The Company will credit the Customer with the reasonable salvage value of any material recovered.

4.7 SERVICE LINES

The Company will own and maintain at its expense, the service line to the point of connection designated by the Company. (See Section 6.1 Service Connections).

4.8 HOUSE PIPING

Prior to the installation of house piping by the Customer in new or altered premises, inquiry should be made of the Company to determine the requirements, sizes of pipe, quality and other specifications.

Customer's installation shall be installed at the Customer's expense and shall be maintained by the Customer in compliance with applicable codes.

RULES AND REGULATIONS

SECTION IV
(Continued)

4.9 INTERFERENCE WITH COMPANY FACILITIES

The Customer shall not open, tamper or interfere with, in any manner, the service line, regulators, or safety appliances installed in connection with service provided to the Customer. The Company's main, service line, service cock, curb box and meter shall not be tampered or interfered with at any time. In the event of the Company's meters or other property being tampered or interfered with, the Customer being supplied through such equipment shall pay the amount which may be reasonably estimated to be due for service used but not registered on the Company's meter, and for any repairs, replacements or changes in facilities required, as well as for costs of inspections, investigations and protective installations.

4.10 RESPONSIBILITY OF CUSTOMER

This Company's ownership and responsibility terminates at the meter outlet. The Customer is warned of the risk of damage to property and the possibility of fire or personal injury resulting from improper house piping and manner of attachment or use and maintenance of gas appliances, fixtures, and apparatus, and is advised to permit no one except experienced and capable pipe fitters to install or to make any changes, alterations, additions or repairs to any part of the Customer's installation. ~~This~~ The Company will not be liable for any injury or damage or loss of gas caused by reason of defects in any portion whereof.

RULES AND REGULATIONS

SECTION V - TESTING AND INSPECTION OF CUSTOMER'S PIPING

5.1 REQUIREMENT

Prior to providing gas service, the Customer's facilities and appliances must be in accordance with the n~~N~~ational and l~~L~~ocal c~~C~~ode requirements.

5.2 COMPANY'S RIGHT TO INSPECT

The Company shall have the right, but shall not be obliged, to inspect any installation before gas is introduced or at any later time, and reserves the right to reject any piping or appliances not in accordance with the Company's standard requirements, or with any national and local code requirements; but such inspection, or failure to inspect, or to reject, shall not render the Company liable or responsible for any loss or damage, resulting from defects in the Customer's installation, piping or appliances, or from violation of the C~~c~~ompany rules, or from accidents which may occur upon the premises of the Customer.

RULES AND REGULATIONS

SECTION VI – SERVICE INSTALLATIONS AND MAIN EXTENSIONS

6.1 SERVICE INSTALLATIONS

The Company will install the service line from its existing distribution main to the Customer's meter location at its expense. However, if the service line exceeds seventy-five (75) feet in length, the Company's initial investment in the entire service installation shall be limited to six (6) times the related estimated annual base tariff revenue excluding all fuel costs ("net revenue") from the Customer. The amount of the investment that exceeds the six (6) times net revenue test for the service installation shall be paid by the Customer in accordance with the terms of Section 6.3.

Service Installations, as used in this section for purposes of the six (6) times net revenue test, refers to the costs associated with the service line piping, meter installation and associated materials from the tap on the Company's gas distribution main system up to and including the Customer's meter.

6.2 MAIN EXTENSIONS

Main extensions to the Company's gas system shall be provided, owned and maintained under the terms and conditions stated herein. Main extensions, as used in this section for purposes of the economic evaluation criteria, refers to the cost of gas distribution mains and associated materials that must be constructed along public streets, roads and highways, or on private property from the Company's existing gas distribution main system to the initiation of the service line. Main extensions are limited to the extent of new investment warranted by the anticipated revenues as stated in this Section VI.

New Residential Development

The economic evaluation criteria for installing natural gas service to the new residential development will be based on an Internal Rate of Return Model ("IRRM") with certain predetermined conditions and guidelines. The applicable procedures and guidelines in the implementation of the IRRM are on file with and have been approved by the Public Service Commission of Delaware. The procedure used to determine whether a financial guarantee will be required from a Customer(s) is part of the IRRM methodology on file with the Commission.

RULES AND REGULATIONS

SECTION VI – SERVICE INSTALLATIONS AND MAIN EXTENSIONS (Continued)

6.2 MAIN EXTENSIONS (Continued)

~~New Residential Development~~

~~The economic evaluation criteria for installing natural gas service to the new residential development will be based on an Internal Rate of Return Model ("IRRM") with certain predetermined conditions and guidelines. The applicable procedures and guidelines in the implementation of the IRRM are on file with and have been approved by the Delaware Public Service Commission~~ of Delaware~~. The procedure used to determine whether a financial guarantee will be required from a Customer(s) is part of the IRRM methodology on file with the Commission.~~

When evaluating potential multi-family housing projects, if the IRRM demonstrates that the anticipated revenues warrant an investment greater than the cost of the main extension and service connection, then the Company may, at its sole discretion, provide a contribution to the Customer to offset costs incurred for the installation of gas piping and venting in the premise. The contribution provided by the Company may not exceed the amount that is warranted by the anticipated revenues and, in any event, may not exceed the actual cost for installation of gas pipe and venting in the premise. A project will be determined to be a multi-family project if there are at least four (4) individually metered dwelling units in one premise. When providing a contribution to offset costs related to the installation of gas piping and venting, the Customer bears all responsibility for proper installation and maintenance of all pipe beyond the Company's meter.

Existing Residential Developments

The economic evaluation criteria for installing natural gas service to an existing residential development will be based on an Internal Rate of Return Model ("IRRM") with certain predetermined conditions and guidelines. The applicable procedures and guidelines in the implementation of the IRRM are on file with and have been approved by the ~~Delaware~~ Public Service Commission of Delaware. The procedure used to determine whether a financial guarantee will be required from a Customer(s) is part of the IRRM methodology on file with the Commission.

Commercial and Industrial Main Extensions

The economic evaluation criteria for installing natural gas service to commercial and industrial C~~c~~ustomers, including transportation and non-firm C~~c~~ustomers, will be the six (6) times net revenue test based on the commercial and industrial C~~c~~ustomers' estimated level of annual non-fuel revenue. The estimated annual non-fuel revenue is defined as the estimated annual base T~~t~~ariff revenue or delivery service revenue excluding all fuel related costs for the respective C~~c~~ustomer. If the estimated investment in the facilities necessary to provide gas service exceeds six (6) times the related annual non-fuel revenue from the respective Customer(s), the Customer(s) shall provide a financial guarantee in accordance with the terms of Section 6.3.

The economic evaluation criteria for negotiated contracts for compression services will be the IRRM and will include the Company's cost of installing Company-owned and maintained compression facilities to meet the pressure demands specified by the Customer.

Issue Date: ~~November 5, 2013~~
Effective Date: ~~For Bills Rendered on and after December 1, 2013~~
Authorization: ~~Order No. 8479 in PSC Docket No. 12-292 dated November 5, 2013~~

RULES AND REGULATIONS

SECTION VI – SERVICE INSTALLATIONS AND MAIN EXTENSIONS (Continued)

6.3 FINANCIAL GUARANTEES

Financial gGuarantees may be made by a Contribution in Aid of Construction ("CIAC"), a Customer Advance, a Letter of Credit, or other financial guarantee at the Company's discretion.

Should the Customer provide a Customer Advance, the Company will provide, in a written agreement with the Customer, for refunds (without interest) of all, or part, of the monies advanced by the Customer in connection with the extension and the applicable economic evaluation criteria. Refunds to the Customer shall extend over a term of years, not to exceed six (6) years, upon such basis or conditions as may be mutually agreeable to the Company and the Customer, and specified in the written agreement. In no case shall the total refund be greater than the Customer's deposit. Any portion of the deposit remaining after the expiration of the term as specified in the written agreement shall be retained by the Company and credited as a Contribution In Aid of Construction.

Should the Customer provide a Letter of Credit or other financial guarantee, the estimated revenue attributable to the extension shall be examined prior to the expiration of the Letter of Credit or other financial guarantee. The Company may either draw on the Letter of Credit or other financial guarantee or require that it be renewed, where a continued financial guarantee is still required.

6.4 RIGHT TO DETERMINATION

In each and every situation where the Company and the prospective Customer cannot agree as to the necessity for a financial guarantee to be borne by the prospective Customer, the prospective Customer will be advised by the Company of the right to have the matter determined by the Public Service Commission of Delaware under 26 Del Code, Section 203.

RULES AND REGULATIONS

SECTION VI – SERVICE INSTALLATIONS AND MAIN EXTENSIONS
(Continued)

6.5 OWNERSHIP AND MAINTENANCE

The Company shall own, maintain and renew all its equipment, between the main and the outlet side of the meter connection.

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RULES AND REGULATIONS

SECTION VII - RIGHTS-OF-WAY/OR EASEMENTS

7.1 RIGHTS-OF-WAY AND/OR EASEMENTS

The A~~a~~pplicant(s)~~ or applicants~~ requesting service shall furnish, without expense to the Company, and to the Company's satisfaction, rights-of-way and/or easements necessary for the supply of service or shall agree to reimburse the Company for expense incurred in the procurement of the necessary rights-of-way and/or easements. The Company shall first exercise reasonable efforts to procure any necessary rights-of-way and/or easements from the land owner for nominal consideration or without charge to the Company and the A~~a~~pplicant(s)~~ or applicants~~ requesting service.

7.2 TERM AND RENTALS

When, to serve a Customer, it is necessary to extend the Company's facilities over the property of another, the Customer shall accept service for such term as is provided in the permit or agreement covering the location and maintenance of such facilities on the land or property of others. The Customer may be required to reimburse the Company for any and all special, or rental, charges that may be made for such rights by said permit or agreement.

7.3 GRADING

Rights-of-way, easements and service routes must be cleared and graded to within six (6) inches of final grade by the A~~a~~pplicant including certification by the A~~a~~pplicant that such grade has been achieved before the ~~utility~~ Company will commence construction. Such clearing and grading must be maintained by the A~~a~~pplicant during construction by the ~~utility~~Company.

7.4 CHANGE IN GRADE

If subsequent to any agreement to construct by the Company, the clearance or grade is changed in such a manner as to require relocation of pipelines or other facilities, the cost of such relocation shall be borne by the A~~a~~pplicant, or the Applicant's~~his~~ executor, administrator, heir or successor.

7.5 DELAYS

Application for service from an extension to be constructed where a right-of-way and/or easement is not owned by the Company, will only be accepted subject to delays incident to obtaining a satisfactory right-of-way and/or easement.

Issue Date: ~~**September 2, 2008**~~
Effective Date: ~~**For Bills Rendered on and after September 3, 2008**~~
Authorization: ~~**Order No. 7434 dated September 2, 2008 in PSC Docket No. 07-186**~~

RULES AND REGULATIONS

SECTION VIII - COMPANY EQUIPMENT ON CUSTOMER'S PREMISES

8.1 MAINTENANCE

The Company shall keep in repair and maintain its own property installed on the premises of the Customer.

8.2 RESPONSIBILITY OF CUSTOMER

The Customer shall not cause damage to the equipment of the Company on ~~his~~ the Customer's premises, and shall not permit any person, except a Company employee having proper Company identification, to break any seals upon, or do any work on any meter, service pipe or other equipment of the Company located on the Customer's premises.

8.3 TAMPERING

In the event of the Company's meters or other property being tampered or interfered with, the Customer being supplied through such equipment shall pay the amount which may be reasonably estimated to be due for service used but not registered on the Company's meter, and for any repairs, replacements or changes in facilities required, as well as for costs of inspections, investigations and protective installations.

8.4 ACCESS TO PREMISES

The Company, or its authorized agents, shall have access at all reasonable times to the property or premises in or on which gas is used to determine if the gas is being carried, distributed and burned in a proper and safe manner and in accordance with these Rules and Regulations, or to read, inspect and test the meter or house lines and other appliances, equipment or facilities. Refusal on the part of the Customer to allow access to ~~his~~ the Customer's premises shall constitute sufficient cause for turning off the gas supply to such premises. (See Section 14.1).

8.5 RELOCATION OR ALTERATION OF COMPANY-OWNED FACILITIES

Any relocation or alteration of Company-owned facilities to furnish gas service to Customers for the convenience and benefit of the Company shall be paid for by the Company; however, any such changes occasioned or necessitated by any action of the Customer, or owner of the property if the Customer is a lessee, may be made only after prior approval of the Company, and shall be at the expense of the Customer or owner.

RULES AND REGULATIONS

SECTION IX - SERVICE CONTINUITY

9.1 REGULARITY OF SUPPLY

The Company will use reasonable diligence to provide a continuous, regular and uninterrupted supply of gas service; but does not and cannot guarantee a constant supply and should the supply be interrupted by the Company for the reasons set forth in Section II, entitled "Curtailment" or for the purpose of making repairs, changes, or improvements, in any part of its system for the general good of the service or the safety of the public, or should the supply of service be interrupted, or fail, by reason of accident, strike, legal process, State or Municipal interference, lack of sufficient gas supply, mechanical failure, or any cause whatsoever, beyond its control, the Company shall not be liable for damages, direct or consequential, resulting from such interruption or failure.

9.2 NOTICE OF TROUBLE

The Customer shall notify the Company, immediately, should the service be unsatisfactory for any reason, or should there be any defects, leaks, trouble, or accident, affecting or resulting from the supply of gas.

9.3 PREARRANGED INTERRUPTION OF SERVICE

Whenever it is necessary to interrupt service for work on mains or other equipment, such work shall be done, as far as practicable, at a time that will cause the least inconvenience to the Customer. The Customer(s) to be affected by such interruption shall, if practicable, be notified in advance.

RULES AND REGULATIONS

SECTION X - CUSTOMER'S USE OF SERVICE

10.1 PRECAUTIONS TO BE TAKEN BY CUSTOMER

The responsibility of detection of defects and leaks on the Customer's premises is upon the Customer; defects among other things, shall mean failure or deficiency of gas, irregular supply, leakage and excessive pressure. In case of detection of a leak within ~~his~~ the Customer's premises, the Customer should

- Leave the home or building immediately and go upwind of the suspected leak.
- Immediately call the Company's local emergency telephone number or 911 from a cellular phone outside the home or building, or from a neighboring location, to report the suspected gas leak.
- Not use their home telephone, turn on or off any electrical switches, light a match or do anything that might create a spark or flame.
- Not re-enter the building where the suspected leak is until emergency officials give the okay.

~~immediately extinguish all flames, or fires within the premises, open all doors and windows to permit the escape of gas, avoid the use of any electrical switches, and at once notify the Company by telephone or messenger, so that the conditions existing may receive prompt and proper attention~~. When gas has been shut off because of a leak in the house lines or fixtures or other hazardous conditions of service, it shall not be turned on again until such leak or other hazardous conditions have been repaired and made safe either by a competent plumber or gas fitter. In the event of failure or deficiency of gas or excessive pressure, the Customer shall notify the Company and be governed by instructions or assistance received from the Company.

10.2 PRUDENT USES OF GAS

A Customer should always make prudent use of gas.

Upon notice by the Customer, the Company will investigate reports of suspected gas leakage and improper functioning of gas appliances.

In the event that gas passes through the meter as a result of the Customer's negligence or malfunctioning of the Customer's piping or appliances, no credit will be issued, unless such use is a result of fault or neglect of agents of the Company.

10.3 SALES OF GAS BY CUSTOMER

The Customer shall not directly or indirectly sell, sublet, assign or otherwise dispose of the gas or any part thereof, unless otherwise specified in the Tariff. Purchase of gas for use by tenants located on the Customer's property, when the cost to the tenant of such gas is included in the normal rental charge for occupancy of the premises, shall not be considered as resale.

Issue Date: ~~September 2, 2008~~

Effective Date: ~~For Bills Rendered on and after September 3, 2008~~

Authorization: ~~Order No. 7434 dated September 2, 2008 in PSC Docket No. 07-186~~

RULES AND REGULATIONS

SECTION X
(Continued)

10.4 SERVICE TO CUSTOMER'S APPLIANCES

The Company shall investigate complaints of gas leaks or odors at any time without charge. The Company shall have the right, but shall not be obliged, to inspect any installation before g~~G~~as is introduced or at any later time, and reserves the right to reject any piping or appliances not in accordance with the Company's standard requirements, or with any national and local code requirements; but such inspection, or failure to inspect, or to reject, shall not render the Company liable or responsible for any loss or damage, resulting from defects in the Customer's installation, piping or appliances, or from violation of the Company rules, or from accidents which may occur upon the premises of the Customer.

10.5 FLUCTUATIONS

Gas service must not be used in such a manner as to cause unusual fluctuations or disturbances in the Company's supply system, and in the case of a violation of this rule, the Company may discontinue service, or require the Customer to modify ~~his~~ their installation and/or equip it with approved controlling devices.

10.6 LIABILITY FOR DAMAGES

The Company shall not be liable for any injury to persons or damage to property arising or occurring in any manner whatsoever from the misuse of gas.

RULES AND REGULATIONS

SECTION XI - MEASUREMENT

11.1 DEFINITION OF A CUBIC FOOT

a. Low Pressure Sales - Standard delivery to the Customer is at low pressure, and for those meters not having temperature correcting devices which correct to a temperature of sixty (60) degrees Fahrenheit, a cubic foot of gas shall be that amount of gas which occupies a volume of one cubic foot at the time metered and under the conditions existing at the Customer's meter.

b. Other Than Low Pressure Sales As Under (a) Above - When at the discretion of the Company, gas is supplied at higher than standard delivery pressure, measurement may be by a meter equipped with a base pressure corrector and the metering is continuously, automatically, and uniformly corrected from the absolute delivery pressure (14.73 atmospheric pressure) in pounds per square inch, to a pressure base of 14.95 lbs. per square inch, at the temperature existing at the meter. Meters may be equipped with a base pressure and temperature corrector and the metering is continuously, automatically and uniformly corrected from the absolute delivery pressure of 14.73 absolute pressure in pounds per square inch to a pressure base of 14.95 lbs. per square inch, and to a temperature of sixty (60) degrees Fahrenheit.

11.2 MEASUREMENT OF GAS

Except as herein otherwise provided, the measurement of gas service shall be by meters furnished and installed by the Company. The Company will furnish each Customer with a meter of such size and type as the Company may determine will adequately serve the Customer's service requirements, and may from time to time, change or alter the equipment to provide for accurate measurement.

Each meter shall be calibrated to serve gas within the tolerance as specified by the ~~Delaware~~ Public Service Commission of Delaware. Registration shall be in cubic feet or multiples thereof depending on service classification.

If any correction factor is applied to any meter, this factor shall be marked on such meter.

RULES AND REGULATIONS

SECTION XI MEASUREMENT
(Continued)

11.2 MEASUREMENT OF GAS (Continued)

The Company shall install, at <u>the </u>Company's expense, a remote reading device on all Customer's served under the LVH, HLFS or Interruptible Transportation Service Rate Schedules with annual consumption of at least <u>one hundred thousand (</u>100,000<u>)</u> Ccf annually. All remote reading devices shall be owned, installed and maintained by the Company. When requested by a Customer below the annual consumption level above, and approved by the Company, a remote reading device may be installed at a cost payable by the Customer. In all cases the Customer shall, at <u>the </u>Customer's expense, provide and maintain electrical power and telephone service to the remote reading device location.

A periodic verification reading shall be taken on the meter and the remote reading device. The Company shall notify the Customer when the periodic verification is required. The Company shall determine the frequency of such verification based on the technical characteristics of the installed equipment and its in-service performance.

In cases of a measurement dispute related to the remote reading device, the Company's meter may be used as the final determinant in measuring consumption.

11.3 METERS NOT AVAILABLE

In cases where meters are not available due to circumstances beyond the control of the Company, and the necessity for rendering gas service to the Customer is urgent, the Company may, after proper authorization by the Commission and by written agreement with the Customer, commence service and render bills temporarily on the basis of estimated gas consumption.

11.4 METER READING INTERVALS

The Company will endeavor to make its regular meter reading and/or estimated meter reading as nearly as reasonably possible at scheduled monthly intervals.

RULES AND REGULATIONS

SECTION XI MEASUREMENT
(Continued)

11.5 ESTIMATED USAGE

The Company may render estimated bills when (1) no meter is installed, as provided above, or (2) when a meter is installed but the scheduled meter reading cannot be obtained due to the inability of the Company's agent or representative to gain access to the meter location at the time scheduled, or (3) in case any meter or measuring device for any reason fails to register for any period of time the full consumption by a Customer, (See Section XII Meter Tests~~ - 12~~), or (4) the Company is unable to obtain a meter reading for causes beyond its control.

Estimated readings shall be based upon prior consumption at the particular location for a similar period of time and may be adjusted for current conditions. The Customer shall be obligated to pay the bill based on the estimated consumption as though the same was based on an actual meter reading, and failure to so pay shall subject the Customer and ~~his~~ the Customer's service to the penalties herein provided. Bills based on estimated readings shall be subject to adjustment for any unusual circumstances found to have affected the quantity of gas used, or for obvious errors in estimates, which adjustments shall be made not later than the next subsequent bill rendered the Customer, or that period of time when an actual reading can be obtained.

The Company will cooperate with the Customer to schedule meter readings; however, in those instances where the Company's agent or representative is unable to gain access to the Customer's premises, during the regular scheduled working hours, to obtain a meter reading, the number of estimated readings shall be limited to three (3) consecutive months, and the Customer's service thereafter, is subject to discontinuance.

RULES AND REGULATIONS

SECTION XII - METER TESTS

12.1 METER TESTS

All meters shall be tested periodically by the Company in compliance with the Rules of the Commission and at the Company's expense.

12.2 ACCURACY OF GAS METERS

When any test of a meter by the Company or by the Commission shows such meter to have an average error of more than ~~2~~ two percent (2%), and no meter tampering has occurred, the following provisions for the adjustment of bills shall be observed:

Fast Meters

Unless the date of the beginning of inaccuracy shall be known, it shall be assumed that the over-registration existed for a period of three (3) years or a period equal to one-half (1/2) of the time since the meter was last tested, whichever is less.

If the meter is found to be over-registering, the Company shall make a refund to the last Customer of record receiving service through the meter for the amount which shall have been charged in excess of that which would have been charged had the meter registered with ~~100~~ one hundred percent (100%) accuracy, provided the refund exceeds one dollar ($1). The refund will be computed upon the assumption that the meter was registering ~~100~~ one hundred percent (100%) accurately prior to the beginning of the period of inaccuracy or the period of adjustment defined in the preceding paragraph. The refund shall be for the period that the last Customer received service through the meter, but for not more than the periods referred to in this S~~s~~ection 12.2.

Slow Meters

If the meter is found to under-register, or is slow, the Company may bill the Customer one-half (1/2) of the unbilled undercharge for a period of twelve (12) months, unless the meter has been tested within that twelve (12) month period, in which event the Company may bill the Customer one-half (1/2) of the unbilled undercharge for the period since the meter was last tested. If the amount of under-~~-~~registration is less than five dollars ($5)~~$5.00~~, the bill will not be adjusted. Installment payments will be arranged equal to the number of months the account was billed in error in the event additional charges are due the Company, and the installment payments are due and payable in addition to the C~~c~~ustomer's regular monthly natural gas service bill.

RULES AND REGULATIONS

SECTION XII
(Continued)

12.2 ACCURACY OF GAS METERS (Continued)

Non-Registering Meters

If the meter is found to be not registering, or is stopped, the Company may estimate, and bill the Customer the proper charge for the unregistered service by reference to the Customer's consumption during similar periods. Except in the case of tampering, theft, or unauthorized use, the estimate shall cover a period of not more than six (6) months. Installment payments will be arranged equal to the number of months the account was billed in error in the event additional charges are due the Company, and the installment payments are due and payable in addition to the C~~c~~ustomer's regular monthly natural gas service bill.

12.3 REQUEST TESTS

Upon request by a C~~c~~ustomer and at no charge the ~~utility~~ Company shall make a test of the accuracy of registration of the meter serving ~~him~~that Customer, providing that such tests need not be made more frequently than once in eighteen (18) months.

Issue Date: ~~**September 2, 2008**~~
Effective Date: ~~**For Bills Rendered on and after September 3, 2008**~~
Authorization: ~~**Order No. 7434 dated September 2, 2008 in PSC Docket No. 07-186**~~

RULES AND REGULATIONS

SECTION XIII - PAYMENT TERMS

13.1 INITIAL RATE SCHEDULE ASSIGNMENT

Subsequent to receiving an application for Gas Delivery Service and prior to activating such service, the Company shall estimate the annual usage of the Customer (based upon the connected gas consuming appliances or equipment) for the purpose of the initial assignment of a Rate Schedule. Where selection of the most favorable schedule is difficult to predetermine, the Company shall, at the request of the C~~c~~ustomer, assist the C~~c~~ustomer in selecting a Rate Schedule.~~.~~ Subsequent to service activation, the C~~c~~ustomer shall be given reasonable opportunity to change to another Rate Schedule, but the Company shall not be required to make refunds for any previous billing under any Rate Schedules selected by the C~~c~~ustomer prior to the time of receipt of a written notice from the C~~c~~ustomer requesting to change to another Rate Schedule.

13.2 ESTABLISHMENT OF CUSTOMER CREDIT

The Company may require a prospective Customer to satisfactorily establish credit before G~~g~~as Delivery Service will be initiated. Such establishment of credit shall not relieve the prospective Customer from complying with the Company's provisions herein for prompt payment of bills. Credit will be deemed so established, and no deposit required, if any one of the following criteria is satisfied:

(a) The Customer has been a Customer of the Company or other similar Delaware utility in the past two (2) years and;
  (1) paid the final bill when due, and
  (2) did not on more than two (2) occasions during the last twelve (12) consecutive months have a bill unpaid after a reasonable period of time after the due date, and
  (3) did not have service discontinued for non-payment, and
  (4) can provide the Company with a letter from the last utility substantiating a good payment history; or

(b) The Customer owns or is purchasing the residence for which the gas service is requested; or,

(c) The Customer can provide a guarantor satisfactory to the Company. This guarantee shall be in writing and must continue in full force and effect for one (1) year from installation date of the service or until Customer's credit is otherwise established, or

(d) The Non-residential Customer possesses and maintains an Experian Intelliscore of sixty (60) or above, or

RULES AND REGULATIONS

SECTION XIII
(Continued)

13.2 ESTABLISHMENT OF CUSTOMER CREDIT (Continued)

(e) The Non-residential Customer possesses and maintains at least an investment grade bond/long-term debt rating from either Standard and Poor's or Moody's. Comparable ratings may be considered from other nationally recognized rating organizations acceptable to the Company. In the event a Customer, whose annual gas consumption exceeds one hundred thousand (100,000) Ccf, does not possess a debt rating or the rating is below investment grade, credit may be established, at the sole discretion of the Company, by the Customer's demonstration of adequate financial strength and stability. The Company may evaluate the Customer's creditworthiness by review of at least two (2) years audited financial statements, accompanied by the opinion of an independent certified public accountant or chartered accountants of recognized national or regional standing, and such other known or discovered factors relating to the Customer's creditworthiness.

(f) The Customers for which credit is established pursuant to this Section 13.2 are subject to periodic review by the Company to assure that no material changes adversely affecting the Customer's creditworthiness have occurred. In the event a material change has occurred, or the Customer has paid its account with a check dishonored by a bank, the Company may request that credit be established by (i) cash deposit, or (ii) irrevocable letter of credit from a bank, or (iii) surety bond.

(g) Notwithstanding anything stated herein to the contrary, a s~~S~~ecurity d~~D~~eposit shall be required if the C~~c~~ustomer has been disconnected by the Company for non-payment within the nine (9) months prior to the C~~c~~ustomer's application for service.

When none of the above conditions are met or service has been discontinued (see Section 14.1-b) the C~~c~~ustomer shall make a deposit with the Company subject to the following:

(a) Amount of d~~D~~eposit required may not be more than two-twelfths (2/12) of the estimated charges for the ensuing twelve (12) months, nor less than five dollars ($5~~.00~~). Residential deposits in excess of one hundred dollars ($100)~~.00~~ may be made with an initial deposit of one hundred dollars ($100)~~.00~~ with the remainder to be paid over the ensuing four (4) ~~-~~week period.

(b) Interest on a deposit shall be simple interest at an annual rate equal to the average of the percent yields of the 1-year Treasury constant maturities for September, October, and November of the preceding year.~~Interest on a deposit shall be 6 per cent per annum, except that no interest will be paid on deposits held less than 90 days.~~ Interest will be paid at the time the deposit is returned. The deposit ceases to draw interest on the date service is terminated, or in the case of good credit, the date the deposit is processed for refund. No interest will be paid on deposits held less than ninety (90) days.

Issue Date: ~~September 2, 2008~~
Effective Date: ~~For Bills Rendered on and after September 3, 2008~~
Authorization: ~~Order No. 7434 dated September 2, 2008 in PSC Docket No. 07-186~~

RULES AND REGULATIONS

SECTION XIII
(Continued)

13.2 ESTABLISHMENT OF CUSTOMER CREDIT (Continued)

(c) Deposits will be refunded to residential C~~c~~ustomers following payment of twelve (12) consecutive bills without arrears.

(d) Refund of d~~D~~eposit upon discontinuance of service will occur promptly and automatically for the deposit and accrued interest less the C~~c~~ustomer's final outstanding balance. A transfer of service from one premises to another within the service area may not be deemed a discontinuance of service.

(e) At the option of the Company a deposit plus accrued interest may be refunded in whole or in part, at any time earlier than the times prescribed in this ~~document~~Tariff.

(f) Commercial deposits will be returned when, in the Company's judgement, such deposit is no longer required.

13.3 BILLING PERIOD

Rates are stated on a monthly basis and bills are rendered monthly following the supply of service based on meter readings to the nearest one hundred (100) or one thousand (1,000) cubic feet, depending on the applicable Rate Schedule, scheduled at approximate monthly intervals of twenty-eight (28) to thirty-four (34) days.

An initial period of less than ten (10) days is included in the next month's billing. If the period is more than ten (10) days, a bill is rendered at the regular billing date. A final period, consisting of the number of days from the most recent meter reading to turn off, will be billed as one (1) month. The Customer is liable for service taken after notice to terminate their service until the meter is read and gas shut off. The final bill for service is due and payable upon presentation. Credit balances in a final bill that are five dollars ($5) or more will be refunded to the C~~c~~ustomer.

13.4 PAYMENT PERIOD

~~Bills are due upon presentation~~. The rates are contingent upon prompt payment. The final date for payment will not fall on any Saturday, Sunday or holiday, and will be due within twenty (20)~~10~~ days of the bill date.~~ir date of presentation.~~ Failure to receive the bill will not excuse the Customer from payment obligations, and payments must be made without regard to any counter claims whatsoever.

RULES AND REGULATIONS

SECTION XIII
(Continued)

13.5 BUDGET PLAN

The Budget Plan is designed for the C~~c~~ustomers under Rate Schedules RS-1, ERS-1, RS-2, ERS-2, GS, and EGS, with their account in good standing, and at least twelve (12) months of consumption history.~~.~~ Seasonal heating bills are spread over the B~~b~~udget P~~p~~lan period (September through May) with equal monthly payments. The Customer's higher monthly bills during the winter heating season are distributed over a nine~~ten~~-(9) month period, with any under or over billing for the season appearing on and being due with the June bill.

If a RS-1, ERS-1, RS-2, ERS-2, GS, or EGS C~~c~~ustomer elects to use the B~~b~~udget P~~p~~lan, the estimated ~~gas~~ bills for the B~~b~~udget P~~p~~lan period will be based upon prior consumption at the particular location for a similar period of time, corrected for current conditions. The estimated total bill for the period is~~totaled and~~ divided by the respective number of months to produce the approximate budget payment, which will then be rounded off to the nearest dollar~~ $1.00~~. Subsequent ~~A~~adjustments to the monthly budget payment amount will~~ may~~ be made by the Company to compensate ~~-~~for temperature and/or rate changes during the Budget Plan period~~if necessary~~, with the Customer receiving immediate notification of their new Budget Plan payment amount.

~~If a Customer has no past history of gas use, the Company will estimate the gas consumption and the projected billing amount for the budget plan period and divide by the respective number of months to produce the budget payments. The Company~~The Company~~ shall require the Customer to provide information on the number, type and size of all gas consuming appliances, along with information on the premises size and type to aid the Company in estimating gas consumption. The Company may adjust the budget payment, with the Customer receiving immediate notification of any adjustment.~~

To remain on the B~~b~~udget P~~p~~lan, a C~~c~~ustomer must pay the current budget payment by the due date each month and pay all balances due as they appear on the bill at the end of the B~~b~~udget P~~p~~lan period.

The Company will normally require that the Customer begin the B~~b~~udget pP~~l~~an in September of each year.

13.6 DISPUTED BILLS

Upon receipt of the Customer's initial complaint prior to due date, the Company will extend to the Customer an additional five (5) days to allow for investigation and review of complaint. During time allotted for investigation and review of the complaint, the Company will not discontinue service or require the C~~c~~ustomer to provide a security deposit. The final date when payment is due after settlement of complaint shall be ten (10) days.

Issue Date: ~~September 2, 2008~~

Effective Date: ~~For Bills Rendered on and after September 3, 2008~~

Authorization: ~~Order No. 7434 dated September 2, 2008 in PSC Docket No. 07-186~~

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SECTION XIII
(Continued)

13.7 UNAUTHORIZED USE

The use of service obtained from the Company without authority may be terminated by the Company without notice. The use of service without notifying the Company and enabling it to read its meter, will render the user liable for any amount due for service supplied to the premises from the time of the last reading of the meter, immediately preceding user's~~his~~ occupancy, as shown by the books of the Company.

13.8 RETURNED PAYMENTS ~~CHARGE~~

Payment for s~~S~~ervices provided under this Tariff, Customer deposits, or other Tariff charges which are returned unpaid by the Customer's bank or other financial institution shall result in an additional twenty dollar ($20) Returned Payment Charge per occurrence and will be charged against the Customer's account. ~~charge included on Sheet No. 46 (Miscellaneous Customer Charges, and will be charged against the customer's account. Failure to pay the full amount of the bill including the Returned Payment Charge may result in a discontinuance of the Customer's service.~~ After the second returned payment the Company reserves the right to notify the C~~c~~ustomer that an alternate payment method ~~(other than a personal check or bank debit)~~ will be required f~~t~~or future payments. ~~of the Company's bill statements.~~

Failure to pay the full amount of the bill including the Returned Payment Charge will result in a discontinuance of the Customer's service. The Company may discontinue service without prior notice if an invalid payment is used to restore service or satisfy a disconnect notice.

13.9 ADJUSTMENTS FOR INCORRECT BILLINGS

Incorrect billings resulting from clerical error or improper service classifications shall be corrected immediately upon discovery and correct billings rendered to the C~~c~~ustomer; however, in no case may additional charges due from the C~~c~~ustomer be collected for more than three (3) years prior to the month of discovery. In the event a C~~c~~ustomer is overcharged, the overbilling will be refunded to the date the error was made, not to exceed five (5) years, such refund shall be paid to the C~~c~~ustomer within sixty (60) days after the error is discovered. Installment payments will be arranged equal to the number of months the account was billed in error in the event additional charges are due the Company, and the installment payments are due and payable in addition to the C~~c~~ustomer's regular monthly natural gas service bill.

RULES AND REGULATIONS
SECTION XIV - DISCONNECTION BY THE COMPANY

14.1 DISCONNECTION BY THE COMPANY

The Company may discontinue service and remove its property without being liable to the Customer, or to tenants or occupants of the premises served, for any loss, cost, damage or expense occasioned by such refusal, discontinuance or removal, for any of the following reasons:

(a) Customer's failure to comply with any of the provisions of the contract, or any applicable regulations of the Commission, or any of the Company's applicable rules or practices currently in effect.

(b) Customer's non-payment of bill at present or former location. A written notice shall set forth the date service will be discontinued, which shall not be less than five (5) days from the date of mailing of such notice.

(c) Customer's failure to provide a deposit to insure payment of bills, when requested by the Company under the provisions of S~~s~~ection 13.2.

(d) After a reasonable request for access to its meter or meters is refused, or if access thereto is obstructed or hazardous.

(e) The Customer's failure to maintain ~~his~~ their equipment in safe condition, in the judgment of the Company.

(f) The Customer's abuse, fraud, or tampering with the connections, meters or other equipment of the Company.

(g) The Customer's equipment or use thereof might injuriously affect the equipment of the Company, or the Company's service to other C~~c~~ustomers.

The notice provided for in this Section shall consist of five (5) days' written notice sent by first class prepaid mail deposited in a United States mailbox and addressed to the Customer at ~~his~~ the Customer's last known mailing address appearing on the records of the Company.

The Company may discontinue service without notice for reasons (e), (f), or (g) above; but, except in emergency situations, in no event shall such termination occur between 12:00 noon on any Friday and 12:00 noon on the succeeding Monday. Should Friday be a legal, state or national holiday, the last preceding business day shall be substituted for Friday. Should Monday be a state or national, legal holiday, the next succeeding business day shall be substituted for Monday. Except in cases of safety or in emergency situations, in no event shall termination occur on a day when the temperature is thirty-two (32) degrees Fahrenheit or below at 8:00 a.m.

RULES AND REGULATIONS

SECTION XIV
(Continued)

14.1 DISCONNECTION BY THE COMPANY (Continued)

The Company may discontinue service without prior notice if an invalid check is used to restore service or to satisfy a disconnect notice.

The Company will comply with the Commission rules regarding weather conditions or medical conditions for disconnections. Except in case of emergency situations, in no event shall ~~such~~ termination occur for non-payment if any occupant of any dwelling unit shall be so ill that the termination of such sale or service shall adversely affect ~~his~~ their health or recovery, which has been so certified by a signed statement from any duly licensed physician, physician assistant or advanced nurse practitioner, of this State or of a state with similar accreditation and received by an authorized agent of the Company. Signed statements from a licensed physician, physician assistant or advanced nurse practitioner, obtained pursuant to this section are effective for one hundred twenty (120) days. Signed statements may be renewed by means of a new signed statement to prevent termination only if a customer makes a good faith effort to make payments towards the utility service being provided.~~a statement from any duly licensed physician of this State or any accredited Christian Science practitioner and received by any authorized agent of the Company, prior to the due date of the bill. The Company's medical waiver of discontinuance of service shall not extend beyond one hundred twenty (120) days unless the need for such extension is certified by a statement from any duly licensed physician of this State or any accredited Christian Science practitioner and received by an authorized agent of the Company~~.

14.2 SEASONAL RECONNECTION AND RECONNECTION CHARGES

Whenever a residential C~~c~~ustomer's gas is turned off or a Customer's meter is disconnected by the Company at the C~~c~~ustomer's request, and the account placed on inactive status, and such account is reactivated by the same C~~c~~ustomer no less than thirty (30) days and not more than one hundred eighty (180) days from the ~~state~~ date of the disconnect, a Seasonal Reconnection Charge equal to the monthly Customer Charge in the Customer's applicable Rate Schedule for each month the account was inactive, plus the Reconnection Charge shall be paid. Such payment, along with other satisfactory arrangements for reconnection, shall be made with the Company for reconnection by the end of the next business day. Details of the charges are contained on Sheet No. 46 (Miscellaneous Customer Charges).

Whenever a C~~c~~ustomer's gas shall be turned off or ~~his~~ such Customer's meter disconnected by reason of non- compliance with these Rules and Regulations or orders of the Public Service Commission of Delaware, a reconnection charge must be paid and other satisfactory arrangements made with the Company prior to 3:00 p.m. of a normal business day before the gas will be turned on again. Details of the charge are contained on Sheet No. 46 (Miscellaneous Customer Charges).

Issue Date: ~~September 2, 2008~~

Effective Date: ~~For Bills Rendered on and after September 3, 2008~~

Authorization: ~~Order No. 7434 dated September 2, 2008 in PSC Docket No. 07-186~~

RULES AND REGULATIONS

SECTION XIV
(Continued)

If the ~~c~~Customer desires that the initial gas service connection or gas service reconnection following disconnection by the Company for any reason, be completed on the same day as the request is received by the Company or outside the Company's normal business hours, such After Hours Reconnection may be performed, subject to the availability of Company personnel. The After Hours Connection or Reconnection Charge must be paid. Details of the charges are contained on Sheet No. 46 (Miscellaneous Customer Charges).

Service interruptions may be avoided by paying the overdue amount prior to the past due date of the gas bill, or by paying the overdue amount plus a collection fee to the Company or an authorized agent of the Company. Details of the charge are contained on Sheet No. 46 (Miscellaneous Customer Charges).

14.3 NON-COMPLIANCE BY COMPANY

Failure on part of the Company to enforce any of its rights at any time shall not be deemed a waiver of any of its rights.

Issue Date: **September 2, 2008**
Effective Date: For Bills Rendered on and after September 3, 2008
Authorization: Order No. 7434 dated September 2, 2008 in PSC Docket No. 07-186

RULES AND REGULATIONS

SECTION XV - TERMINATION OF SERVICE

15.1 TERMINATION BY COMPANY

The Company's obligation to serve a particular premise shall, at the option of the Company cease and terminate (1) in case the property served is vacated or a change of occupancy occurs; (2) in case of an assignment for the benefit of creditors; (3) in case of the illegal use of gas.

15.2 TERMINATION BY CUSTOMER

A Customer who intends to vacate a premises, discontinue the use of Gas, or terminate the liability to pay for gas delivered to the premises, shall give at least five (5) days~~'~~ notice to the Company prior to the date of service termination. The Company shall take its final read of the terminating C~~c~~ustomer's meter, within normal business hours, on the date designated by the Customer as the termination date, but shall have no obligation to read the meter before the fifth (5th) day following receipt of the Customer's termination notice. If such notice is not given, the Customer shall be liable for g~~G~~as registered by the meter until the meter is read by the Company and the account terminated. Receipt of a notice to discontinue gas service from a Customer with a contract term of service shall not relieve such Customer from any minimum or guaranteed payment under such contract.

15.3 FINAL BILL

The Customer is liable for service taken after notice to terminate their~~his~~ service until the meter is read and gas shut off. The final bill for service is due and payable upon presentation. Credit balances on a final bill that are five dollars ($5) or more will be refunded to the Customer.

Issue Date: ~~**September 2, 2008**~~

Effective Date: ~~**For Bills Rendered on and after September 3, 2008**~~

Authorization: ~~**Order No. 7434 dated September 2, 2008 in PSC Docket No. 07-186**~~

RULES AND REGULATIONS

SECTION XVI - APPLICATION OF RATES

16.1 DEFINITION OF THE TERM "CUSTOMER"

For the purpose of applying rate schedules in this ~~natural gas~~ T~~t~~ariff, the term "C~~c~~ustomer" is defined as any individual, firm, or organization purchasing natural gas delivery service and gas sales service or transportation and balancing service in any one (1) month at one (1) location for one (1) classification of service through one (1) meter. Each individual C~~c~~ustomer shall be properly accounted for and identified in the Company's billing system through the combination of a Customer Account number and a Service Identification and Extension number. The schedule of rates is based on delivering and billing service to the end user for retail service only and does not permit resale or redistribution, unless otherwise specified in the T~~t~~ariff.

A "month" does not refer to a calendar month, but shall mean the period between any two scheduled consecutive readings of the meters by the Company.

In those cases where, at the Company's election, two (2) or more meters are installed at a single metering location on the same premises for the same C~~c~~ustomer for the same class of service, the amount of gas supplied through all such meters will be combined in arriving at the total charge, and the customer charge will be the same as though one (1) meter was installed.

Where a single commercial, industrial, or institutional C~~c~~ustomer occupies more than one (1) unit of space in the conduct of the same business, each separate unit will be metered separately and considered a distinct C~~c~~ustomer, unless the C~~c~~ustomer makes the necessary provisions to permit metering of all gas used for each class of service in the various units at a single metering location. This rule shall apply only where the units are located on contiguous property with no intervening public property or private property controlled by others. Only one (1) service connection will be provided for each class of service furnished, and the metering location shall be as close as possible to the point of service entrance.

RATE SCHEDULE "RS - 1"

RESIDENTIAL SERVICE - 1

AVAILABILITY

This R~~r~~ate S~~s~~chedule is available to any individually metered C~~c~~ustomer using gas in a residential dwelling or unit for space heating, cooking, water heating, or other domestic purpose with an annual consumption of two hundred forty (240) Ccf or less. The Company will annually review those C~~c~~ustomers receiving service under this R~~r~~ate S~~s~~chedule in order to determine the appropriate firm residential R~~r~~ate S~~s~~chedule should their annual consumption warrant such a change. A Customer on RS-1 Service will be moved to Rate Schedule with annual consumption equal to or greater than two hundred sixty-four (264) Ccf. This annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between R~~r~~ate S~~s~~chedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the C~~c~~ustomer's location apply to all C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule.

Customer Charge:	$15.00~~10.50~~	per month
First 20 Ccf	$0.852~~0.607~~	per Ccf
Next 30 Ccf	$0.525~~0.280~~	per Ccf
Over 50 Ccf	$0.415~~0.170~~	per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule are subject to the gas cost rate applicable to Rate Schedule "RS-1" provided on Sheet No. 42.

PAYMENT TERMS

Bills are due within twenty~~ten~~ (20~~10~~) days of their date.

MINIMUM BILL

The minimum monthly bill under this R~~r~~ate S~~s~~chedule is the C~~c~~ustomer charge.

Issue Date: ~~**September 2, 2008**~~
Effective Date: ~~**For Bills Rendered on and after September 3, 2008**~~
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SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this R~~r~~ate S~~s~~chedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the C~~c~~ustomer in one (1) location only and is not to be shared or sold to others.

(3) In addition to the above Delivery Service rates, C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

REVENUE NORMALIZATION ADJUSTMENT ("RNA"):

The Delivery Service Revenue for Customers under this Rate Schedule is adjusted quarterly via a separate line item on the bill titled "Revenue Normalization Adjustment." The RNA is calculated to reflect a targeted annual average margin per customer for this Rate Schedule as established in PSC Docket No. 15- _____, specifically $278 per Customer. The RNA is determined under the guidelines approved on Sheet No. 42.5.

RATE SCHEDULE "RS - 2"

RESIDENTIAL SERVICE – 2

AVAILABILITY

This R~~r~~ate S~~s~~chedule is available to any individually metered C~~c~~ustomer using gas in a residential dwelling or unit for space heating, cooking, water heating, or other domestic purpose with annual consumption of greater than two hundred forty (240) Ccf. The Company will annually review those C~~c~~ustomers receiving service under this R~~r~~ate S~~s~~chedule in order to determine the appropriate firm residential R~~r~~ate S~~s~~chedule should their annual consumption warrant such a change. A Customer on RS-1 Service will be moved to this R~~r~~ate S~~s~~chedule with annual consumption equal to or greater than two hundred sixty-four (264) Ccf. A Customer on this R~~r~~ate S~~s~~chedule will be moved to RS-1 Service with annual consumption less than two hundred sixteen (216) Ccf. This annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between R~~r~~ate S~~s~~chedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the C~~c~~ustomer's location apply to all C~~c~~ustomers served under this R~~r~~ate~~ ~~S~~s~~chedule.

Customer Charge:	$17.00~~13.00~~	per month
First 20 Ccf	$0.656~~0.578~~	per Ccf
Next 30 Ccf	$0.397~~0.319~~	per Ccf
Over 50 Ccf	$0.210~~0.132~~	per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule are subject to the gas cost rate applicable to Rate Schedule "RS-2" provided on Sheet No. 42.

PAYMENT TERMS

Bills are due within twenty~~ten~~ (20~~10~~) days of their date.

MINIMUM BILL

The minimum monthly bill under this R~~r~~ate S~~s~~chedule is the C~~c~~ustomer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this R~~r~~ate S~~s~~chedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the C~~c~~ustomer in one (1) location only and is not to be shared or sold to others.

(3) In addition to the above Delivery Service rates, C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

REVENUE NORMALIZATION ADJUSTMENT ("RNA"):

The Delivery Service revenue for Customers under this Rate Schedule is adjusted quarterly via a separate line item on the bill titled "Revenue Normalization Adjustment." The RNA is calculated to reflect a targeted annual average margin per customer for this Rate Schedule as established in PSC Docket No. 15- _____, specifically $453 per Customer. The RNA is determined under the guidelines approved on Sheet No. 42.5.

RATE SCHEDULE "ERS-1"

EXPANSION AREA RESIDENTIAL SERVICE – 1

AVAILABILITY

This R~~r~~ate S~~s~~chedule is available to any individually metered C~~c~~ustomer within the southeastern Sussex County, Delaware, expansion area using gas in a residential dwelling or unit for space heating, cooking, water heating, or other domestic purpose with an annual consumption of two hundred forty (240) Ccf or less. The southeastern Sussex County, Delaware, expansion area is defined as the area east of Chesapeake's district regulator station located on Route 9 in Lewes, Delaware, that is connected to Chesapeake's distribution main and any area that is connected to Chesapeake's distribution main behind the three (3) Eastern Shore Natural Gas transmission pipeline City Gates located in Dagsboro, Frankford, and Selbyville, Delaware. The Company will annually review those C~~c~~ustomers receiving service under this R~~r~~ate S~~s~~chedule in order to determine the appropriate firm residential R~~r~~ate S~~s~~chedule should their annual consumption warrant such a change. A Customer on ERS-1 Service will be moved to Rate Schedule ERS-2 with annual consumption equal to or greater than two hundred sixty-four (264) Ccf. This annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between R~~r~~ate S~~s~~chedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the C~~c~~ustomer's location apply to all C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule.

Customer Charge:	$16.50	per month
First 20 Ccf	$0.852~~0.607~~	per Ccf
Next 30 Ccf	$0.525~~0.280~~	per Ccf
Over 50 Ccf	$0.415~~0.170~~	per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule are subject to the gas cost rate applicable to Rate Schedule "ERS" provided on Sheet No. 42.

PAYMENT TERMS

Bills are due within twenty~~ten~~ (20~~10~~) days of their date.

RATE SCHEDULE "ERS-1"

EXPANSION AREA RESIDENTIAL SERVICE – 1
(Continued)

MINIMUM BILL

The minimum monthly bill under this R~~r~~ate S~~s~~chedule is the C~~c~~ustomer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this R~~r~~ate S~~s~~chedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the C~~c~~ustomer in one (1) location only and is not to be shared or sold to others.

(3) In addition to the above Delivery Service rates, C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

REVENUE NORMALIZATION ADJUSTMENT (“RNA”):

The Delivery Service revenue for Customers under this Rate Schedule is adjusted quarterly via a separate line item on the bill titled “Revenue Normalization Adjustment.” The RNA is calculated to reflect a targeted annual average margin per customer for this Rate Schedule as established in PSC Docket No. 15-____, specifically $335 per Customer. The RNA is determined under the guidelines approved on Sheet No. 42.5.

RATE SCHEDULE "ERS-2"

EXPANSION AREA RESIDENTIAL SERVICE – 2

AVAILABILITY

This R~~r~~ate S~~s~~chedule is available to any individually metered C~~c~~ustomer within the southeastern Sussex County, Delaware, expansion area using gas in a residential dwelling or unit for space heating, cooking, water heating, or other domestic purpose with annual consumption of greater than two hundred forty (240) Ccf. The southeastern Sussex County, Delaware, expansion area is defined as the area east of Chesapeake's district regulator station located on Route 9 in Lewes, Delaware, that is connected to Chesapeake's distribution main and any area that is connected to Chesapeake's distribution main behind the three (3) Eastern Shore Natural Gas transmission pipeline City Gates located in Dagsboro, Frankford, and Selbyville, Delaware. The Company will annually review those C~~c~~ustomers receiving service under this R~~r~~ate S~~s~~chedule in order to determine the appropriate firm residential R~~r~~ate S~~s~~chedule should their annual consumptions warrant such a change. A Customer on ERS-1 Service will be moved to this R~~r~~ate S~~s~~chedule with annual consumption equal to or greater than two hundred sixty-four (264) Ccf. A Customer on this R~~r~~ate S~~s~~chedule will be moved to ERS-1 Service with annual consumption less than two hundred sixteen (216) Ccf. This annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between R~~r~~ate S~~s~~chedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the C~~c~~ustomer's location apply to all C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule.

Customer Charge:	$31.75 per month
First 20 Ccf	$0.656~~0.578~~ per Ccf
Next 30 Ccf	$0.397~~0.319~~ per Ccf
Over 50 Ccf	$0.210~~0.132~~ per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule are subject to the gas cost rate applicable to Rate Schedule "ERS" provided on Sheet No. 42.

PAYMENT TERMS

Bills are due within twenty~~ten~~ (20~~10~~) days of their date.

Issue Date: ~~**November 5, 2013**~~
Effective Date: ~~**For Bills Rendered on and after December 1, 2013**~~
Authorization: ~~**Order No. 8479 in PSC Docket No. 12-292 dated November 5, 2013**~~

RATE SCHEDULE ""ERS-2""

EXPANSION AREA `RESIDENTIAL SERVICE – 2
(Continued)

MINIMUM BILL

The minimum monthly bill under this Rrate Sschedule is the Ccustomer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this Rrate Sschedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the ""Availability"" clause above.

(2) Natural gas purchased hereunder is for the use of the Ccustomer in one (1) location only and is not to be shared or sold to others.

(3) In addition to the above Delivery Service rates, Ccustomers served under this Rrate Sschedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

REVENUE NORMALIZATION ADJUSTMENT (“RNA”):

The Delivery Service revenue for Customers under this Rate Schedule is adjusted quarterly via a separate line item on the bill titled “Revenue Normalization Adjustment.” The RNA is calculated to reflect a targeted annual average margin per customer for this Rate Schedule as established in PSC Docket No. 15-____, specifically $620 per Customer. The RNA is determined under the guidelines approved on Sheet No. 42.5.

RATE SCHEDULE ~~"~~“GS~~"~~”
GENERAL SERVICE

AVAILABILITY

This R~~r~~ate S~~s~~chedule is available to any C~~c~~ustomer using gas for commercial and/or industrial purposes with an annual consumption of less than four thousand (4,000) Ccf. The Company will annually review those C~~c~~ustomers receiving service under this R~~r~~ate S~~s~~chedule in order to determine the appropriate firm commercial and/or industrial R~~r~~ate S~~s~~chedule should their annual consumption warrant such a change. A Customer on General Service will be moved to Rate Schedule MVS with annual consumption equal to or greater than four thousand four hundred (4,400) Ccf. This annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between R~~r~~ate S~~s~~chedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the C~~c~~ustomer’s location apply to all C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule.

Customer Charge:	$34.00~~26.00~~	per month
First 20 Ccf	$0.506~~0.447~~	per Ccf
Next 30 Ccf	$0.337~~0.278~~	per Ccf
Over 50 Ccf	$0.199~~0.140~~	per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, C~~c~~ustomers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule “GS” provided on Sheet No. 42.

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial C~~c~~ustomers on this Rate Schedule~~with annual consumption through one or more contiguous meters in a specific geographic location equal to, or greater than, 30,000 Ccf per year that choose to have their own gas transported through the Company’s distribution system. Customers purchasing natural gas from a supplier, other than the Company, must have the natural gas delivered to the Company’s city gate in accordance with~~ who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the C~~c~~ustomer is subject to the following Firm Balancing Service Rate applied to all gas consumption.

Firm Balancing Service Rate: **$0.081** per Ccf of gas consumed

RATE SCHEDULE "GS"

GENERAL SERVICE
(Continued)

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the C~~c~~ustomer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty~~ten~~ (20~~10~~) days of their date.

MINIMUM BILL

The minimum monthly bill under this R~~r~~ate S~~s~~chedule is the C~~c~~ustomer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this R~~r~~ate S~~s~~chedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the C~~c~~ustomer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of compressed natural gas ("CNG") to third parties.~~.~~

(3) A firm C~~c~~ustomer that transfers from Gas Sales Service to Transportation and Balancing Service, as authorized under the Company's T~~t~~ariff, may be required to pay a transition charge in the future to prevent the remaining firm Gas Sales Service C~~c~~ustomers from having to absorb stranded fixed gas supply costs which would otherwise be collected from the firm Gas Sales Service C~~c~~ustomers switching to Transportation and Balancing Service.

(4) A firm C~~c~~ustomer that transfers from Gas Sales Service to Transportation and Balancing Service or to Interruptible Sales Service, as authorized under the Company's T~~t~~ariff, will be billed for or receive credit for any under or over collection of gas costs from prior periods.

(5) In addition to the above Delivery Service rates, C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

Issue Date: ~~**July 21, 2015**~~
Effective Date: ~~**For Bills Rendered on and after September 1, 2015**~~

Authorization: ~~**Order 8752 in PSC Docket No. 13-383 dated July 21, 2015**~~

RATE SCHEDULE "~~E~~GS"

~~EXPANSION AREA~~ GENERAL SERVICE

(Continued)

REVENUE NORMALIZATION ADJUSTMENT ("RNA"):

The Delivery Service revenue for Customers under this Rate Schedule is adjusted quarterly via a separate line item on the bill titled "Revenue Normalization Adjustment." The RNA is calculated to reflect a targeted annual average margin per customer for this Rate Schedule as established in PSC Docket No. 15-_____, specifically $663 per Customer. The RNA is determined under the guidelines approved on Sheet No. 42.5.

RATE SCHEDULE “EGS”

EXPANSION AREA GENERAL SERVICE
~~(Continued)~~

AVAILABILITY

This R~~r~~ate S~~s~~chedule is available to any C~~c~~ustomer within the southeastern Sussex County, Delaware, expansion area using gas for commercial and/or industrial purposes with an annual consumption of less than four thousand (4,000) Ccf. The southeastern Sussex County, Delaware, expansion area is defined as the area east of Chesapeake’s district regulator station located on Route 9 in Lewes, Delaware, that is connected to Chesapeake’s distribution main and any area that is connected to Chesapeake’s distribution main behind the three (3) Eastern Shore Natural Gas transmission pipeline City Gates located in Dagsboro, Frankford, and Selbyville, Delaware. The Company will annually review those C~~c~~ustomers receiving service under this R~~r~~ate S~~s~~chedule in order to determine the appropriate firm commercial and/or industrial rate schedule should their annual consumption warrant such a change. A Customer on Rate Schedule EGS will be moved to Rate Schedule EMVS with annual consumption equal to or greater than four thousand four hundred (4,400) Ccf This annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between R~~r~~ate S~~s~~chedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the C~~c~~ustomer’s location apply to all C~~c~~ustomers served under this ~~r~~Rate S~~s~~chedule.

Customer Charge:	$56.00 per month
First 20 Ccf	$0.506~~0.447~~ per Ccf
Next 30 Ccf	$0.337~~0.278~~ per Ccf
Over 50 Ccf	$0.199~~0.140~~ per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, C~~c~~ustomers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule “EGS” provided on Sheet No. 42.

~~TRANSPORTATION AND BALANCING RIDER~~

~~Transportation service is available to commercial and industrial customers with annual consumption through one or more contiguous meters in a specific geographic location equal to, or greater than, 30,000 Ccf per year that choose to have their own gas transported through the Company’s distribution system. Customers purchasing natural gas from a supplier, other than the Company,~~
~~must have the natural gas delivered to the Company’s city gate in accordance with the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the customer is subject to the following Firm Balancing Service Rate applied to~~

~~all gas consumption~~

~~Firm Balancing Service Rate~~~~:~~ ~~$0.081 per Ccf of gas consumed~~

~~PUBLIC UTILITIES TAX~~

~~The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the customer is exempt from such tax.~~

~~PAYMENT TERMS~~

~~Bills are due within ten (10) days of their date.~~

~~MINIMUM BILL~~

~~The minimum monthly bill under this rate schedule is the customer charge.~~

~~SPECIAL TERMS AND CONDITIONS OF SERVICE~~

~~(1)~~ ~~Service under this rate schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.~~

~~(2)(1)~~ ~~Natural gas purchased hereunder is for the use of the customer in one location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles.~~

Issue Date: **~~September 1, 2015~~**
Effective Date: **~~For Service Rendered on and after November 1, 2015 – Temporary Basis~~**
Authorization: **~~Order No. 8792 in PSC Docket No. 15-1362 dated September 22, 2015~~**

RATE SCHEDULE "EGS"

EXPANSION AREA GENERAL SERVICE
(Continued)

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial C~~c~~ustomers on this Rate Schedule ~~with annual consumption through one or more contiguous meters in a specific geographic location equal to, or greater than, 30,000 Ccf per year that choose to have their own gas transported through the Company's distribution system. Customers purchasing natural gas from a supplier, other than the Company,must have the natural gas delivered to the Company's city gate in accordance with~~ who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the C~~c~~ustomer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate: $0.081 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the C~~c~~ustomer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty~~ten~~ (20~~10~~) days of their date.

MINIMUM BILL

The minimum monthly bill under this R~~r~~ate S~~s~~chedule is the C~~c~~ustomer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this R~~r~~ate S~~s~~chedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the C~~c~~ustomer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

~~**SPECIAL TERMS AND CONDITIONS OF SERVICE (Continued)**~~

~~(3) A firm customer that transfer from Gas Sales Service to Transportation an Balancing Service, as authorized under the Company's tariff, may be required to pay a transition charge in the future to prevent the remaining firm Gas Sales Service customers from having to absorb stranded fixed~~

~~gas supply costs which would otherwise be collected from the firm Gas Sales Service customers switching to Transportation and Balancing Service.~~

~~(4)~~(3) ~~A firm customer that transfers from Gas Sales Service to Transportation and Balancing Service or to Interruptible Sales Service, as authorized under the Company's tariff, will be billed for or receive credit for any under or over collection of gas costs from prior periods.~~

~~(5)~~(3) ~~In addition to the above Delivery Service rates, customers served under this rate schedule may be subject to one or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.~~

Issue Date: ~~**July 21, 2015**~~
Effective Date: ~~**For Bills Rendered on and after September 1, 2015**~~
Authorization: ~~**Order 8752 in PSC Docket No. 13-383 dated July 21, 2015**~~

RATE SCHEDULE "EGS"

EXPANSION AREA GENERAL SERVICE
(Continued)

SPECIAL TERMS AND CONDITIONS OF SERVICE (Continued)

(3) A firm C~~c~~ustomer that transfers from Gas Sales Service to Transportation and Balancing Service, as authorized under the ~~Company~~Company's T~~t~~ariff, may be required to pay a transition charge in the future to prevent the remaining firm Gas Sales Service C~~c~~ustomers from having to absorb stranded fixed gas supply costs which would otherwise be collected from the firm Gas Sales Service C~~c~~ustomers switching to Transportation and Balancing Service.

(4) A firm C~~c~~ustomer that transfers from Gas Sales Service to Transportation and Balancing Service or to Interruptible Sales Service, as authorized under the ~~Company~~Company's T~~t~~ariff, will be billed for or receive credit for any under or over collection of gas costs from prior periods.

(5) In addition to the above Delivery Service rates, C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

REVENUE NORMALIZATION ADJUSTMENT ("RNA"):

The Delivery Service revenue for Customers under this Rate Schedule is adjusted quarterly via a separate line item on the bill titled "Revenue Normalization Adjustment." The RNA is calculated to reflect a targeted annual average margin per customer for this Rate Schedule as established in PSC Docket No. 15-_____, specifically $897 per Customer. The RNA is determined under the guidelines approved on Sheet No. 42.5.

Issue Date:
Effective Date:
Authorization:

RATE SCHEDULE "MVS"
MEDIUM VOLUME SERVICE

AVAILABILITY

This R~~r~~ate S~~s~~chedule is available to any C~~c~~ustomer using gas for commercial and/or industrial purposes with an annual consumption generally equal to or greater than four thousand (4,000) Ccf and less than fifteen thousand (15,000) Ccf. The Company will annually review those Customers receiving service under this R~~r~~ate S~~s~~chedule in order to determine the appropriate firm commercial and/or industrial R~~r~~ate S~~s~~chedule should their annual consumption warrant such a change. A Customer on General Service will be moved to this R~~r~~ate S~~s~~chedule with annual consumption equal to or greater than four thousand four hundred (4,400) Ccf. A Customer on this R~~r~~ate S~~s~~chedule will be moved to General Service with annual consumption less than three thousand six hundred (3,600) Ccf. The annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between R~~r~~ate S~~s~~chedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the C~~c~~ustomer's location apply to all C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule.

Customer Charge:	$80.00~~65.00~~ per month
First 200 Ccf	$0.237~~0.227~~ per Ccf
Over 200 Ccf	$0.125~~0.115~~ per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, C~~c~~ustomers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "MVS" provided on Sheet No. 42.

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial C~~c~~ustomers on this Rate ~~with annual consumption through one or more contiguous meters in a specific geographic location equal to, or greater than, 30,000 Ccf per year that choose to have their own gas transported through the Company's distribution system. Customers purchasing natural gas from a supplier, other than the Company, must have the natural gas delivered to the Company's city gate in accordance with~~ who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the customer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate: $0.091 per Ccf of gas consumed

Issue Date: ~~**September 1, 2015**~~
Effective Date: ~~**For Service Rendered on and after November 1, 2015 – Temporary Basis**~~
Authorization: ~~**Order No. 8792 in PSC Docket No. 15-1362 dated September 22, 2015**~~

RATE SCHEDULE "MVS"

MEDIUM VOLUME SERVICE

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the C~~c~~ustomer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty~~ten~~ (20~~10~~) days of their date.

MINIMUM BILL

The minimum monthly bill under this R~~r~~ate S~~s~~chedule is the C~~c~~ustomer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this R~~r~~ate S~~s~~chedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the C~~c~~ustomer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

(3) A firm C~~c~~ustomer that transfers from Gas Sales Service to Transportation and Balancing Service, as authorized under the Company's T~~t~~ariff, may be required to pay a transition charge in the future to prevent the remaining firm Gas Sales Service C~~c~~ustomers from having to absorb stranded fixed gas supply costs which would otherwise be collected from the firm Gas Sales Service C~~c~~ustomers switching to Transportation and Balancing Service.

(4) A firm C~~c~~ustomer that transfers from Gas Sales Service to Transportation and Balancing Service or Interruptible Sales Service, as authorized under the Company's T~~t~~ariff, will be billed for or receive credit for any under or over collection of gas costs from prior periods.

(5) In addition to the above Delivery Service rates, C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

Authorization: ~~**Order 8752 in PSC Docket No. 13-383 dated July 21, 2015**~~

RATE SCHEDULE “EMVS”

EXPANSION AREA MEDIUM VOLUME SERVICE

AVAILABILITY

This R~~r~~ate S~~s~~chedule is available to any C~~c~~ustomer within the southeastern Sussex County, Delaware, expansion area using gas for commercial and/or industrial purposes with an annual consumption generally equal to or greater than four thousand (4,000) Ccf and less than fifteen thousand (15,000) Ccf. The southeastern Sussex County, Delaware, expansion area is defined as the area east of Chesapeake’s district regulator station located on Route 9 in Lewes, Delaware, that is connected to Chesapeake’s distribution main and any area that is connected to Chesapeake’s distribution main behind the three (3) Eastern Shore Natural Gas transmission pipeline City Gates located in Dagsboro, Frankford, and Selbyville, Delaware. The Company will annually review those Customers receiving service under this R~~r~~ate S~~s~~chedule in order to determine the appropriate firm commercial and/or industrial R~~r~~ate S~~s~~chedule should their annual consumption warrant such a change. A Customer on Rate Schedule EGS will be moved to this R~~r~~ate S~~s~~chedule with annual consumption equal to or greater than four thousand four hundred (4,400) Ccf. A Customer on this R~~r~~ate S~~s~~chedule will be moved to R~~r~~ate S~~s~~chedule EGS with annual consumption less than three thousand six hundred (3,600) Ccf. The annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between R~~r~~ate S~~s~~chedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the C~~c~~ustomer’s location apply to all C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule.

Customer Charge:	$158.75 per month
First 200 Ccf	$0.237~~0.227~~ per Ccf
Over 200 Ccf	$0.125~~0.115~~ per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, C~~c~~ustomers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule “EMVS” provided on Sheet No. 42.

Issue Date: ~~**July 21, 2015**~~
Effective Date: ~~**For Bills Rendered on and after September 1, 2015**~~
Authorization: ~~**Order 8752 in PSC Docket No. 13-383 dated July 21, 2015**~~

RATE SCHEDULE "EMVS"

EXPANSION AREA MEDIUM VOLUME SERVICE
(Continued)

TRANSPORTATION AND BALANCING RIDER

Transportation service is available to commercial and industrial C~~c~~ustomers on this Rate ~~with annual consumption through one or more contiguous meters in a specific geographic location equal to, or greater than, 30,000 Ccf per year that choose to have their own gas transported through the Company's distribution system. Customers purchasing natural gas from a supplier, other than the Company, must have the natural gas delivered to the Company's city gate in accordance with~~ who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the C~~c~~ustomer is subject to the following Firm Balancing Service Rate applied to all gas consumption

Firm Balancing Service Rate: $0.091 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the C~~c~~ustomer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty~~ten~~ (20~~10~~) days of their date.

MINIMUM BILL

The minimum monthly bill under this R~~r~~ate S~~s~~chedule is the C~~c~~ustomer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this R~~r~~ate S~~s~~chedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the C~~c~~ustomer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

RATE SCHEDULE "EMVS"

EXPANSION AREA MEDIUM VOLUME SERVICE
(Continued)

SPECIAL TERMS AND CONDITIONS OF SERVICE (Continued)

(3) A firm C~~c~~ustomer that transfers from Gas Sales Service to Transportation and Balancing Service, as authorized under the Company's T~~t~~ariff, may be required to pay a transition charge in the future to prevent the remaining firm Gas Sales Service C~~c~~ustomers from having to absorb stranded fixed gas supply costs which would otherwise be collected from the firm Gas Sales Service C~~c~~ustomers switching to Transportation and Balancing Service.

(4) A firm C~~c~~ustomer that transfers from Gas Sales Service to Transportation and Balancing Service or Interruptible Sales Service, as authorized under the Company's T~~t~~ariff, will be billed for or receive credit for any under or over collection of gas costs from prior periods.

(5) In addition to the above Delivery Service rates, C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

RATE SCHEDULE "LVS"

LARGE VOLUME SERVICE

AVAILABILITY

This R~~r~~ate S~~s~~chedule is available to any C~~c~~ustomer using gas for commercial and/or industrial purposes with an annual consumption generally equal to or greater than fifteen thousand (15,000) Ccf. The Company will annually review those C~~c~~ustomers receiving service under this R~~r~~ate S~~s~~chedule in order to determine the appropriate firm commercial and/or industrial R~~r~~ate S~~s~~chedule should their annual consumption warrant such a change. A Customer on Medium Volume Service will be moved to this R~~r~~ate S~~s~~chedule with annual consumption equal to or greater than sixteen thousand five hundred (16,500) Ccf. A Customer on this R~~r~~ate S~~s~~chedule will be moved to Medium Volume Service with annual consumption less than thirteen thousand five hundred (13,500) Ccf. The annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between R~~r~~ate S~~s~~chedules due to changes in annual consumption other than at the annual review time.

DELIVERY SERVICE RATES

The following rates for delivering gas to the C~~c~~ustomer's location apply to all C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule.

Customer charge:	$175.00~~125.00~~ per month
First 1000 Ccf	$0.218~~0.326~~ per Ccf
Over 1000 Ccf	$0.088~~0.083~~ per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, C~~c~~ustomers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "LVS" provided on Sheet No. 42.

Issue Date: ~~**September 2, 2008**~~
Effective Date: ~~**For Bills Rendered on and after September 3, 2008**~~
Authorization: ~~**Order No. 7434 dated September 2, 2008 in PSC Docket No. 07-186**~~

RATE SCHEDULE "LVS"

LARGE VOLUME SERVICE
(Continued)

TRANSPORTATION AND BALANCING SERVICE

Transportation service is available to commercial and industrial C~~c~~ustomers on this Rate Schedule ~~with annual consumption through one or more contiguous meters in a specific geographic location equal to, or greater than, 30,000 Ccf per year that choose to have their own gas transported through the Company's distribution system. Customers purchasing natural gas from a supplier, other than the Company, must have the natural gas delivered to the Company's city gate in accordance with~~ who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service rate applied to all gas consumption.

Firm Balancing Service Rate: $0.073 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the C~~c~~ustomer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty~~ten~~ (20~~10~~) days of their date.

MINIMUM BILL

The minimum monthly bill under this R~~r~~ate S~~s~~chedule is the C~~c~~ustomer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this R~~r~~ate S~~s~~chedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the C~~c~~ustomer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

RATE SCHEDULE "LVS"

LARGE VOLUME SERVICE
(Continued)

SPECIAL TERMS AND CONDITIONS OF SERVICE (Continued)

(3) A firm C~~c~~ustomer that transfers from Gas Sales Service to Transportation and Balancing Service, as authorized under the Company's T~~t~~ariff, may be required to pay a transition charge in the future to prevent the remaining firm Gas Sales Service C~~c~~ustomers from having to absorb stranded fixed gas supply costs which would otherwise be collected from the firm Gas Sales Service C~~c~~ustomers switching to Transportation and Balancing Service.

(4) A firm C~~c~~ustomer that transfers from Gas Sales Service to Transportation and Balancing Service or to Interruptible Sales Service, as authorized under the Company's T~~t~~ariff, will be billed for or receive credit for any under or over collection of gas costs from prior periods.

(5) In addition to the above Delivery Service rates, C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

RATE SCHEDULE "HLFS"
HIGH LOAD FACTOR SERVICE

AVAILABILITY

This R~~r~~ate S~~s~~chedule is available to any C~~c~~ustomer using gas for commercial and/or industrial purposes that would otherwise qualify for Medium Volume Service or Large Volume Service and with winter months' consumption, defined as the months of January through March, being less than thirty-five percent (35%) of their annual consumption. In addition, the C~~c~~ustomer must use natural gas in at least eleven (11) of the twelve (12) months under review and usage must be fairly evenly distributed throughout the review period. The Company will annually review those Customers receiving service under this R~~r~~ate S~~s~~chedule in order to determine the appropriate firm commercial and/or industrial R~~r~~ate S~~s~~chedule should their annual consumption or winter months consumption warrant such a change. A Customer will remain on this R~~r~~ate S~~s~~chedule as long as winter months' consumption is less than thirty-seven percent (37%) of their annual consumption and the Customer qualifies for Medium Volume Service or Large Volume Service. The annual review process will be based on the twelve (12) months ended August. Customers will not be shifted between R~~r~~ate S~~s~~chedules due to changes in annual consumption or winter months' consumption other than after the annual review.

DELIVERY SERVICE RATES

The following rates for delivering gas to the C~~c~~ustomer's location apply to all C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule.

Customer Charge:	$125.00~~75.000~~	per month
All gas consumed	$0.0800~~0.087~~	per Ccf

GAS SALES SERVICE

In addition to the above Delivery Service rates, C~~c~~ustomers purchasing their natural gas supply from the Company are subject to the gas cost rate applicable to Rate Schedule "HLFS" provided on Sheet No. 42.

Issue Date: ~~September 2, 2008~~
Effective Date: ~~For Bills Rendered on and after September 3, 2008~~
Authorization: ~~Order No. 7434 dated September 2, 2008 in PSC Docket No. 07-186~~

RATE SCHEDULE "HLFS"
HIGH LOAD FACTOR SERVICE
(Continued)

TRANSPORTATION AND BALANCING SERVICE

Transportation service is available to commercial and industrial C~~c~~ustomers on this Rate ~~with annual consumption through one or more contiguous meters in a specific geographic location equal to, or greater than, 30,000 Ccf per year that choose to have their own gas transported through the Company's distribution system. Customers purchasing natural gas from a supplier, other than the Company, must have the natural gas delivered to the Company's city gate in accordance with~~ who meet the eligibility requirements set forth in the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the C~~c~~ustomer is subject to the following Firm Balancing Service rate applied to all gas consumption

Firm Balancing Service Rate: $0.024 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the C~~c~~ustomer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty~~ten~~ (20~~10~~) days of their date.

MINIMUM BILL

The minimum monthly bill under this R~~r~~ate S~~s~~chedule is the C~~c~~ustomer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this R~~r~~ate Schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the C~~c~~ustomer in one (1) location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles and except for sale or transportation of CNG to third parties.

Issue Date: ~~**September 1, 2015**~~
Effective Date: ~~**For Service Rendered on and after November 1, 2015 – Temporary Basis**~~
Authorization: ~~**Order No. 8792 in PSC Docket No. 15-1362 dated September 22, 2015**~~

RATE SCHEDULE "HLFS"

HIGH LOAD FACTOR SERVICE
(Continued)

SPECIAL TERMS AND CONDITIONS OF SERVICE (Continued)

(3) A firm C~~c~~ustomer that transfers from Gas Sales Service to Transportation and Balancing Service, as authorized under the Company's T~~t~~ariff, may be required to pay a transition charge in the future to prevent the remaining firm Gas Sales Service C~~c~~ustomers from having to absorb stranded fixed gas supply costs which would otherwise be collected from the firm Gas Sales Service C~~c~~ustomers switching to Transportation and Balancing Service.

(4) A firm C~~c~~ustomer that transfers from Gas Sales Service to Transportation and Balancing Service or to Interruptible Sales Service, as authorized under the Company's T~~t~~ariff, will be billed for or receive credit for any under or over collection of gas costs from prior periods.

(5) In addition to the above Delivery Service rates, C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

RATE SCHEDULE "NGV"

NATURAL GAS VEHICLE

SERVICE AVAILABILITY

This R~~r~~ate S~~s~~chedule is available to any C~~c~~ustomer operating a motor vehicle that is capable of using compressed natural gas ("CNG") as a fuel if the equipment installed on the vehicle meets industry recognized standards and if the operator is authorized by the Company to fuel a motor vehicle with the CNG as the result of completing the Company's training program or a program determined by the Company, in its sole discretion, to be an equivalent training program.

This gas service will be available at Chesapeake Utilities Corporation, 350 South Queen Street, Dover, Delaware 19904. Service hereunder is subject to availability of the Company's gas supply, adequate distribution system capabilities and other resources available to and as determined by the Company.

This gas service is subject to interruption, at the Company's option, at any time during the year without notice and for an indefinite period of time. The Company has no obligation whatsoever to make CNG available to any C~~c~~ustomer and may interrupt service at any time without notice.

TERM

Service under this contract will terminate, with ninety (90) days' notice, at the discretion of the Company or the Commission. This notice shall be given by registered letter.

COMMODITY CHARGE (Posted Price)

The price per Ccf of CNG will be posted at the CNG Station on the first (1st) day of each month and will be set at the average price for CNG for the central Atlantic region as published by the U.S. Department of Energy in its most recent Clean Cities Alternative Fuel Price Report or its successor publication, plus any applicable tax imposed by any governmental entity on natural gas sales or CNG sales.

The price charged to any C~~c~~ustomer will be reduced from the posted price to the extent the posted price includes a tax or taxes imposed by any governmental entity on natural gas sales or CNG sales and the C~~c~~ustomer is exempt from such tax or taxes.

If the C~~c~~ustomer is exempt from federal or state taxes imposed with respect to sales of CNG for motor vehicle use, the price charged to the C~~c~~ustomer will be reduced from the posted price by the tax or taxes on CNG from which the C~~c~~ustomer is exempt.

In no event will CNG be sold if the price as determined above is below the price level established for Company-Use Gas.

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RATE SCHEDULE "GLR"

GAS LIGHTING SERVICE

AVAILABILITY

This R~~r~~ate S~~s~~chedule is available for unmetered residential outdoor gas lights as herein specified where the Company's existing distribution mains and services are suitable to supply such service.

DELIVERY SERVICE RATE

The following rate for delivering gas to the C~~c~~ustomer's location applies to all C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule.

Each 2 cu. ft./hr. or less $16.72~~11.75~~ per month.

GAS SALES SERVICE

In addition to the above Delivery Service rates, C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule are subject to the gas cost rate applicable to Rate Schedule "GLR" provided on Sheet No. 42.

PAYMENT TERMS

Bills are due within twenty~~ten~~ (20~~10~~) days of their date.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this R~~r~~ate S~~s~~chedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) The Customer shall install and own the lighting devices.

(3) In addition to the above Delivery Service rates, C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

RATE SCHEDULE "GLO"

GAS LIGHTING SERVICE

AVAILABILITY

This R~~r~~ate S~~s~~chedule is available for unmetered outdoor gas lights for other than residential use as herein specified where the Company's existing distribution mains and services are suitable to supply such service.

DELIVERY SERVICE RATE

The following rate for delivering gas to the C~~c~~ustomer's location applies to all C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule.

Each 2 cu. ft./hr. or less $16.72~~11.75~~ per month.

GAS SALES SERVICE

In addition to the above Delivery Service rates, C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule are subject to the gas cost rate applicable to Rate Schedule "GLO" provided on Sheet No. 42.

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the C~~c~~ustomer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty~~ten~~ (~~10~~20)~~)~~ days of their date.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this R~~r~~ate S~~s~~chedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) The Customer shall install and own the lighting devices.

(3) In addition to the above Delivery Service rates, C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

RATE SCHEDULE "NCR"

NEGOTIATED CONTRACT RATE

AVAILABILITY

This negotiated contract T~~t~~ariff provision enables the Company to respond to Customers' competitive options in the energy services market. The Company shall use this negotiated contract T~~t~~ariff to compete with alternate pricing situations resulting from, but not limited to, fuel switching, facility relocation or expansion, partial or complete plant production ~~-~~shifting, potential physical bypass, or other options available to the Customer. The Company shall use the provisions of this T~~t~~ariff only after a determination by the Company and the Customer that other existing T~~t~~ariff options will not meet the Customer's needs.

ELIGIBILITY

This contract T~~t~~ariff is available to any qualifying Customer as specified herein. Customer qualification shall be based upon meeting each of the following criteria as determined solely by the Company:

(1) The Customer has an economic competitive alternative to full or partial service from the Company's standard T~~t~~ariff rates, as determined by the Company;

(2) The Customer is likely to select said alternative if the Company does not provide a negotiated contract rate; and

(3) The price to the Customer will provide net revenues above the incremental costs to provide service under this negotiated contract rate~~.~~; and

(4) The Customer desires fixed pricing for a term of one (1) year or more which requires a gas supply tailored to the specified term and pricing conditions.

The Company shall determine eligibility on a case-by-case basis based upon information supplied by the Customer and in accordance with the Company's internal pricing guidelines. The Company's decision on the application shall consider the economics of the competitive alternative, as well as the practical aspects of securing that alternative (e.g., ability to secure environmental permitting, feasibility studies, switching ability, ability to secure required capital).

Issue Date: ~~**April 28, 2010**~~
Effective Date: ~~**For Bills Rendered on and after June 1, 2010**~~
Authorization: ~~**Order No. 7781 dated June 1, 2010 in PSC Docket No. 10-159**~~

RATE SCHEDULE "NCR"

NEGOTIATED CONTRACT RATE
(Continued)

SERVICE OPTIONS

If the Company concludes that the Customer meets all the eligibility requirements listed above, the Company shall enter into negotiations with the Customer for the purpose of offering such services as are believed to meet the Customer's requirements. Competitive offers may be made in a manner which provides the Customer with numerous choices for service. A menu of service options differentiated by contract term, quantity, pricing options, and service attributes may be made available to the qualifying Customer.

RATE

Pricing for delivery service only, a combination of delivery service and gas supply, and balancing service shall be determined on a case-by-case basis according to the nature of the competitive situation. The final arrangements between the Company and the Customer shall be included in the c~~C~~ontract.

PUBLIC UTILITES TAX

All rates and charges under this R~~r~~ate S~~s~~chedule, including gas cost if applicable, are subject to the Delaware Public Utilities Tax unless the Customer is exempt from such tax.

CONTRACT TERM

The contract term shall be specified in a contract between the Customer and the Company. The minimum term of any contract will be one (1) year and the maximum term will be five (5) years.

SPECIAL TERMS AND PROVISIONS

(1) Upon agreement on service options, the Customer and the Company shall enter into a contract which specifies the services and the terms and conditions of providing the services. The Customer must sign the c~~C~~ontract prior to commencement of this service and any investment by the Company. Service under the contractual agreement will commence on the date specified in the contract.

RATE SCHEDULE "NCR"

NEGOTIATED CONTRACT RATE
(Continued)

SPECIAL TERMS AND PROVISIONS (Continued)

(2) The contract shall be considered a confidential document between the Company and the Customer. By signing the contract, the Customer and the Company agree not to share the contract or information contained within the contract with anyone except the parties to the contract, the ~~Delaware~~ Public Service Commission of Delaware and the Office of the Public Advocate, unless given written consent from the other party. Violations by the Customer of the confidentiality agreement shall permit the Company to immediately terminate the contract with the Customer and serve the Customer under another rate schedule for which the Customer qualifies. The Customer shall also be responsible for the penalty provision described below and additional damages or prejudices to any other existing or potential contracts resulting from the breach of confidentiality.

(3) The contract between the Company and the Customer shall include penalty provisions for early contract cancellation. If at any time prior to the end of the contract term the Customer elects to terminate the contractual agreement with the Company without exercising a re-contracting option for continuing service, the Customer shall be obligated to the terms for cancellation as specified within the contract.

(4) The Company may offer value-added services in conjunction with the contract. All service attributes agreed to between the Company and the Customer shall be included in the contract.

(5) The Company shall file all required information with the ~~Delaware~~ Public Service Commission of Delaware within thirty (30) days of the executed Contract.

RATE SCHEDULE "ITS"

INTERRUPTIBLE TRANSPORTATION SERVICE

AVAILABILITY

This R~~r~~ate S~~s~~chedule is available to any non-residential C~~c~~ustomer with annual consumption of at least one hundred thousand (100,000) Ccf with facilities in operating condition capable of utilizing an alternative fuel due to the fact gas service provided is subject to complete interruption at any time during the year at the Company's option. The definition of an alternative fuel under this rate schedule shall be propane, fuel oil, or electricity. When applying for service under this Rate Schedule, the Customer is required to provide the Company, in writing, with the type and specific grade of alternative fuel utilized by the Customer. The Customer shall submit, within thirty (30) days of any change in operations, written notification when such change affects its alternate fuel capability. The Customer must also purchase all of its gas from or through a qualified supplier of natural gas as set forth in Rate Schedule SUP.

DELIVERY SERVICE RATE

Customer charge: $935.00 per month

The rate per Ccf of consumption shall be determined on an individual C~~c~~ustomer basis according to the nature of the interruptible service to be provided. This rate can be adjusted upon one (1) day's notice to the Customer.

TRANSPORTATION AND BALANCING SERVICE

Customers must have the natural gas delivered to the Company's city gate in accordance with the Transportation and Balancing Rider General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rate, the Customer is subject to the following Interruptible Balancing Service rate applied to all gas consumption.

Interruptible Balancing Service Rate: $0.014 per Ccf of gas consumed

RATE SCHEDULE "ITS"

INTERRUPTIBLE TRANSPORTATION SERVICE
(Continued)

PUBLIC UTILITIES TAX

The Delivery Service, Interruptible Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the C~~c~~ustomer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty~~ten~~ (20~~10~~) days of their date.

MINIMUM BILL

The minimum monthly bill under this R~~r~~ate S~~s~~chedule is the C~~c~~ustomer charge.

CONTRACT TERMS

The contract term shall be specified in a contract between the Customer and the Company. The minimum term of any contract will be one (1) year.

SERVICE INTERRUPTION

The Company will endeavor to provide as much notice as possible to Customers prior to any interruption or~~of~~ curtailment of gas delivery service. Customer agrees to accept complete interruption of service upon at least four (4) hours advance notice from any hour of the day. If the Customer fails to interrupt service, the Customer shall pay a P~~p~~enalty R~~r~~ate of five dollars ($5) per Ccf in addition to the currently effective rate. The Penalty Rate, which shall be credited to firm C~~c~~ustomers through the GSR mechanism, shall remain in effect until such time as the Company, in its sole discretion, determines that normal service can be restored. The Customer agrees to hold the Company harmless from any loss, cost or damage occasioned by the interruption of service resulting from the Company's enforcement of this provision. In the event the Customer has an emergency that would cause the Customer great hardship if gas service is interrupted, the Company may, at its sole discretion based on available gas supply, waive interruption for a specified period of time. If the Customer fails to interrupt by the end of the specified period, the Customer shall pay the penalty shown above.

Issue Date: ~~**September 2, 2008**~~
Effective Date: ~~**For Bills Rendered on and after September 3, 2008**~~
Authorization: ~~**Order No. 7434 dated September 2, 2008 in PSC Docket No. 07-186**~~

RATE SCHEDULE "ITS"

INTERRUPTIBLE TRANSPORTATION SERVICE
(Continued)

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this R~~r~~ate S~~s~~chedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Service purchased hereunder is for the use of the Customer in one (1) location only and is not to be shared or sold to others.

(3) Service hereunder will be interrupted at the sole discretion of the Company.

(4) Service hereunder will not be supplied from the Company's peaking facilities unless the Company waives the interruption of service due to an emergency.

(5) In addition to the above Delivery Service rates, C~~c~~ustomers served under this R~~r~~ate S~~s~~chedule may be subject to one (1) or more riders containing additional charges applicable to the service received, such as ER and any applicable franchise fees.

RATE SCHEDULE "IBE"

INTERRUPTIBLE BEST EFFORTS SALES SERVICE

AVAILABILITY

This R~~r~~ate S~~s~~chedule is available to any commercial or industrial transportation C~~c~~ustomer or S~~s~~upplier for use as an interruptible gas supply for deliveries to or upstream of the distribution system or to any entity for off-system deliveries to replace third-party gas for any reason or to serve incremental loads. This service is available only on a best efforts basis subject to the ability of the Company to obtain gas supply and subject to interruption for any reason determined by the Company. Service under this R~~r~~ate S~~s~~chedule must be scheduled no later than 7:00 a.m. of the day before service is to begin. Transportation Customers that have a third-party supply interrupted will be subject to any applicable penalties that accrue before this service is scheduled.

DELIVERY SERVICE RATE

The rate for delivering gas to the Customer's location through the Company's distribution system will be at the Delivery Service rate set forth in the R~~r~~ate S~~s~~chedule under which the Customer normally receives service.

GAS SERVICE RATE

The gas rate for natural gas service shall be a negotiated, market-based rate. Any margins received under this rate shall be credited eighty percent (80%) to the firm customers through the GSR mechanism with twenty percent (20%) being retained by the Company.

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the C~~c~~ustomer is exempt from such tax.

PAYMENT TERMS

Bills are due within twenty~~ten~~ (20~~10~~) days of their date.

CONTRACT TERMS

The contract term shall be specified in a contract between the Customer and the Company. The minimum term of any contract is one (1) day.

RATE SCHEDULE "IBE"

INTERRUPTIBLE BEST EFFORTS SALES SERVICE
(Continued)

SERVICE INTERRUPTION

The C~~c~~ustomer agrees to accept complete interruption of service upon at least four (4) hour advance notice from any hour of the day. If the customer fails to interrupt service, the C~~c~~ustomer shall pay a P~~p~~enalty R~~r~~ate of five dollars ($5) per Ccf in addition to the currently effective rates. The Penalty Rate, which shall be credited to firm C~~c~~ustomers through the GSR mechanism, shall remain in effect until such time as the Company, in its sole discretion, determines that normal service can be restored. The C~~c~~ustomer agrees to hold the Company harmless from any loss, cost or damage occasioned by the interruption of service resulting from the Company's enforcement of this provision. In the event the C~~c~~ustomer has an emergency that would cause the C~~c~~ustomer great hardship if gas service is interrupted, the Company may, at its sole discretion based on available gas supply, waive interruption for a specified period of time. If the C~~c~~ustomer fails to interrupt by the end of the specified period, the C~~c~~ustomer shall pay the penalty shown above.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this R~~r~~ate S~~s~~chedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Service purchased hereunder is for the use of the C~~c~~ustomer in one (1) location only and is not to be shared or sold to others.

(3) Service hereunder will be interrupted at the sole discretion of the Company.

(4) Service hereunder will not be supplied from the Company's peaking facilities unless the Company waives the interruption of service due to an emergency.

Issue Date: ~~**September 2, 2008**~~
Effective Date: ~~**For Bills Rendered on and after September 3, 2008**~~
Authorization: ~~**Order No. 7434 dated September 2, 2008 in PSC Docket No. 07-186**~~

RATE SCHEDULE "GSR"

GAS SALES SERVICE RATES

FIRM SALES RATE SCHEDULES

The Gas Sales Service Rates applicable to the respective firm R~~r~~ate S~~s~~chedules, as listed below, will be applied to all C~~c~~ustomers served on that schedule based on a volumetric charge per Ccf (100 cubic feet). The Gas Sales Service Rates only apply to the respective firm R~~r~~ate S~~s~~chedules listed below and do not apply to the Interruptible Transportation Service, Transportation Service, Negotiated Contract Rate, and Interruptible Best Efforts Sales Service. The Gas Sales Service Rates will be calculated to the nearest tenth of a cent (.1¢).

The following lists the applicable Gas Sales Service Rates for the respective firm R~~r~~ate S~~s~~chedules as defined in this T~~t~~ariff:

RATE SCHEDULE	GAS SALES SERVICE RATES
RS, ERS, GS, EGS, MVS, EMVS LVS	$0.681 per Ccf
HLFS	$0.488 per Ccf
GLR and GLO	$0.218 per Ccf

These rates are subject to change based on actual and estimated gas costs. The ~~Company~~The Company will file with the Commission a copy of these Gas Sales Service Rates at least sixty (60) days prior to the regularly scheduled adjustment date, which shall be each November 1.

The November 1 rates will be based on a projected twelve (12) ~~-~~month period of November through October (projected period). The rates computed under this R~~r~~ate S~~s~~chedule shall remain in effect for the projected period provided the latest estimated over collection does not exceed 4½% or the latest estimated under collection does not exceed 6% of the actual firm gas costs incurred to date along with the Company's latest firm gas cost estimates for the remainder of the over/under collection period (over/under period). The twelve (12) ~~-~~month period used for the calculation of the over/under period will be based on the actual nine (9) months ended July 31 of each year and the projected three (3) months ended October 31 of each year. If it appears that the use of these rates for the twelve (12) ~~-~~month over/under period will result in an over or under collection exceeding these limits, the Company shall apply to the Commission for revised rates to be effective until the next annual adjustment in the rates.

Issue Date: ~~**September 1, 2015**~~
Effective Date: ~~**For Service Rendered on and after November 1, 2015 – Temporary Basis**~~
Authorization: ~~**Order No. 8792 in PSC Docket No. 15-1362 dated September 22, 2015**~~

RATE SCHEDULE "GSR"
GAS SALES SERVICE RATES
(Continued)

OVERALL METHODOLOGY

The overall projected firm gas costs for the twelve (12) ~~-~~month projected period shall include:

(1) Natural gas purchased from any S~~s~~upplier; plus

(2) Liquefied petroleum gas (LPG); plus

(3) Liquefied natural gas (LNG); plus

(4) Other hydrocarbons distributed to C~~c~~ustomers or used as feedstock for production of substitute natural gas (SNG); plus

(5) Storage, transportation, and any other gas related costs, including costs related to the gas supply department; plus

(6) Charges paid to the Company's S~~s~~uppliers for past periods unless disallowed by ~~Delaware~~ the Public Service Commission of Delaware; less

(7) The projected commodity gas costs for Interruptible Service; less

(8) The demand and commodity gas costs for Negotiated Contract Rate C~~c~~ustomers who are not charged the gas sales service rate associated with a firm R~~r~~ate S~~s~~chedule; less

(9) The commodity gas costs for Interruptible Best Efforts Sales Service; less

(10) All demand and commodity S~~s~~upplier refunds received from the Company's S~~s~~uppliers; less

(11) The firm sales C~~c~~ustomers receipt of one hundred percent (100~~-~~%) of the firm and interruptible transportation balancing service margins which will be a demand related gas cost; less or plus

(12) The over or under collection for the prior over/under period of the actual nine (9) months ended July 31 and the projected three (3) months ended October 31. Interest will be calculated on the actual monthly over or under collection balances net of deferred income taxes at the rate of one-twelfth (1/12th) the annual refund interest rate issued by the Federal Energy Regulatory Commission on a quarterly basis; less or plus

(13) Any other applicable gas cost adjustments~~.~~

Issue Date: ~~**September 2, 2008**~~

Effective Date: ~~**For Bills Rendered on and after September 3, 2008**~~

Authorization: ~~**Order No. 7434 dated September 2, 2008 in PSC Docket No. 07-186**~~

RATE SCHEDULE ~~"~~“GSR~~"~~”

GAS SALES SERVICE RATES
(Continued)

OVERALL METHODOLOGY (Continued)

A Demand Rate will be determined by dividing the total firm fixed cost components by the firm peak day capacity requirements. A Commodity Rate will be determined by dividing the total firm commodity cost components by total firm consumption for the respective determination period.

ALLOCATION TO RESPECTIVE FIRM RATE SCHEDULES

Rate Schedule HLFS ~~-~~– High Load Factor Service will be charged a single gas cost rate per Ccf based on the combination of a weighted average Demand and Commodity Rate developed on an overall seventy-one and fifty-seven one hundredths percent (71.57%) load factor for the customer class with the overall system weighted average gas cost rate. The purchased gas costs will be allocated to this Rate Schedule based on its annual consumption for the projected period.

Rate Schedule GLO, GLR ~~-~~– The Gas Lighting Services will be charged the weighted average Demand and Commodity Rates through a single gas cost rate per Ccf based on a one hundred percent (100%) load factor. The purchased gas costs will be allocated to this Rate Schedule based on its annual consumption for the projected period.

Rate Schedule RS-1, ERS-1, RS-2, ERS-2, GS, EGS, MVS, EMVS, LVS ~~-~~– These rate schedules will be assigned the remaining firm purchased gas costs after the firm purchased gas costs have been allocated to the above mentioned Rate Schedules less the portion of any shared margins resulting from capacity release, or off-system sales. These Rate Schedules will be charged a single gas cost rate per Ccf. This rate will reflect the sum of the projected demand and commodity costs for these classes divided by the sum of their annual consumption for the projected period.

MARGIN SHARING

Margins as used herein for off system sales means revenues less: (a) associated gas costs and (b) any applicable taxes based on gross receipts. Margins as used herein for capacity release means revenues less any applicable taxes based on gross receipts. As used in this T~~t~~ariff, the term “Shared Margins” means off system sales margins, and upstream capacity release margins.

RATE SCHEDULE ~~"~~“GSR~~"~~”

GAS SALES SERVICE RATES
(Continued)

MARGIN SHARING (Continued)

During the over/under period, the Company shall retain twenty percent (20%) and the firm customers, as described above, will receive eighty percent (80%) of all Shared Margins resulting from off-system sales. Additionally, during the over/under period, the Company shall retain ten percent (10%) and the firm customers, as described above, will receive ninety percent (90%) of all Shared Margins resulting from upstream capacity release transactions.

UNACCOUNTED FOR GAS INCENTIVE MECHANISM

The Unaccounted For Gas Incentive Mechanism was originally approved by the Commission on an experimental basis for the following three (3) consecutive twelve (12) month ending periods: August 31, 1993, 1994 and 1995. The Commission reviewed the Incentive Mechanism and determined it should be continued beyond the initial three (3) year period by Order No. 4189 in PSC Docket No. 95-206F.

DEFINITIONS

The terms utilized in the Unaccounted For Gas Incentive Mechanism shall have the following meanings:

1. Unaccounted For Gas shall be defined as the difference between total gas sales, billed and unbilled, and total gas send-out, exclusive of C~~c~~ompany-~~-~~use gas and pressure compensated gas volumes.

2. The Unaccounted For Gas Target (UFG-T) shall be ~~3.20~~ three and two tenths percent (3.20%) of total gas sendout or total gas requirements.

3. The Dead Band shall mean +/- one-half percent (0.5%) ~~points~~ around the three and two tenths percent ~~-~~(3.20%) UFG-T. Unaccounted For Gas volumes which are within two and seven tenths percent (2.70%) to three and seven tenths percent (3.70%) of total gas sendout will be considered to be within the "dead band". Unaccounted For Gas volumes within the dead band will be regarded as meeting the objectives of this mechanism.

Issue Date: ~~**September 4, 2009**~~
Effective Date: ~~**For Service Rendered on and after November1, 2009 – Temporary Basis**~~
Authorization: ~~**Order No. 7665 in PSC Docket No. 09-398F dated October 6, 2009**~~

RATE SCHEDULE "GSR"

GAS SALES SERVICE RATES
(Continued)

PROCESS

The Company, as part of its annual Gas Sales Service Rate filing in September, will provide the actual Unaccounted For Gas volumes and total gas sendout for the preceding twelve (12) month period, ended July 31, in order that the Unaccounted For Gas can be expressed as a percentage of total gas sendout. This percentage will be compared to the target percentage of three and two tenths percent (3.20%) with a range of plus or minus one-half percent (+/-0.5%) by the ~~Delaware~~ Public Service Commission of Delaware Staff. The Staff will review the actual Unaccounted For Gas volumes on an annual basis and review the Delaware Division's performance under this mechanism in the next base rate proceeding.

RATE SCHEDULE "RNA"

REVENUE NORMALIZATION ADJUSTMENT

FIRM SALES RATE SCHEDULES

The Revenue Normalization Adjustment (RNA) will be applicable to Customers on Rate Schedules RS-1, ERS-1, RS-2, ERS-2, GS, and EGS.

OVERALL METHODOLOGY

Delivery Service revenues for Customers under the Rate Schedules described above are adjusted quarterly via a separate line item on the bill titled "Revenue Normalization Adjustment." The RNA is calculated to reflect a targeted annual average margin per Customer for each Rate Schedule as established in PSC Docket No. ________. The RNA is determined from the following series of calculations:

(1) Actual Margin per Customer for month and Rate Schedule **-** Targeted Normalized Margin per Customer for month and Rate Schedule **=** the Difference per Customer for month and Rate Schedule;

(2) Difference per Customer for month and Rate Schedule **x** the Customer count for month and Rate Schedule **=** the Over or Under Collection for month and Rate Schedule;

(3) Total Over or Under Collection for quarter **=** Sum of the Over or Under Collection for all Rate Schedules subject to the RNA for three months of the quarter;

(4) Current Quarter RNA Adjustment **=** Over or Under Collection for the quarter ÷ Projected Sales Volume over the next twelve (12) months for all Rate Schedules subject to the RNA;

(5) Total RNA Adjustment **=** the Current Quarter RNA Adjustment **+** the previous three (3) Quarter RNA Adjustments **+** the Annual True-Up.

~~(1)~~(6) Annual True-Up = difference between the Projected RNA Collection and Actual RNA Collection for the previous twelve (12) months ÷ by the Projected Sales Volume over the previous twelve (12) moths for all Rate Schedules subject to the RNA.

Issue Date:
Effective Date:
Authorization:

TRANSPORTATION AND BALANCING RIDER
GENERAL TERMS AND CONDITIONS

1 GENERAL

1.1 Transportation service is available to commercial and industrial <u>C</u>~~c~~ustomers ~~with one or more contiguous meters within a specific geographic location~~ having consumption equal to, or greater than, 30,000 CCF per year. <u>For purposes of meeting the 30,000 CCF threshold, a Customer may aggregate consumption from accounts it holds for meters located on contiguous properties; or in the case of poultry houses, the properties need not be contiguous but must be set up under a common name for billing purposes to qualify for aggregation to meet the threshold.</u> This service provides the Customer with the ability to purchase their own Gas supply (Customer-owned Gas) and transport, or have transported, such Gas to the Company's distribution system. Transportation service consists of the following components with associated charges: (a) the transportation of the Customer-owned Gas through pipeline systems upstream of the Company, including the interstate pipeline system of Eastern Shore Natural Gas Company (ESNG), (b) the transportation of the Customer-owned Gas through the Company's distribution system to the Company's installed meter, (c) balancing the difference between the Volume of Gas provided by the Customer and the Volume of Gas actually consumed by the Customer on a daily basis, and (d) the resolution of imbalances created by the difference between the Volume of Gas the Customer provided and the Volume of Gas the Customer consumed which may exist at the end of a billing Month. Customers utilizing transportation service will be billed for delivery service, balancing service, Capacity, a one-time transition charge (or credit) for under (or over) collection of gas costs from prior periods, and other charges applicable for the rate schedule under which they are served.

1.2 Once approved for transportation service it is necessary for the Customer to execute a firm contract(s) with a Qualified Supplier of Natural Gas and other entities, if necessary, to ensure the firm transportation of such Gas to the Point(s) of Receipt. The Customer is required to notify the Company of the name of its Qualified Supplier prior to the fifteenth (15th) calendar day of the Month preceding the Month for which transportation will commence.

2 DEFINITIONS

Agent: An entity authorized to act on behalf of the Customer, more specifically defined in Section 10 of this Transportation and Balancing Rider.

British Thermal Unit: The amount of heat required to raise the temperature of one (1) pound of water one (1) degree Fahrenheit at 60 degrees Fahrenheit.

Broker: An entity or individual that acts as an intermediary in the sale and purchase of Gas but does not take title to Gas. A Broker can be an Agent.

Effective Date: ~~**For Bills Rendered on and after September 1, 2015**~~
Authorization: ~~**Order 8752 in PSC Docket No. 13-383 dated July 21, 2015**~~

Capacity: The physical space, in dekatherms (DTs), provided by a pipeline for a fixed monthly reservation charge which gives a shipper the right to transport up to a maximum daily Quantity of Gas between defined points on the pipeline's system.

CCF: One hundred (100) cubic feet of Gas.
CCT: Central Clock Time, which includes the recognition of Daylight Savings Time.

Customer: For the purposes of this Transportation and Balancing Rider, Customer shall mean an individual Customer as defined in the Section 16.1 of the Rules and Regulations of this tariff or the aggregation of Customer accounts of one or more contiguous meters in a specific geographic location for the purpose of transporting their own Gas through the Company's distribution system.

Customer-owned Gas: Gas to which the Customer has title clear of any liens and encumbrances.

Daily Contract Quantity (DCQ): The monthly Quantity of Gas scheduled by the Customer to be delivered to the Company's distribution system each Day of the Month, which has been adjusted to account for the Shrinkage Factor.

Flowing Gas: Gas flowing through a pipeline or distribution system excluding Gas taken out of storage.

Gas or Natural Gas: Processed or unprocessed natural gas, vaporized liquid natural gas, synthetic gas, gas from coal seams or any mixture of these gases.

Gas Day or Day: A period of twenty-four (24) consecutive hours, beginning at nine o'clock (9:00) a.m. Central Clock Time (CCT).

Imbalance: Any difference between the Volume of Gas provided by the Customer and the Volume of Gas consumed by the Customer. Nominations are adjusted for thermal content and shrinkage to determine the Volume of Gas provided by the Customer.

Marketer: An entity that purchases and takes title to Gas as an intermediary for sale to a Customer. A Marketer can be an Agent.

MCF: One thousand (1,000) cubic feet of gas.

Month: The period beginning at nine o'clock (9:00) a.m. CCT or the hour otherwise agreed upon by the Customer and the Company on the first Day of the calendar month and ending at the same hour on the first Day of the next succeeding calendar month.

Nomination: The Quantity of Gas, adjusted by the Shrinkage Factor, that the Customer is delivering, or having delivered on its behalf, to a Point(s) of Receipt in the electronic format as provided by the Company.

Point(s) of Delivery: The point(s) at the connection at which the Gas leaves the facilities of the Company and enters the downstream facilities of the Customer.

Point(s) of Receipt: The point(s) at the connection at which the Gas enters the facilities of the Company and leaves the facilities of ESNG.

Qualified Supplier: An entity that has met all qualification requirements as stated in Rate Schedule "SUP", and is deemed capable of holding title to the Gas, and causing it to be delivered to the upstream pipeline interconnect on behalf of the customer.

Quantity of Gas: The Volume of Gas adjusted by the Thermal Factor and expressed in dekatherms, unless otherwise specified.

Replacement Shipper: An entity that takes title to Capacity upstream of the Company's distribution system under the terms of the interstate pipeline's tariff.

Shrinkage Factor: A percentage applied to a Nomination to adjust for Gas lost and unaccounted-for within the Company's distribution system. The Shrinkage Factor shall be determined annually and will be the five-year average.

Summer Peaking Customer: A Customer whose lowest DCQ from November to March does not exceed ten percent (10%) of its highest DCQ for the Year.

Thermal Factor: The amount of British Thermal Units in one MCF of Natural Gas divided by one million. The thermal factor for converting between DT and MCF shall be 1.035 unless otherwise specified by the Company.

Volume of Gas: The number of units of Gas expressed in cubic feet, unless otherwise specified.

Year: A period of three hundred sixty-five (365) consecutive Days; provided, however, that any such Year which contains a date of February 29th shall consist of three hundred sixty-six
(366) consecutive Days.

3 REQUEST FOR TRANSPORTATION SERVICE

Each prospective transportation Customer, or existing transportation Customer seeking enrollment of a new meter, must submit a completed application on the standard form provided by the Company no later than the first (1st) calendar day of the Month preceding the Month in which the transportation service will commence. Service will be provided by the Company based upon the established criteria referenced within the Customer's applicable rate schedule, available capacity and the Customer providing suitable Gas to the Point(s) of Receipt.

4 CONTRACT FOR SERVICE

A Service Agreement with an initial term of one Year must be executed by each A~~a~~pplicant as a condition of receiving transportation service. The Service Agreement shall specify the date on which service is to begin, Point(s) of Receipt and Point(s) of Delivery, the rate schedule(s) under which service is to be provided and other conditions of receipt by the Company and delivery to the Customer. Transportation of Gas will not begin until a fully executed Service Agreement is completed. Service Agreements must be renewed annually, and received by the Company no later than the fifteenth (15th) calendar day of the Month preceding the Month of renewal in order for the customer to continue participating in the transportation program without an interruption of service. The Company may waive the annual renewal requirement at its discretion.

5 GAS TO BE TRANSPORTED BY THE COMPANY

The Customer is responsible for making all arrangements necessary for transporting the Gas to a Point(s) of Receipt in compliance with pressure requirements established by the Company or any upstream pipeline for such Point(s) of Receipt. Gas received for one Customer will be commingled with the Gas of other customers and suppliers. Gas transported by the Company shall be and remain the property of the Customer.

6 QUALITY OF GAS

Gas received by the Company for the account of the Customer shall be Natural Gas conforming to the quality specifications as provided for in the General Terms and Conditions of the tariff of the pipeline that is interconnected to the Company's distribution system. Any Gas entering the Company's system at a Point(s) of Receipt that is not an interconnection with an interstate pipeline must also meet the "pipeline quality" standard set forth above.

7 TITLE TO GAS

The Customer must have good title to all the Gas that enters the Company's distribution system for transportation to a Point(s) of Delivery. Such title shall be free and clear of all liens, encumbrances, and claims whatsoever. The Customer agrees to indemnify and hold the Company harmless against any loss or cost incurred by the Company on account of liens, encumbrances or claims resulting from any possession or transportation by the Company.

8 LIABILITY

The Company shall not be liable for any loss to the Customer arising from or out of transportation service under any rate schedule, including loss of gas in the possession of the Company. The Company makes no guarantee against and assumes no liability for interruptions of service.

9 METERING AND ASSOCIATED EQUIPMENT

Transportation service of Customer-owned Gas to the Point(s) of Delivery is not expected to require any special metering or communication equipment in excess of what would be needed to provide regular delivery and standard Gas sales service. However, there may be situations which will require knowledge of daily usage by transportation Customers that will require additional equipment. If any additional metering or communication equipment is required to provide transportation service, the Customer will reimburse the Company for such equipment and its installation. The Customer shall provide any electrical supply or phone line needed for the operation of any additional equipment. As referenced in Section 11.2 of the Rules and Regulations of this Tariff, remote reading will be utilized for customers with consumption greater than 100,000 annual CCF.

10 AGENTS ACTING ON BEHALF OF THE CUSTOMER

A Customer may use the services of an Agent to act on its behalf for the delivery of Gas to the Company's distribution system. An Agent can be a Broker, Marketer or a Qualified Supplier. All Customers are required to have a Qualified Supplier on record. If a Customer engages the use of an Agent, it is the responsibility of the Customer to notify the Company, using the standard form provided by the Company, of their designation of such Agent to conduct business on their behalf. A Customer may choose to designate an Agent in addition to their Qualified Supplier. Any notices provided to a Customer's Agent shall be deemed to have been provided to the Customer and the Company shall be held harmless from any actions taken by the Agent.

11 COMPANY AS AGENT

The Company may act as Agent for a Customer in securing and transporting Gas supply to a Point(s) of Receipt. The Company shall not be responsible for charges incurred on behalf of the Customer, nor for the performance, non-performance or continued availability of any pipeline or other services. The charges for this service shall be determined by negotiation between the Company and the Customer.

12 DETERMINATION OF DAILY CONTRACT QUANTITY

12.1 A Daily Contract Quantity (DCQ) for each Month for the following twelve (12) month period shall be calculated annually by the Company based on usage during the previous three Years, if available. Previous usage shall be adjusted for normal weather in a matter determined by the Company. The Customer will be obligated to have the DCQ delivered each Day of the Month to the agreed upon Point(s) of Receipt.

12.2 The Company may approve adjustments to the Monthly DCQs on an ongoing basis due to changes in a Customer's Gas equipment, pattern of usage, or any other information affecting demand that is deemed reliable by the Company. To be considered, such information must be provided to the Company in writing from the Customer or the Customer's Agent.

12.3 The Company considers DCQ information to be confidential and proprietary data for the Customer. The Company will only provide usage data to the Customer or the Customer's Agent. If a Customer wishes to authorize a third party to have access to such data the Company must receive a written letter of authorization, on the Customer's official letterhead, and signed by the authority referenced as a contact under the Customer's account information.

12.4 The Company will not provide DCQ information to multiple third parties simultaneously. If multiple parties are requesting DCQ information for the same Customer, the Company will provide that data directly to the Customer or to one Agent for such Customer.

13 NOMINATIONS AND SCHEDULING

13.1 A Customer's DCQ will be considered their daily Nomination. The Company shall require from either the Customer or the Customer's Agent on record a signed DCQ Nomination form. The Nomination form must be received by the Company via mail, electronic mail, or facsimile transmission no later than the fifteenth (15^{th}) calendar day of the Month prior to the first Day of the Month in which transportation service begins, and annually on that date thereafter. If the nomination cannot be confirmed with the delivering pipeline(s) or other source(s), the nomination will be rejected.

13.2 Upon receipt of a completed and properly executed DCQ Nomination form by the Company, the Company will release upstream ESNG transportation Capacity to the Customer, or the Customer's Agent on record, to facilitate the transportation of Gas to the Point(s) of Receipt.

a. The Customer, or Customer's Agent on record, as the recipient of released Capacity becomes the Replacement Shipper with respect to ESNG.
b. For all Customers other than Summer Peaking Customers, the amount of ESNG Capacity to be released will be equal to the highest DCQ within the twelve (12) Months of DCQs calculated.
c. For Summer Peaking Customers, the amount of ESNG Capacity to be released will be equal to the monthly calculated DCQ.
d. ESNG will invoice the Replacement Shipper for all pipeline Capacity and commodity charges associated with the released Capacity.

13.3 Upon the release of Capacity, the Customer, or their Agent on record, shall be responsible for scheduling their DCQ Nomination Quantity on ESNG for the ultimate delivery to the designated Point(s) of Receipt.

13.4 Any variance between the Nomination Quantity and the approved DCQ will be subject to a balancing penalty of $30.00 per DT. Such penalty shall be paid by the Customer in addition to the cost of Gas supply used to serve the customer.

13.5 In the event that changes to existing DCQ's, as referenced in section 12.2, are approved, the Customer is required to resubmit their DCQ nomination sheet by the deadline stated in section 13.1.

14 FIRM BALANCING SERVICE

14.1 Balancing the difference between the Customer's nominated DCQ and the Volume of Gas consumed by the Customer is performed daily by the Company on a firm basis. The Company will charge a Firm Balancing Service Rate pursuant to the applicable rate schedule under which service is provided.

14.2 Any Imbalance for a billing month will be reconciled (*i.e.*, "cashed-in" or "cashed-out") at the Company's weighted average cost at the city gate for Flowing Gas for the calendar month in which most of the billing month occurs. Estimated costs will be used based on nominations made by the Company when the applicable calendar month is not completed before billing the Customer.

14.3 For the purposes of Company invoicing, nominated Quantities of Gas shall be converted to CCF using the Thermal Factor and reduced by the Shrinkage Factor to determine the volume actually delivered to the Point(s) of Delivery.

15 INTERRUPTIBLE BALANCING SERVICE

15.1 Balancing between the Customer's DCQ and the Volume of Gas consumed by the Customer is performed daily by the Company on an interruptible basis. Imbalances between the Volume of Gas provided by the Customer and the Volume of Gas consumed by the Customer for a billing Month will be cashed-in or cashed-out at the Company's weighted average cost at the city gate for Flowing Gas for the calendar Month in which most of the billing month occurs. Estimated costs will be used based on Nominations made by the Company when the applicable calendar month is not completed before billing the Customer.

15.2 The Customer is expected to cease using Gas if the Customer's supply is interrupted. When a supply interruption occurs the Customer must notify the Company immediately upon interruption and upon resumption of supply. During the interruption period the Customer's DCQ will be set to zero for purposes of calculating daily shortfalls and monthly imbalances. Using Gas during a period of supply interruption will subject the Customer to the same penalty rate specified in the interruptible rate schedule for failure to interrupt service unless the Company is not interrupting customers and has Gas supply available. In the later case, the fee specified in 15.3, below, will apply to Gas used during the Customer's supply interruption unless the Customer schedules another service from the Company.

15.3 If the Customer, or the Customer's Qualified Supplier, fails to supply the DCQ on any Gas day the Customer shall be billed a fee of $30.00 per DT for the difference between the DCQ Nomination, which is in DTs, and the Volume actually supplied by the Customer. Such penalty is in addition to any cash-in or cash-out price paid by the Customer for monthly imbalances.

15.4 On a daily basis, the Company, in its sole discretion, may limit Customer usage to the Volume of Customer-owned Gas that is delivered to the Company's distribution system.

15.5 When the Company interrupts the delivery of Customer-owned Gas to an Interruptible Transportation Customer for distribution system reasons any monthly imbalance up to the total DCQ Volumes delivered to the Company's distribution system by such Interruptible Transportation Customer during the period of interruption will be purchased by the Company at the Customer's cost or the otherwise effective cash-in or cash-out price, whichever is greater.

16 OPERATIONAL FLOW ORDER

At any time that Customer-owned Gas, in the sole judgment of the Company, adversely impacts the Company's distribution system or its ability to serve firm Customers, the Company may issue an Operational Flow Order and refuse to accept Customer-owned Gas at the Point(s) of Receipt or require the Customer to adjust its Nominations up or down. Operational Flow Orders will be issued by the Company eight (8) hours in advance of implementation, unless exigent circumstances dictate a shorter notice period.

RATE SCHEDULE “SUP”

GAS SUPPLIER REQUIREMENTS

AVAILABILITY

The requirements under this Schedule apply to Qualified Suppliers that contract with a Customer to deliver the Customer’s Daily Contract Quantity (DCQ) to the Point(s) of Receipt under the General Terms and Conditions of the Transportation and Balancing Rider. To become a Qualified Supplier, a supplier must submit a completed application on the Company’s standard form to provide service to Customers under this Schedule and must satisfy the Company’s credit requirements set forth below.

RESPONSIBILITY FOR GAS DELIVERY

The Qualified Supplier shall provide the necessary Gas supply to facilitate Nomination and delivery of the Customer’s DCQ in accordance with the General Terms and Conditions of the Transportation and Balancing Rider. If the Qualified Supplier has more than one Customer, and has become a Replacement Shipper on behalf of the Customer(s), a Nomination which is the sum for more than one Customer will be made on interstate pipelines upstream of the Company’s distribution system but the Quantity of Gas for each Customer must be identified on the Nomination to the Company. Failure to deliver the required Quantity of Gas will make the Qualified Supplier subject to penalties as stated in the General Terms and Conditions of the Transportation and Balancing Rider. If the Qualified Supplier fails to pay any penalties, the Customer for whom the Qualified Supplier is delivering Gas shall be responsible for payment of such penalties.

CREDITWORTHINESS

To become a Qualified Supplier, the supplier must demonstrate to the Company’s satisfaction that it has met and continues to meet the creditworthiness criteria of at least one non-affiliated interstate pipeline that delivers Natural Gas to the Company’s city gate or to an interstate pipeline that is connected to Eastern Shore Natural Gas. Upon notification by the Company that the supplier no longer satisfies the credit criteria or has failed to timely pay any bill rendered under this Schedule, the supplier is disqualified until such time as satisfactory evidence is provided by the supplier that the supplier’s overall financial condition again meets the Company’s credit criteria or an acceptable credit enhancement, including but not limited to a cash deposit, letters of credit or surety bonds, is furnished to the Company.

TAXES

Any applicable taxes including, but not limited to, the Public Utilities Tax will be added to all charges.

PAYMENT TERMS

Bills are due within twenty~~ten~~ (20~~10~~) calendar days of their date.

LIABILITY LIMITS

The Company shall not be liable for any loss, cost, damage or expense occasioned by the calculation of the DCQ. The Qualified Supplier shall warrant that, at the time of delivery of Gas to the Point(s) of Receipt, it will have good title to deliver all Gas Quantities. The Company shall have no liability with respect to any Gas prior to its delivery to the Point(s) of Receipt or after its delivery to the Point(s) of Delivery.

RATE SCHEDULE “ER”

ENVIRONMENTAL RIDER

PURPOSE

The purpose of this rider is to recover reasonable environmental costs associated with cleaning up former manufactured gas plants (MGP). Applicable environmental costs are those incurred as a result of, but not limited to, investigation, testing, monitoring, remediation (including remediation of the groundwater), land acquisition, and legal costs relating to former MGP sites, disposal sites, or sites to which material may have migrated as a result of the earlier operation and/or decommissioning of MGPs. Environmental costs expended will be offset by any payments related to these costs received by the Company from insurance proceeds or from another party. Environmental costs shall not include expenses incurred in connection with litigation by third parties claiming personal injury or by third parties claiming damage to their property as a result of the operation or decommissioning of MGPs or as a result of the migration of materials from MGP sites.

APPLICABILITY

The environmental rider will be applicable to all firm Delivery Service customers.

OPERATION OF THE RIDER

The Company will file with the Commission a copy of the environmental rider computation at least 30 days prior to the proposed effective date, which will be each December 1.

The calculation filed will be supported by all bills and receipts relating to the amount of any environmental costs incurred in the preceding Environmental Cost Year for which the Company seeks to begin recovery. In the same filing, the Company shall include similar material and information to support any expenses and/or recoveries resulting from Third Party claims. The Company shall also submit in its annual filing a projection of environmental costs for the following Environmental Cost Year based on the best information available at the time of filing.

RATE

The rate for the rider effective December 1, 2015 is $0.0001 per Ccf.

RATE SCHEDULE "ER"

ENVIRONMENTAL RIDER
(Continued)

DETERMINATION OF RATE

The rider shall be comprised of an amortization factor and a reconciliation factor as follows:

(1) Amortization Factor: Recovery of net environmental costs incurred during an Environmental Cost Year will be accomplished through a five (5) year amortization, offset by the tax benefit associated with those environmental costs as defined below. A net annual amortization amount will be calculated for each of the five (5) years of amortization scheduled for the Environmental Cost Year. The amortization factor for any year will be comprised of the total net annual amount scheduled for that year.

(2) Reconciliation Factor: The reconciliation factor shall be equal to the over/under collection of the environmental cost rider. Over/under collection is the accumulated experienced net over or under recovery of the environmental costs during the twelve (12)~~-~~ month period ending with the month of August immediately preceding the beginning of the next Recovery Year.

(3) Rider Rate: The rider rate shall be equal to the sum of the amortization and reconciliation factors divided by projected firm sales over the next recovery period of December 1 through November 30. The rate shall be rounded to four (4) decimal places per Ccf.

DEFINITIONS

(1) Environmental Cost Year is the time period over which environmental costs are incurred and any payments from other parties are netted against the costs. For purposes of this rider, the Environmental Cost Year will be from October 1 through September 30. The Environmental Cost Year will include actual data recorded for the year. Recovery of environmental costs for an Environmental Cost Year will begin with the Recovery Year that starts immediately following the end of the Environmental Cost Year.

(2) Recovery Year is each December 1 through November 30 and is the time period over which the annually calculated environmental rider rate will be billed to firm customers.

RATE SCHEDULE "ER"

ENVIRONMENTAL RIDER
(Continued)

DEFINITIONS (Continued)

(3) Tax benefit (TB) associated with environmental expenditures shall be calculated as follows:

Tbn	=	AECn * [5-x)/5] * .1306 * .39742

where:

AECn	=	Actual Environmental Costs incurred in Environmental Cost Year "n"
x	=	The number of years that the Actual Environmental Costs (AEC) incurred in Year "n" have been subject to amortization (x = 1, 2, 3, and 4)
.1306	=	Before Tax Cost Rate
.39742	=	Effective Combined Federal and State Income Tax Rate.

The Before Tax Cost Rate of .1306 and the Effective Combined Federal and State Income Tax Rate of .39742 are the rates at the time of implementation of this rider and are subject to change. Any change in the Before Tax Cost Rate will be implemented starting when the next Rider Rate is calculated for the next Recovery Year. Any change in the Effective Combined Federal and State Income Tax Rate will be implemented starting with the recovery calculation for next Environmental Cost Year that ends after the rate changes.

MISCELLANEOUS CUSTOMER CHARGES

1 CONNECTION CHARGE

Each Applicant for gas service shall pay to the Company a Connection Charge of thirty-five dollars ($35) before gas service is activated by the Company at the Customer's premises. Such Connection Charge shall not be collected from builders or other contractors activating gas service during the construction of a premises prior to occupation by the Company's customer of record.

2 RECONNECTION CHARGE

Whenever a Customer's gas is turned off at Customer's request, or Customer's meter disconnected by reason of non-compliance with these Rules and Regulations or orders of the Public Service Commission of Delaware, a Reconnection Charge of thirty five dollars ($35) must be paid and other satisfactory arrangements made with the Company prior to 3:00p.m. of a normal business day before the account is reactivated and gas service reconnected by the end of the next business day.

3 AFTER HOURS SERVICE CONNECTION OR RECONNECTION CHARGE

If the Customer desires that the initial gas service connection or gas service reconnection following disconnection by the Company for any reason, be completed on the same day as the request is received by Company or outside the Company's normal business hours, such After Hours Reconnection may be performed, subject to the availability of Company personnel. The After Hours Connection or Reconnection Charge shall be sixty dollars ($60).

4 SEASONAL RECONNECTION CHARGE

Whenever a residential Customer's gas is turned off or Customer's meter disconnected by the Company at Customer's request and the account placed on inactive status, and such account is reactivated by the same Customer no less than thirty (30) days and no more than one hundred eighty (180) days from the date of the disconnect, a Seasonal Reconnection Charge equal to the monthly Customer Charge in the Customer's applicable Rate Schedule for each month the account was inactive, plus the Reconnection Charge provided in 2 (above), shall be paid. Such payment, along with other satisfactory arrangements for reconnection, shall be made with the Company for reconnection the following normal business day.

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MISCELLANEOUS CUSTOMER CHARGES (Continued)

5 FIELD COLLECTION CHARGE

Service interruptions may be avoided by paying the overdue amount prior to the past due date of the gas bill, or by paying the overdue amount plus a collection fee of seventeen dollars ($17) to the Company or an authorized agent of the Company.

6 RETURNED PAYMENT CHARGE

Payment for Services provided under this Tariff, Customer deposits, or other Tariff charges which are returned unpaid by the Customer's bank or other financial institution shall result in an additional charge of twenty dollars ($20) per occurrence, and will be charged against the Customer's account. Failure to pay the full amount of the bill including the Returned Payment Charge may result in discontinuance of the Customer's service. After the second returned payment the Company reserves the right to notify the Customer that an alternate payment method (other than a personal check or bank debit) will be required for payment of the Company's bill statements.

7 CHANGE OF ACCOUNT CHARGE

If the change of occupants in a premise with existing gas service occurs without a physical service disconnection, a Change of Account may occur. The Company shall bill to the a~~A~~pplicant a Change of Account Charge in the amount of seventeen dollars ($17).

8 FAILED TRIP CHARGE

In the event a Customer, or other entity, requesting service from the Company that requires a field visit to a premise, fails to keep a scheduled appointment with the Company's employee at said premises to provide a service requested by the Customer, the Customer shall pay a Failed Trip Charge of thirty-five dollars ($35).

.

RATE SCHEDULE "TSFF"

TOWN OF SMYRNA FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the Town of Smyrna franchise fee, from all customers within the limits of the Town of Smyrna in accordance with the Franchise Agreement between the Company and the Town of Smyrna. This franchise fee will be in effect until December 31, 2029.

APPLICABILITY

The Town of Smyrna Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the Town of Smyrna.

RATE

The rate applicable to all Delivery Service throughput is $.0181 per Ccf.

RATE SCHEDULE "CMFF"

CITY OF MILFORD FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the City of Milford franchise fee, from all customers within the limits of the City of Milford in accordance with the Franchise Agreement between the Company and the City of Milford. This franchise fee will be in effect until June 27, 2019.

APPLICABILITY

The City of Milford Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the City of Milford, excluding those customers from whom the Company is prohibited by law from collecting said surcharge.

RATE

The rate applicable to all Delivery Service throughput is $0.010 per Ccf.

RATE SCHEDULE "TGFF"

TOWN OF GEORGETOWN FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the Town of Georgetown franchise fee, from all customers within the limits of the Town of Georgetown in accordance with the Franchise Agreement between the Company and the Town of Georgetown. This franchise fee will be in effect until June 27, 2021.

APPLICABILITY

The Town of Georgetown Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the Town of Georgetown, excluding those customers from whom the Company is prohibited by law from collecting said surcharge.

RATE

The rate applicable to all Delivery Service throughput is $0.010 per Ccf.

Issue Date: September 2, 2008
Effective Date: For Bills Rendered on and after September 3, 2008
Authorization: Order No. 7434 dated September 2, 2008 in PSC Docket No. 07-186

RATE SCHEDULE "MBFF"

TOWN OF MILLSBORO FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the Town of Millsboro franchise fee, from all customers within the limits of the Town of Millsboro in accordance with the Franchise Agreement between the Company and the Town of Millsboro. This franchise fee will be in effect until September 4, 2021.

APPLICABILITY

The Town of Millsboro Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the Town of Millsboro, excluding those customers from whom the Company is prohibited by law from collecting said surcharge.

RATE

The rate applicable to all Delivery Service throughput is $0.0181 per Ccf.

RATE SCHEDULE "MTFF"

TOWN OF MILTON FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the Town of Milton franchise fee, from all customers within the limits of the Town of Milton in accordance with the Franchise Agreement between the Company and the Town of Milton. This franchise fee will be in effect until January 7, 2032.

APPLICABILITY

The Town of Milton Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the Town of Milton, excluding those customers from whom the Company is prohibited by law from collecting said surcharge.

RATE

The rate applicable to all Delivery Service throughput is $0.0181 per Ccf.

RATE SCHEDULE "SFFF"

CITY OF SEAFORD FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the City of Seaford franchise fee, from all customers within the limits of the City of Seaford in accordance with the Franchise Agreement between the Company and the City of Seaford. This franchise fee will be in effect until June 23, 2033.

APPLICABILITY

The City of Seaford Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the City of Seaford, excluding those customers from whom the Company is prohibited by law from collecting said surcharge.

RATE

The rate applicable to all Delivery Service throughput is $0.0181 per Ccf.

RATE SCHEDULE "DBFF"

TOWN OF DAGSBORO FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the Town of Dagsboro franchise fee, from all customers within the limits of the Town of Dagsboro in accordance with the Franchise Agreement between the Company and the Town of Dagsboro. This franchise fee will be in effect until December 20, 2022.

APPLICABILITY

The Town of Dagsboro Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the Town of Dagsboro, excluding those customers from whom the Company is prohibited by law from collecting said surcharge.

RATE

The rate applicable to all Delivery Service throughput is $0.0181 per Ccf.

RATE SCHEDULE "CLFF"

CITY OF LEWES FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the City of Lewes franchise fee, from all customers within the limits of the City of Lewes in accordance with the Franchise Agreement between the Company and the City of Lewes. This franchise fee will be in effect until September 11, 2031.

APPLICABILITY

The City of Lewes Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the City of Lewes, excluding those customers from whom the Company is prohibited by law from collecting said surcharge.

RATE

The rate applicable to all Delivery Service throughput is $0.0181 per Ccf.

RATE SCHEDULE "SBFF"

TOWN OF SELBYVILLE FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the Town of Selbyville franchise fee, from all customers within the limits of the Town of Selbyville in accordance with the Franchise Agreement between the Company and the Town of Selbyville. This franchise fee will be in effect until June 11, 2027.

APPLICABILITY

The Town of Selbyville Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the Town of Selbyville, excluding those customers from whom the Company is prohibited by law from collecting said surcharge.

RATE

The rate applicable to all Delivery Service throughput is $0.0181 per Ccf.

RATE SCHEDULE "TFFF"

TOWN OF FREDERICA FRANCHISE FEE RIDER

PURPOSE

The purpose of this rider is to recover the Town of Frederica franchise fee, from all customers within the limits of the Town of Frederica in accordance with the Franchise Agreement between the Company and the Town of Frederica.

APPLICABILITY

The Town of Frederica Franchise Fee Rider will be applicable to all firm and interruptible Delivery Service customers within the limits of the Town of Frederica, excluding those customers from whom the Company is prohibited by law from collecting said surcharge.

RATE

The rate applicable to all Delivery Service throughput is $0.010 per Ccf.

Summary of Significant Assumptions
For the Test Period

The Test Period ending March 31, 2016 was developed by adjusting the Test Year amounts to annualize known and measurable changes and to properly reflect transactions as they would occur in a “normal” year for which the rates would be in effect.

Assumptions to Adjust Test Year

Rate Base

The Rate Base for the Test Period was based primarily on the forecasted thirteen-month average balances. Actual balances for March 31, 2015 through June 30, 2015 and forecast of the month-end balances for July 1, 2015 through March 31, 2016 were used for the Test Period. The Deferred Income Tax and ITC were based on the average of the actual March 31, 2015 balances and forecasted March 31, 2016 balances. Investor supplied cash working capital was calculated using the lag days calculated for 2015 applied to the forecasted expenses for the Test Period. In addition, certain adjustments were made to Plant in Service and Accumulated Depreciation.

Plant in Service – All projects classified as Construction Work in Progress at June 30, 2015 were expected to be complete by March 31, 2016 and were therefore closed to plant for the test period. The Delaware Division’s 2015 and 2016 Capital Budget was used to forecast retirements and construction work completed and closed to Plant in Service by March 31, 2016, the test period. Construction Work in Progress at March 31, 2016 is estimated to be zero.

Accumulated Depreciation – Test Period 13 month average accumulated depreciation balance was forecasted using the actual balances for the period March 31, 2015 to June 30, 2015. Depreciation expense for the period July 2015 through March 2016 was based on the forecasted Plant in Service balances (described above) and was added to the accumulated depreciation balances from the prior month to arrive at the forecasted month end balance.

Net Operating Income

Sales Adjustment – Test year heat sensitive firm sales levels were adjusted to reflect sales levels expected in a normal degree day year (based on a 10-year average) and were also adjusted to reflect the number of customers projected to be on the distribution system at the end of the test period. Interruptible sales levels for Propane Parity Service, No. 2 Fuel Oil Parity Service, and No. 6 Fuel Oil Parity Service were adjusted on an individual customer basis using historical sales levels.

Payroll Adjustment – Payroll Expense was annualized utilizing the projected staffing level and pay rates effective March 31, 2016.

Benefits Adjustment – Benefits expense adjustment includes the annualized expense of health, dental, and prescription claims and administration fees at the projected March 31, 2016 expense level and the March 2016 staffing level. Current rates and adjusted payroll were used to annualize life, long-term disability and accidental death and dismemberment insurance and 401(k) expenses. OPRB and 401(k) forfeitures were annualized at the March 2016 level.

Vehicle Depreciation Adjustment – Vehicle Depreciation was annualized utilizing the forecasted plant in-service at March 31, 2016 and the current depreciation rates.

Property Insurance and Injuries and Damages – Insurance expense was annualized based on the most current policy premiums.

Bad Debts – The test period expense was calculated using a five year average of bad debt write-offs as a percentage of firm revenue times the test period firm revenue.

Settlement Percentages – Department settlement percentages were adjusted to reflect the current settlement methodology and organizational structure.

Merchant Fee Adjustment – Merchant fees were removed from the test period.

Facilities Adjustment – This adjustment includes an additional rent expense based on a recent appraisal of the property used by distribution operations and for expanding into additional office space

Regulatory Commission Expense – Regulatory Commission Expense was normalized based upon a five year history, plus the five year amortization of the estimated cost of the current rate case.

Taxes Other Than Income – Payroll Related Taxes were adjusted for the change in payroll dollars. Property Taxes were adjusted by annualizing the most current property tax invoices in addition to an estimated increase related to additional plant in service. Revenue Related Taxes were adjusted to annualize the current statutory rate and apply to forecasted revenues.

Depreciation – Annual depreciation expense was calculated based on projected Plant in Service at March 31, 2016 using current depreciation rates.

Interest Synchronization – Income tax expense was adjusted to reflect ratemaking interest expense inherent in the capital structure and cost of capital.

Rate of Return

The proposed Rate of Return on common equity is 11.00%.

Summary of Significant Accounting Policies

The schedules for the Test Year ended June 30, 2015 have been prepared in accordance with generally accepted accounting principles.

The schedules for the Test Period ending March 31, 2016 have been prepared on the basis of those same generally accepted accounting principles and in accordance with those accounting policies prescribed by the regulatory commissions having jurisdiction with respect to accounting matters.

There have been no additional authoritative standards (ASC – FASB Accounting Standards Codification) issued by the Financial Accounting Standards Board since the last rate case (PSC Docket No. 07-186) that affect the test period schedules.

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Schedule A
DEFINITIONS

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Moore**
Reference: **Part A, Paragraph B.1 and B.2**

In all of the following schedules the following definitions are applicable:

Test Year: Twelve Months Ended June 30, 2015

Test Period: Twelve Months Ending March 31, 2016
including annualization adjustments

Schedule B
DATA PREVIOUSLY FILED OR NOT APPLICABLE

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Moore**
Reference: **Part A, Paragraph F.5**

Line No.	Paragraph Designation	Description
1	Part II, Paragraph B.2.a.b.d.e.	Gas Supply Plan 2015
2		
3	Part III, Paragraph B.1	Supporting Documents
4		a. Annual Reports
5		b. FERC Reports
6		c. SEC 10-K Reports
7		d. Proxy Statements
8		e. Prospectus
9		
10	Part VI, Paragraph C	Preferred Stock Calculations -- Not Applicable

Schedule C
ELEMENTS OF RATE INCREASE

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Moore**

Elements of Proposed Increase:

	Amount (000's)
Increase due to investment in bare steel replacement	$1,661
Increase due to decline in customer fixed margin contribution - Residential	1,357
Increase in ROE requirement for gas utility investments	902
Increase due to O&M expenses	622
Other	199
Grand Total	$4,742

Schedule D
AMOUNT OF GAS - MCF SUPPLIED BY SUPPLIER

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Hardy**
Reference: **Part II, Paragraph B.2.c**

Line No.	Month	Year	New Jersey Resources	Eastern Shore Natural Gas Co	Net Storage (Inj.) and W/d	Imbalance & Transportation Deliveries	Other	Total MCF Supplied
1	January	2015	734,952	(5,479)	155,417	435,384	18	1,320,292
2	February	2015	789,531	(5,790)	167,932	407,847	(1,076)	1,358,444
3	March	2015	525,949	(3,888)	130,492	391,143	6	1,043,702
4	April	2015	232,313	(1,464)	(1,707)	317,092	21	546,255
5	May	2015	93,171	(589)	(15,395)	278,148	9	355,344
6	June	2015	99,840	(620)	(12,424)	247,402	3	334,201
7	July	2014	78,011	(1,855)	(15,772)	248,436	41	308,861
8	August	2014	86,157	(3,985)	(10,662)	250,215	23	321,748
9	September	2014	106,159	(3,797)	(11,048)	282,522	21	373,857
10	October	2014	177,034	(1,134)	(3,763)	293,465	38	465,640
11	November	2014	395,005	(4,719)	49,323	352,343	35	791,987
12	December	2014	512,860	(6,078)	81,303	399,621	21	987,727
13	Total		3,830,982	(39,398)	513,696	3,903,618	(840)	8,208,058

Schedule E

COMPARISON OF PRESENT AND PROPOSED REVENUES FOR TEST PERIOD

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Hardy**
Reference: **Part II, Paragraph C.1**

Line No.	Description	(1) Present Revenues	(2) Proposed Interim Revenues	Difference	Percentage
1	Rate Schedule "RS-1"	$1,171,099	$1,263,601	$92,502	7.90%
2	Rate Schedule "ERS-1"	$44,488	$45,545	$1,057	2.38%
3	Rate Schedule "RS-2"	$30,756,946	$32,301,107	$1,544,161	5.02%
4	Rate Schedule "ERS-2"	$471,974	$481,711	$9,737	2.06%
5	Rate Schedule "GS"	$3,287,520	$3,449,739	$162,219	4.93%
6	Rate Schedule "EGS"	$20,383	$20,745	$362	1.77%
7	Rate Schedule "MVS"	$2,815,416	$2,904,396	$88,980	3.16%
8	Rate Schedule "EMVS"	$10,574	$10,876	$302	2.86%
9	Rate Schedule "LVS"	$3,709,020	$3,907,143	$198,123	5.34%
10	Rate Schedule "HLFS"	$3,976,147	$4,375,654	$399,507	10.05%
11	Rate Schedule "NGV"	$2,606	$2,606	$0	0.00%
12	Rate Schedule "GLR"	$885	$885	$0	0.00%
13	Rate Schedule "NCR"	$149,843	$150,947	$1,104	0.74%
14	Rate Schedule "ITS"	$162,637	$162,637	$0	0.00%
15	Subtotal Revenue	$46,579,538	$49,077,591	$2,498,053	5.36%
16	Other Revenue	$575,457	$575,457	$0	0.00%
17	Miscellaneous Fees	$455,585	$455,585	$0	0.00%
18	Total Operating Revenue	$47,610,580	$50,108,633	$2,498,053	5.25%

1/ At Current Rates
2/ Proposed Interim Revenues are based on the proposed interim rates which are designed on the $2,500,000 increase.

Schedule E
COMPARISON OF PRESENT AND PROPOSED REVENUES FOR TEST PERIOD

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Hardy**
Reference: **Part II, Paragraph C.1**

Line No.	Description	(1) Present Revenues	(2) Full Proposed Revenues	Difference	Percentage
1	Rate Schedule "RS-1"	$1,171,099	$1,530,420	$359,321	30.68%
2	Rate Schedule "ERS-1"	$44,488	$49,495	$5,007	11.25%
3	Rate Schedule "RS-2"	$30,756,946	$34,547,964	$3,791,018	12.33%
4	Rate Schedule "ERS-2"	$471,974	$495,376	$23,402	4.96%
5	Rate Schedule "GS"	$3,287,520	$3,725,462	$437,942	13.32%
6	Rate Schedule "EGS"	$20,383	$20,934	$551	2.70%
7	Rate Schedule "MVS"	$2,815,416	$2,938,756	$123,340	4.38%
8	Rate Schedule "EMVS"	$10,574	$10,982	$408	3.86%
9	Rate Schedule "LVS"	$3,709,020	$3,706,820	($2,200)	-0.06%
10	Rate Schedule "HLFS"	$3,976,147	$3,971,873	($4,274)	-0.11%
11	Rate Schedule "NGV"	$2,606	$2,606	$0	0.00%
12	Rate Schedule "GLR"	$885	$1,183	$298	33.67%
13	Rate Schedule "NCR"	$149,843	$156,844	$7,001	4.67%
14	Rate Schedule "ITS"	$162,637	$162,637	$0	0.00%
15	Subtotal Revenue	$46,579,538	$51,321,352	$4,741,814	10.18%
16	Other Revenue	$575,457	$575,457	$0	0.00%
17	Miscellaneous Fees	$455,585	$455,585	$0	N/A
18	Total Operating Revenue	$47,610,580	$52,352,394	$4,741,814	9.96%

1/ At Current Rates
2/ Proposed Revenues are based on the full proposed rates which are designed on the $4,741,823 increase.

Schedule No. 1
OVERALL FINANCIAL SUMMARY

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Moore**

		Test Year Twelve Months Ended June 30, 2015		Test Period Twelve Months Ending March 31, 2016	
Line No.	Description	Ref Sched	Amount $	Ref Sched	Amount $
1	Rate Base	2	$65,854,598	2	$70,938,749
2	Net Operating Income	3	$4,084,055	3	$3,267,298
3	Earned Rate of Return (L2 / L1)		6.20%		4.61%
4	Proposed Fair Rate of Return	4	8.55%	4	8.55%
5	Required Operating Income (L1 x L4)		$5,630,568		$6,065,262
6	Operating Income Deficiency (L5 - L2)		$1,546,513		$2,797,964
7	Gross Revenue Conversion Factor	5	1.69474	5	1.69474
8	Revenue Deficiency		$2,620,937		$4,741,823
9	Revenue Increase Requested		4.00%		9.96%

Schedule No. 2
JURISDICTIONAL RATE BASE SUMMARY

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **M. Everngam**

Line No.	Description	Test Year Twelve Months Ended June 30, 2015	Utility Proposed Test Period Twelve Months Ending March 31, 2016	
			Ref Sched	Amount $
1	Gas Plant In Service	$119,853,062	2-A	$128,018,672
2	Intangible Assets	1,256,046	2-B	1,256,046
	Less:			
3	Accumulated Depreciation	34,695,018	2-C	35,983,960
4	Net Plant	$86,414,090		$93,290,758
	Less:			
5	Accumulated Deferred Income Taxes	$21,525,575	2-D	$22,938,550
6	Customer Deposits	2,573,682	2-F	1,698,560
7	Customer Advances for Construction	144,774	2-C-1	27,692
8	Unamortized Investment Tax Credit	0	2-D	0
9	Operating Reserves	1,512,396		1,547,011
	Plus:			
10	Material and Supplies	2,528,176	2-E-1	2,168,597
11	Investor Supplied Cash Working Capital	1,028,566	2-E-2	1,028,566
12	Construction Work In Progress	1,640,192		662,641
13	Total Claimed Rate Base	$65,854,598		$70,938,749

Schedule No. 2-A
USED AND USEFUL UTILITY PLANT

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **M. Everngam**

Test Year	Utiltiy Plant In Service	CWIP	Total Plant
June - 2014	115,235,718	2,584,673	117,820,391
July	115,814,712	2,710,162	118,524,874
August	116,802,653	2,536,361	119,339,014
September	117,523,940	2,799,709	120,323,649
October	118,508,966	2,799,300	121,308,266
November	119,003,753	3,177,753	122,181,506
December	120,522,445	194,311	120,716,756
January - 2015	120,681,260	781,538	121,462,798
February	121,571,841	363,853	121,935,694
March	122,226,129	295,676	122,521,805
April	122,753,957	893,574	123,647,531
May	123,394,637	1,079,957	124,474,594
June	124,049,797	1,105,630	125,155,427
13 Month Average	$119,853,062	$1,640,192	$121,493,254

Test Period	Utility Plant in Service	CWIP	Total Plant
March - 2015	122,226,129	295,676	122,521,805
April	122,753,957	893,574	123,647,531
May	123,394,637	1,079,957	124,474,594
June	124,049,797	1,105,630	125,155,427
July	125,307,369	1,892,492	127,199,861
August	126,103,565	1,862,070	127,965,635
September	128,372,367	609,620	128,981,987
October	129,254,564	437,660	129,692,224
November	129,974,729	437,660	130,412,389
December	131,179,782	0	131,179,782
January	132,598,938	0	132,598,938
February	133,985,684	0	133,985,684
March	135,041,218	0	135,041,218
13 Month Average	$128,018,672	$662,641	$128,681,313
Terminal Value Adjustment	0	0	0
Adjusted 13 Month Average	$128,018,672	$662,641	$128,681,313

Schedule No. 2-B
INTANGIBLE ASSETS CLAIMED IN RATE BASE

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **M. Everngam**

Line No.	Account No.	Description and Location of Asset	Test Year Ended June 30, 2015	Test Period Ending March 31, 2016
		Intangible Plant in Service		
1	301	Organization Expense	$6,038	$6,038
2	302	Franchise and Consents	248	248
3	303	Miscellaneous Intangible Plant	1,249,760	1,249,760
4		Total Intangible Property	$1,256,046	$1,256,046

Schedule No. 2-C
ACCUMULATED DEPRECIATION

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **M. Everngam**

Actuals	Test Year
June - 2014	(34,020,331)
July	(34,157,583)
August	(34,370,629)
September	(34,489,559)
October	(34,734,818)
November	(34,921,072)
December	(34,377,743)
January - 2015	(34,542,587)
February	(34,714,990)
March	(34,869,271)
April	(35,080,412)
May	(35,285,246)
June	(35,470,995)
13 Month Average	($34,695,018)

Test Period	Utility Plant in Service
March - 2015	(34,869,271)
April	(35,080,412)
May	(35,285,246)
June	(35,470,995)
July	(35,629,428)
August	(35,752,981)
September	(36,003,961)
October	(36,148,950)
November	(36,339,093)
December	(36,522,521)
January - 2016	(36,708,021)
February	(36,895,553)
March	(37,085,051)
13 Month Average	($35,983,960)
Terminal Value Adjustment	0
Adjusted 13 Month Average	($35,983,960)

Schedule No. 2-C-1
CUSTOMER ADVANCES- CAIC 2230-2520

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **M. Everngam**

Test Year		Test Year Ended June 30 2015
June	2014	184,840
July		184,840
August		184,840
September		184,840
October		181,349
November		181,349
December		180,000
January	2015	120,000
February		120,000
March		120,000
April		120,000
May		120,000
June		0
13 Month Average		144,774

Test Period		Test Period Ended March 31, 2016
March	2015	120,000
April		120,000
May		120,000
June		0
July		0
August		0
September		0
October		0
November		0
December		0
January	2016	0
February		0
March		0
13 Month Average		27,692

Schedule No. 2-D
ACCUMULATED DEFERRED INCOME TAXES

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **M. Everngam**

Line No.	Description of Deferral	Balance Beginning of Test Period March 31, 2015	Balance Test Period Ending March 31, 2016	Test Period Average Balance
1	Accelerated Tax Depreciation	($23,436,579)	($23,943,148)	(23,689,863)
2	Unrecovered Purchase Gas Costs	n/a	n/a	n/a
3	Bad Debts	47,610	47,610	47,610
4	Capitalized Interest, Overhead & AFUDC	177,706	175,397	176,551
5	Environmental Costs	n/a	n/a	n/a
6	Pension	196,895	196,895	196,895
7	Other Post Retirement Benefits	210,778	210,778	210,778
8	Real Property Taxes	(202,632)	(202,632)	(202,632)
	Repairs	0	(195,897)	(97,949)
9	Self-Insurance	214,028	214,028	214,028
10	Insurance reserves	(60,896)	(60,896)	(60,896)
11	Incentive compensation	186,781	228,780	207,781
12	Regulatory Asset	60,826	57,469	59,148
13	Total	($22,605,483)	($23,271,616)	($22,938,550)
14	Unamortized Investment Tax Credits	$0	$0	

Schedule No. 2-D
ACCUMULATED DEFERRED INCOME TAXES

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **M. Everngam**

Line No.	Description of Deferral	Balance Beginning of Test Year June 30, 2014	Balance Test Year Ending June 30, 2015	Test Year Average Balance
1	Accelerated Tax Depreciation	($21,144,058)	($23,556,467)	($22,350,263)
2	Unrecovered Purchase Gas Costs	n/a	n/a	n/a
3	Bad Debts	85,308	$47,610	$66,459
4	Capitalized Interest, Overhead & AFUDC	181,054	$177,320	$179,187
5	Environmental Costs	n/a	n/a	n/a
6	Pension	190,812	$196,895	$193,854
7	Other Post Retirement Benefits	219,024	$210,778	$214,901
8	Real Property Taxes	(194,237)	($202,632)	($198,435)
9	Self-Insurance	179,611	$214,028	$196,820
10	Insurance reserves	(61,188)	($60,896)	($61,042)
11	Incentive compensation	141,777	$200,781	$171,279
12	Regulatory Asset	63,344	$59,987	$61,666
13	Total	($20,338,553)	($22,712,596)	($21,525,575)
14	Unamortized Investment Tax Credits	$0	$0	

Schedule No. 2-E
MATERIALS AND SUPPLIES

Delaware Public Service Commission

Company:	**Chesapeake Utilities Corporation**
Docket No.:	**15-**
Witness:	**Everngam**

Line	Working Capital Component	Test Year End June 30 2015	Test Period Ending March 31 2016
1	Natural Gas in Storage	$1,903,616	$1,538,611
2	Propane in Storage	300,563	264,685
3	Plant Materials and Operaing Supplies	323,997	365,301
4	Total Materials and Supplies	$2,528,176	$2,168,597

Schedule No. 2-E-1a
MATERIALS AND SUPPLIES

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Everngam**

Test Period		Total Materials and Supplies	Natural Gas in Storage	Propane in Storage	Plant Materials and Supplies
March	2015	$1,034,781	$470,614	$189,006	$375,161
April		1,317,862	775,652	189,006	353,204
May		1,774,245	1,155,750	189,006	429,489
June		2,040,640	1,463,457	189,006	388,177
July		2,296,905	1,765,217	241,886	289,802
August		2,698,102	2,014,911	345,940	337,251
September		3,024,647	2,262,208	377,972	384,467
October		3,161,594	2,401,077	395,661	364,856
November		2,168,597	1,538,611	264,685	365,301
December		2,168,597	1,538,611	264,685	365,301
January	2016	2,168,597	1,538,611	264,685	365,301
February		2,168,597	1,538,611	264,685	365,301
March		2,168,597	1,538,611	264,685	365,301
13 Month Average		$2,168,597	$1,538,611	$264,685	$365,301

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Schedule No. 2-E-1b
MATERIALS AND SUPPLIES

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Everngam**

Test Year		Total Materials and Supplies	Natural Gas in Storage	Propane in Storage	Plant Materials and Supplies
June	2014	$2,341,149	$1,798,237	$254,785	$288,127
July		2,873,106	2,229,995	315,078	328,033
August		3,209,336	2,605,207	315,078	289,051
September		3,566,380	2,922,736	386,724	256,920
October		3,834,831	3,136,637	418,714	279,480
November		3,537,441	2,846,453	413,443	277,545
December		3,155,716	2,474,034	414,567	267,115
January	2015	2,531,777	1,800,741	402,123	328,913
February		1,649,023	1,067,490	230,786	350,747
March		1,034,781	470,614	189,006	375,161
April		1,317,862	775,652	189,006	353,204
May		1,774,245	1,155,750	189,006	429,489
June		2,040,640	1,463,457	189,006	388,177
13 Month Average		$2,528,176	$1,903,616	$300,563	$323,997

Schedule No. 2-E-2
INVESTOR SUPPLIED CASH WORKING CAPITAL

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **M. Everngam**

Line No.	Working Capital Component - Test Period	Cash Disbursements Test Year	Lag Days	Dollar Days	Weighted Net Lag Days
1	**Total Revenue Collection Lag**				32.82
	Cash Disbursements for Operating Expenses Lag:				
2	Weekly Payroll	3,035,144	10.50	31,869,012	
3	Bi-Weekly Payroll	3,754,447	7.00	26,281,129	
4	Semi-Monthly Payroll	531,049	7.60	4,035,973	
5	Other Operations & Maintenance Costs - DNG	4,384,061	24.29	106,488,847	
6	Other Operations & Maintenance Costs - Corporate	2,057,320	13.62	28,020,704	
7	Taxes Other than Income	2,020,339	-26.80	(54,145,085)	
8		$15,782,361		$142,550,580	9.03
9	**Weighted Net Lag Days**				23.79
10	Average Daily Cash Disbursement				$43,239
11	**Cash Working Capital Requirement**				$1,028,566

Schedule No. 2-F
OTHER ELEMENTS OF RATE BASE

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **M. Everngam**

Test Period		Customer Deposits	Abandoned Property Liability	Total Other Elements of Rate Base
March	2015	1,729,629	11,279	$1,740,908
April		1,712,097	11,279	1,723,376
May		1,652,450	11,279	1,663,729
June		1,637,551	11,279	1,648,830
July		1,639,234	11,279	1,650,513
August		1,634,084	11,279	1,645,363
September		1,645,400	11,279	1,656,679
October		1,692,337	11,279	1,703,616
November		1,700,957	11,279	1,712,236
December		1,709,621	11,279	1,720,900
January	2016	1,718,330	11,279	1,729,609
February		1,727,082	11,279	1,738,361
March		1,735,879	11,279	1,747,158
13 Month Average		$1,687,281	$11,279	$1,698,560

Schedule No. 2-F-1
OTHER ELEMENTS OF RATE BASE

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **M. Everngam**

Test Year		Customer Deposits	Abandoned Property Liability	Total Other Elements of Rate Base
June	2014	$2,734,486	$22,161	$2,756,647
July		2,724,704	22,161	2,746,865
August		2,742,622	22,161	2,764,783
September		2,760,364	22,161	2,782,525
October		2,806,427	22,161	2,828,588
November		2,851,876	22,161	2,874,037
December		2,883,788	22,161	2,905,949
January	2015	2,897,307	20,347	2,917,654
February		2,911,628	20,347	2,931,975
March		2,901,629	11,279	2,912,908
April		1,712,097	11,279	1,723,376
May		1,652,450	11,279	1,663,729
June		1,637,551	11,279	1,648,830
13 Month Average		$2,555,148	$18,534	$2,573,682

Schedule No. 3
NET OPERATING INCOME SUMMARY

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Moore**

Line No.	Description	Test Year Ended June 30, 2015		Test Period Ending March 31, 2016 (at current rates)	
		Ref Sched	Amount $	Ref Sched	Amount $
1	Operating Revenues	3-A	$65,518,579	3-A	$47,610,580
2	Operating Expenses	3-B	57,637,753	3-B	40,888,404
3	Interest on Customer Deposits		74,347		74,347
4	Taxes Other Than Income	3-I	1,807,907	3-I	2,039,884
5	Net Operating Income		$5,998,572		$4,607,945
6	Total Operating Taxes	3-I	$1,914,520	3-I	$1,340,647
7	Net Operating Income		$4,084,052		$3,267,298
8	AFUDC		$0		$0
9	Net Income Available for Return		$4,084,052		$3,267,298

Schedule No. 3-A
OPERATING REVENUES

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Hardy**

Line No.	Description	Test Year Ended June 30, 2015	Test Period Ending March 31, 2016
1	Rate Schedule "RS-1"	$1,836,611	$1,171,099
2	Rate Schedule "ERS-1"	$56,113	$44,488
3	Rate Schedule "RS-2"	$43,108,633	$30,756,946
4	Rate Schedule "ERS-2"	$309,670	$471,974
5	Rate Schedule "GS"	$4,856,770	$3,287,520
6	Rate Schedule "EGS"	$28,625	$20,383
7	Rate Schedule "MVS"	$4,082,408	$2,815,416
8	Rate Schedule "EMVS"	$20,929	$10,574
9	Rate Schedule "LVS"	$4,322,408	$3,709,020
10	Rate Schedule "HLFS"	$5,075,066	$3,976,147
11	Rate Schedule "GLR"	$1,217	$885
12	Rate Schedule "NCR"	$969,548	$149,843
13	Rate Schedule "ITS"	$162,637	$162,637
14	Rate Schedule "NGV"	$3,000	$2,606
15	Subtotal Revenue	$64,833,635	$46,579,538
16	Other Revenue	$684,944	$1,031,042
17	Total Operating Revenue	$65,518,579	$47,610,580

Schedule No. 3-A-1
SUMMARY OF ADJUSTMENTS TO TEST YEAR REVENUES

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Hardy**

Line No.	Description	Test Year Ended June 30, 2015	Test Year Adjustments	Temperature Normalization	Customer Growth	Other Adjustments and Annualizations (1)	Sub-total	Test Period Ending March 31, 2016
1	Rate Schedule "RS-1"	$1,836,611	($266,993)	($77,677)	$0	($320,842)	($665,512)	$1,171,099
2	Rate Schedule "ERS-1"	$56,113	($3,092)	$0	$0	($8,533)	($11,625)	$44,488
3	Rate Schedule "RS-2"	$43,108,633	$119,042	($2,219,992)	$315,870	($10,566,607)	($12,351,687)	$30,756,946
4	Rate Schedule "ERS-2"	$309,670	$317	($13,071)	$234,839	($59,781)	$162,304	$471,974
5	Rate Schedule "GS"	$4,856,770	($148,638)	($286,376)	$74,839	($1,209,075)	($1,569,250)	$3,287,520
6	Rate Schedule "EGS"	$28,625	($1,692)	$0	($1,144)	($5,406)	($8,242)	$20,383
7	Rate Schedule "MVS"	$4,082,408	$111,093	($229,226)	$11,449	($1,160,308)	($1,266,992)	$2,815,416
8	Rate Schedule "EMVS"	$20,929	($6,926)	$0	$953	($4,382)	($10,355)	$10,574
9	Rate Schedule "LVS"	$4,322,408	$312,757	($98,477)	$82,041	($909,709)	($613,388)	$3,709,020
10	Rate Schedule "HLFS"	$5,075,066	($89,267)	($15,755)	$34,511	($1,028,408)	($1,098,919)	$3,976,147
11	Rate Schedule "GLR"	$1,217	$0	$0	$0	($332)	($332)	$885
12	Rate Schedule "NCR"	$969,548	($931,721)	$0	$22,438	$89,578	($819,705)	$149,843
13	Rate Schedule "ITS"	$162,637	$0	$0	$0	$0	$0	$162,637
14	Rate Schedule "NGV"	$3,000	$0	$0	$0	($394)	($394)	$2,606
15	Subtotal Revenue	$64,833,635	($905,120)	($2,940,574)	$775,796	($15,184,199)	($18,254,097)	$46,579,538
16	Other Revenue	$684,944	$0	$0	$0	$346,098	$346,098	$1,031,042
17	Total Operating Revenue	$65,518,579	($905,120)	($2,940,574)	$775,796	($14,838,101)	($17,907,999)	$47,610,580

Schedule No. 3-A-2
SUMMARY OF ADJUSTMENTS TO TEST YEAR SALES (MCF)

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Hardy**

Line No.	Firm Rate Classes	Test Year Ended June 30, 2015	Test Year Adjustments	Temperature Normalization	Customer Growth	Other Adjustments and Annualizations	Sub-total	Test Period Ending March 31, 2016
1	Rate Schedule "RS-1"	82,376	(21,010)	(6,207)	0	(6)	(27,223)	55,153
2	Rate Schedule "ERS-1"	2,235	(189)	0	0	1	(188)	2,047
3	Rate Schedule "RS-2"	2,720,560	21,010	(254,913)	20,184	(4)	(213,723)	2,506,837
4	Rate Schedule "ERS-2"	15,619	189	(1,262)	15,769	2	14,698	30,317
5	Rate Schedule "GS"	322,018	(17,481)	(34,006)	6,000	(8)	(45,495)	276,523
6	Rate Schedule "EGS"	1,493	0	0	(93)	(1)	(94)	1,399
7	Rate Schedule "MVS"	367,958	9,506	(28,416)	568	840	(17,502)	350,456
8	Rate Schedule "EMVS"	2,408	0	0	0	0	0	2,408
9	Rate Schedule "LVS"	1,266,457	397,693	(13,070)	8,958	(49,041)	344,540	1,610,997
10	Rate Schedule "HLFS"	2,873,205	(86,263)	(2,740)	5,808	38,472	(44,723)	2,828,482
11	Rate Schedule "GLR"	84	0	0	0	0	0	84
12	Rate Schedule "NCR"	305,471	(303,456)	0	5,417	18,943	(279,096)	26,375
13	Rate Schedule "ITS"	72,699	0	0	0	0	0	72,699
14	Rate Schedule "NGV"	124	0	0	0	4	4	128
15	Total	8,032,707	(1)	(340,614)	62,611	9,202	(268,802)	7,763,905

Schedule No. 3-A-3
SALES AND REVENUE BY RATE CLASS

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Hardy**

Description	Total	Rate "RS-1"	Rate "ERS-1"	Rate "RS-2"	Rate "ERS-2"	Rate "GS"	Rate "EGS"	Rate "MVS"	Rate "EMVS"	Rate "LVS"	Rate "HLFS"	Rate "GLR"	Rate "NCR"	Rate "ITS"	Rate "NGV"	Other Revenue
Actual Twelve Months Ended June 30, 2013																
Mcf Sales	7,287,535	92,504	0	2,318,228	0	280,078	0	284,812	0	997,569	2,391,081	120	827,270	95,822	51	
Base Revenues	$22,201,592	1,033,537	0	12,757,181	0	1,418,255	0	702,674	0	1,460,284	2,393,314	989	1,651,737	191,578	1,167	590,876
GSR Revenues	$33,550,778	922,261	0	23,115,433	0	2,738,239	0	2,468,601	0	2,201,501	2,241,673	659	0	0	193	(137,782)
Total Revenues	$55,752,370	$1,955,798	$0	$35,872,614	$0	$4,156,494	$0	$3,171,275	$0	$3,661,785	$4,634,987	$1,648	$1,651,737	$191,578	$1,360	$453,094
Actual Twelve Months Ended June 30, 2014																
Mcf Sales	7,771,078	100,243	195	2,580,658	3,459	330,160	330	337,255	417	1,170,495	2,825,157	87	354,651	67,862	109	
Base Revenues	$22,965,633	1,079,154	3,291	13,354,979	31,248	1,525,487	3,882	786,287	1,761	1,678,481	2,795,572	730	984,192	149,690	2,470	568,409
GSR Revenues	$38,883,347	1,018,240	1,986	26,250,450	35,592	3,247,904	3,191	2,867,371	4,369	2,706,860	2,337,580	490	0	0	490	408,824
Total Revenues	$61,848,980	$2,097,394	$5,277	$39,605,429	$66,840	$4,773,391	$7,073	$3,653,658	$6,130	$4,385,341	$5,133,152	$1,220	$984,192	$149,690	$2,960	$977,233
Test Year - Twelve Months Ended June 30, 2015																
Mcf Sales	8,032,707	82,376	2,235	2,720,560	15,619	322,018	1,493	367,958	2,408	1,266,457	2,873,205	84	305,471	72,699	124	
Base Revenues	$23,989,327	953,703	32,264	13,963,822	142,893	1,517,590	13,643	876,449	8,576	1,779,776	2,779,580	707	969,548	162,637	2,606	785,533
GSR Revenues	$41,529,252	882,908	23,849	29,144,811	166,777	3,339,180	14,982	3,205,959	12,353	2,542,632	2,295,486	510	0	0	394	(100,589)
Total Revenues	$65,518,579	$1,836,611	$56,113	$43,108,633	$309,670	$4,856,770	$28,625	$4,082,408	$20,929	$4,322,408	$5,075,066	$1,217	$969,548	$162,637	$3,000	$684,944
Test Period - Twelve Months Ended March 31, 2016																
Mcf Sales	7,763,905	55,153	2,047	2,506,837	30,317	276,523	1,399	350,456	2,408	1,610,997	2,828,482	84	26,375	72,699	128	
Base Revenues	$22,965,902	794,382	$30,505	$13,634,169	$264,897	$1,452,167	$12,909	$875,513	$9,491	$2,097,668	$2,738,233	$705	$149,843	$162,637	$2,606	$740,177
GSR Revenues	$24,644,678	$376,717	$13,983	$17,122,777	$207,077	$1,835,353	7,474	1,939,903	1,083	1,611,352	1,237,914	180	0	0	0	290,865
Total Revenues	$47,610,580	$1,171,099	$44,488	$30,756,946	$471,974	$3,287,520	$20,383	$2,815,416	$10,574	$3,709,020	$3,976,147	$885	$149,843	$162,637	$2,606	$1,031,042
	$0															
	$0															

Schedule No. 3-B
OPERATING EXPENSES

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **J. Weiss**

Line No.	Description	Test Year Ended June 30, 2015	Test Period Ending March 31, 2016
	Operations and Maintenance Expenses		
	Operations		
1	Manufactured Gas Production	$60,322	$ 60,684.40
2	Purchased Gas	41,529,258	24,644,678
3	Distribution Expense	1,472,340	1,461,299
4	Customer Accounting Expense	2,285,233	2,436,282
5	Sales Expense	747,206	936,569
6	Administrative and General Expense	8,306,308	7,856,967
7	Total Operations Expense	$54,400,667	$37,396,479
	Maintenance		
8	Manufactured Gas Production	$89,616	$ 47,461.16
9	Distribution Expense	605,583	670,556
10	Administrative and General Expense	139,056	119,858
11	Total Maintenance Expense	$834,255	$837,875
12	Total Operations and Maintenance Expense	$55,234,922	$38,234,354
13	Depreciation and Amortization Expense	2,402,831	2,654,050
14	Total Operating Expense	$57,637,753	$40,888,404

Schedule No. 3-C
PAYROLL COSTS

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Weiss**

		Test Year Ended June 30, 2015				Test Period Ending March 31, 2016			
Line No.	Distribution	Payroll Costs	Benefits	Payroll Related Taxes	Total Payroll Costs	Payroll Costs	Benefits	Payroll Related Taxes	Total Payroll Costs
1	Delaware Division Payroll	7,289,262	1,660,821	507,116	$9,457,199	8,131,414	1,764,395	592,404	$10,488,213
	Less								
2	Amounts Charged to Construction	1,718,112	415,388	129,992	$2,263,492	1,636,323	363,646	128,263	$2,128,232
3	Total Delaware Expense Portion (1 - 2)	5,571,150	1,245,433	377,124	$7,193,707	6,495,091	1,400,749	464,141	$8,359,981

Schedule No. 3-D
EXECUTIVE COMPENSATION (1)

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Weiss / Dewey**

Line No.	Name and Title	Annual Salary (1)	Stock Awards, Bonus, and Non-Equity Incentive Plan Compensation (1)	All Other Compensation (1)	Total Compensation (1)
1	Michael P. McMasters, Chief Executive Officer, President and Director	$466,250	$783,606	$175,466	$1,425,322
2	Stephen C. Thompson, Senior Vice President	327,500	351,678	190,465	$869,643
3	Beth W. Cooper, Senior Vice President and Chief Financial Officer	293,625	318,732	66,181	$678,538
4	Elaine B. Bittner, Senior Vice President	253,750	271,144	30,632	$555,526
5	Jeffry M Householder, President of Florida Public Utilities Company	279,711	283,080	38,055	$600,846
6	Total Executive Compensation	$1,620,836	$2,008,240	$500,799	$4,129,875

Notes: (1) 2014 Summary, per the Chesapeake Utilities Corporation 2015 Proxy Statement

Line No.	Name and Title	Annual Salary (2)	Stock Awards, Bonus, and Non-Equity Incentive Plan Compensation (2)	All Other Compensation (2) (3)	Total Compensation (2)
7	Michael P. McMasters, Chief Executive Officer, President and Director	$55,548	$84,257	$18,934	$158,739
8	Stephen C. Thompson, Senior Vice President	120,349	117,644	48,785	$286,778
9	Beth W. Cooper, Senior Vice President and Chief Financial Officer	32,917	32,882	2,043	$67,842
10	Elaine B. Bittner, Senior Vice President	34,099	32,722	4,735	$71,555
11	Jeffry M Householder, President of Florida Public Utilities Company	0	0	0	$0
12	Total Executive Compensation	$242,912	$267,505	$74,497	$584,914

Notes: (2) Allocated to Delaware Division for the Test Period As Adjusted - 12 Months Ended 3/31/2016
(3) Term Life Insurance and Vehicle Allowance are based on 2014 amounts inflated at 3%

Schedule No. 3-E
SALES PROMOTION AND ADVERTISING EXPENSES

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **J. Weiss**

			Test Year Ended June 30, 2015		Test Period Ending March 31, 2016	
Line No.	Account No.	Description	Description of Activity	Delaware Portion	Description of Activity	Delaware Portion
1	912	Demonstration and Selling Expense	Customer Information and Demonstrations	10,767	Customer Information and Demonstrations	11,052
2	913	Advertising Expense	Advertising	141,392	Advertising	144,614
3		Total		$152,158		$155,666

Schedule No. 3-F
CONTRIBUTIONS AND LOBBYING COSTS

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **J. Weiss**

No contributions for educational or other charitable purposes or lobbying costs are included as part of the cost of service to be recovered from the ratepayers.

Schedule No. 3-G
SOCIAL AND SERVICE CLUB DUES

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **J. Weiss**

Line No.	Department	Test Year Ended June 30, 2015	Test Period Ending March 31, 2016
1	MG110 - Natural Gas Distribution Management	190	191
2	MG111 - Distribution Operations Manager	454	471
3	MG771 & MG715 - AVP Customer Engagement	1,647	3,193
4	MK110 - Marketing	15,472	16,398
5	OP114 - Operations Tech - Central	24	24
6	OP115 - Operations Tech - Southeast	11	11
7	OP116 - Operations Tech - Southwest	2	2
8	OP120 - Line Locating	57	57
9	RA110 - Regulatory Affairs	82	82
10	SA110 - Sales	1,182	1,209
11	SM770 & SM714 - Safety Management	82	82
12	SM771 & SM710 - Safety Management	239	239
13	AC800 - Business Unit Accounting	112	102
14	AC900 - Corporate Accounting	123	124
15	BD900 - Board of Directors	1,776	1,763
16	CM900 - Communications	124	119
17	GV900 - Corporate Governance	78	69
18	HR900 & HR940 - Human Resources	302	288
19	IA800 - Internal Audit	298	289
20	IR900 - Investor Relations	100	86
21	IT801 - Financial Systems	32	33
22	MG901 - Chief Executive Officer	1,507	1,363
23	MG903 - Chief Financial Officer	62	59
24	MG904 - Controller	29	28
25	MG905 - VP of Strategic Development	99	92
26	PM900 & IT808 - Project Management Office	9	6
27	SP900 & NE980 - Strategic Development	1,367	3,741
28	TM900 - Treasury Management	64	53
29	Total	$25,524	$30,177

Schedule No. 3-H
RATE CASE EXPENSE

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **J. Weiss**

Comparison of Projected Expenses of Current Case to Prior Rate Case

Line No.	Item of Expense	Current Case Estimated	Prior Case Actual
1	State Commission Expenses	$250,000	$218,188
2	Legal & Court Reporting	100,000	96,631
3	Cost of Service, Rate Design	155,000	126,536
4	Cost of Capital	50,000	25,348
5	Rate Base / O & M Expenses	0	48,912
6	Depreciation	0	43,772
7	Miscellaneous Estimated Expenses	30,000	22,014
8	Total	$585,000	$581,402

Schedule No. 3-H-1
INTERCOMPANY ACCOUNT ANALYSIS

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **J. Weiss**

		Test Year: Twelve Months Ended June 30, 2015				Test Period: Twelve Months Ending March 31, 2016			
Line No.	Description	Amount	Allocation Basis	Change in Allocation		Amount	Allocation Basis	Change in Allocation	Description
1	Rents	$304,279	Employee Allocation	No		$312,631	Employee Allocation	No	Facility Rent
2	BravePoint, Inc. Information System Services	$13,387	Department Allocation	No	(1)	$0	N/A	No	Information Systmen Services
3	Natural Gas Purchases	$11,692,894	Direct	No		$11,692,894	Direct	No	Natural gas Purchases
4	Corporate Cost Centers	$3,760,205	(2)	Yes		$4,092,401	(2)	No	General corporate services
5	Purchases of Natural Gas for Facilities	$1,449	Invoiced Rates	No		$1,346	Invoiced Rates	No	Utility Expense

(1) BravePoint was sold in October 2014 and is no longer an affiliated company.

(2) Please see Exhibit XXX for the allocations and methodoligies to allocate corporate cost centers to Delaware Division

Schedule No. 3-I
OPERATING TAXES

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Elder**

Line No.	Description	Test Year Ended June 30, 2016	Test Period Ending 31-Mar-16
1	Federal Income Tax - Current	($270,399)	680,674
2	State Income Tax - Current	(16,931)	185,319
3	Deferred Federal Income Tax	1,747,952	363,399
4	Deferred State Income Tax	440,235	98,938
5	Sub-total	$1,900,857	$1,328,330
6	Other Federal, State and Local Taxes	13,663	12,451
7	Total Operating Taxes	$1,914,520	$1,340,781

Schedule No. 3-J
TEST PERIOD FEDERAL AND STATE INCOME TAX

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Elder**

Line No.	Description		Test Period Ending 31-Mar-16
1	Operating Income before Income Taxes and Interest Expense		$4,607,945
2	Less: Interest Expense for the Test Period		1,354,930
3	Plus: 50% meals for the period		14,308
4	Earnings before taxes		$3,267,323
	Timing Differences:		
5	Accelerated Depreciation		(1,261,569)
6	Incentive Compensation		103,316
7	Purchased Gas Costs		21,031
8	Total Timing Differences		($1,137,222)
9	State Taxable Income		$2,130,101
10	State Tax at 8.7%	8.70%	$185,319
11	State tax provision to return adjustments		($28,602)
12	Total State Tax		$156,717
13	Federal Taxable Income		$1,973,384
14	Federal Income Tax at 35%	35.00%	$690,684
15	Federal tax provision to return adjustments		($155,063)
16	Total Federal income tax		$535,621
17	Total Current Income Tax Expense (12 + 16)		$692,338

Schedule No. 3-K
TEST PERIOD DEFERRED FEDERAL AND STATE INCOME TAX

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Elder**

Line No.	Description	Tax Basis	Test Period Ending March 31, 2016 Federal	State
	Deferred Income Taxes:			
1	Depreciation Related			
2	Deferred State Tax	($1,261,569)		$109,757
3	Deferred Federal Tax	($1,151,812)	$403,134	
4	Incentive Compensation			
5	Deferred State Tax	$103,316		($8,988)
6	Deferred Federal Tax	$94,328	($33,015)	
7	Purchased gas costs			
8	Deferred State Tax	$21,031		($1,830)
9	Deferred Federal Tax	$19,201	($6,720)	
32	Total Deferred Income Taxes		$363,399	$98,939
33	Total Current Income Taxes		$680,674	$185,319
34	Total Income Tax Adjustments (Current and Deferred)		$12,119	$331
35	Total Income Taxes		$1,056,192	$284,589
36	Statutory Income Tax Rates		35.00%	8.70%

Schedule No. 3-K-1
STATEMENT OF INCOME TAX ACCOUNTING

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness:

Statement on Deferred Tax Accounting

Deferred income results from the fact that certain transactions affect the determination of net income for financial accounting purposes in one reporting period and the computation of taxable income and income taxes payable in different reporting periods. The items that generate deferred income taxes are listed below:

1) Accelerated depreciation methods are utilized for income tax reporting while straight-line depreciation is used for financial reporting purposes.

2) Certain repair and replacement costs are deducted on a cash basis consistent with the 2014 Tangible Property Regulations while they are capitalized for financial reporting purposes.

3) Purchase gas costs as incurred are utilized as a current deduction for income tax reporting while a deferred method is utilized for financial reporting.

4) Bad debts are a reduction for income tax reporting as write offs occur while an allowance is maintained for bad debts for financial reporting purposes.

5) The tax rules associated with the capitalization of overheads and interest on self-constructed capital projects generates additional capitalization of overheads and interest for income tax reporting which is not required for financial reporting.

6) Certain incentive compensation costs are deductible on a cash basis while an accrual is maintained for financial reporting purposes.

7) With respect to accounting for pension expense for tax purposes, the Company deducts the amounts paid during the year, subject to certain limitations. For financial reporting purposes the Company expenses the net periodic pension costs based on actuarial calculations in accordance with ASC 715.

8) Other post retirement benefit expenses for tax purposes are accounted for in the same manner as pension expense as explained above.

9) Real property taxes are deductible on a cash basis for income tax reporting while an accrual basis is utilized for financial reporting.

10) Self-Insurance reserve amounts are deductible on a cash basis for income tax reporting and on an accrual basis for financial reporting.

SFAS No. 109 Accounting for Income Taxes

Effective January 1, 1993, the Company adopted Statement of Financial Accounting Standards No. 109 "Accounting for Income Taxes" ("SFAS No. 109"). The adoption of SFAS No. 109 changed the method of accounting for income taxes from the deferred method to the asset and liability approach.

The principal effect on the Company's financial statements of adopting SFAS No. 109 was the recording of deferred regulatory assets and liabilities for the estimated deficiency and excess deferred income taxes associated with depreciation.

At the point of adoption of SFAS No.109, the Company was required to have all deferred income taxes associated with temporary differences between financial statement and tax basis of assets and liabilities recorded at current effective income tax rates. All deferred income tax account balances at December 31, 1992 were reconciled to insure that the balance for each timing difference was at current income tax rates, with the exception of accumulated depreciation.

The calculation to reconcile deferred income taxes associated with accumulated depreciation was slightly more complex because the book and tax basis had to be adjusted for Equity Allowance for Funds Used During Construction ("AFUDC") and Investment Tax Credit ("ITC") basis reduction, respectively. At the point of adoption of SFAS No.109, the reconciliation determined that the Company's balance for accumulated deferred income taxes associated with depreciation was unfunded by $194,020.

SFAS No. 109 then required the Company to establish a deferred regulatory asset and deferred income tax liability associated with the revenue requirement and corresponding income tax liability to reflect the deficiency. To complicate accounting further, the deficiency ($194,020) is actually the net of over funded deferred taxes for some years ($329,405) and under funded deferred taxes for other years ($135,385). The excess deferred income taxes were generated from the reduction of the income tax rates in the mid 1980's. The Company recorded the following journal entries in March 1993 to record the excess and under funded deferred tax liability:

		Debit	Credit
1932 1823	109 Reg Asset-Rev Req-Depreciation	$546,812	
26DP 2822	Acc Def I/T-Depreciation-Long Term		$329,405
26DP 2829	Acc Def I/T-Depreciation-Long Term 109		217,407

To record the revenue requirement associated with unfunded income tax liability on depreciation ($329,405 x 1.66 = $546,812)

The Company has previously utilized the average rate assumption method for calculating and recording deferred income taxes associated with depreciation.

		Debit	Credit
26DP 2822	Acc Def I/T-Depreciation-Long Term	$135,385	
26DP 2829	Acc Def I/T-Depreciation-Long Term 109	89,354	
2970 2540	109 Regulatory Liability Depreciation		$224,739

To record negative revenue requirement associated with excess deferred income taxes on depreciation ($135,385 x 1.66 = $ $224,739)

In June 1996, in accordance with SFAS No. 109, the Company recorded the following journal entry to recognize the revenue requirement associated with Equity AFUDC on capital projects closed in 1995:

Schedule No. 3-K-1
STATEMENT OF INCOME TAX ACCOUNTING

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness:

		Debit	Credit
1931 1823	109 Reg Asset-Equity AFUDC	$65,885	
26AF 2829	Acc Def I/T AFUDC-Long Term 109		$26,185
26DP 2822	Acc Def I/T-Depreciation-Long Term		39,700

Statement on Allocation of the Consolidated Federal Income Tax

Present Company policy provides that each company and division compute its income tax liability on a separate company (stand alone) basis. However, in the event that on the separate company basis, a company or division should incur a taxable loss or unused investment tax credit which is utilized elsewhere on the consolidated tax return, the parent reimburses the company or the division for the tax benefits realized. Earnings in equity of subsidiaries are eliminated in the consolidated return.

Schedule No. 3-L
UNAMORTIZED INVESTMENT TAX CREDIT

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Elder**

Unamortized Balance as of June 30, 2014	$0
ITC Generated during TME June 30, 2015	0
Amortization	0
Unamortized Balance as of June 30, 2015	$0
ITC Generated July 2015 - March 2016	0
Amortization July 2015 - March 2016	0
Unamortized Balance as of March 31, 2016	$0

(1) Delaware Division has no unamortized investment tax credit.

Schedule No. 3-M
OTHER FEDERAL, STATE AND LOCAL TAXES

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **J. Weiss**

Line No.	Description	Test Year Ended June 30, 2015	Test Period Ending March 31, 2016
1	Payroll Taxes	428,191.34	511,237.28
2	Property Taxes	1,158,875	1,359,722
3	Revenue Related Taxes	195,870	142,832
4	Sub-total	$1,782,936	$2,013,791
	Other Taxes		
5	Natural Gas Vehicle	1,050.16	1,837.32
6	State Franchise	22,859	23,374
7	Other	1,060	881
8	Sub-total Other Taxes	$24,970	$26,092
9	Total Other Federal, State and Local Taxes	$1,807,906	$2,039,883

Schedule No. 3-N
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **J. Weiss**

The Company computes Allowance For Funds Used During Construction ("AFUDC") for capital projects that meet certain criteria. The criteria for applying AFUDC to a capital project is that the capital project costs at least fifty thousand dollars ($50,000), and will take more than six months to complete. The component of AFUDC for borrowed funds (allowance for borrowed funds used during construction) includes the cost of short-term and long-term debt used to finance utility construction. The component of AFUDC for other funds (allowance for other funds used construction) includes the cost of common equity used to finance utility construction.

AFUDC is an accounting procedure whereby the cost of borrowed and other funds used to finance utility construction projects is capitalized as part of utility plant with a corresponding credit to income. On the income statement, allowance for borrowed funds used during construction is reported as a credit to interest expense, and allowance for other funds used during construction is reported as other income. The Company accrues AFUDC on all eligible capital projects as defined above. AFUDC is not taxable income and the depreciation of capitalized AFUDC is not a tax-deductible expense.

There was no AFUDC for the years 2007 - 2015.

Schedule No. 3-O
OTHER INCOME AND DEDUCTIONS

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **J. Weiss**

Line No.	Description	Test Year Ended June 30, 2015	Test Period Ending March 31, 2016
1	M & J Expense	($21,310)	($21,603)
2	Non-Utility Expense	($8,744)	($9,006)
3	Interest & Dividend Income	$27,606	$28,337
4	Donations	($38,250)	($38,876)
5	Civic & Political Expense	($730)	($752)
6	Other Income & Taxes	$44,212	$45,225
7	Deferred IT Debt	($27,667)	($28,497)
8	Taxes on Other Income	$10,116	$10,234
9	Total Net Other Income	($14,767)	($14,938)

Schedule No. 4
PROPOSED FAIR RATE OF RETURN

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Moore**

1. Cost of Capital Summary

Type of Capital	Capital Structure Ratio in %	Cost Rate	Weighted Cost of Capital
Long-Term Debt	39.61%	4.82%	1.91%
Common Equity	60.39%	11.00%	6.64%
Total Cost of Capital	100.00%		8.55%

Schedule No. 4-A
CAPITAL STRUCTURE AND RELATED RATIOS

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Moore**

		At Test Year End-June 30, 2015		At Test Period End-March 31, 2016	
Line No.	Description	Amount Outstanding	Ratios	Amount Outstanding	Ratios
	Long-Term Debt:				
1	Senior Notes	$151,681,818	29.84%	$215,454,545	35.79%
2	Convertible Debentures	0	0.00%	0	0.00%
3	Total Long-Term Debt	$151,681,818	29.84%	$215,454,545	35.79%
4	Consolidated Common Equity	$356,654,628	70.16%	$386,533,868	64.21%
5	Total Permanent Capital	$508,336,446	100.00%	$601,988,413	100.00%

Schedule No. 4-B
COMPOSITE COST RATE OF DEBT

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Moore**

Line No.	Series or Issue Designation	Amount Outstanding Test Period Ending March 31, 2016	Percent To Total	Cost Rate Schedule 4-C Effective	Cost Rate Weighted
1	Chesapeake Senior Note 5	$5,454,545	2.53%	6.71%	0.17%
2	Chesapeake Senior Note 6	$10,000,000	4.64%	5.56%	0.26%
3	Chesapeake Senior Note 7	$24,000,000	11.14%	5.95%	0.66%
4	Chesapeake Senior Note 8	$29,000,000	13.46%	6.38%	0.86%
5	Chesapeake Senior Note 9	$7,000,000	3.25%	6.68%	0.22%
6	Chesapeake Senior Note 10	$20,000,000	9.28%	3.77%	0.35%
7	Chesapeake Senior Note 11	$50,000,000	23.21%	3.93%	0.91%
8	Chesapeake Senior Note 12	$70,000,000	32.49%	4.52%	1.47%
9	Total	$215,454,545	100.00%		4.90%

Schedule No. 4-B-1
COMPOSITE COST RATE OF DEBT

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Moore**

Line No.	Series or Issue Designation	Amount Outstanding at June 30, 2015	Principal Payments through March 31, 2016	Amount Outstanding at March 31, 2016	
1	Chesapeake Senior Note 5	$8,181,818	$2,727,273	$5,454,545	
2	Chesapeake Senior Note 6	12,000,000	2,000,000	$10,000,000	
3	Chesapeake Senior Note 7	25,500,000	1,500,000	$24,000,000	
4	Chesapeake Senior Note 8	29,000,000	0	$29,000,000	
5	Chesapeake Senior Note 9	7,000,000	0	$7,000,000	
6	Chesapeake Senior Note 10	20,000,000	0	$20,000,000	
7	Chesapeake Senior Note 11	50,000,000	0	$50,000,000	
8	Total	$151,681,818	$6,227,273	$145,454,545	(1)

(1) Does not include issuance of $70,000,000 made after end of Test Year, which is included in Test Period balance on Schedule 4B

Schedule No. 4-C
CALCULATION OF THE EFFECTIVE COST RATE FOR LONG-TERM DEBT

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Moore**

Line No.	Series	Stated Interest or Coupon Rate	Nominal Date of Issuance	Date of Maturity	Average Term in Years	Original Amount Issued	Premium or (Discount) at Issuance	Company Issuance Expenses	Net Proceeds	Net Proceeds Ratio	Effective Cost Rate
1	Chesapeake Senior Note 5	6.64%	31-Oct-2002	31-Oct-2017	15	$30,000,000	$0	$141,831	$29,858,169	99.527%	6.71%
2	Chesapeake Senior Note 6	5.50%	12-Oct-2006	12-Oct-2020	14	$20,000,000	$0	$79,566	$19,920,434	99.602%	5.56%
3	Chesapeake Senior Note 7	5.93%	31-Oct-2008	31-Oct-2023	15	$30,000,000	$0	$39,518	$29,960,482	99.868%	5.95%
4	Chesapeake Senior Note 8	5.68%	24-Jun-2011	30-Jun-2026	15	$29,000,000	$0	$1,496,322	$27,503,678	94.840%	6.38%
5	Chesapeake Senior Note 9	6.43%	2-May-2013	2-May-2028	15	$7,000,000	$0	$121,631	$6,878,369	98.262%	6.68%
6	Chesapeake Senior Note 10	3.73%	16-Dec-2013	16-Dec-2028	15	$20,000,000	$0	$68,794	$19,931,206	99.656%	3.77%
7	Chesapeake Senior Note 11	3.88%	15-May-2014	15-May-2029	15	$50,000,000	$0	$192,790	$49,807,210	99.614%	3.93%
8	Chesapeake Senior Note 12	4.50%	31-Dec-2015	31-Dec-1930	15	$130,000,000	$0	$220,000	$129,780,000	99.831%	4.52%

Schedule No. 4-D
COMPOSITE COST RATE OF PREFERRED STOCK

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**

Witness Responsible: ______________________

Line No.	Series Designation	Amount Outstanding	Percent to Total	Cost Rate Schedule 4-E Effective	Cost Rate Weighted

Chesapeake Utilities Corporation does not have any preferred stock issued or outstanding.

Schedule No. 4-E
CALCULATION OF THE EFFECTIVE COST RATE OF PREFERRED SOTCK

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**

Witness Responsible: ______________________________

Line No.	Series Designation (2)	Stated Dividend Rate	Average Term In Years (1)	Date of Issue	Original Amount Issued	Premium (Discount) at Issuance	Company Issuance Expenses	Net Proceeds on Principal Amount Issued	Net Proceeds Ratio	Effective Cost Rate
	Chesapeake Utilities Corporation does not have any preferred stock issued or outstanding.									

Notes: (1) Determined by taking into account the effect of annual sinking fund requirements which are met by the retirement of shares which reduce the average term of each series
(2) The effective cost rate for each issue is the cost rate to maturity using as inputs the average term of issue, dividend rate and the net proceeds ration.

Schedule No. 4-F
PUBLIC OFFERINGS OF COMMON STOCK

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Moore**

Line No.	Item	Public Offering	Offering Related to Acqusition	Company Programs (1)	Company Programs (1)	Company Programs (1)	Company Programs (1)	Company Programs (1)
1	Date of Prospectus	n/a	04/01/15	2010	2011	2012	2013	2014
2	Subscription Offering Ratio	n/a	n/a	n/a	n/a	n/a	n/a	n/a
3	Number of Shares Offered	n/a	n/a	n/a	n/a	n/a	n/a	n/a
4	Number of Shares Issued	n/a	592,970	194,822	64,668	45,288	61,097	131,366
5	Share Price	n/a	$50.87	$17.80	$19.70	$30.23	$26.47	$32.65
6	Underwriting Discount	n/a	$0	$0	$0	$0	$0	$0
7	Gross Value to Company	n/a	$30,164,384	$3,467,832	$1,273,960	$1,369,056	$1,617,238	$4,289,100
8	Estimated Company Expenses	n/a	$0	$0	$0	$0	$0	$0
9	Earnings Per Share (Actual Reported) for 12 Months Ended June 30, 2015	n/a	$2.76					
10	Net value Per Share	n/a	$30,164,384	$3,467,832	$1,273,960	$1,369,056	$1,617,238	$4,289,100
11	Latest Annualized Reported Dividend at Time of Offering	n/a	$1.15	$0.88	$0.92	$0.97	$1.03	$1.08
12	Book Value Per Share as of June 30, 2015	n/a	$23.04					
13	Earnings/Net Value Ratio per share	n/a	5.43%					
14	Net Value/ Book Ratio	n/a	8.59%					
15	Dividend Yield on Offering Price	n/a	2.26%					
16	Pro Forma Permanent Capital (After New Financing)	n/a						
		Stockholders Equity 6/30/15	$351,175,912	68.0%				
		Long-Term deb 6/30/15	$165,374,670	32.0%				
			$516,550,582					

(1) Includes Dividend Reinvestment and Dividend and Direct Stock Purchase Plan, 401K Plan, Stock Incentive Compensation.

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Schedule No. 4-F-1
SUMMARY STATEMENT OF COMMON EQUITY CHANGE

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness:

Chesapeake's Board of Directors approved a three-for-two stock split of the Company's outstanding stock on July 2, 2014. This stock split was effected in the form of a stock dividend entitling each stockholder as of the record date (August 13, 2014) to receive one additional share of common stock for every two shares of common stock owned. This stock dividend was issued on September 8, 2014. There were no changes to common stock par value as a result of this stock split.

Schedule No. 4-G
COMPARATIVE FINANCIAL DATA - GENERAL

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness:

Line No.	Item	2013 Next Most Recent Calendar Year	2014 Most Recent Calendar Year	Test Year Ended June 30, 2015	Test Period Ending March 31, 2016
1	Embedded Cost - Long-Term Debt	5.77%	5.14%	5.12%	4.82%
2	Embedded Cost - Preferred Stock	n/a	n/a	n/a	n/a
3	Pretax Interest Coverage	7.66	7.33	7.80	7.33
4	Pretax Interest Coverage, Before AFUDC	7.66	7.33	7.80	7.33
5	After Tax Interest Coverage	4.98	4.81	5.09	4.88
6	After Tax Interest Coverage, Before AFUDC	4.98	4.81	5.09	4.88
7	Indenture Provision Coverage 1/	6.65	6.41	6.24	6.44
8	After Tax Interest & Pfd. Div. Coverage	4.98	4.81	4.81	4.88
9	After Tax Interest & Pfd. Div. Coverage, Before AFUDC	4.98	4.81	5.09	4.88
10	Moody's Bond Rating - Senior Debt	not rated	not rated	not rated	not rated
11	S & P Bond Rating - Senior Debt	not rated	not rated	not rated	not rated
12	NAIC Debt Rating 3/	NAIC1	NAIC1	NAIC1	NAIC1
13	Moody's Preferred Stock Rating	n/a	n/a	n/a	n/a
14	S & P Preferred Stock Rating	n/a	n/a	n/a	n/a
15	Rate of Return on Net Plant in Service	5.19%	5.23%	5.15%	4.60%
16	Rate of Return on Total Capital	11.76%	12.02%	11.58%	9.70%
17	Percentage of Revenues from Gas Service 2/	99.00%	99.00%	99.00%	99.00%
	Percentage of Revenues from Other 2/	1.00%	1.00%	1.00%	1.00%
18	Composite Depreciation Rates	3.81%	3.78%	3.42%	3.05%

1/ Indentures to the long-term debt of the Company contain various restrictions. The most stringent restrictions state that the Company must maintain an equity to total capitalization ratio of at least 40% and the pro-forma fixed charge coverage ratio must be 1.2 times. The Company is in compliance with all of its debt covenants.

2/ This represents the percentage of revenues from gas service for the Delaware Division only.
Total Delaware Division revenues were $56,630,876 in 2013 $62,841,044 in 2014, and $65,518,579 for the 12 months ended June 30, 2015.

Except as noted above, the information presented is for Chesapeake Utilities Corporation consolidated results.

3/ National Association of nsurance Commissioners Ratings on Private Placment Debt - NAIC1 equals Highest Rating (A Equivalent Rating)

Schedule No. 4-H
COMPARATIVE FINANCIAL DATA - COMMON STOCK (1)

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness:

Line No.	Item	2013 Next Most Recent Calendar Year	2014 Most Recent Calendar Year	Test Year Ended June 30, 2015	Test Period Ending March 31, 2016
1	Shares Outstanding Period End	14,457,345	14,588,711	15,242,967	16,094,813
2	Shares Outstanding - Weighted Average	14,430,962	14,551,308	14,749,645	15,338,344
3	Basic Earnings Per Share - on Weighted Average	$2.27	$2.48	$2.76	$2.62
4	Dividends Paid Per Share	$1.000	$1.053	$1.053	$1.133
5	Dividends Declared Per Share	$1.013	$1.067	$1.098	$1.150
6	Dividend Payout Ratio (Declared Basis) (5 / 3)	44.64%	43.01%	39.76%	43.89%
7	Market Price - Average of Quarterly Averages of High and Low Prices	$35.25	$43.69	$47.34	$49.41
8	Book Value Per Share - Period End	$19.28	$20.59	$23.04	$25.76
9	Average Book Value (Beginning & End of Period)	$18.55	$19.90	$21.78	$23.30
10	Earnings to Price Ratio (7 / 3)	15.53	17.62	17.15	18.86
11	Market to Book Ratio (7 / 9)	1.90	2.20	2.17	2.12
12	Dividend Yield (5 / 7)	2.88%	2.44%	2.32%	2.33%
13	Rate of Return on Average Book Common Equity (3 / 9)	12.24%	12.46%	12.67%	11.24%
14	AFUDC as % Earnings for Common	0.00%	0.00%	0.00%	0.00%
15	Effective Income Tax Rate (Federal & State)	40.655% (2)	40.655% (2)	40.655% (2)	40.655% (2)

(1) The information provided in lines 1 through 14 is for Chesapeake Utilities Corporation consolidated results. The Delaware Division does not have its own stockholders.

(2) Represents Delaware Division's Effective Income Tax Rate.

Schedule No. 5
COMPUTATION OF GROSS REVENUE CONVERSION FACTOR

Delaware Public Service Commission

Company: **Chesapeake Utilities Corporation**
Docket No.: **15-**
Witness: **Hardy**

Line No.	Item	% Incremental Gross Revenues	
		Actual	
1	Gross Operating Revenue		100.00
2	Adjustment for Uncollectibles	0.2709%	0.27090
3	Adjusted Operating Revenue		99.72910
4	Less: P.S.C. Assessment	0.3000%	0.30000
5	Income Before State Income Tax		99.42910
6	State Income Tax	8.70%	8.65033
7	Income Before Federal Income Tax		90.77877
8	Federal Income Tax	35.00%	31.77257
9	Income After Federal Income Tax		59.00620
10	Operating Income		59.00620
11	Gross Revenue Conversion Factor (100% divided by Operating Income Percentage)		1.69474

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	**)**	
CHESAPEAKE UTILITIES CORPORATION	**)**	
FOR A GENERAL INCREASE IN ITS	**)**	**P.S.C. DOCKET NO. 15-**
NATURAL GAS RATES AND FOR	**)**	
APPROVAL OF CERTAIN OTHER	**)**	
CHANGES TO ITS NATURAL GAS TARIFF	**)**	

DIRECT TESTIMONY OF C. JAMES MOORE

On Behalf of Chesapeake Utilities Corporation

Delaware Division

Submitted for filing: December 21, 2015

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

A. My name is C. James Moore and I am a Vice President with Chesapeake Utilities Corporation ("Chesapeake"). My business address is 350 S. Queen Street, Dover, Delaware 19904.

Q. DESCRIBE BRIEFLY YOUR EDUCATION AND RELEVANT PROFESSIONAL BACKGROUND.

A. I hold a Bachelor of Science Degree in Business Administration from Salisbury State College in Salisbury Maryland and I have served with Chesapeake for nearly 30 years. Over my tenure with Chesapeake I have held several positions in both our natural gas and propane segments including Vice President of Sharpgas, Inc., General Manager of Eastern Shore Natural Gas Company, Manager of Supply & Marketing, Director of Natural Gas Distribution and Director of Gas Supply & Business Development for Chesapeake's Delaware and Maryland divisions. I have served as the Vice President of Chesapeake's Delmarva Natural Gas Distribution business unit since September 2014.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes. I have testified before the Commission in prior Delaware Division Gas Sales Service Rate proceedings.

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

A. As Vice President for Chesapeake's Delaware Division ("Delaware Division" or the "Company"), I have overall responsibility for the Delaware Division's application for a general increase in its natural gas rates throughout its service territory in Delaware along with the other requested changes to its natural gas tariff. My direct testimony consists of the following subject areas:

I. Need for Rate Relief
II. Organization of Filing
III. Identification of Attachments
IV. Chesapeake Utilities Corporation Organization
V. Net Operating Income
VI. Capital Structure
VII. Overall Return Requirement
VIII. Cost of Service Study

I. <u>Need for Rate Relief</u>

Q. WHAT IS THE PRINCIPLE REASON FOR FILING THIS RATE CASE?

A. The Delaware Division of Chesapeake Utilities Corporation has been unable to earn its allowed rate of return for the twelve months ended June 30, 2015, which is the test year selected by the Company in this proceeding. As indicated on Minimum Filing Requirement ("MFR") Schedule No. 1, the actual earned rate of return for the Delaware Division during the test year was 6.20%. As a result, the primary reasons for the Company's proposed rate increase relate to increases in the return requirement for gas utility plant investments, a significant decline in fixed margin contribution from the Company's residential, commercial and industrial firm customer classes, and an increase in taxes and fees. The major components of the requested rate increase are shown on Schedule C of the MFR's.

Q. WHEN DID THE DELAWARE DIVISION LAST IMPLEMENT AN INCREASE IN BASE RATES OR DELIVERY SERVICE RATES?

A. The Delaware Division's most recent base rate increase was initiated by the Company on July 6, 2007 in Docket No. 07-186. The Commission granted the Company an increase in base rates of $325,000 effective with bills rendered on and after September 3, 2008, by Order No. 7434, dated September 2, 2008.

Q. AS A RESULT OF THIS COMMISSION ORDER FROM THE COMPANY'S LAST BASE RATE CASE PROCEEDING, WERE THERE ANY ISSUES THAT CHESAPEAKE'S DELAWARE DIVISION WAS DIRECTED TO ADDRESS IN ITS NEXT BASE RATE FILING?

A. Yes. As a result of the settlement agreement in Docket No. 07-186 and Commission Order No. 7434, Chesapeake's Delaware Division was directed to include in its next base rate proceeding, an evaluation of all incremental main extensions of greater than 500 feet initiated by the Company since March 2007, that the Company proposed to include in rate base. If, in aggregate, these projects earn the Company's authorized rate of return over the life of the project, then all investment is included in rate base. If, in aggregate, the projects do not earn the Company's authorized rate of return, then 50% of the return shortfall is excluded from rate base.

Q. HAS CHESAPEAKE'S DELAWARE DIVISION COMPLIED WITH THE REQUIREMENTS OF THIS PRIOR COMMISSION ORDER IN THIS BASE RATE APPLICATION FILING?

A. Yes. An evaluation of the incremental main extensions since March 2007 was performed and the results are discussed in the direct testimony of Mr. Jeffrey Weiss.

Q. WHAT IS THE TEST YEAR AND TEST PERIOD THAT THE COMPANY PROPOSES TO UTILIZE IN THIS PROCEEDING?

A. The proposed test year is the twelve months ended June 30, 2015 and the test period is the twelve months ending March 31, 2016, as adjusted.

II. Organization of Filing

Q. PLEASE EXPLAIN HOW THE DELAWARE DIVISION'S RATE APPLICATION FILING IS ORGANIZED.

A. The Company's rate application filing is contained in one (1) notebook or volume. Contained within the notebook are the Company's base rate application, briefing sheet, the proposed tariff, a redlined version of the proposed tariff, Minimum Filing Requirements, and the pre-filed direct testimonies and attachments of the witnesses. The Company is presenting a total of thirteen (13) witnesses in this proceeding. The witnesses are myself, Sarah Hardy, Matthew Everngam, Jeffrey Weiss, Matthew Dewey, Lisa Elder, Christopher Redd, Autumn Chalabala, Shane Breakie, Kathy McVay, John Taylor, Ronald Amen and Paul R. Moul.

I am providing an overall summary of the reasons for the filing. Ms. Sarah Hardy, Rate Analyst III, is providing testimony related to sales and revenues, cost of service internal cost studies, the request for interim rates, and proposed changes to the tariff. Mr. Matthew Everngam, Rate Analyst III, is providing testimony on the proposed rate base. Mr. Jeffrey Weiss, Rate Analyst II, is providing testimony related to business unit operations and maintenance expenditures as well as the result of the combined internal rate of return model as dictated by the settlement agreement in the last base rate proceeding. Mr. Matthew Dewey, Director of Accounting Shared Services, is providing testimony related to corporate operations and maintenance expenditure adjustments and cost allocation procedures. Ms. Lisa Elder, Director of Financial Reporting and Tax, is providing testimony related to income taxes. Mr. Christopher Redd, Director, Gas Operations and Engineering, is providing testimony related to capital spending. Ms. Autumn Chalabala, Manager, Financial Analysis and Services, is providing testimony related to actual operating and maintenance expenses. Mr. Shane Breakie, Director, Energy Services, is providing testimony related to newly proposed services. Ms. Kathy McVay, an independent consultant, is putting forth a proposal regarding the Company's pension plan, Mr. John Taylor, a regulatory consultant, is providing the results of the Delaware Division's cost of service study. Mr. Ronald Amen, a regulatory consultant, is providing testimony on the Delaware Division's proposed rate design and a proposed revenue normalization mechanism. Mr. Paul R. Moul, a management consultant on cost of capital, is providing testimony related to a return on equity and an overall rate of return for Delaware Division.

III. Identification of Attachments

Q. DO YOU SPONSOR ANY ATTACHMENTS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I do. All of the Minimum Filing Requirement Schedules included with the Company's application were prepared under my direction and supervision and are based upon information derived from the books and records of the Company.

IV. Chesapeake Utilities Corporation Organization

Q. PLEASE DESCRIBE CHESAPEAKE UTILITIES CORPORATION'S ORGANIZATIONAL STRUCTURE.

A. Chesapeake Utilities Corporation is a diversified utility company engaged in natural gas gathering, distribution, transmission and marketing, electric distribution, propane distribution and wholesale marketing.

Chesapeake's natural gas distribution operations serve approximately 141,000 residential, commercial and industrial customers in Delaware, Maryland and Florida. In Delaware and Maryland, it operates as Chesapeake Utilities Corporation. In Maryland it also operates as Sandpiper Energy, Inc. The Delaware Division serves southern New Castle County and is the only natural gas distribution system serving Delaware's Kent and Sussex counties. The Maryland Division and Sandpiper operate the only natural gas distribution systems, with the exception of one municipal system, on Maryland's Eastern shore. In Florida, Chesapeake Utilities Corporation operates both as a division of Chesapeake, Central Florida Gas ("CFG"), as well as a wholly owned subsidiary, Florida Public Utilities Company ("FPUC"). CFG is engaged in the distribution of natural gas to residential, commercial and industrial customers throughout nine counties in the State of Florida, while FPUC distributes and sells natural gas, to residential, commercial and industrial customers throughout six counties within the State of Florida. Additionally, FPUC distributes and sells electricity to four counties in the northwestern and northeastern parts of Florida. Chesapeake's natural gas marketing subsidiary, Peninsula Energy Services Company, Inc. ("PESCO"), buys gas from various suppliers and sells gas to commercial and industrial customers. PESCO is active in the states of Florida, Ohio, Pennsylvania, Maryland and Delaware. The relative size of the operations in each of the jurisdictions is shown in the following table that provides deliveries and average number of customers for the year 2014.

Chesapeake Utilities Corporation Natural Gas Distribution
For the Year 2014

Deliveries in MMcf	Total	Delaware	Maryland	Sandpiper	Florida
Firm:					
Residential	5,132	2,697	564	289	1,582
Commercial & Industrial	4,540	1,120	529	373	2,518
Transportation	22,884	4,005	1,715	89	17,075
Interruptible:	637	0	0	0	637
Total Deliveries	33,193	7,822	2,808	751	21,812

Number of Customers	Total	Delaware	Maryland	Sandpiper	Florida
Firm:					
Residential	127,430	41,466	10,930	9,819	65,215
Commercial & Industrial	10,609	3,429	1,756	1,080	4,344
Transportation	3,114	310	71	8	2,725
Interruptible:	20	5	0	0	15
Total Customers	141,173	45,210	12,757	10,907	72,299

Chesapeake's natural gas transmission subsidiary, Eastern Shore Natural Gas Company ("ESNG"), operates an interstate pipeline system that transports natural gas through interconnects with three upstream interstate pipeline systems at four separate interconnect locations, three in southeastern Pennsylvania and one in northern Delaware. The pipeline transports and delivers natural gas through 442 miles of transmission pipeline to Chesapeake's Delaware and Maryland Divisions and Sandpiper, as well as four non-affiliated local distribution companies (including one municipality), four electric generation customers and ten industrial customers located in Delaware, the Eastern Shore of Maryland and Pennsylvania. Eastern Shore Natural Gas Company is regulated by the Federal Energy Regulatory Commission ("FERC"). Based in Georgetown, Delaware, Chesapeake's wholly owned propane distribution subsidiary, Sharp Energy, Inc., distributes propane to approximately 37,000 residential, commercial and industrial customers in Delaware, Maryland, Virginia, and Pennsylvania. Chesapeake's propane marketing subsidiary, Xeron, Inc., based in Houston, Texas, markets propane to large independent oil and petrochemical companies, resellers and propane distribution companies located in the southeastern region of the country.

Chesapeake's other subsidiaries include Skipjack, Inc. and Eastern Shore Real Estate, Inc., which both own and lease property, primarily to affiliates of Chesapeake.

V. <u>Net Operating Income</u>

Q. WHAT ARE THE COMPONENTS OF THE DELAWARE DIVISION'S NET OPERATING INCOME ("NOI") FOR THE TEST YEAR ENDED JUNE 30, 2015?

A. Net Operating Income for the Test Year is comprised of actual results of operations for the twelve month period ended June 30, 2015 and is shown on MFR Schedule No. 3 as follows:

Operating Revenues

Operating Expenses

Interest on Customer Deposits

Taxes Other Than Income

Total Operating Taxes
Net Operating Income
Allowance for Funds Used During Construction
Net Income Available for Return

Q. ARE THE COMPONENTS THE SAME FOR THE TEST PERIOD ENDING MARCH 31, 2016?

A. Yes, the components in NOI for the Test Year ended June 30, 2015 are the same for the Test Period ending March 31, 2016.

Q. ARE THERE ANY DIFFERENCES IN THE METHODOLOGY USED IN CALCULATING THE TEST YEAR AND TEST PERIOD NET OPERATING INCOME?

A. Yes. The Test Year ended June 30, 2015 NOI was based upon an actual twelve month experience. The Test Period ending March 31, 2016 NOI was determined by adjusting the Test Year amounts to annualize costs for known and measurable changes in an effort to properly match expenses with sales during the period in which the proposed rates will be in effect, and to properly reflect transactions as they would be expected to occur in a "normal year."

Q. PLEASE EXPLAIN HOW THE DELAWARE DIVISION'S TEST PERIOD OPERATING REVENUES, AS SHOWN IN MFR SCHEDULE 3-A, WERE CALCULATED.

A. As shown on Schedule No. 3-A-1, Test Year heat sensitive firm revenues have been adjusted to reflect sales levels expected in a normal degree day year and also adjusted to reflect the number of customers projected to be on the distribution system through the end of the Test Period. The determination of a normal degree day year is based upon weather data for a ten-year average of degree days for the months of July 2005 through June 2015. The adjustments to operating revenue are more fully discussed in the direct testimony of Ms. Sarah Hardy.

Q. IS THE DELAWARE DIVISION PROPOSING ANY CHANGES TO ITS RATE SCHEDULES?

A. No. At this time, the Delaware Division is not proposing any changes to its rate schedules.

Q. PLEASE EXPLAIN HOW THE DELAWARE DIVISION'S TEST PERIOD OPERATING EXPENSES WERE CALCULATED AS SHOWN ON SCHEDULE 3-B.

A. A summary of Test Period adjustments made to operating expenses and net operating income is documented in the Direct Testimonies of Mr. Jeffrey Weiss and Mr. Matthew Dewey.

VI. Capital Structure

Q. HOW WAS THE PROPOSED TEST PERIOD CAPITAL STRUCTURE DETERMINED?

A. The proposed Test Period capital structure is based upon the estimated long-term debt balances and effective cost rates and Common Equity balance at March 31, 2016 for Chesapeake Utilities Corporation. This is comprised of 39.61% Long-Term Debt and 60.39% Common Equity.

Q. WHAT IS THE DELAWARE DIVISION'S PROPOSED OVERALL RATE OF RETURN IN THIS PROCEEDING?

A. As shown below and on Schedule No. 4, the Delaware Division proposes an overall rate of return of 8.55% for the Test Period.

	Ratio	Effective Cost Rate	Weighted Cost of Capital
Long-Term Debt	39.61%	4.82%	1.91%
Common Equity	60.39%	11.00%	6.64%
Total Cost of Capital	100.00%		8.55%

Mr. Paul R. Moul testifies that the appropriate cost of Common Equity for the Delaware Division in this proceeding is 11.00%, with the Company's proposed Revenue Normalization Mechanism. The effective long-term debt cost rate utilized is for Chesapeake Utilities Corporation at March 31, 2016.

VII. <u>Overall Return Requirement</u>

Q. WHAT IS THE PROPOSED RETURN REQUIREMENT FOR THE DELAWARE DIVISION IN THIS BASE RATE PROCEEDING?

A. As shown on Schedule No. 1, the proposed Test Period return requirement is $6,065,262. This is based upon a Test Period rate base of $70,938,749 and a proposed overall rate of return of 8.55%. The Company is proposing to increase its revenue by $4,741,823, or approximately 9.96% of total Test Period operating revenue to achieve the forecasted return requirement.

VIII. <u>Cost of Service Study</u>

Q. IS THE COMPANY SUBMITTING A COST OF SERVICE STUDY IN SUPPORT OF THIS BASE RATE APPLICATION?

A. Yes. Cost of service study summaries, both at the current and proposed rate classes, are included in this filing and are outlined in the testimony of Mr. John Taylor.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DATED: DECEMBER __21__, 2015

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF C. JAMES MOORE

C. JAMES MOORE, being first duly sworn according to law, on oath deposes and says that he is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of C. James Moore"; that, if asked the questions which appear in the text of the direct testimony, he would give the answers that are therein set forth; and that he adopts this testimony as his sworn direct testimony in these proceedings.

C. James Moore

C. James Moore

Then personally appeared this __21st__ day of December 2015 the above-named C. James Moore and acknowledged the foregoing Testimony to be his free act and deed. Before me,

REBECCA K. GRIER NOTARY PUBLIC MY COMMISSION EXPIRES ON 07-17-18 STATE OF DELAWARE

Rebecca K. Grier

Notary Public
My Commission Expires: 7·17·18

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	**)**	
CHESAPEAKE UTILITIES CORPORATION	**)**	
FOR A GENERAL INCREASE IN ITS	**)**	**P.S.C. DOCKET NO. 15-**
NATURAL GAS RATES AND FOR	**)**	
APPROVAL OF CERTAIN OTHER	**)**	
CHANGES TO ITS NATURAL GAS TARIFF	**)**	

DIRECT TESTIMONY OF SARAH E. HARDY

On Behalf of Chesapeake Utilities Corporation

Delaware Division

Submitted for filing: December 21, 2015

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

A. My name is Sarah E. Hardy and I am a Regulatory Analyst III with Chesapeake Utilities Corporation ("Chesapeake" or the "Company"). My business address is 350 S. Queen Street, Dover, Delaware 19904.

Q. DESCRIBE BRIEFLY YOUR EDUCATION AND RELEVANT PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Business Administration with concentrations in Management and Operations Management and a Minor in International Business from the University of Delaware in Newark, Delaware, in 2005. I received a Masters of Business Administration from the University of Delaware in Newark, Delaware, in 2009. I was hired by Chesapeake as a Regulatory Analyst II in June 2010, and promoted to a Regulatory Analyst III in October of 2014. As a Regulatory Analyst III, I have primarily been involved in the areas of gas cost recovery, rate of return analysis, and budgeting for the Delaware natural gas distribution company. Prior to joining Chesapeake, I was employed by Conectiv Energy Supply, Inc. from July, 2005 until May, 2010, most recently as a Senior Accountant. As a Senior Accountant, I was responsible for Conectiv Energy's derivatives accounting (including preparation of derivatives disclosures for SEC reporting), Federal Energy Regulatory Commission (FERC) filings, and other general accounting duties.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes. I have testified before the Commission during the Delaware Division's previous Gas Sales Service Rate proceedings, Franchise Fee proceedings, and its Transportation Program proceeding.

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

A. My direct testimony consists of the following subject areas:

I. Sales and Revenue for the Test Period

II. Proposed Interim Rates

III. Cost of Service Internal Cost Studies

IV. Tariff Changes

I. <u>Sales and Revenue for the Test Period</u>

Q. PLEASE EXPLAIN HOW THE DELAWARE DIVISION'S TEST PERIOD REVENUES, AS SHOWN IN MFR SCHEDULE 3-A, WERE CALCULATED.

A. As shown on Schedule No. 3-A-1, Test Year heat sensitive firm revenues have been adjusted to reflect sales levels expected in a normal degree day year and also adjusted to reflect the number of customers projected to be on the distribution system at the end of the Test Period. The determination of a normal degree day year is based upon weather data for a ten-year average of degree days for the months of July 2005 through June 2015. Also, an adjustment was included to reflect a lower cost of gas in the Test Period.

Q. WERE THERE ANY ADJUSTMENTS DUE TO CUSTOMERS MOVING BETWEEN RATE CLASSES?

A. Yes, an additional adjustment was made to reflect the revenue impact of customers moving to different rate schedules during the Test Period. The primary component of this adjustment was related to customers who moved from above-tariff negotiated rates in the Test Year to tariff rate schedules in the Test Period.

II. Proposed Interim Rates

Q. WHAT GENERAL GUIDELINES DID THE COMPANY FOLLOW IN DESIGNING ITS PROPOSED INTERIM RATES?

A. The Company is proposing to design its interim rates based upon a $2,500,000 increase. For Chesapeake's Delaware Division, according to the Delaware statute under 26 Del. C. §306(c) the maximum amount of revenue allowed under bond is $2,500,000. Chesapeake's Delaware Division, as demonstrated on Attachment SEH-1, spread this interim rate increase equally to all firm rate classes based on their Delivery Service revenue. The Company did not modify customer charges contained in its Expansion Area rate schedules. Please see Attachment SEH-1 for a summary of the rate derivation and proposed natural gas tariff rates. The Company is proposing these interim rates to become effective with service rendered on and after February 19, 2016 pursuant to 26 Del. C. §306(c).

III. Cost of Service Internal Cost Studies

Q. IS THE COMPANY SUBMITTING A COST OF SERVICE STUDY IN SUPPORT OF THIS BASE RATE APPLICATION?

A. Yes. A Cost of service study is included in this filing and is outlined in the testimony of John D. Taylor of Black & Veatch Corporation.

Q. DID THE COMPANY PERFORM ANY INTERNAL COST STUDIES RELATED TO ITS COST OF SERVICE?

A. Yes. The Company performed several internal cost studies in deriving the external and internal allocators referenced in its cost of service studies. The data included in the cost studies corresponds to the Test Year and Test Period information used in this proceeding. It includes items such as an analysis of plant data by account, operating costs, sales revenue as well as customer usage details.

IV. Tariff Changes

Q. ARE THERE ANY PROPOSED CHANGES TO THE COMPANY'S TARIFF THAT YOU WISH TO DISCUSS AT THIS TIME?

A. Yes. The Company has submitted its proposed natural gas tariff that includes the proposed rates for the firm rate schedules (as outlined in the direct testimony of Ronald Amen of Black & Veatch Corporation), a proposed Revenue Normalization Adjustment (also outlined in the direct testimony of Ronald Amen of Black & Veatch Corporation), proposed modifications to the Company's curtailment policy, a proposed extension in the bill payment due date from ten (10) days to twenty (20) days, a proposed modification to the Company's interest rate on customer deposits, and general formatting and clarification changes.

In addition, the Company is also proposing the following tariff changes, which are described more fully in the direct testimony of Shane E. Breakie:

a. Multi-Family Housing Program

b. Compressed Natural Gas Services

c. Poultry House Account Aggregation

Q. IS THE INFORMATION SET FORTH IN ATTACHMENTS SEH-1 TRUE AND CORRECT TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes, it is.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DATED: DECEMBER __21__, 2015

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF SARAH E. HARDY

SARAH E. HARDY, being first duly sworn according to law, on oath deposes and says that she is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of Sarah E. Hardy"; that, if asked the questions which appear in the text of the direct testimony, she would give the answers that are therein set forth; and that she adopts this testimony as her sworn direct testimony in these proceedings.

Sarah E. Hardy

Then personally appeared this __21st__ day of December 2015 the above-named Sarah E. Hardy and acknowledged the foregoing Testimony to be her free act and deed.

Before me,

REBECCA K. GRIER
NOTARY
PUBLIC
MY COMMISSION
EXPIRES ON
07-17-18
STATE OF DELAWARE

Notary Public
My Commission Expires: 7·17·18

Chesapeake Utilities Corporation - Delaware Division
Rate Derivation Model
Proposed Interim Rates
Based on a Rate Increase of $2,500,000

Customer Class	Rate Blocks	Volumes (Mcf)	Current Rates	Calculated Delivery Service Revenue	Calculated Rate Increase	11.41%	Calculated Delivery Service Revenue	Calculated Rates	Proposed Rates	Proposed Delivery Service Revenue	Proposed Rate Increase
RS-1	Customers	4,147	$ 10.500	$522,522	$59,619		$582,141	$11.70	$11.75	$584,727	$62,205
	First 2.0	37,145	$ 6.070	$225,470	$25,726		$251,196	$6.76	$6.75	$250,729	$25,259
	Next 3.0	14,369	$ 2.800	$40,233	$4,591		$44,824	$3.12	$3.10	$44,544	$4,311
	Over 5.0	3,638	$ 1.700	$6,185	$706		$6,890	$1.89	$1.90	$6,912	$728
RS-1 Total		55,152		$794,410	$90,641		$885,050			$886,912	$92,502
ERS-1	Customers	106	$ 16.500	$20,988	$2,395		$23,383	$18.38	$16.50	$20,988	$0
	First 2.0	1,205	$ 6.070	$7,314	$835		$8,149	$6.76	$6.75	$8,134	$819
	Next 3.0	687	$ 2.800	$1,924	$219		$2,143	$3.12	$3.10	$2,130	$206
	Over 5.0	155	$ 1.700	$264	$30		$294	$1.89	$1.90	$295	$31
ERS-1 Total		2,047		$30,489	$3,479		$33,968			$31,546	$1,057
RS-2	Customers	38,500	$ 13.000	$6,006,000	$685,272		$6,691,272	$14.48	$14.50	$6,699,000	$693,000
	First 2.0	697,253	$ 5.780	$4,030,122	$459,829		$4,489,951	$6.44	$6.45	$4,497,282	$467,160
	Next 3.0	646,763	$ 3.190	$2,063,174	$235,404		$2,298,578	$3.55	$3.55	$2,296,009	$232,835
	Over 5.0	1,162,821	$ 1.320	$1,534,924	$175,132		$1,710,055	$1.47	$1.45	$1,686,090	$151,167
RS-2 Total		2,506,837		$13,634,220	$1,555,636		$15,189,856			$15,178,381	$1,544,161
ERS-2	Customers	465	$ 31.750	$177,165	$20,214		$197,379	$35.37	$31.75	$177,165	$0
	First 2.0	7,296	$ 5.780	$42,171	$4,812		$46,982	$6.44	$6.45	$47,059	$4,888
	Next 3.0	8,065	$ 3.190	$25,727	$2,935		$28,663	$3.55	$3.55	$28,631	$2,903
	Over 5.0	14,957	$ 1.320	$19,743	$2,253		$21,996	$1.47	$1.45	$21,688	$1,944
ERS-2 Total		30,318		$264,806	$30,214		$295,020			$274,543	$9,736
Total Residential Service		2,594,354		$14,723,926	$1,679,969		$16,403,895			$16,371,381	$1,647,455
GS	Customers	2,851	$ 26.000	$889,512	$101,491		$991,003	$28.97	$28.95	$990,437	$100,925
	First 2.0	38,391	$ 4.470	$171,608	$19,580		$191,188	$4.98	$4.95	$190,035	$18,428
	Next 3.0	42,030	$ 2.780	$116,843	$13,332		$130,175	$3.10	$3.10	$130,293	$13,450
	Over 5.0	196,103	$ 1.400	$274,544	$31,325		$305,869	$1.56	$1.55	$303,960	$29,415
GS Total		276,524		$1,452,507	$165,728		$1,618,235			$1,614,726	$162,218
EGS	Customers	15	$ 56.000	$10,080	$1,150		$11,230	$62.39	$56.00	$10,080	$0
	First 2.0	173	$ 4.470	$773	$88		$862	$4.98	$5.00	$865	$92
	Next 3.0	205	$ 2.780	$570	$65		$635	$3.10	$3.10	$636	$66
	Over 5.0	1,022	$ 1.400	$1,431	$163		$1,594	$1.56	$1.60	$1,635	$204
EGS Total		1,400		$12,854	$1,467		$14,321			$13,216	$362
MVS	Customers	484	$ 65.000	$377,520	$43,074		$420,594	$72.42	$72.40	$420,499	$42,979
	First 20.0	84,272	$ 2.270	$191,297	$21,827		$213,124	$2.53	$2.50	$210,680	$19,383
	Over 20.0	266,184	$ 1.150	$306,112	$34,927		$341,038	$1.28	$1.25	$332,730	$26,618
MVS Total		350,456		$874,929	$99,828		$974,757			$963,909	$88,980
EMVS	Customers	3	$ 158.750	$5,715	$652		$6,367	$176.86	$158.75	$5,715	$0
	First 20.0	473	$ 2.270	$1,074	$123		$1,196	$2.53	$2.50	$1,183	$109
	Over 20.0	1,935	$ 1.150	$2,225	$254		$2,479	$1.28	$1.25	$2,419	$194
EMVS Total		2,408		$9,014	$1,028		$10,042			$9,316	$302
LVS	Customers	205	$ 125.000	$307,500	$35,085		$342,585	$139.26	$139.25	$342,555	$35,055
	First 100.0	186,282	$ 3.260	$607,279	$69,289		$676,569	$3.63	$3.60	$670,615	$63,336
	Over 100.0	1,424,712	$ 0.830	$1,182,509	$134,922		$1,317,431	$0.92	$0.90	$1,282,241	$99,732
LVS Total		1,610,994		$2,097,288	$239,296		$2,336,585			$2,295,411	$198,123

Chesapeake Utilities Corporation - Delaware Division
Rate Derivation Model
Proposed Interim Rates
Based on a Rate Increase of $2,500,000

Customer Class	Rate Blocks	Volumes (Mcf)	Current Rates	Calculated Delivery Service Revenue	Calculated Rate Increase	11.41%	Calculated Delivery Service Revenue	Calculated Rates	Proposed Rates	Proposed Delivery Service Revenue	Proposed Rate Increase
HLFS	Customers	310	$ 75.000	$279,000	$31,833		$310,833	$83.56	$83.55	$310,806	$31,806
	All Consumption	2,828,481	$ 0.870	$2,460,780	$280,770		$2,741,550	$0.97	$1.00	$2,828,481	$367,701
HLFS Total		2,828,481		$2,739,780	$312,603		$3,052,384			$3,139,287	$399,507
NCR-1	Customers	1	$ 125.000	$1,500	$0		$1,500	$125.00	$139.25	$1,671	$171
	All Consumption	2,167	$ 5.250	$11,377	$0		$11,377	$5.25	$5.25	$11,377	$0
NCR-1 Total		2,167		$12,877	$0		$12,877			$13,048	$171
NCR-2	Customers	2	$ 75.000	$1,800	$0		$1,800	$75.00	$83.55	$2,005	$205
	All Consumption	3,250	$ 2.950	$9,588	$0		$9,588	$2.95	$2.95	$9,588	$0
NCR-2 Total		3,250		$11,388	$0		$11,388			$11,593	$205
NCR-3	Customers	2	$ 26.000	$624	$0		$624	$26.00	$28.95	$695	$71
	All Consumption	742	$ 5.250	$3,896	$0		$3,896	$5.25	$5.25	$3,896	$0
NCR-3 Total		742		$4,520	$0		$4,520			$4,590	$71
NCR-4	Customers	2	$ 65.000	$1,560	$0		$1,560	$65.00	$72.40	$1,738	$178
	All Consumption	775	$ 5.250	$4,069	$0		$4,069	$5.25	$5.25	$4,069	$0
NCR-4 Total		775		$5,629	$0		$5,629			$5,807	$178
NCR-5	Customers	1	$ 125.000	$1,500	$0		$1,500	$125.00	$139.25	$1,671	$171
	All Consumption	693	$ 5.250	$3,638	$0		$3,638	$5.25	$5.25	$3,638	$0
NCR-5 Total		693		$5,138	$0		$5,138			$5,309	$171
NCR-6	Customers	2	$ 75.000	$1,800	$0		$1,800	$75.00	$83.55	$2,005	$205
	All Consumption	16,125	$ 5.250	$84,656	$0		$84,656	$5.25	$5.25	$84,656	$0
NCR-6 Total		16,125		$86,456	$0		$86,456			$86,661	$205
NCR-7	Customers	1	$ 75.000	$900	$0		$900	$75.00	$83.55	$1,003	$103
	All Consumption	2,623	$ 9.600	$25,181	$0		$25,181	$9.60	$9.60	$25,181	$0
NCR-7 Total		2,623		$26,081	$0		$26,081			$26,184	$103
GL	Customers	5	$ 11.750	$705	$80		$785	$13.09	$11.75	$705	$0
GL Total		5		$705	$80		$785			$705	$0
Total Commercial/ Industrial Service		5,096,638		$7,338,461	$819,950		$8,158,411			$8,189,056	$850,596
Total Firm Delivery Service		7,690,997		$22,063,092	$2,500,000		$24,563,092			$24,561,143	$2,498,051

Chesapeake Utilities Corporation - Delaware Division
Comparison of Current and Proposed Revenue
Proposed Interim Rates
Based on a Rate Increase of $2,500,000

Customer Class	Rate Blocks	Calculated Delivery Service Revenue	Final Customers & Billing Adjustments	Actual Delivery Service Revenue	Actual Gas Sales Service Revenue	Actual Total Revenue	Proposed Delivery Service Revenue	Final Customers & Billing Adjustments	Total Proposed Delivery Service Revenue	Actual Gas Sales Service Revenue	Total Revenue After Increase	% Revenue Increase
RS-1	Customers	$522,522	($18)	$522,504	$0	$522,504	$584,727	($18)	$584,709	$0	$584,709	
	First 2.0	$225,470	($8)	$225,462	$253,720	$479,182	$250,729	($8)	$250,721	$253,720	$504,441	
	Next 3.0	$40,233	($1)	$40,232	$98,148	$138,380	$44,544	($1)	$44,542	$98,148	$142,690	
	Over 5.0	$6,185	($0)	$6,184	$24,849	$31,034	$6,912	($0)	$6,912	$24,849	$31,761	
RS-1 Total		$794,410	($28)	$794,382	$376,717	$1,171,099	$886,912	($28)	$886,884	$376,717	$1,263,601	7.90%
ERS-1	Customers	$20,988	$11	$20,999	$0	$20,999	$20,988	$11	$20,999	$0	$20,999	
	First 2.0	$7,314	$4	$7,318	$8,231	$15,550	$8,134	$4	$8,138	$8,231	$16,369	
	Next 3.0	$1,924	$1	$1,925	$4,693	$6,617	$2,130	$1	$2,131	$4,693	$6,824	
	Over 5.0	$264	$0	$264	$1,059	$1,322	$295	$0	$295	$1,059	$1,353	
ERS-1 Total		$30,489	$16	$30,505	$13,983	$44,488	$31,546	$16	$31,562	$13,983	$45,545	2.37%
RS-2	Customers	$6,006,000	($22)	$6,005,978	$0	$6,005,978	$6,699,000	($22)	$6,698,978	$0	$6,698,978	
	First 2.0	$4,030,122	($15)	$4,030,107	$4,762,538	$8,792,646	$4,497,282	($15)	$4,497,267	$4,762,538	$9,259,805	
	Next 3.0	$2,063,174	($8)	$2,063,166	$4,417,670	$6,480,836	$2,296,009	($8)	$2,296,001	$4,417,670	$6,713,671	
	Over 5.0	$1,534,924	($6)	$1,534,918	$7,942,569	$9,477,487	$1,686,090	($6)	$1,686,085	$7,942,569	$9,628,653	
RS-2 Total		$13,634,220	($51)	$13,634,169	$17,122,777	$30,756,946	$15,178,381	($51)	$15,178,330	$17,122,777	$32,301,107	5.02%
ERS-2	Customers	$177,165	$61	$177,226	$0	$177,226	$177,165	$61	$177,226	$0	$177,226	
	First 2.0	$42,171	$14	$42,185	$49,833	$92,018	$47,059	$14	$47,074	$49,833	$96,907	
	Next 3.0	$25,727	$9	$25,736	$55,085	$80,821	$28,631	$9	$28,640	$55,085	$83,725	
	Over 5.0	$19,743	$7	$19,750	$102,159	$121,909	$21,688	$7	$21,694	$102,159	$123,853	
ERS-2 Total		$264,806	$91	$264,897	$207,077	$471,974	$274,543	$91	$274,634	$207,077	$481,711	2.06%
Total Residential Service		$14,723,926	$28	$14,723,954	$17,720,554	$32,444,508	$16,371,381	$28	$16,371,409	$17,720,554	$34,091,963	5.08%
GS	Customers	$889,512	($208)	$889,304	$0	$889,304	$990,437	($208)	$990,229	$0	$990,229	
	First 2.0	$171,608	($40)	$171,568	$254,810	$426,377	$190,035	($40)	$189,995	$254,810	$444,805	
	Next 3.0	$116,843	($27)	$116,816	$278,963	$395,779	$130,293	($27)	$130,266	$278,963	$409,228	
	Over 5.0	$274,544	($64)	$274,480	$1,301,580	$1,576,060	$303,960	($64)	$303,895	$1,301,580	$1,605,476	
GS Total		$1,452,507	($340)	$1,452,167	$1,835,353	$3,287,520	$1,614,726	($340)	$1,614,386	$1,835,353	$3,449,739	4.93%
EGS	Customers	$10,080	$43	$10,123	$0	$10,123	$10,080	$43	$10,123	$0	$10,123	
	First 2.0	$773	$3	$777	$924	$1,700	$865	$3	$868	$924	$1,792	
	Next 3.0	$570	$2	$572	$1,094	$1,667	$636	$2	$638	$1,094	$1,732	
	Over 5.0	$1,431	$6	$1,437	$5,456	$6,893	$1,635	$6	$1,641	$5,456	$7,097	
EGS Total		$12,854	$55	$12,909	$7,474	$20,383	$13,216	$55	$13,271	$7,474	$20,745	1.77%
MVS	Customers	$377,520	$252	$377,772	$0	$377,772	$420,499	$252	$420,751	$0	$420,751	
	First 20.0	$191,297	$128	$191,425	$466,477	$657,902	$210,680	$128	$210,808	$466,477	$677,284	
	Over 20.0	$306,112	$204	$306,316	$1,473,426	$1,779,742	$332,730	$204	$332,934	$1,473,426	$1,806,361	
MVS Total		$874,929	$584	$875,513	$1,939,903	$2,815,416	$963,909	$584	$964,493	$1,939,903	$2,904,396	3.16%
EMVS	Customers	$5,715	$302	$6,017	$0	$6,017	$5,715	$302	$6,017	$0	$6,017	
	First 20.0	$1,074	$57	$1,131	$213	$1,343	$1,183	$57	$1,239	$213	$1,452	
	Over 20.0	$2,225	$118	$2,343	$870	$3,213	$2,419	$118	$2,537	$870	$3,407	
EMVS Total		$9,014	$477	$9,491	$1,083	$10,574	$9,316	$477	$9,793	$1,083	$10,876	2.86%
LVS	Customers	$307,500	$56	$307,556	$0	$307,556	$342,555	$56	$342,611	$0	$342,611	
	First 100.0	$607,279	$110	$607,389	$186,323	$793,713	$670,615	$110	$670,725	$186,323	$857,049	
	Over 100.0	$1,182,509	$214	$1,182,723	$1,425,029	$2,607,752	$1,282,241	$214	$1,282,455	$1,425,029	$2,707,484	
LVS Total		$2,097,288	$380	$2,097,668	$1,611,352	$3,709,020	$2,295,411	$380	$2,295,791	$1,611,352	$3,907,143	5.34%
HLFS	Customers	$279,000	($158)	$278,842	$0	$278,842	$310,806	($158)	$310,648	$0	$310,648	
	All Consumption	$2,460,780	($1,389)	$2,459,391	$1,237,914	$3,697,305	$2,828,481	($1,389)	$2,827,092	$1,237,914	$4,065,006	
HLFS Total		$2,739,780	($1,547)	$2,738,233	$1,237,914	$3,976,147	$3,139,287	($1,547)	$3,137,740	$1,237,914	$4,375,654	10.05%

NCR-1	Customers	$1,500	$0	$1,500	$0	$1,500	$1,671	$0	$1,671	$0	$1,671	
	All Consumption	$11,377	$0	$11,377	$0	$11,377	$11,377	$0	$11,377	$0	$11,377	
NCR-1 Total		$12,877	$0	$12,877	$0	$12,877	$13,048	$0	$13,048	$0	$13,048	1.33%
NCR-2	Customers	$1,800	$0	$1,800	$0	$1,800	$2,005	$0	$2,005	$0	$2,005	
	All Consumption	$9,588	$0	$9,588	$0	$9,588	$9,588	$0	$9,588	$0	$9,588	
NCR-2 Total		$11,388	$0	$11,388	$0	$11,388	$11,593	$0	$11,593	$0	$11,593	1.80%
NCR-3	Customers	$624	$0	$624	$0	$624	$695	$0	$695	$0	$695	
	All Consumption	$3,896	$0	$3,896	$0	$3,896	$3,896	$0	$3,896	$0	$3,896	
NCR-3 Total		$4,520	$0	$4,520	$0	$4,520	$4,590	$0	$4,590	$0	$4,590	1.57%
NCR-4	Customers	$1,560	$0	$1,560	$0	$1,560	$1,738	$0	$1,738	$0	$1,738	
	All Consumption	$4,069	$0	$4,069	$0	$4,069	$4,069	$0	$4,069	$0	$4,069	
NCR-4 Total		$5,629	$0	$5,629	$0	$5,629	$5,807	$0	$5,807	$0	$5,807	3.16%
NCR-5	Customers	$1,500	$0	$1,500	$0	$1,500	$1,671	$0	$1,671	$0	$1,671	
	All Consumption	$3,638	$0	$3,638	$0	$3,638	$3,638	$0	$3,638	$0	$3,638	
NCR-5 Total		$5,138	$0	$5,138	$0	$5,138	$5,309	$0	$5,309	$0	$5,309	3.33%
NCR-6	Customers	$1,800		$1,800	$0	$1,800	$2,005	$0	$2,005	$0	$2,005	
	All Consumption	$84,656	($2,245)	$82,411	$0	$82,411	$84,656	($2,245)	$82,411	$0	$82,411	
NCR-6 Total		$86,456	($2,245)	$84,211	$0	$84,211	$86,661	($2,245)	$84,416	$0	$84,416	0.24%
NCR-7	Customers	$900	$0	$900	$0	$900	$1,003	$0	$1,003	$0	$1,003	
	All Consumption	$25,181	$0	$25,181	$0	$25,181	$25,181	$0	$25,181	$0	$25,181	
NCR-7 Total		$26,081	$0	$26,081	$0	$26,081	$26,184	$0	$26,184	$0	$26,184	0.39%
GL	Customers	$705	$0	$705	$180	$885	$705	$0	$705	$180	$885	
GL Total		$705	$0	$705	$180	$885	$705	$0	$705	$180	$885	0.00%
Total Commercial/ Industrial Service		$7,338,461	($2,636)	$7,335,825	$6,633,079	$13,968,904	$8,189,056	($2,636)	$8,186,420	$6,633,079	$14,819,499	6.09%
Total Firm Revenue		$22,063,092	($2,608)	$22,060,484	$24,353,813	$46,414,297	$24,561,143	($2,608)	$24,558,535	$24,353,813	$48,912,348	5.38%

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	**)**	
CHESAPEAKE UTILITIES CORPORATION	**)**	
FOR A GENERAL INCREASE IN ITS	**)**	
NATURAL GAS RATES AND FOR	**)**	**P.S.C. DOCKET NO. 15-**
APPROVAL OF CERTAIN OTHER	**)**	
CHANGES TO ITS NATURAL GAS TARIFF	**)**	

DIRECT TESTIMONY OF MATTHEW M. EVERNGAM

On Behalf of Chesapeake Utilities Corporation

Delaware Division.

Submitted for filing: December 21, 2015

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

A. My name is Matthew M. Everngam and I am a Regulatory Analyst III with Chesapeake Utilities Corporation. My business address is 350 S. Queen Street, Dover, Delaware 19904. I support the Company's natural gas distribution businesses in Delaware and Maryland, as well as Sandpiper Energy, Inc. ("Sandpiper") in Maryland.

Q. DESCRIBE BRIEFLY YOUR EDUCATION AND RELEVANT PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Business Administration and a Masters of Business Administration from Salisbury University in Salisbury, MD. I was hired by Chesapeake as a Regulatory Analyst II in October 2010. As a Regulatory Analyst III, I have primarily been involved in the areas of gas cost recovery, rate of return analysis, and budgeting for Sandpiper Energy Inc. and Chesapeake Utilities – Delaware & Maryland natural gas distribution divisions. I have also performed economic analysis related to capital expenditure projects. Prior to joining Chesapeake, I was employed by Edward Jones Investments as a Financial Advisor. In this position I held Series 7 and Series 66 licenses with the National Association of Securities Dealers ("NASD").

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

A. The purpose of my testimony is to provide support for the following subject areas:

I. Derivation of Rate Base

I. <u>Derivation of Rate Base</u>

Q. PLEASE DESCRIBE THE COMPONENTS OF CHESAPEAKE UTILITIES CORPORATION – DELAWARE DIVISON'S ("COMPANY") RATE BASE FOR THE TEST YEAR.

A. The Company's actual Rate Base for the test year is comprised of the actual average balances for the period ended June 30, 2015 (except for Investor Supplied Cash Working Capital, which is based on average lead and lag days for cash receipts and disbursements). The components of average rate base per Schedule No. 2 are:

1) Gas Plant in Service – 13 month avg for the period ended June 30, 2015
2) Accumulated Depreciation – 13 month avg for the period ended June 30, 2015
3) Construction Work in Process – 13 month avg for the period ended June 30, 2015
4) Materials and Supplies– 13 month avg for the period ended June 30, 2015
5) Investor Supplied Cash Working Capital – Based on avg lead and lag days for cash receipts and operating expense disbursements
6) Accumulated Deferred Income Taxes – Average of the balances of June 30, 2014 and June 30, 2015
7) Customer Deposits - 13 month avg for the period ended June 30, 2015

8) Customer Advances for Construction - 13 month avg for the period ended June 30, 2015

9) Unamortized Investment Tax Credits - 13 month avg for the period ended June 30, 2015

10) Deferred Debits (Behind the Meter Conversion Costs) - 13 month avg for the period ended June 30, 2015

Q. ARE THE COMPONENTS THE SAME FOR THE TEST PERIOD ENDING March 31, 2016?

A. Yes, the components in Rate Base are the same for the actual year ended June 30, 2015 and for the Test Period ending March 31, 2016.

Q. WHAT IS THE COMPANY'S CALCULATED AVERAGE RATE BASE FOR THE TEST PERIOD CONTAINED IN THIS APPLICATION?

A. The calculated average rate base for the test period is $70,938,749.

Q. HOW WAS TEST PERIOD TOTAL PLANT IN SERVICE CALCULATED?

A. The Test Period Plant in Service balance is based on a forecasted thirteen-month average. Actual month end balances were used for the months of March 2015 through June 2015. For the test period months of July 2015 through March 2016 forecasted amounts were used. Accumulated depreciation balances for the test period were deducted from the gross plant in service to arrive at total plant in service.

Q. HOW WAS TEST PERIOD ACCUMULATED DEPRECIATION CALCULATED?

A. The Test Period Accumulated Depreciation balance is based on a forecasted thirteen-month average. Actual month end balances, were used for the months of March 2015 through June 2015. Forecasted amounts for July 2015 through March 2016 were used. The forecasted Plant in Service balances, described above, were used to calculate depreciation expense for the months from July 2015 through March 31, 2016. The depreciation expense for July 2015 through March 2016 was then added to each month's accumulated depreciation balance.

Q. HOW WERE THE TEST PERIOD ACCUMULATED DEFERRED INCOME TAXES CALCULATED?

A. The Company calculated the Test Period Accumulated Deferred Income Taxes by averaging the March 31, 2015 balances and the adjusted balances at March 31, 2016. Please see the testimony of Lisa Elder for a description of the test period adjustments and calculation of deferred income taxes.

Q. HOW WERE TEST PERIOD CUSTOMER DEPOSITS CALCULATED?

A. The Test Period Customer Deposit balance is based on a forecasted thirteen-month average. Actual month end balances were used for the months of March 2015 through June 2015 and forecasted amounts for July 2015 through March

2016. The forecast was based on the growth rate in customer deposits during the test year.

Q. WHAT ARE THE COMPONENTS OF THE RATE BASE ITEM ENTITLED "MATERIALS AND SUPPLIES"?

A. The Rate Base item entitled "Materials and Supplies" is comprised of Propane Storage and Plant Materials and Supplies. Both of these components are based upon a thirteen-month average.

Q. HOW WERE TEST PERIOD PROPANE STORAGE AND PLANT MATERIALS AND SUPPLIES CALCULATED?

A. The balances for both of these items are based on a forecasted thirteen-month average. Actual month end balances were used for the months of March 2015 through June 2015. Projected amounts were used for July 2015 through March 2016 account balances.

Q. HOW WAS TEST PERIOD INVESTOR SUPPLIED CASH WORKING CAPITAL CALCULATED?

A. The investor supplied cash working capital component of rate base is calculated by subtracting the weighted average lag days for cash disbursements from the weighted average lag days for cash receipts from the collection of revenue. The resulting net lag days were multiplied by the average daily cash disbursements to arrive at the cash working capital requirement.

Q. PLEASE DISCUSS THE SCHEDULE THAT SETS FORTH THE DETAILS OF THE INVESTOR SUPPLIED CASH WORKING CAPITAL CALCULATIONS.

A. Schedule No. 2-D develops the total amount of cash working capital applicable to the test period ended March 31, 2016. The necessity for cash working capital results from the fact that the lag in the Company's collection of revenue after service has been rendered is greater than the lag in the Company's payment of expenses. The first line of the exhibit shows the lag of collection of revenue. This was derived from a study of the lag in revenue based upon the twelve (12) months ended June 2015. Lines 2 through 7 show the various operating expense categories projected to be incurred during the test period. The operating expenses include the adjustments the Company is proposing. The average lag days for operating expenses is 9.03 days less per Line 8. Line 10 shows the average daily cash disbursements to be $43,239. This is calculated by dividing operating expenses by 365 days. The cash working capital shown on Line 11 is calculated by multiplying the average daily cash disbursement by weighted net lag days.

Q. WHAT ELEMENTS MAKE UP THE AVERAGE LAG IN COLLECTION OF REVENUES FROM CUSTOMERS?

A. There are three (3) elements that make up the revenue lag. The first is the average number of days service has been supplied before the meter is read. The second is the average number of days for the meter to be read, the bill prepared and the bill mailed to the customer. The third element is the average lag in days from the time the customer's bill is mailed and payment is received.

Q. WHAT ELEMENTS MAKE UP THE AVERAGE LAG IN THE PAYMENT OF OPERATING EXPENSES?

A. Lines 2 through 7 show the various classes of operating expenses. Each class of expense is multiplied by lag days calculated for test period costs. The sum of the dollar days is divided by the sum of the adjusted test period expenses to determine the combined weighted average number of lag days.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DATED: DECEMBER __21__, 2015

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF MATTHEW M. EVERNGAM

MATTHEW M. EVERNGAM, being first duly sworn according to law, on oath deposes and says that he is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of Matthew M. Everngam"; that, if asked the questions which appear in the text of the direct testimony, he would give the answers that are therein set forth; and that he adopts this testimony as his sworn direct testimony in these proceedings.

Matthew M. Everngam

Matthew M. Everngam

Then personally appeared this __21st__ day of December 2015 the above-named Matthew M. Everngam and acknowledged the foregoing Testimony to be his free act and deed. Before me,

REBECCA K. GRIER
NOTARY
PUBLIC
MY COMMISSION
EXPIRES ON
07-17-18
STATE OF DELAWARE

Rebecca K. Grier

Notary Public
My Commission Expires: 7.17.18

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	**)**	
CHESAPEAKE UTILITIES CORPORATION	**)**	
FOR A GENERAL INCREASE IN ITS	**)**	**PSC DOCKET NO. 15-**
NATURAL GAS RATES AND FOR	**)**	
APPROVAL OF CERTAIN OTHER	**)**	
CHANGES TO ITS NATURAL GAS TARIFF	**)**	

DIRECT TESTIMONY OF JEFFREY WEISS

On Behalf of Chesapeake Utilities Corporation

Delaware Division

Submitted for filing: December 21, 2015

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

A. My name is Jeffrey Weiss and I am a Regulatory Analyst with Chesapeake Utilities Corporation ("Chesapeake" or the "Company"). My business address is 350 S. Queen Street, Dover, Delaware 19904.

Q. DESCRIBE BRIEFLY YOUR EDUCATION AND RELEVANT PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Accounting from Wesley College in Dover, DE, in 2007. In 2009, I received a Master's of Business Administration from Wesley College. I was hired by Chesapeake as a Regulatory Analyst I in August 2013, and promoted to a Regulatory Analyst II in October 2014. As a Regulatory Analyst II, I have primarily been involved in the areas of gas cost recovery, rate of return analysis, and budgeting for the Maryland natural gas distribution division. I have also performed economic analysis related to capital expenditure projects. Prior to joining Chesapeake's regulatory team, I was employed as an Internal Auditor for the Company from May 2007 until August 2013. My duties as an internal auditor included performing financial, operational and procedural audits for the Company in addition to ensuring the Company's ongoing compliance with the Sarbanes-Oxley Act.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN RATE PROCEEDINGS?

A. No, I have not previously testified before the Delaware Public Service Commission. However, I have testified on behalf of Chesapeake Utilities -

Maryland Division before the Maryland Public Service Commission in purchased gas adjustment proceedings. In addition, I currently have testimony pending in a base rate proceeding before the Maryland Public Service Commission for Sandpiper Energy, Inc., a wholly owned subsidiary of Chesapeake.

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

A. The purpose of my testimony is to describe and support the test period adjustments relating to the Delaware Division's operation, maintenance and depreciation expenses as well as the taxes other than income for the business unit departments only. The adjustments relating to corporate departments are included in the direct testimony of Matthew Dewey. In addition, I describe and support the Main Extension aggregated internal rate of return model ("IRRM") prepared in accordance with the proposed settlement from the Company's previous base rate proceeding, as approved by the PSC in Order No. 7434, dated September 2, 2008, in Docket No. 07-186 ("2008 Settlement Agreement").

Q. DO YOU SPONSOR ANY ATTACHMENTS IN SUPPORT OF YOUR TESTIMONY?

A. Yes. I sponsor three (3) attachments, which supports my testimony. The adjustments to the operating, maintenance and depreciation expenses as well as the taxes other than income for the business unit departments are supported by the Schedules included in this filing. Attachment JW-1 summarizes the operating expenses as adjusted, which I will explain in more detail below. Attachment JW-2 summarizes the total capital investments in mains, meters and service installations as well as the average margin per customer and customer additions by rate class for the time period of April 1, 2007 through September 24, 2015. Attachment JW-3 shows the inputs and corresponding results of the Main Extension aggregated IRRM which will also be explained in more detail below.

Q. PLEASE DESCRIBE THE OPERATION AND MAINTENANCE EXPENSES INCLUDED IN THIS FILING?

A. As shown on Attachment JW-1, the test period operations and maintenance expenses are $13,589,676 of which business unit costs are $9,623,491. The attachment shows the results for the twelve months ended March 31, 2016, Test Period Unadjusted, followed by thirteen (13) adjustments for the test period.

Adjustment No. 1 – Inflation Adjustment The base period consists of the actual expenses for the twelve months ended June 30, 2015. The forecasted period consists of the actual three months ended June 30, 2015 and the projected nine months ended March 31, 2016. The inflation adjustment is $283,309 of which business unit expenses are $200,357. This adjustment reflects the change in the base period level of expenses to an expense amount equivalent to three months actual and nine months forecast, exclusive of any other adjustments.

Adjustment No. 2 – Total Payroll & Staffing Adjustment Delaware Division has included an $837,012 adjustment to the Company's labor costs of which business unit costs are $573,366. This adjustment reflects a test period level of business unit staffing salary and wage expense. This adjustment results from annualizing the staff's current pay rate, adjusting staffing level to the current business unit organizational structure.

Adjustment No. 3 – Non-Payroll Staffing and Payroll-Related Adjustments Delaware Division has included an ($193,082) adjustment for non-payroll related expenses of which business unit costs are ($15,741). This adjustment is due to organizational changes as well as other changes in the department settlement rates effective in the test period.

Adjustment No. 4 – Benefits Adjustment Delaware Division has included a $200,040 adjustment for benefits of which business unit costs are $99,317. This adjustment includes the annualized expense of health, dental, and prescription claims and administration fees at the projected March expense level for the current business unit organizational structure. This adjustment also includes the annualized expense of life, short-term disability, long-term disability and accidental death and dismemberment insurance and 401(k) expenses at the most current rates and at the adjusted payroll.

Adjustment No. 5 – Insurance Adjustment Delaware Division has included a ($13,927) adjustment for insurance expenses of which business unit expenses are ($14,325). This adjustment is to annualize the insurance expenses effective

March 31, 2016. It does not include payroll-related insurance, which are included in the benefit adjustment.

Adjustment No. 6 – ECIS Adjustment Delaware Division has included a ($1,130,454) adjustment to remove non-recurring expenses related to a billing system upgrade.

Adjustment No. 7 – Depreciation Adjustment Delaware Division has included a $27,139 adjustment to annualize the depreciation expenses included in O&M costs to the expense level effective March 31, 2016. The adjustment is primarily related to changes to the business unit's projected vehicle depreciation expenses. An additional adjustment to the plant depreciation and asset removal cost expenses totaling $251,220 was made to align the test period expenses with the business unit's projected plant balance as of March 31, 2016. This adjustment is inclusive of a depreciation expense increase of $237,356 and an increase to asset removal costs of $13,863.

Adjustment No. 8 – Regulatory Expense Adjustment Delaware Division has included a $104,939 adjustment primarily for the expected rate case costs associated with this regulatory proceeding amortized over a five-year period.

Adjustment No. 9 – Bad Debts Adjustment Delaware Division has included a ($17,196) adjustment to synchronize the Bad Debt expense with the projected Firm Revenue (before the proposed increase) included in this filing.

Adjustment No. 10 – Maintenance Adjustment Delaware Division has included a ($71,503) adjustment to adjust the maintenance accounts to reflect a five-year average expense based on the twelve months ended June 2011 - 2015.

Adjustment No. 11 – Gas Control Department Adjustment Delaware Division has included a ($172,759) adjustment to exclude expenses associated with the business unit's Gas Control department from the O&M expense totals. The Delaware Division is proposing that these expenses be recovered through the business unit's Gas Sales Rate.

Adjustment No. 12 – Miscellaneous Adjustment Delaware Division has included a $30,493 adjustment for miscellaneous items of which business unit expenses are ($4,936).

Q. PLEASE DESCRIBE THE TAXES OTHER THAN INCOME INCLUDED IN THIS FILING?

A. As shown on Schedule 3-M the taxes other than income are $2,039,883 for the test period. The basis for the taxes other than income is the actual, "per book", balance for the twelve months ended June 30, 2015 of $1,807,907. Five (5) adjustments were added or subtracted from the actual results to get to the test period expense level.

Adjustment No. 1 – Inflation Adjustment Delaware Division has included a $41,402 adjustment for other taxes of which the business unit expenses are $39,280. The adjustment is due to the change in the base period level of expenses, to an expense amount equivalent to three months actual and nine months forecast, exclusive of any other adjustments.

Adjustment No. 3 – Non-Payroll Staffing & Payroll-Related Adjustment Delaware Division has included an $85,782 adjustment of which business unit expenses are $61,514. This adjustment to adjust payroll taxes in order to reflect the level of business unit staffing, salary and wage expense expected by March 31, 2016.

Adjustment No. 11 – Gas Control Department Adjustment Delaware Division has included a ($10,847) adjustment to exclude expenses associated with the business unit's Gas Control department from the O&M expense totals. The Delaware Division is proposing that these expenses be recovered through the Business Unit's Gas Sales Rate.

Adjustment No. 12 – Miscellaneous Adjustment Delaware Division has included a ($1,154) adjustment for various business unit related items.

Adjustment No. 13 – Non-Payroll Taxes Other than Income Adjustment Delaware Division has included an $116,793 adjustment for regulatory and property taxes. The property tax expense adjustment of $174,652 is to adjust the expense to the June 2015 plant levels at the most current invoiced rate. The PSC assessment expense adjustment of ($57,859) is to synchronize the PSC assessment expense with the projected Revenue included in this filing.

Q. PLEASE DESCRIBE THE RESULTS OF THE MAIN EXTENSION AGGREGATION IRRM INCLUDED IN THIS FILING?

A. Under the 2008 Settlement Agreement, the Company agreed that in its next base rate proceeding, all incremental capital projects for main extensions in excess of 500 feet proposed for rate base treatment and initiated subsequent to March 31, 2007 will be evaluated in the aggregate to determine if said capital projects earned the Company's authorized rate of return of 8.91 percent. For all capital projects initiated subsequent to March 31, 2007, and as recently as September 24, 2015, the Company has made an aggregated capital investment in mains and in meters/services of $18,445,965 and $13,240,569, respectively. As seen in Attachment JW-2, the 6,443 total customer additions supported by these capital projects have generated a total average annual margin of approximately $5,164,900. By inputting the capital costs and average annual margin totals into our IRRM, the Company calculates its rate of return to be 10.47 percent, which exceeds the required rate of return of 8.91 percent. It is noted that these figures are exclusive of capital investments and customer additions in the Company's Expansion Area in southeastern Sussex County for which the Company has entered into a separate agreement regarding IRRM results in Docket No. 12-292. (See Order No. 8479, dated November 5, 2013.) In accordance with Order No.8479, the Company files annual reports with the Commission regarding the progress made within the Expansion Area and will file a separate aggregate IRRM in the 1st quarter of 2017.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DATED: DECEMBER __21__, 2015

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF JEFFREY WEISS

JEFFREY WEISS, being first duly sworn according to law, on oath deposes and says that he is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of Jeffrey Weiss"; that, if asked the questions which appear in the text of the direct testimony, he would give the answers that are therein set forth; and that he adopts this testimony as his sworn direct testimony in these proceedings.

Jeffrey Weiss

Then personally appeared this __21st__ day of December 2015 the above-named Jeffrey Weiss and acknowledged the foregoing Testimony to be his free act and deed. Before me,

REBECCA K. GRIER
NOTARY
PUBLIC
MY COMMISSION
EXPIRES ON
07-17-18
STATE OF DELAWARE

Notary Public
My Commission Expires: 7.17.18

Chesapeake Utilities Corporation
Delaware Division Account Analysis
Summary by FERC
Test Period Adjusted - 12 Months Ended 3/31/2016
Exhibit JW - 1 (Page 1 of 2)

		Test Year Unadjusted	Inflation Adjustment No. 1	Total Payroll & Staffing Adjustment No. 2	Non-Payroll Staffing & Payroll-Related Adjustment No. 3	Benefits Adjustment No. 4	Insurance Adjustment No. 5	ECIS Adjustment No. 6	Depreciation Adjustment No. 7	Regulatory Commission Adjustment No. 8	Bad Debt Adjustment No. 9	Maintenance Adjustment No. 10	GC110 Removal Adjustment No. 11	Misc. Adjustment No. 12	Non-Payroll Taxes Other than Income Adjustment No. 13	Test Period as Adjusted
PRODUCTION																
Liquefied Petroleum Gas Expenses	717	$ 30,314.33	$ 859.97	$ -	$ -	$ -	$ -	$ -	$ (1,208.02)	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,966
Operation labor and expenses	841	30,007.69	710.43	-	-	-	-	-	-	-	-	-	-	-	-	30,718.12
Total Production Operations		$ 60,322.02	$ 1,570.40	$ -	$ -	$ -	$ -	$ -	$ (1,208.02)	$ -	$ -	$ -	$ -	$ -	$ -	$ 60,684
Maintenance of Production Equipment	742	$ 89,616.11	$ 2,639.68	$ 1,935.12	$ -	$ -	$ -	$ -	$ (745.18)	$ -	$ -	$ (45,984.57)	$ -	$ -	$ -	$ 47,461
Total Production Expenses		$ 149,938.13	$ 4,210.08	$ 1,935.12	$ -	$ -	$ -	$ -	$ (1,953.20)	$ -	$ -	$ (45,984.57)	$ -	$ -	$ -	$ 108,146
DISTRIBUTION EXPENSES																
Operation Supervision and Engineering	870	$ 421,208.66	$ 9,333.76	$ 40,673.99	$ -	$ -	$ -	$ -	$ 342.38	$ -	$ -	$ -	$ -	$ -	$ -	$ 471,559
Distribution Load Dispatching	871	111,071.43	2,549.73	46,049.12	-	-	-	-	-	-	-	-	(143,104.75)	(16,565.52)	-	0.00
Mains and Services Expenses	874	477,407.22	10,912.52	3,702.84	-	-	-	-	(1,222.19)	-	-	-	-	-	-	490,800.39
Measuring and Regulating Station Expenses - General	875	13,820.48	219.34	159.83	-	-	-	-	(55.97)	-	-	-	-	-	-	14,143.68
Measuring and Regulating Station Expenses - Industrial	876	18,296.97	470.33	1,944.88	-	-	-	-	155.28	-	-	-	-	-	-	20,867.46
Measuring and Regulating Station Expenses - City Gate	877	10,450.78	228.62	425.90	-	-	-	-	(582.71)	-	-	-	-	-	-	10,522.59
Meter and House Regulator Expenses	878	352,364.74	7,671.11	8,663.22	-	-	-	-	9,544.82	-	-	-	-	-	-	378,243.89
Customer Installations Expenses	879	58,801.19	2,038.65	8,564.40	-	-	-	-	(3,358.59)	-	-	-	-	-	-	66,045.65
Other Expenses	880	3,153.62	67.39	16.15	-	-	-	-	(1.51)	-	-	-	-	-	-	3,235.65
Rents	881	5,765.10	116.06	-	-	-	-	-	-	-	-	-	-	-	-	5,881.16
Total Distribution Operations		$ 1,472,340.19	$ 33,607.50	$ 110,200.33	$ -	$ -	$ -	$ -	$ 4,821.51	$ -	$ -	$ -	$ (143,104.75)	$ (16,565.52)	$ -	$ 1,461,299
Maintenance of Mains	887	$ 214,769.12	$ 3,249.54	$ 6,539.10	$ -	$ -	$ -	$ -	$ 12,009.53	$ -	$ -	$ 78,864.80	$ -	$ -	$ -	$ 315,432
Maintenance of M&R Station Equipment - General	889	37,687.84	724.99	10,709.03	-	-	-	-	(728.24)	-	-	(19,692.43)	-	-	-	28,701.19
Maintenance of M&R Station Equipment - Industrial	890	37,863.13	959.06	1,952.01	-	-	-	-	224.32	-	-	24,714.14	-	-	-	65,712.66
Maintenance of M&R Station Equipment - City Gate	891	4,289.45	113.38	1,664.67	-	-	-	-	(198.10)	-	-	(971.27)	-	-	-	4,898.12
Maintenance of Services	892	140,704.56	3,005.48	1,455.50	-	-	-	-	9,008.06	-	-	(15,516.69)	-	-	-	138,656.91
Maintenance of Meters and House Regulators	893	146,460.65	3,311.60	5,436.53	-	-	-	-	222.59	-	-	(55,311.50)	-	-	-	100,119.87
Maintenance of Other Equipment	894	23,807.98	432.34	-	-	-	-	-	-	-	-	(7,205.36)	-	-	-	17,034.97
Total Distribution Maintenance		$ 605,582.73	$ 11,796.39	$ 27,756.84	$ -	$ -	$ -	$ -	$ 20,538.16	$ -	$ -	$ 4,881.69	$ -	$ -	$ -	$ 670,556
Total Distribution Expenses		$ 2,077,922.92	$ 45,403.88	$ 137,957.18	$ -	$ -	$ -	$ -	$ 25,359.67	$ -	$ -	$ 4,881.69	$ (143,104.75)	$ (16,565.52)	$ -	$ 2,131,855
CUSTOMER SERVICE EXPENSES																
Supervision-Customer Accounting	901	$ 264,491.42	$ 6,000.64	$ (2,262.02)	$ -	$ -	$ -	$ -	$ 156.02	$ -	$ -	$ -	$ -	$ -	$ -	$ 268,386
Meter Reading Expenses	902	252,184.97	5,706.73	14,438.92	-	-	-	-	(365.60)	-	-	-	-	-	-	271,965.02
Customer Records & Collection Expenses	903	1,562,645.49	34,432.35	97,721.26	192.03	-	-	-	6,434.27	-	-	-	-	895.48	-	1,702,320.87
Uncollectible Accounts	904	143,160.90	3,012.02	-	-	-	-	-	-	-	(17,195.86)	-	-	-	-	128,977.06
Info & Inst Advertising	909	62,750.10	1,882.50	-	-	-	-	-	-	-	-	-	-	-	-	64,632.60
Total Customer Service Expenses		$ 2,285,232.88	$ 51,034.25	$ 109,898.15	$ 192.03	$ -	$ -	$ -	$ 6,224.69	$ -	$ (17,195.86)	$ -	$ -	$ 895.48	$ -	$ 2,436,282
SALES																
Demonstrating and Selling Expenses	912	$ 605,814.83	$ 13,921.04	$ 173,297.20	$ -	$ -	$ -	$ -	$ 1,704.42	$ -	$ -	$ -	$ -	$ (2,782.75)	$ -	$ 791,955
Advertising Expenses	913	141,391.54	3,222.74	-	-	-	-	-	-	-	-	-	-	-	-	144,614.28
Total Sales		$ 747,206.37	$ 17,143.78	$ 173,297.20	$ -	$ -	$ -	$ -	$ 1,704.42	$ -	$ -	$ -	$ -	$ (2,782.75)	$ -	$ 936,569
ADMINISTRATIVE AND GENERAL EXPENSES																
Administrative and General Salaries	920	$ 2,865,700.98	$ 65,370.28	$ 402,496.28	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,863.90	$ -	$ 3,341,431
Office Supplies and Expenses	921	834,574.44	18,265.33	-	(45,843.00)	-	-	-	(1,867.06)	-	-	-	-	47,685.03	-	852,814.75
Outside Services Employed	923	2,213,958.47	25,823.90	-	(63,559.42)	-	-	(1,130,453.80)	-	-	-	-	-	(13,139.03)	-	1,032,630.13
Property Insurance	924	28,294.45	655.90	-	(8.35)	-	(3,223.41)	-	-	-	-	-	-	-	-	25,718.59
Injuries and Damages	925	354,295.23	7,418.55	-	(16,026.21)	-	(10,703.77)	-	382.72	-	-	-	(301.24)	(12.63)	-	335,052.65
Employee Pensions and Benefits	926	1,266,344.94	28,093.36	-	(24,493.11)	200,039.86	-	-	-	-	-	-	(29,352.76)	(31,558.98)	-	1,409,073.31
Regulatory Commission Expense	928	139,105.01	3,089.90	-	-	-	-	-	-	104,938.68	-	-	-	-	-	247,133.59
General Advertising Expenses	930.1	39,344.64	795.67	-	(2,044.48)	-	-	-	-	-	-	-	-	(16,116.43)	-	21,979.40
Miscellaneous General Expenses	930.2	246,444.46	5,385.76	-	(35,822.84)	-	-	-	-	-	-	-	-	43,462.04	-	259,469.43
Rents	931	318,244.89	7,073.98	-	(4,276.84)	-	-	-	-	-	-	-	-	10,621.33	-	331,663.35
Administrative and General -Operation		$ 8,306,307.51	$ 161,972.63	$ 402,496.28	$ (192,074.23)	$ 200,039.86	$ (13,927.18)	$ (1,130,453.80)	$ (1,484.34)	$ 104,938.68	$ -	$ -	$ (29,654.00)	$ 48,805.23	$ -	$ 7,856,967
Maintenance of General Plant	932	$ 139,056.36	$ 3,544.81	$ 11,428.50	$ (1,200.26)	$ -	$ -	$ -	$ (2,711.76)	$ -	$ -	$ (30,399.84)	$ -	$ 140.18	$ -	$ 119,858
Administrative and General -Maintenance		$ 139,056.36	$ 3,544.81	$ 11,428.50	$ (1,200.26)	$ -	$ -	$ -	$ (2,711.76)	$ -	$ -	$ (30,399.84)	$ -	$ 140.18	$ -	$ 119,858
Total Administrative and General Expense		$ 8,445,363.87	$ 165,517.44	$ 413,924.78	$ (193,274.49)	$ 200,039.86	$ (13,927.18)	$ (1,130,453.80)	$ (4,196.10)	$ 104,938.68	$ -	$ (30,399.84)	$ (29,654.00)	$ 48,945.41	$ -	$ 7,976,825
TOTAL O&M and A&G EXPENSES		$ 13,705,664.17	$ 283,309.43	$ 837,012.43	$ (193,082.46)	$ 200,039.86	$ (13,927.18)	$ (1,130,453.80)	$ 27,139.48	$ 104,938.68	$ (17,195.86)	$ (71,502.71)	$ (172,758.75)	$ 30,492.61	$ -	$ 13,589,676
Taxes Other than Income	408.1	$ 1,807,906.92	$ 41,401.53	$ -	$ 85,782.39	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (10,846.64)	$ (1,153.74)	$ 116,793.00	$ 2,039,883
Depreciation	403	$ 2,292,563.72	$ -	$ -	$ -	$ -	$ -	$ -	$ 237,356.22	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,529,919.94
Asset Removal Costs	403.2	$ 110,267.09	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,863.47	$ -	$ -	$ -	$ -	$ -	$ -	$ 124,130.56

Chesapeake Utilities Corporation
Delaware Division Account Analysis
Summary by FERC
Test Period Adjusted - 12 Months Ended 3/31/2016
Exhibit JW - 1 (Page 2 of 2)

		Test Year Unadjusted	Inflation Adjustment No. 1	Total Payroll & Staffing Adjustment No. 2	Non-Payroll Staffing & Payroll-Related Adjustment No. 3	Benefits Adjustment No. 4	Insurance Adjustment No. 5	ECIS Adjustment No. 6	Depreciation Adjustment No. 7	Regulatory Commission Adjustment No. 8	Bad Debt Adjustment No. 9	Maintenance Adjustment No. 10	GC110 Removal Adjustment No. 11	Misc. Adjustment No. 12	Non-Payroll Taxes Other than Income Adjustment No. 13	Test Period as Adjusted
PRODUCTION																
Liquefied Petroleum Gas Expenses	717	$ 30,314.33	$ 859.97	$ -	$ -	$ -	$ -	$ -	$ (1,208.02)	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,966.28
Operation labor and expenses	841	30,007.69	710.43	-	-	-	-	-	-	-	-	-	-	-	-	30,718.12
Total Production Operations		$ 60,322.02	$ 1,570.40	$ -	$ -	$ -	$ -	$ -	$ (1,208.02)	$ -	$ -	$ -	$ -	$ -	$ -	$ 60,684.40
Maintenance of Production Equipment	742	$ 89,616.11	$ 2,639.68	$ 1,935.12	$ -	$ -	$ -	$ -	$ (745.18)	$ -	$ -	$ (45,984.57)	$ -	$ -	$ -	$ 47,461.16
Total Production Expenses		$ 149,938.13	$ 4,210.08	$ 1,935.12	$ -	$ -	$ -	$ -	$ (1,953.20)	$ -	$ -	$ (45,984.57)	$ -	$ -	$ -	$ 108,145.56
DISTRIBUTION EXPENSES																
Operation Supervision and Engineering	870	$ 421,208.66	$ 9,333.76	$ 40,673.99	$ -	$ -	$ -	$ -	$ 342.38	$ -	$ -	$ -	$ -	$ -	$ -	$ 471,558.80
Distribution Load Dispatching	871	111,071.43	2,549.73	46,049.12	-	-	-	-	-	-	-	-	(143,104.75)	(16,565.52)	-	0.00
Mains and Services Expenses	874	477,407.22	10,912.52	3,702.84	-	-	-	-	(1,222.19)	-	-	-	-	-	-	490,800.39
Measuring and Regulating Station Expenses - General	875	13,820.48	219.34	159.83	-	-	-	-	(55.97)	-	-	-	-	-	-	14,143.68
Measuring and Regulating Station Expenses - Industrial	876	18,296.97	470.33	1,944.88	-	-	-	-	155.28	-	-	-	-	-	-	20,867.46
Measuring and Regulating Station Expenses - City Gate	877	10,450.78	228.62	425.90	-	-	-	-	(582.71)	-	-	-	-	-	-	10,522.59
Meter and House Regulator Expenses	878	352,364.74	7,671.11	8,663.22	-	-	-	-	9,544.82	-	-	-	-	-	-	378,243.89
Customer Installations Expenses	879	58,801.19	2,038.65	8,564.40	-	-	-	-	(3,358.59)	-	-	-	-	-	-	66,045.65
Other Expenses	880	3,153.62	67.39	16.15	-	-	-	-	(1.51)	-	-	-	-	-	-	3,235.65
Rents	881	5,765.10	116.06	-	-	-	-	-	-	-	-	-	-	-	-	5,881.16
Total Distribution Operations		$ 1,472,340.19	$ 33,607.50	$ 110,200.33	$ -	$ -	$ -	$ -	$ 4,821.51	$ -	$ -	$ -	$ (143,104.75)	$ (16,565.52)	$ -	$ 1,461,299.26
Maintenance of Mains	887	$ 214,769.12	$ 3,249.54	$ 6,539.10	$ -	$ -	$ -	$ -	$ 12,009.53	$ -	$ -	$ 78,864.80	$ -	$ -	$ -	$ 315,432.09
Maintenance of M&R Station Equipment - General	889	37,687.84	724.99	10,709.03	-	-	-	-	(728.24)	-	-	(19,692.43)	-	-	-	28,701.19
Maintenance of M&R Station Equipment - Industrial	890	37,863.13	959.06	1,952.01	-	-	-	-	224.32	-	-	24,714.14	-	-	-	65,712.66
Maintenance of M&R Station Equipment - City Gate	891	4,289.45	113.38	1,664.67	-	-	-	-	(198.10)	-	-	(971.27)	-	-	-	4,898.12
Maintenance of Services	892	140,704.56	3,005.48	1,455.50	-	-	-	-	9,008.06	-	-	(15,516.69)	-	-	-	138,656.91
Maintenance of Meters and House Regulators	893	146,460.65	3,311.60	5,436.53	-	-	-	-	222.59	-	-	(55,311.50)	-	-	-	100,119.87
Maintenance of Other Equipment	894	23,807.98	432.34	-	-	-	-	-	-	-	-	(7,205.36)	-	-	-	17,034.97
Total Distribution Maintenance		$ 605,582.73	$ 11,796.39	$ 27,756.84	$ -	$ -	$ -	$ -	$ 20,538.16	$ -	$ -	$ 4,881.69	$ -	$ -	$ -	$ 670,555.81
Total Distribution Expenses		$ 2,077,922.92	$ 45,403.88	$ 137,957.18	$ -	$ -	$ -	$ -	$ 25,359.67	$ -	$ -	$ 4,881.69	$ (143,104.75)	$ (16,565.52)	$ -	$ 2,131,855.07
CUSTOMER SERVICE EXPENSES																
Supervision-Customer Accounting	901	$ 264,491.42	$ 6,000.64	$ (2,262.02)	$ -	$ -	$ -	$ -	$ 156.02	$ -	$ -	$ -	$ -	$ -	$ -	$ 268,386.06
Meter Reading Expenses	902	252,184.97	5,706.73	14,438.92	-	-	-	-	(365.60)	-	-	-	-	-	-	271,965.02
Customer Records & Collection Expenses	903	1,549,169.11	34,145.60	97,721.26	-	-	-	-	6,434.27	-	-	-	-	-	-	1,687,470.23
Uncollectible Accounts	904	143,160.90	3,012.02	-	-	-	-	-	-	-	(17,195.86)	-	-	-	-	128,977.06
Info & Inst Advertising	909	62,750.10	1,882.50	-	-	-	-	-	-	-	-	-	-	-	-	64,632.60
Total Customer Service Expenses		$ 2,271,756.50	$ 50,747.50	$ 109,898.15	$ -	$ -	$ -	$ -	$ 6,224.69	$ -	$ (17,195.86)	$ -	$ -	$ -	$ -	$ 2,421,430.98
SALES																
Demonstrating and Selling Expenses	912	$ 605,814.83	$ 13,921.04	$ 173,297.20	$ -	$ -	$ -	$ -	$ 1,704.42	$ -	$ -	$ -	$ -	$ (2,782.75)	$ -	$ 791,954.74
Advertising Expenses	913	141,391.54	3,222.74	-	-	-	-	-	-	-	-	-	-	-	-	144,614.28
Total Sales		$ 747,206.37	$ 17,143.78	$ 173,297.20	$ -	$ -	$ -	$ -	$ 1,704.42	$ -	$ -	$ -	$ -	$ (2,782.75)	$ -	$ 936,569.03
ADMINISTRATIVE AND GENERAL EXPENSES																
Administrative and General Salaries	920	$ 1,249,550.66	$ 29,285.38	$ 138,850.05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,863.90	$ -	$ 1,425,549.98
Office Supplies and Expenses	921	208,645.51	4,547.27	-	1,638.61	-	-	-	(1,867.06)	-	-	-	-	7,863.90	-	220,828.23
Outside Services Employed	923	1,492,883.64	8,462.24	-	-	-	-	(1,130,453.80)	-	-	-	-	-	-	-	370,892.08
Property Insurance	924	28,152.00	652.59	-	-	-	(3,207.59)	-	-	-	-	-	-	-	-	25,597.00
Injuries and Damages	925	347,423.73	7,272.65	-	(16,503.31)	-	(11,117.63)	-	382.72	-	-	-	(301.24)	(12.63)	-	334,161.69
Employee Pensions and Benefits	926	950,810.84	20,821.66	-	(3,322.41)	99,317.49	-	-	-	-	-	-	(29,352.76)	(1,303.04)	-	1,036,971.78
Regulatory Commission Expense	928	139,105.01	3,089.90	-	-	-	-	-	-	104,938.68	-	-	-	-	-	247,133.59
General Advertising Expenses	930.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous General Expenses	930.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rents	931	250,694.79	5,557.36	-	2,150.97	-	-	-	-	-	-	-	-	-	-	258,403.12
Administrative and General -Operation		$ 4,667,266.18	$ 79,689.05	$ 138,850.05	$ (16,036.13)	$ 99,317.49	$ (14,325.22)	$ (1,130,453.80)	$ (1,484.34)	$ 104,938.68	$ -	$ -	$ (29,654.00)	$ 14,412.13	$ -	$ 3,919,537.48
Maintenance of General Plant	932	$ 124,178.99	$ 3,162.24	$ 11,428.50	$ 295.16	$ -	$ -	$ -	$ (2,711.76)	$ -	$ -	$ (30,399.84)	$ -	$ -	$ -	$ 105,953.30
Administrative and General -Maintenance		$ 124,178.99	$ 3,162.24	$ 11,428.50	$ 295.16	$ -	$ -	$ -	$ (2,711.76)	$ -	$ -	$ (30,399.84)	$ -	$ -	$ -	$ 105,953.30
Total Administrative and General Expense		$ 4,791,445.17	$ 82,851.29	$ 150,278.55	$ (15,740.97)	$ 99,317.49	$ (14,325.22)	$ (1,130,453.80)	$ (4,196.10)	$ 104,938.68	$ -	$ (30,399.84)	$ (29,654.00)	$ 14,412.13	$ -	$ 4,025,490.78
TOTAL O&M and A&G EXPENSES		$ 10,038,269.09	$ 200,356.53	$ 573,366.19	$ (15,740.97)	$ 99,317.49	$ (14,325.22)	$ (1,130,453.80)	$ 27,139.48	$ 104,938.68	$ (17,195.86)	$ (71,502.71)	$ (172,758.75)	$ (4,936.15)	$ -	$ 9,623,491.41
Taxes Other than Income	408.1	$ 1,715,097.46	$ 39,280.33	$ -	$ 61,513.85	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (10,846.64)	$ (1,153.74)	$ 116,793.00	$ 1,920,684.26

Chesapeake Utilities Corporation
Delaware Division
Aggregated IRRM Inputs
Exhibit JW - 2

	9 ME Dec. 2007	Dec. 2008	Dec. 2009	Dec. 2010	Dec. 2011	Dec. 2012	Dec. 2013	Dec. 2014	YTD 2015	Total
Main	$ 2,197,868.67	$ 2,946,172.61	$ 1,878,809.35	$ 3,108,923.11	$ 3,386,172.95	$ 1,530,877.26	$ 1,062,244.32	$ 1,805,549.75	$ 529,347.06	**$ 18,445,965.08**
Meters & Service Cost	481,193.82	850,000.32	963,861.31	1,287,381.48	1,515,271.42	2,029,717.02	2,219,760.24	2,124,791.41	1,768,591.90	**13,240,568.92**
Sub-total :	$ 2,679,062.49	$ 3,796,172.93	$ 2,842,670.66	$ 4,396,304.59	$ 4,901,444.37	$ 3,560,594.28	$ 3,282,004.56	$ 3,930,341.16	$ 2,297,938.96	**$ 31,686,534.00**
Margin Per Customer by Rate Class										
Residential Service Heat	$ 365.14	$ 381.60	$ 354.33	$ 352.28	$ 348.37	$ 334.13	$ 349.60	$ 355.64	$ 375.03	
Residential Service Other	$ 213.05	$ 232.68	$ 228.77	$ 229.89	$ 232.41	$ 231.36	$ 240.53	$ 249.01	$ 255.30	
Other Residential	$ 147.70	$ 149.63	$ 141.00	$ 138.00	$ 140.57	$ 140.57	$ 135.00	$ 141.60	$ 157.33	
General Service Heat	$ 530.77	$ 550.70	$ 515.56	$ 520.82	$ 515.28	$ 483.89	$ 527.83	$ 547.64	$ 582.45	
Medium Volume Heat	$ 1,869.21	$ 1,914.52	$ 1,886.52	$ 1,836.23	$ 1,785.17	$ 1,682.13	$ 1,855.54	$ 1,911.52	$ 2,025.63	
Large Volume Heat	$ 7,313.68	$ 7,776.26	$ 7,091.54	$ 7,262.73	$ 7,616.86	$ 6,861.31	$ 6,876.26	$ 7,216.40	$ 7,546.73	
High Load Heat	$ 3,631.36	$ 3,698.30	$ 3,781.29	$ 3,837.74	$ 3,680.79	$ 3,537.40	$ 3,431.19	$ 3,291.32	$ 3,042.94	
High Load Commercial Other	$ 1,936.44	$ 2,777.00	$ 3,096.81	$ 4,212.57	$ 4,354.18	$ 2,348.32	$ 2,765.99	$ 2,846.26	$ 2,751.54	
Other Commercial	$ 683.61	$ 731.16	$ 698.40	$ 824.59	$ 1,070.20	$ 1,311.93	$ 1,737.63	$ 1,942.86	$ 1,971.19	
Large Volume Industrial Heat	$ 16,673.20	$ 13,853.00	$ 8,426.57	$ 7,973.56	$ 10,572.13	$ 12,270.40	$ 10,840.14	$ 11,645.00	$ 12,085.71	
High Load Industrial Heat	$ 17,764.00	$ 18,813.50	$ 33,331.29	$ 44,727.71	$ 43,729.86	$ 47,724.14	$ 51,545.43	$ 52,198.33	$ 54,655.25	
High Load Industrial Other	$ 34,164.33	$ 36,655.50	$ 30,972.33	$ 38,170.50	$ 57,792.97	$ 74,855.06	$ 80,426.29	$ 67,229.17	$ 65,022.96	
Other Industrial	$ 5,104.86	$ 2,987.86	$ 5,739.35	$ 5,046.33	$ 6,203.39	$ 6,428.21	$ 9,396.05	$ 11,142.00	$ 9,341.46	
Interruptible	$ 14,977.49	$ 44,953.79	$ 108,184.67	$ 129,884.40	$ 43,756.75	$ 45,708.40	$ 23,942.00	$ 23,215.14	$ 34,174.67	
Customer Additions by Rate Class										
Residential Service Heat	300	465	397	577	622	746	726	873	584	5290
Residential Service Other	5	5	7	14	2	19	11	13	22	98
Other Residential	0	0	0	0	0	0	0	0	0	0
General Service Heat	107	128	97	55	72	60	73	77	49	718
Medium Volume Heat	15	14	15	12	8	14	37	7	10	132
Large Volume Heat	5	4	7	3	1	6	4	0	4	34
High Load Heat	6	9	4	1	2	5	1	2	8	38
High Load Commercial Other	1	5	3	1	4	6	3	5	2	30
Other Commercial	4	9	3	4	4	5	17	2	6	54
Large Volume Industrial Heat	0	1	0	1	0	0	1	0	0	3
High Load Industrial Heat	0	0	0	0	2	0	0	0	1	3
High Load Industrial Other	2	4	3	9	5	3	4	4	2	36
Other Industrial	1	1	0	3	2	0	0	0	0	7
Interruptible	0	0	0	0	0	0	0	0	0	0
Total Additions:	446	645	536	680	724	864	877	983	688	6443
Average Margin Per Customer Addition:	$ 744.17	$ 812.74	$ 726.95	$ 966.10	$ 958.62	$ 706.38	$ 872.24	$ 674.34	$ 770.34	
Cumulative Average:	$ 744.17	$ 784.71	$ 765.68	$ 824.76	$ 856.73	$ 823.38	$ 832.36	$ 805.37	$ 801.63	
Total Annual Margin:	$ 331,899.27	$ 856,119.01	$ 1,245,764.78	$ 1,902,714.48	$ 2,596,757.54	$ 3,207,070.75	$ 3,972,028.59	$ 4,634,905.78	$ 5,164,900.13	

Delaware Division
Sussex County Expansion Area
Overall Project Summary
Consolidated DE Model 3/31/07 - 9/30/2015
Delaware
October 5, 2015

Project Summary:

Customer Type (check one)	
New Residential Development	X
Existing Development (Conversion)	X
Commercial (Rate Schedule __________)	X
Industrial (Rate Schedule __________)	X
Interruptible (Alternate Fuel __________)	

Average Square Feet per Home	

Gas Equipment (check all that apply)	
Heat	X
Water Heater	X
Range	X
Dryer	X
Gas Logs	
Gas Lights	
Boiler	
Other:	X

Number of Customers in Model:	6,443
Anticipated Build-out Years:	9

Financial Summary:

Capital Investment	
Total Approach & Development Main	$18,445,965
Service Installations (Includes: mtr & reg):	$13,240,569
Other (specify):	$0
Total Capital Investment:	$31,686,534

Margin	
Total Annual Margin	$5,164,900
Annual Margin Per Customer	$802

	Financial Test	% Required	% Results	Meets Test
	Rate of Return	8.91%	10.37%	Yes
	Return on Equity	10.25%	12.62%	Yes
**	Net Revenue Test	n/a	n/a	n/a

** **Indicates applicable financial test

Contribution In Aid of Construction ("CIAC")	
CIAC Required?	No
Total Amount for Project (Builder)	n/a
Total Amount Per Customer	n/a
Verification of Acceptance of CIAC	

Business Unit Approvals Required

Director of Energy Services (Shane Breakie)	*Date*

Director of Pricing and Regulatory Affairs (Bill O'Brien)	*Date*

Vice President (Jim Moore)	*Date*

Senior Vice President (Steve Thompson - Capital Investments > $150,000)	*Date*

Chesapeake Utilities Corporation
Delaware Division
Summary of Internal Rate of Return Results
Consolidated DE Model 3/31/07 - 9/30/2015
Delaware

Cost of Capital

	Ratio	Cost	Weighted Cost of Capital	Pre-tax Cost
Equity	61.81%	10.25%	6.34%	10.68%
Short-Term Debt	0.00%	0.00%	0.00%	0.00%
Long-Term Debt	38.19%	6.74%	2.57%	2.57%
Total	100.00%	N/A	8.91%	13.25%

Federal Tax Rate	35.00%
State Tax Rate	8.70%
Composite Tax Rate	40.655%
After-tax Rate	59.35%

Internal Rate of Return ("IRR") Summary Results

	Ratio	IRR	Weighted IRR
Equity	61.81%	12.62%	7.80%
Short-Term Debt	0.00%	0.00%	0.00%
Long-Term Debt	38.19%	6.74%	2.57%
Total	100.00%	N/A	**10.37%**

Calculation of CIAC

Capital Cost at 0.00% Rate of Return	$31,686,534
Allowed Capital Cost for 7.77% Rate of Return	-
Level of Capital Cost above Allowed Rate of Return	$31,686,534
Tax Rate	31.905%
Level of Capital Cost with Tax Gross Up (CIAC)	N/A

Chesapeake Utilities Corporation
Delaware Division
Determination of Annual Non-Fuel Revenue ("Net Revenue")
Consolidated DE Model 3/31/07 - 9/30/2015
Delaware

Determination of Annual Non-Fuel Revenue ("Net Revenue")

	Residential Service			Cumulative Total		
Year	Number of Customers	Non-Fuel Revenue Per Customer	Annual Non-Fuel Revenue	Number of Customers	Non-Fuel Revenue Per Customer	Annual Non-Fuel Revenue
1	446	$744	$331,899	446	$744	$331,899
2	645	$785	$506,138	1,091	$785	$856,119.01
3	536	$766	$410,406	1,627	$766	$1,245,765
4	680	$825	$560,835	2,307	$825	$1,902,714
5	724	$857	$620,275	3,031	$857	$2,596,758
6	864	$823	$711,402	3,895	$823	$3,207,071
7	877	$832	$729,981	4,772	$832	$3,972,029
8	983	$805	$791,679	5,755	$805	$4,634,906
9	688	$802	$551,521	6,443	$802	$5,164,900
10	0	$802	$0	6,443	$802	$5,164,900
Total	6,443		$5,164,900			

Determination of Capital Costs

	Determination of Capital Cost Investments				Total Capital Costs		
	Non-Depr.	Depreciable					
Year	Land	M & R Station	Approach & Distribution Main	Service Installation	Total Non-Depreciable	Total Depreciable	Total
0	$0	$0	$2,197,869	$0	$0	$2,197,869	$2,197,869
1	$0	$0	$2,946,173	$481,194	$0	$3,427,366	$3,427,366
2	$0	$0	$1,878,809	$850,000	$0	$2,728,810	$2,728,810
3	$0	$0	$3,108,923	$963,861	$0	$4,072,784	$4,072,784
4	$0	$0	$3,386,173	$1,287,381	$0	$4,673,554	$4,673,554
5	$0	$0	$1,530,877	$1,515,271	$0	$3,046,149	$3,046,149
6	$0	$0	$1,062,244	$2,029,717	$0	$3,091,961	$3,091,961
7	$0	$0	$1,805,550	$2,219,760	$0	$4,025,310	$4,025,310
8	$0	$0	$529,347	$2,124,791	$0	$2,654,138	$2,654,138
9	$0	$0	$0	$1,768,592	$0	$1,768,592	$1,768,592
10	$0	$0	$0	$0	$0	$0	$0
Total	$0	$0	$18,445,965	$13,240,569	$0	$31,686,534	$31,686,534

Depreciation Rates	3.81%	1.61%	2.12%		**Estimated Book Life**
Annual Depr Amount	$0	$296,980	$280,700	$577,680	**55 Years**

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	**)**	
CHESAPEAKE UTILITIES CORPORATION	**)**	
FOR A GENERAL INCREASE IN ITS	**)**	**PSC DOCKET NO. 15-**
NATURAL GAS RATES AND FOR	**)**	
APPROVAL OF CERTAIN OTHER	**)**	
CHANGES TO ITS NATURAL GAS TARIFF	**)**	

DIRECT TESTIMONY OF MATTHEW DEWEY

<u>On Behalf of Chesapeake Utilities Corporation</u>
<u>Delaware Division.</u>

Submitted for filing: December 21, 2015

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

A. My name is Matthew Dewey, and I am the Director of Accounting Shared Services for Chesapeake Utilities Corporation ("Chesapeake"). My business address is 909 Silver Lake Boulevard, Dover, Delaware 19904.

Q. DESCRIBE BRIEFLY YOUR EDUCATION AND RELEVANT PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science in Accounting from Goldey-Beacom College in 1981. I joined Chesapeake in 1987 as a general ledger accountant. During my twenty eight years of experience in Chesapeake's accounting department I have held the following positions: General Ledger Accounting Manager, Corporate Controller, Controller for Delmarva Propane, Director of Business Unit Accounting and my current position of Director of Accounting Shared Services. In my current role, I manage various corporate accounting areas which includes the following: general ledger accounting for all of Chesapeake's corporate office, costs settlement process, cash reconciliations and accounts payable.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN RATE PROCEEDINGS?

A. Yes. I have submitted pre-filed testimony with the Federal Energy Regulatory Commission, Delaware Public Service Commission, Maryland Public Service Commission, and the Florida Public Service Commission.

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

A. The purpose of my testimony is to describe and support the test period adjustments relating to Delaware Division's operation and maintenance expenses and taxes other than income for the corporate departments only. It is also to request regulatory treatment for non-capitalized costs associated with the set-up and implementation of new Technology. This includes but is not limited to Customer Information System, Fixed Assets, Accounting, Procurement, Work Force Management, Safety, Budgeting and Forecasting.

Q. DO YOU SPONSOR ANY ATTACHMENTS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I do. I sponsor two (2) attachments, which support my testimony. Attachment MD-1 displays a flow chart representation of the cost settlement process, which I will explain in more detail below. Attachment MD-2 summarizes the operating expenses as adjusted, which I will explain in more detail below.

Q. PLEASE BRIEFLY EXPLAIN THE OVERALL COST SETTLEMENT PROCESS.

A. Charges that can be directly identified to a business unit, like Delaware Division ("DE"), are directly charged to that business unit and are not part of the settlement process. Examples of items that are directly charged include accounts payable vouchers, prepaid insurance journal entries, and inventory issues. Other charges that cannot be directly identified to a business unit are allocated in the cost settlement process. In Attachment MD-1, a flow chart representation of the settlement process is shown for illustrative purposes. The cost settlement process is the process of allocating costs to the business unit that either causes the cost being incurred or benefits from the cost being incurred. Costs are accumulated by operational departments. Employee based departments include costs like payroll, benefits, payroll taxes, vehicle costs and other employee related expenses. Non-employee departments are used to accumulate costs for such items as shared facilities, information systems, benefits, and mailroom expenses. The costs are then allocated to the business units, including DE, using department specific- settlement rates.

Q. PLEASE DESCRIBE THE OPERATION AND MAINTENANCE EXPENSES INCLUDED IN THIS FILING?

A. As shown in Attachment MD-2, the test period operations and maintenance expenses are $13,589,676 of which corporate costs are $3,973,202. The attachment shows the results for the twelve months ended June 30, 2015, Test Period Unadjusted, followed by thirteen (13) adjustments for the test period. The majority of the adjustments are discussed in the testimony of Mr. Jeffrey Weiss, only the ones impacting corporate costs are described below.

<u>Adjustment No. 1 – Inflation</u> As stated earlier, the base period consists of the actual corporate expenses for the twelve months ended June 30, 2015. The

forecasted period consists of the actual three months ended June 30, 2015 and projected nine months ended March 31, 2016. The Inflation adjustment of $283,309 of which corporate is $82,953. This adjustment reflects the change in the base period level of expenses to an expense amount equivalent to three months actual and nine months reflecting three (3) percent inflation, exclusive of any other adjustments.

Adjustment No. 2 – Payroll and Staffing Delaware Division has included an $837,012 adjustment to the Company's labor costs of which corporate is $263,646. This adjustment reflects a test period level of corporate staffing salary and wage expense. This adjustment results from annualizing the staff's projected pay rate and adjusting staffing level to the current corporate organizational structure.

Adjustment No. 3 – Non-Payroll Staffing and Payroll-Related Adjustments Delaware Division has included a ($193,074) adjustment to the Company's costs of which corporate is ($177,341). The adjustment is due to organizational changes or changes in the department settlement rates effective in the test period.

Adjustment No. 4 – Benefits Adjustment Delaware Division has included a $200,040 adjustment for benefits of which corporate is $100,722. This adjustment includes the annualized expense of health, dental, and prescription claims and administration fees at the projected March 31, 2016 expense level for the current corporate organization structure. This adjustment also includes the annualized expense of life, short-term disability, long-term disability and accidental death and dismemberment insurance and 401(k) expenses at the most current rates and at the adjusted payroll.

Adjustment No. 5 – Insurance Adjustment Delaware Division has included a ($13,927) adjustment for insurance expenses of which corporate is $398. This adjustment is to annualize the insurance expenses effective March 31, 2016. It does not include payroll-related insurance, which are included in the benefit adjustment.

Adjustment No. 12 – Miscellaneous Adjustment Delaware Division has included a $30,493 adjustment for various items of which corporate is $35,429. These adjustments include annualizing specific items and costs associated with leasing additional corporate office space in Dover Delaware,

Q. PLEASE DESCRIBE THE TAXES OTHER THAN INCOME INCLUDED IN THIS FILING?

A. As shown on Schedule 3-M the taxes other than income are $2,039,883 for the test period of which corporate is $119,199. The basis for the taxes other than income is the actual, "per book", balance for the twelve months ended June 30, 2015 of $1,807,907. The corporate adjustments listed below were added to the actual results to get to the test period expense level. The adjustments that are not listed below have no impact on taxes other than income.

Adjustment No. 1 – Inflation Adjustment Delaware Division has included a $41,402 adjustment for other taxes of which corporate is $2,121. The adjustment is due to the change in the base period level of expenses, to an expense amount equivalent to six months actual and six months forecast, exclusive of any other adjustments.

Adjustment No. 3 – Non-Payroll Staffing & Payroll Related Adjustment Delaware Division has included an $85,782 adjustment of which corporate is $24,269. This adjustment to adjust payroll taxes in order to reflect the level of corporate staffing, salary and wage expense expected by March 2016.

Q. PLEASE BRIEFLY EXPLAIN THE REASON YOU ARE REQUESTING APPROVAL FOR THE REGULATORY TREATMENT FOR COSTS RELATED TO THE SET-UP AND IMPLEMENTATION OF NEW TECHNOLOGIES.

A. There are several new Technologies available that are beneficial to utilities. Additionally, we foresee that the Company's existing technology systems will need to updated or replaced in the near future. Specifically, the Customer Information System for Chesapeake is currently over 20 years old and utilizes older technology. The system is fully depreciated so this filing doesn't include any recovery of software costs (depreciation) and/or rate base treatment. Chesapeake is currently starting the search for a new Customer Information System. In conjunction with the search, technology selection, and implementation the company will incur costs which are currently not capitalizable under Generally Accepted Accounting Principles "GAAP".

Q. PLEASE DESCRIBE THE NON-CAPITALIZABLE COSTS.

A When implementing a new technology the following examples of costs are not allowed to be capitalized by GAAP: 1) Expertise to assist in the search and selection process, 2) Documenting current processes and tariff requirements, 3) Process re-engineering to adapt the targeted software to our current tariff requirements with little or no modifications to the technology, 4) Data conversion which includes taking our customer information current stored in a specific format and technology and to adjust to the targeted software and 5) training during and after implementation.

Q. HOW WERE THESE SPECIFIC COSTS HANDLED IN THE CURRENT CUSTOMER INFORMATION SYSTEM?

A. These costs were capitalized when our existing software was implemented in the 90s based on the GAAP guidelines in effect at the time.

Q. HOW DO YOU EXPECT TO ACCOUNT FOR THESE COSTS WHEN REGULATORY TREATMENT IS GRANTED?

A. Chesapeake would record costs for each new Technology to a regulatory asset. The regulatory treatments for this asset would be consistent with the rate base treatment and amortization period for the new technology implemented. Recovery of the costs to be included in base rates during the next base rate proceeding.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DATED: DECEMBER 21, 2015

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF MATTHEW DEWEY

MATTHEW DEWEY, being first duly sworn according to law, on oath deposes and says that he is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of Matthew Dewey"; that, if asked the questions which appear in the text of the direct testimony, he would give the answers that are therein set forth; and that he adopts this testimony as his sworn direct testimony in these proceedings.

Matthew Dewey

Matthew Dewey

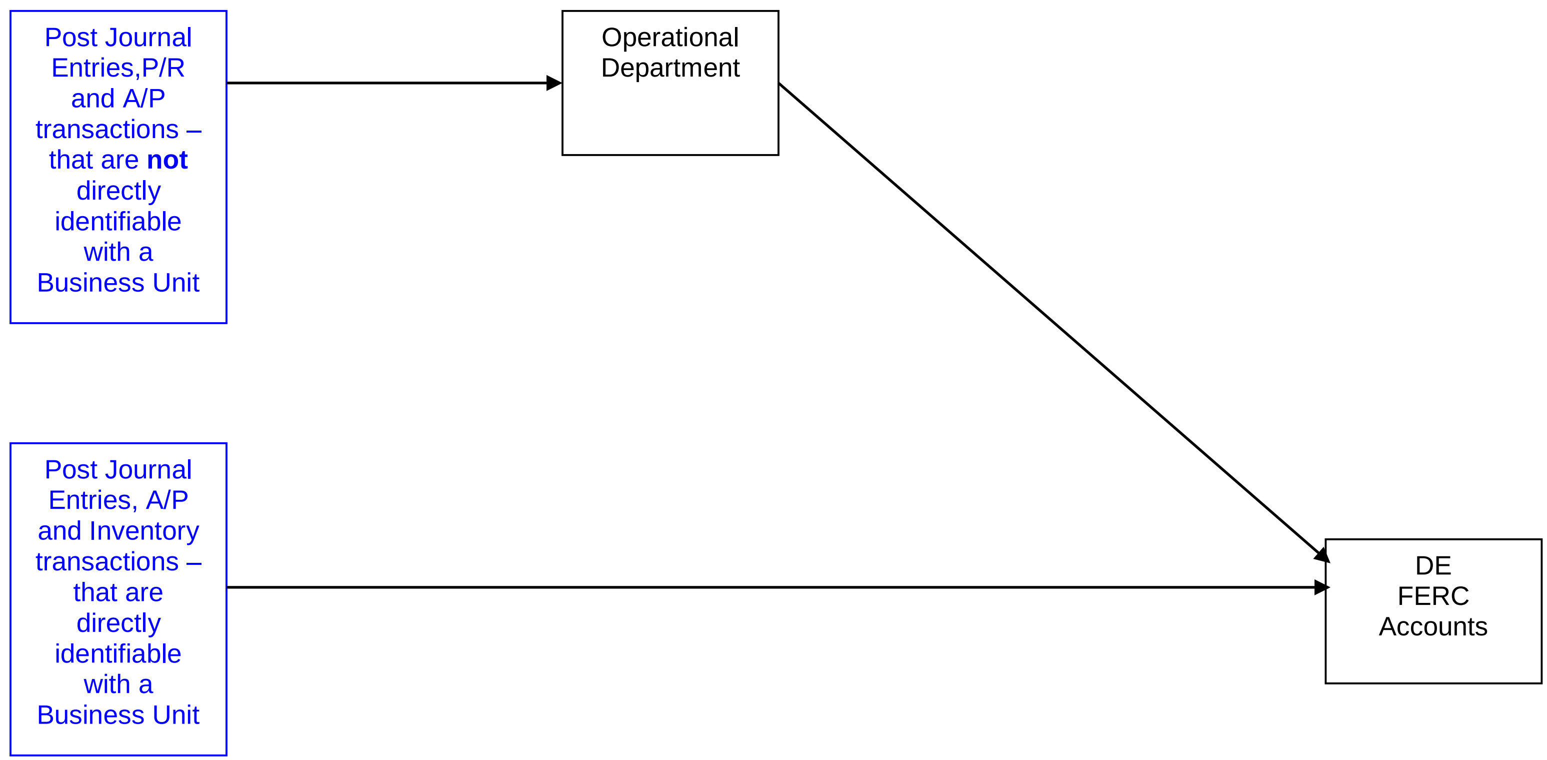
Then personally appeared this 21st day of December 2015 the above-named Matthew Dewey and acknowledged the foregoing Testimony to be his free act and deed. Before me,

REBECCA K. GRIER NOTARY PUBLIC MY COMMISSION EXPIRES ON 07-17-18 STATE OF DELAWARE

Rebecca K. Grier

Notary Public
My Commission Expires: 7-17-18

Chesapeake Utilities Corporation – Delaware Division
Cost Settlement Flow Chart
Exhibit MD-1



Chesapeake Utilities Corporation
Delaware Division Account Analysis
Summary by FERC
Test Period Adjusted - 12 Months Ended 3/31/2016
Exhibit MD - 2 (Page 1 of 2)

		Test Year Unadjusted	Inflation Adjustment No. 1	Total Payroll & Staffing Adjustment No. 2	Non-Payroll Staffing & Payroll-Related Adjustment No. 3	Benefits Adjustment No. 4	Insurance Adjustment No. 5	ECIS Adjustment No. 6	Depreciation Adjustment No. 7	Regulatory Commission Adjustment No. 8	Bad Debt Adjustment No. 9	Maintenance Adjustment No. 10	GC110 Removal Adjustment No. 11	Misc. Adjustment No. 12	Non-Payroll Taxes Other than Income Adjustment No. 13	Test Period as Adjusted
PRODUCTION																
Liquefied Petroleum Gas Expenses	717	$ 30,314.33	$ 859.97	$ -	$ -	$ -	$ -	$ -	$ (1,208.02)	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,966
Operation labor and expenses	841	30,007.69	710.43	-	-	-	-	-	-	-	-	-	-	-	-	30,718.12
Total Production Operations		$ 60,322.02	$ 1,570.40	$ -	$ -	$ -	$ -	$ -	$ (1,208.02)	$ -	$ -	$ -	$ -	$ -	$ -	$ 60,684
Maintenance of Production Equipment	742	$ 89,616.11	$ 2,639.68	$ 1,935.12	$ -	$ -	$ -	$ -	$ (745.18)	$ -	$ -	$ (45,984.57)	$ -	$ -	$ -	$ 47,461
Total Production Expenses		$ 149,938.13	$ 4,210.08	$ 1,935.12	$ -	$ -	$ -	$ -	$ (1,953.20)	$ -	$ -	$ (45,984.57)	$ -	$ -	$ -	$ 108,146
DISTRIBUTION EXPENSES																
Operation Supervision and Engineering	870	$ 421,208.66	$ 9,333.76	$ 40,673.99	$ -	$ -	$ -	$ -	$ 342.38	$ -	$ -	$ -	$ -	$ -	$ -	$ 471,559
Distribution Load Dispatching	871	111,071.43	2,549.73	46,049.12	-	-	-	-	-	-	-	-	(143,104.75)	(16,565.52)	-	0.00
Mains and Services Expenses	874	477,407.22	10,912.52	3,702.84	-	-	-	-	(1,222.19)	-	-	-	-	-	-	490,800.39
Measuring and Regulating Station Expenses - General	875	13,820.48	219.34	159.83	-	-	-	-	(55.97)	-	-	-	-	-	-	14,143.68
Measuring and Regulating Station Expenses - Industrial	876	18,296.97	470.33	1,944.88	-	-	-	-	155.28	-	-	-	-	-	-	20,867.46
Measuring and Regulating Station Expenses - City Gate	877	10,450.78	228.62	425.90	-	-	-	-	(582.71)	-	-	-	-	-	-	10,522.59
Meter and House Regulator Expenses	878	352,364.74	7,671.11	8,663.22	-	-	-	-	9,544.82	-	-	-	-	-	-	378,243.89
Customer Installations Expenses	879	58,801.19	2,038.65	8,564.40	-	-	-	-	(3,358.59)	-	-	-	-	-	-	66,045.65
Other Expenses	880	3,153.62	67.39	16.15	-	-	-	-	(1.51)	-	-	-	-	-	-	3,235.65
Rents	881	5,765.10	116.06	-	-	-	-	-	-	-	-	-	-	-	-	5,881.16
Total Distribution Operations		$ 1,472,340.19	$ 33,607.50	$ 110,200.33	$ -	$ -	$ -	$ -	$ 4,821.51	$ -	$ -	$ -	$ (143,104.75)	$ (16,565.52)	$ -	$ 1,461,299
Maintenance of Mains	887	$ 214,769.12	$ 3,249.54	$ 6,539.10	$ -	$ -	$ -	$ -	$ 12,009.53	$ -	$ -	$ 78,864.80	$ -	$ -	$ -	$ 315,432
Maintenance of M&R Station Equipment - General	889	37,687.84	724.99	10,709.03	-	-	-	-	(728.24)	-	-	(19,692.43)	-	-	-	28,701.19
Maintenance of M&R Station Equipment - Industrial	890	37,863.13	959.06	1,952.01	-	-	-	-	224.32	-	-	24,714.14	-	-	-	65,712.66
Maintenance of M&R Station Equipment - City Gate	891	4,289.45	113.38	1,664.67	-	-	-	-	(198.10)	-	-	(971.27)	-	-	-	4,898.12
Maintenance of Services	892	140,704.56	3,005.48	1,455.50	-	-	-	-	9,008.06	-	-	(15,516.69)	-	-	-	138,656.91
Maintenance of Meters and House Regulators	893	146,460.65	3,311.60	5,436.53	-	-	-	-	222.59	-	-	(55,311.50)	-	-	-	100,119.87
Maintenance of Other Equipment	894	23,807.98	432.34	-	-	-	-	-	-	-	-	(7,205.36)	-	-	-	17,034.97
Total Distribution Maintenance		$ 605,582.73	$ 11,796.39	$ 27,756.84	$ -	$ -	$ -	$ -	$ 20,538.16	$ -	$ -	$ 4,881.69	$ -	$ -	$ -	$ 670,556
Total Distribution Expenses		$ 2,077,922.92	$ 45,403.88	$ 137,957.18	$ -	$ -	$ -	$ -	$ 25,359.67	$ -	$ -	$ 4,881.69	$ (143,104.75)	$ (16,565.52)	$ -	$ 2,131,855
CUSTOMER SERVICE EXPENSES																
Supervision-Customer Accounting	901	$ 264,491.42	$ 6,000.64	$ (2,262.02)	$ -	$ -	$ -	$ -	$ 156.02	$ -	$ -	$ -	$ -	$ -	$ -	$ 268,386
Meter Reading Expenses	902	252,184.97	5,706.73	14,438.92	-	-	-	-	(365.60)	-	-	-	-	-	-	271,965.02
Customer Records & Collection Expenses	903	1,562,645.49	34,432.35	97,721.26	192.03	-	-	-	6,434.27	-	-	-	-	895.48	-	1,702,320.87
Uncollectible Accounts	904	143,160.90	3,012.02	-	-	-	-	-	-	-	(17,195.86)	-	-	-	-	128,977.06
Info & Inst Advertising	909	62,750.10	1,882.50	-	-	-	-	-	-	-	-	-	-	-	-	64,632.60
Total Customer Service Expenses		$ 2,285,232.88	$ 51,034.25	$ 109,898.15	$ 192.03	$ -	$ -	$ -	$ 6,224.69	$ -	$ (17,195.86)	$ -	$ -	$ 895.48	$ -	$ 2,436,282
SALES																
Demonstrating and Selling Expenses	912	$ 605,814.83	$ 13,921.04	$ 173,297.20	$ -	$ -	$ -	$ -	$ 1,704.42	$ -	$ -	$ -	$ -	$ (2,782.75)	$ -	$ 791,955
Advertising Expenses	913	141,391.54	3,222.74	-	-	-	-	-	-	-	-	-	-	-	-	144,614.28
Total Sales		$ 747,206.37	$ 17,143.78	$ 173,297.20	$ -	$ -	$ -	$ -	$ 1,704.42	$ -	$ -	$ -	$ -	$ (2,782.75)	$ -	$ 936,569
ADMINISTRATIVE AND GENERAL EXPENSES																
Administrative and General Salaries	920	$ 2,865,700.98	$ 65,370.28	$ 402,496.28	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,863.90	$ -	$ 3,341,431
Office Supplies and Expenses	921	834,574.44	18,265.33	-	(45,843.00)	-	-	-	(1,867.06)	-	-	-	-	47,685.03	-	852,814.75
Outside Services Employed	923	2,213,958.47	25,823.90	-	(63,559.42)	-	-	(1,130,453.80)	-	-	-	-	-	(13,139.03)	-	1,032,630.13
Property Insurance	924	28,294.45	655.90	-	(8.35)	-	(3,223.41)	-	-	-	-	-	-	-	-	25,718.59
Injuries and Damages	925	354,295.23	7,418.55	-	(16,026.21)	-	(10,703.77)	-	382.72	-	-	-	(301.24)	(12.63)	-	335,052.65
Employee Pensions and Benefits	926	1,266,344.94	28,093.36	-	(24,493.11)	200,039.86	-	-	-	-	-	-	(29,352.76)	(31,558.98)	-	1,409,073.31
Regulatory Commission Expense	928	139,105.01	3,089.90	-	-	-	-	-	-	104,938.68	-	-	-	-	-	247,133.59
General Advertising Expenses	930.1	39,344.64	795.67	-	(2,044.48)	-	-	-	-	-	-	-	-	(16,116.43)	-	21,979.40
Miscellaneous General Expenses	930.2	246,444.46	5,385.76	-	(35,822.84)	-	-	-	-	-	-	-	-	43,462.04	-	259,469.43
Rents	931	318,244.89	7,073.98	-	(4,276.84)	-	-	-	-	-	-	-	-	10,621.33	-	331,663.35
Administrative and General -Operation		$ 8,306,307.51	$ 161,972.63	$ 402,496.28	$ (192,074.23)	$ 200,039.86	$ (13,927.18)	$ (1,130,453.80)	$ (1,484.34)	$ 104,938.68	$ -	$ -	$ (29,654.00)	$ 48,805.23	$ -	$ 7,856,967
Maintenance of General Plant	932	$ 139,056.36	$ 3,544.81	$ 11,428.50	$ (1,200.26)	$ -	$ -	$ -	$ (2,711.76)	$ -	$ -	$ (30,399.84)	$ -	$ 140.18	$ -	$ 119,858
Administrative and General -Maintenance		$ 139,056.36	$ 3,544.81	$ 11,428.50	$ (1,200.26)	$ -	$ -	$ -	$ (2,711.76)	$ -	$ -	$ (30,399.84)	$ -	$ 140.18	$ -	$ 119,858
Total Administrative and General Expense		$ 8,445,363.87	$ 165,517.44	$ 413,924.78	$ (193,274.49)	$ 200,039.86	$ (13,927.18)	$ (1,130,453.80)	$ (4,196.10)	$ 104,938.68	$ -	$ (30,399.84)	$ (29,654.00)	$ 48,945.41	$ -	$ 7,976,825
TOTAL O&M and A&G EXPENSES		$ 13,705,664.17	$ 283,309.43	$ 837,012.43	$ (193,082.46)	$ 200,039.86	$ (13,927.18)	$ (1,130,453.80)	$ 27,139.48	$ 104,938.68	$ (17,195.86)	$ (71,502.71)	$ (172,758.75)	$ 30,492.61	$ -	$ 13,589,676
Taxes Other than Income	408.1	$ 1,807,906.92	$ 41,401.53	$ -	$ 85,782.39	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (10,846.64)	$ (1,153.74)	$ 116,793.00	$ 2,039,883
Depreciation	403	$ 2,292,563.72	$ -	$ -	$ -	$ -	$ -	$ -	$ 237,356.22	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,529,919.94
Asset Removal Costs	403.2	$ 110,267.09	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,863.47	$ -	$ -	$ -	$ -	$ -	$ -	$ 124,130.56

Chesapeake Utilities Corporation
Delaware Division Account Analysis
Summary by FERC
Test Period Adjusted - 12 Months Ended 3/31/2016
Exhibit MD - 2 (Page 2 of 2)

		Test Year Unadjusted	Inflation Adjustment No. 1	Total Payroll & Staffing Adjustment No. 2	Non-Payroll Staffing & Payroll-Related Adjustment No. 3	Benefits Adjustment No. 4	Insurance Adjustment No. 5	ECIS Adjustment No. 6	Depreciation Adjustment No. 7	Regulatory Commission Adjustment No. 8	Bad Debt Adjustment No. 9	Maintenance Adjustment No. 10	GC110 Removal Adjustment No. 11	Misc. Adjustment No. 12	Non-Payroll Taxes Other than Income Adjustment No. 13	Test Period as Adjusted
PRODUCTION																
Liquefied Petroleum Gas Expenses	717															
Operation labor and expenses	841															
Total Production Operations		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Maintenance of Production Equipment	742															
Total Production Expenses		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DISTRIBUTION EXPENSES																
Operation Supervision and Engineering	870															
Distribution Load Dispatching	871															
Mains and Services Expenses	874															
Measuring and Regulating Station Expenses - General	875															
Measuring and Regulating Station Expenses - Industrial	876															
Measuring and Regulating Station Expenses - City Gate	877															
Meter and House Regulator Expenses	878															
Customer Installations Expenses	879															
Other Expenses	880															
Rents	881															
Total Distribution Operations		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Maintenance of Mains	887															
Maintenance of M&R Station Equipment - General	889															
Maintenance of M&R Station Equipment - Industrial	890															
Maintenance of M&R Station Equipment - City Gate	891															
Maintenance of Services	892															
Maintenance of Meters and House Regulators	893															
Maintenance of Other Equipment	894															
Total Distribution Maintenance		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Distribution Expenses		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CUSTOMER SERVICE EXPENSES																
Supervision-Customer Accounting	901															
Meter Reading Expenses	902															
Customer Records & Collection Expenses	903	13,476.38	286.75	-	192.03	-	-	-	-	-	-	-	-	895.48	-	14,850.64
Uncollectible Accounts	904															
Info & Inst Advertising	909															
Total Customer Service Expenses		$ 13,476.38	$ 286.75	$ -	$ 192.03	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 895.48	$ -	$ 14,850.64
SALES																
Demonstrating and Selling Expenses	912															
Advertising Expenses	913															
Total Sales		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ADMINISTRATIVE AND GENERAL EXPENSES																
Administrative and General Salaries	920	$ 1,616,150.32	$ 36,084.90	$ 263,646.24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,915,881.46
Office Supplies and Expenses	921	625,928.93	13,718.06	-	(47,481.61)	-	-	-	-	-	-	-	-	39,821.13	-	631,986.52
Outside Services Employed	923	721,074.83	17,361.66	-	(63,559.42)	-	-	-	-	-	-	-	-	(13,139.03)	-	661,738.05
Property Insurance	924	142.45	3.31	-	(8.35)	-	(15.82)	-	-	-	-	-	-	-	-	121.59
Injuries and Damages	925	6,871.50	145.90	-	477.10	-	413.86	-	-	-	-	-	-	-	-	7,908.36
Employee Pensions and Benefits	926	315,534.10	7,271.70	-	(21,170.70)	100,722.37	-	-	-	-	-	-	-	(30,255.94)	-	372,101.53
Regulatory Commission Expense	928															
General Advertising Expenses	930.1	39,344.64	795.67	-	(2,044.48)	-	-	-	-	-	-	-	-	(16,116.43)	-	21,979.40
Miscellaneous General Expenses	930.2	246,444.46	5,385.76	-	(35,822.84)	-	-	-	-	-	-	-	-	43,462.04	-	259,469.43
Rents	931	67,550.10	1,516.61	-	(6,427.81)	-	-	-	-	-	-	-	-	10,621.33	-	73,260.23
Administrative and General -Operation		$ 3,639,041.33	$ 82,283.58	$ 263,646.24	$ (176,038.10)	$ 100,722.37	$ 398.04	$ -	$ -	$ -	$ -	$ -	$ -	$ 34,393.10	$ -	$ 3,944,446.56
Maintenance of General Plant	932	$ 14,877.37	$ 382.57	$ -	$ (1,495.42)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 140.18	$ -	$ 13,904.70
Administrative and General -Maintenance		$ 14,877.37	$ 382.57	$ -	$ (1,495.42)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 140.18	$ -	$ 13,904.70
Total Administrative and General Expense		$ 3,653,918.70	$ 82,666.15	$ 263,646.24	$ (177,533.52)	$ 100,722.37	$ 398.04	$ -	$ -	$ -	$ -	$ -	$ -	$ 34,533.28	$ -	$ 3,958,351.25
TOTAL O&M and A&G EXPENSES		$ 3,667,395.08	$ 82,952.90	$ 263,646.24	$ (177,341.49)	$ 100,722.37	$ 398.04	$ -	$ -	$ -	$ -	$ -	$ -	$ 35,428.76	$ -	$ 3,973,201.89
Taxes Other than Income	408.1	$ 92,809.46	$ 2,121.20	$ -	$ 24,268.54	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 119,199.20
Total		$ 3,760,204.54	$ 85,074.10	$ 263,646.24	$ (153,072.96)	$ 100,722.37	$ 398.04	$ -	$ -	$ -	$ -	$ -	$ -	$ 35,428.76	$ -	$ 4,092,401.09

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	**)**	
CHESAPEAKE UTILITIES CORPORATION	**)**	
FOR A GENERAL INCREASE IN ITS	**)**	**PSC Docket No. 15-**
NATURAL GAS RATES AND FOR	**)**	
APPROVAL OF CERTAIN OTHER	**)**	
CHANGES TO ITS NATURAL GAS TARIFF	**)**	

DIRECT TESTIMONY OF LISA C. ELDER

On Behalf of Chesapeake Utilities Corporation

Delaware Division

Submitted for filing: December 21, 2015

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

A. My name is Lisa C. Elder, and I am the Director of Financial Reporting and Tax for Chesapeake Utilities Corporation ("Chesapeake"). My business address is 909 Silver Lake Boulevard, Dover, Delaware 19904.

Q. DESCRIBE BRIEFLY YOUR EDUCATION AND RELEVANT PROFESSIONAL BACKGROUND.

A. I received my Bachelor of Science in Accounting from Goldey Beacom College in Wilmington, Delaware in 2000 and my Master of Science in Taxation from the same college in 2015. In addition, I am a Certified Public Accountant, licensed in the state of Delaware, with over 15 years of professional accounting experience. I spent eight of my 15 years of experience in financial accounting, holding positions of Staff Accountant, Senior Financial Reporting and Corporate Accounting Manager. My remaining ten years of experience were in public accounting and cost accounting positions, including Staff Accountant and Senior Accountant. In March 2014, I assumed my current role of Director of Financial Reporting and Tax for Chesapeake Utilities Corporation.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN RATE PROCEEDINGS?

A. I have submitted testimony on behalf of Sandpiper Energy in Case No. 9410, filed with the Maryland Public Service Commission.

Q. WHAT ARE YOUR PRESENT DUTIES AND RESPONSIBILITIES?

A. As Director of Financial Reporting, I am responsible for the Company's external reporting, including earnings releases, Form 10-Q and Form 10-K, and compliance of accounting standards. I am also responsible for income taxes.

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

A. The purpose of my testimony is to provide support for income taxes in the cost of service and deferred income taxes in the rate base.

Q. PLEASE SUMMARIZE THE STATE AND FEDERAL TAXES INCLUDED IN THE COST OF SERVICE.

A. The state and federal income taxes included in the Test Period Cost of Service were calculated using the statutory tax rates for State and Federal income taxes currently in effect for Sandpiper Energy. Additionally, the effect of permanent differences and the amortization of unfunded deferred income tax liabilities were included in the calculation. They are shown on Schedules 3-I, 3-J, and 3-K

Q. PLEASE SUMMARIZE THE STATE AND FEDERAL DEFERRED INCOME TAXES INCLUDED IN THE RATE BASE.

A. The state and federal deferred income taxes included in the rate base are the tax effect of temporary differences between the tax basis of an asset or liability and its reported amount in the financial statements that will result in taxable amounts or deductible amounts in future years when the reported amount of the asset is recovered or when the reported amount of the liability is a settled liability. The temporary differences and their related tax effect are listed on Schedule 3-K.

Q. HOW WERE THE TEST PERIOD ACCUMULATED DEFERRED INCOME TAXES CALCULATED?

A. The Delaware Division calculated the average Test Period Accumulated Deferred Income Taxes by taking the June 30, 2015 balances and forecasting changes to the balances for the period of July 1, 2015 through March 31, 2016. Additionally, deferred income taxes related to un-recovered purchased gas costs were subtracted from the total deferred taxes. The average of the forecasted March 31, 2016 and the actual March 31, 2015 (adjusted for un-recovered purchased gas costs) balances were used as the average Test Period Accumulated Deferred Income Taxes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DATED: DECEMBER 21, 2015

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF LISA C. ELDER

LISA C. ELDER, being first duly sworn according to law, on oath deposes and says that she is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of Lisa C. Elder"; that, if asked the questions which appear in the text of the direct testimony, she would give the answers that are therein set forth; and that she adopts this testimony as her sworn direct testimony in these proceedings.

Lisa C. Elder

Then personally appeared this 21st day of December 2015 the above-named Lisa C. Elder and acknowledged the foregoing Testimony to be her free act and deed. Before me,

REBECCA K. GRIER NOTARY PUBLIC MY COMMISSION EXPIRES ON 07-17-18 STATE OF DELAWARE

Rebecca K. Grier
Notary Public
My Commission Expires: 7-17-18

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	**)**	
CHESAPEAKE UTILITIES CORPORATION	**)**	
FOR A GENERAL INCREASE IN ITS	**)**	**PSC DOCKET NO. 15-**
NATURAL GAS RATES AND FOR	**)**	
APPROVAL OF CERTAIN OTHER	**)**	
CHANGES TO ITS NATURAL GAS TARIFF	**)**	

DIRECT TESTIMONY OF CHRISTOPHER REDD

On Behalf of Chesapeake Utilities Corporation
Delaware Division.

Submitted for filing: December 21, 2015

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

A. My name is Christopher Redd, and I am the Director of Gas Operations and Engineering for Chesapeake Utilities Corporation ("Chesapeake"). My business address is 350 South Queen Street, Dover, Delaware 19904. I support Chesapeake's natural gas distribution businesses in Delaware and Maryland.

Q. DESCRIBE BRIEFLY YOUR EDUCATION AND RELEVANT PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Arts in Accounting from Park University in Parkville, Missouri in 2001 and my Masters in Business Administration from Wilmington University in New Castle, Delaware in 2007. I joined Chesapeake in 2004 and spent 2 years in accounting and analytical roles within the corporate office before joining the Delaware and Maryland distribution segment. I held the position of Senior Business Analyst and Distribution Expansion and Planning Manager before I was promoted to Director of Gas Operations and Engineering in 2011. In my current role I have direct responsibility for engineering, field operations and conversions activities in Delaware and Maryland.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE DELAWARE PUBILIC SERVICE COMMISSION ("COMMISSION")?

A. No, I have not. However, I do have testimony pending before the Maryland Public Service Commission in a base rate proceeding.

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

A. The purpose of my testimony is to provide an overview of Chesapeake's Delaware Division ("Delaware Division" or "the Company") natural gas distribution system as well as discuss the primary reasons for the increase in rate base since the last base rate proceeding.

Q. DESCRIBE DELAWARE DIVISION'S NATURAL GAS DISTRIBUTION SYSTEM.

A. Delaware Division's natural gas distribution system consists of approximately 970 miles of main and 47,000 service lines. The distribution system is interconnected directly with the Eastern Shore Natural Gas transmission pipeline system via sixty (60) metered receipt points.

Q. WHAT AREAS DOES DELAWARE DIVISION SERVE?

A. Delaware Division operates natural gas distribution systems in southern New Castle County, Kent County and Sussex County, Delaware serving residential, commercial, and industrial customers. The majority of those customers utilize natural gas for heat, requiring the Company to build distribution systems that are capable of providing service during extremely cold weather when the demand peaks.

Q. HOW HAS CHESAPEAKE'S RATE BASE CHANGED SINCE ITS LAST RATE

FILING IN 2007 AND WHAT ARE THE PRIMARY REASONS?

A. In its last base rate filing in July 2007, Chesapeake's filed rate base was approximately $43.4 million. As described in the direct testimony of Mr. Matthew Everngam, the rate base in this filing is approximately $70.9 million. The increase has been primarily caused by customer growth and pipeline replacements.

Q. THAT IS A SIGNIFICANT INCREASE IN RATE BASE SINCE 2007. HAS THIS CAPITAL INVESTMENT HAD AN IMPACT ON CUSTOMERS' RATES?

A. Aside from a rate structure designed to facilitate expansion in eastern Sussex County (PSC Docket No. 12-292), until recently the Company has been able to earn a reasonable return on its investment with no impact on our customers' delivery service rates. This has been accomplished through increased revenue from additional customers as well as controlling expenses.

Q. PLEASE EXPLAIN THE INCREASE IN RATE BASE RELATED TO CUSTOMER GROWTH.

A. Since 2007, the number of customers served by Chesapeake has increased from 36,224 in 2007 to 47,013 through November 2015. As a result of this growth, the mains component of plant in service has increased approximately $20.8 million since the rate base rate filing.

Q. WHAT ARE THE REASONS WHY THE DELAWARE DIVISION WOULD

NEED TO REPLACE ITS NATURAL GAS PIPELINES?

A. The majority of the Delaware Division pipe being replaced is unprotected bare steel pipe installed before the 1970's. This type of pipe is particularly subject to the risk of corrosion. This includes both distribution main and services. The Company has also replaced cast iron pipe because this material was used in the early days of providing natural gas supply when manufactured gas was prevalent. Manufactured gas is wetter and allowed the seals to remain more pliable. With the introduction of drier natural gas the unions of cast iron pipe are much more prone to leak. Additionally iron pipe is more susceptible to cracking over time than steel. Other instances that require the Company to replace pipe include pipe relocations for the Delaware Department of Transportation ("DelDOT") and various municipality projects. In these instances, the Company is required to relocate pipe due to road and infrastructure improvement projects.

Q. HOW MUCH BARE STEEL AND CAST IRON HAS BEEN RETIRED SINCE JANUARY 2007?

A. Approximately 27 miles of bare steel and cast iron distribution main have been retired since January 2007. During that same time period over 800 services have been replaced as well.

Q. HOW MUCH HAS BEEN SPENT ON REPLACING PIPE?

A. Delaware Division has spent approximately $10.7 million on main and service replacements from January 2007 through November 2015. We estimate an additional $600,000 will be spent through March of 2016.

Q. HOW DOES THIS EXPENDITURE IMPACT CUSTOMERS' RATES?

A. The replacement of cast iron and bare steel pipe to improve the integrity and safety of the distribution system does not generate additional revenue for the Company. Without new revenues to support the investment, it is reasonable to expect that at some point Customers' rates will need to increase to enable the Company to earn its authorized return on the investment being made to replace this infrastructure.

Q. HOW MUCH BARE STEEL AND CAST IRON MAIN IS REMAINING AS OF NOVEMBER 2015?

A. There is approximately eight (8) miles of bare steel distribution main and 200 bare steel services remaining on Delaware Division's distribution system. All cast iron main has been replaced. The Company anticipates that the majority of this bare steel will be replaced by the end of 2017.

Q. ARE THERE ANY OTHER LARGE CAPITAL EXPENDITURES YOU WOULD LIKE TO MENTION?

A. Yes. Included in the test period rate base is a parcel of land acquired by Chesapeake located in Dover, Delaware. Among other things, Chesapeake intends to build a new administrative and operations facility on this property in the near future. At this time, the Company intends to file a limited issue application seeking recovery of the costs associated with this facility once they are incurred.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DATED: DECEMBER __21__, 2015

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF CHRISTOPHER REDD

CHRISTOPHER REDD, being first duly sworn according to law, on oath deposes and says that he is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of Christopher Redd"; that, if asked the questions which appear in the text of the direct testimony, he would give the answers that are therein set forth; and that he adopts this testimony as his sworn direct testimony in these proceedings.

Chris Redd

Christopher Redd

Then personally appeared this __21st__ day of December 2015 the above-named Christopher Redd and acknowledged the foregoing Testimony to be his free act and deed.

Before me,

REBECCA K. GRIER
NOTARY
PUBLIC
MY COMMISSION
EXPIRES ON
07-17-18
STATE OF DELAWARE

Rebecca K. Grier

Notary Public
My Commission Expires: 7·17·18

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	**)**	
CHESAPEAKE UTILITIES CORPORATION	**)**	
FOR A GENERAL INCREASE IN ITS	**)**	**PSC DOCKET NO. 15-**
NATURAL GAS RATES AND FOR	**)**	
APPROVAL OF CERTAIN OTHER	**)**	
CHANGES TO ITS NATURAL GAS TARIFF	**)**	

DIRECT TESTIMONY OF AUTUMN CHALABALA

On Behalf of Chesapeake Utilities Corporation
Delaware Division.

Submitted for filing: December 21, 2015

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

A. My name is Autumn Chalabala, and I am the Manager of Financial Analysis and Services for Chesapeake Utilities Corporation ("Chesapeake"). My business address is 350 South Queen Street, Dover, Delaware 19904. I support the Company's natural gas distribution businesses in Delaware and Maryland.

Q. DESCRIBE BRIEFLY YOUR EDUCATION AND RELEVANT PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Business Administration with a concentration in Business Management from Pennsylvania State University in York, Pennsylvania in 2000. I received my Masters of Business Administration from Wilmington University in Dover, Delaware in 2012. Prior to joining Chesapeake, I was employed by Sinclair Broadcast Group as the Senior Financial Analyst, Yorktowne Cabinetry, Inc. and USA Direct, Inc. as the Accounting Manager. My career at Chesapeake began in 2010 and I initially held the position of Financial Analyst prior to being promoted to Operations Analysis Manager. I was promoted to Manager of Financial Analysis and Services in 2015. In my current role I have direct responsibility for reviewing and reporting financial activities as they pertain to the operating and capital budgets for the Delaware and Maryland Divisions of Chesapeake and Sandpiper Energy, Inc.

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

A. The purpose of my testimony is to provide an overview of the increased Operations and Maintenance ("O&M") expenses that have been experienced in Chesapeake's Delaware Division ("Delaware Division") since the last Delaware rate case proceeding, which was filed in July of 2007.

Q. PLEASE BRIEFLY DESCRIBE THE CUSTOMER GROWTH EXPERIENCED BY DELAWARE DIVISION.

A. Since the 2007 rate case, Delaware Division has increased its customer base from 36,224 customers in 2007 to 47,013 customers through November 2015. This is an increase of approximately 30%. The growth has been a mix of residential, commercial and industrial customers and has occurred across the service territory.

Q. WHY ARE DELAWARE DIVISION'S O&M COSTS GREATER IN 2015 THAN 2007?

A. Delaware Division O&M costs have increased primarily due to the customer growth previously mentioned, the rising costs of labor and the impact of inflation. Employment and compensation costs continue to grow which includes wages, benefits and labor-related taxes. The general price of goods and services required to provide service to our customers has gradually increased over the past eight years. There are also increased costs associated with meeting regulatory requirements, such as the Distribution Integrity Management plan and Environmental Protection Agency reporting requirements. Specific changes in O&M costs are more thoroughly documented in the direct testimony of Mr. Jeffrey Weiss and Mr. Matthew Dewey.

Q. WHY DOES THE INCREASE IN CUSTOMERS DIRECTLY LEAD TO AN INCREASE IN O&M COSTS?

A. There are a number of costs that are incurred by Chesapeake and are directly impacted by the number of customers on our system. Meter reading costs are a perfect example. Every customer addition adds one more meter that will need to be read every month. Costs related to billing are another example. Each new customer will require 12 additional bills to be mailed each month. A final example is the cost for leak surveys. As our distribution system expands, there are additional surveys to be done.

Q. HAS THE VARIABLE COST PER CUSTOMER INCREASED AS WELL SINCE THE LAST RATE PROCEEDING?

A. Yes. Every year the Company files a report with the Commission outlining the inputs to its Internal Rate of Return Models for that particular year. A component of this filing is the average variable cost per customer addition. It is derived by taking a simple average of the prior three years O&M costs (for accounts deemed “variable”) and dividing that by a three year average of customers. This variable cost per customer has increased from $106 per customer addition in 2007 to $130 per customer in 2015, for an increase of $24 per customer, or a 23% increase in O&M costs.

Q. ARE THERE ANY OTHER TRENDS IN O&M COSTS THAT YOU WOULD LIKE TO MENTION?

A. Yes. The Company is discovering that the level of O&M costs are becoming increasingly more volatile in today's economy. The volatility of O&M costs are difficult to predict and there is a need for revenue stability which is discussed in the testimony of Mr. Ronald Amen. Also, there are large technology projects planned to update or replace the Company's existing technology systems. The request of regulatory treatment for non-capitalized costs associated with the set-up and implementation of new technology is discussed in the testimony of Mr. Matthew Dewey.

Q. PLEASE BRIEFLY DESCRIBE THE VOLATILITY OF O&M COSTS.

A. Vehicle fuel prices are a perfect example demonstrating the volatility of O&M costs. Since the time of the last rate proceeding, vehicle fuel prices have varied from a high of $4.19 per gallon in November 2012 to a low of $2.13 per gallon in May 2011. Vehicle fuel prices are also completely subject to the market and outside of the Company's control.

Q. WHAT IS YOUR CONCLUSION WITH REGARD TO THE DELAWARE DIVISION'S O&M COSTS?

A. The forecast of the costs associated with the O&M of the Delaware Division distribution system are reasonable. These expenses reflect our commitment toward sustaining safe and reliable service to our customers while also striving to control expenses without compromising safety or regulatory compliance.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DATED: DECEMBER 21, 2015

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF AUTUMN CHALABALA

AUTUMN CHALABALA, being first duly sworn according to law, on oath deposes and says that she is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of Autumn Chalabala"; that, if asked the questions which appear in the text of the direct testimony, she would give the answers that are therein set forth; and that she adopts this testimony as her sworn direct testimony in these proceedings.

Autumn Chalabala

Autumn Chalabala

Then personally appeared this 21st day of December 2015 the above-named Autumn Chalabala and acknowledged the foregoing Testimony to be her free act and deed. Before me,

REBECCA K. GRIER
NOTARY
PUBLIC
MY COMMISSION
EXPIRES ON
07-17-18
STATE OF DELAWARE

Rebecca K. Grier

Notary Public
My Commission Expires: 7.17.18

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	**)**	
CHESAPEAKE UTILITIES CORPORATION	**)**	
FOR A GENERAL INCREASE IN ITS	**)**	**P.S.C. DOCKET NO. 15-**
NATURAL GAS RATES AND FOR	**)**	
APPROVAL OF CERTAIN OTHER	**)**	
CHANGES TO ITS NATURAL GAS TARIFF	**)**	

DIRECT TESTIMONY OF SHANE BREAKIE

<u>On Behalf of Chesapeake Utilities Corporation</u>

<u>Delaware Division.</u>

Submitted for filing: December 21, 2015

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Shane Breakie, and my business address is Chesapeake Utilities Corporation, 350 South Queen Street, Dover, Delaware 19904.

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I hold Bachelor of Science Degrees from the University of Delaware in Accounting and in Finance and a Master's Degree in Business Administration from Wilmington University (formerly "Wilmington College"). I began my career at Chesapeake Utilities Corporation ("Chesapeake") in 1993 and have held various positions including Accountant, Accounting Manager, Regional Distribution Customer Service Manager, Director of Consumer Services, and Director of Operations. My current position title is Director of Energy Services and I have held this position since 2009. In this position I support Chesapeake's natural gas distribution businesses in Delaware and Maryland, as well as Sandpiper Energy, Inc.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR ANY OTHER COMMISSION OR REGULATORY BODY?

A. Yes. I have testified previously before the Delaware Public Service Commission on behalf of Chesapeake's Delaware Division (the "Company") in its Gas Sales Service Rate proceeding.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will present several programs designed to facilitate system expansion and any associated changes or additions to the retail gas service tariff of the Company. First, I will discuss the Company's proposal to allow for a financial contribution that may be provided to builders, developers or owners of multi-family housing to offset the initial cost of piping and venting of appliances to individually metered apartments or condominium units, provided that the extension project still generates an internal rate of return ("IRR") that meets or exceeds the Company's authorized rate of return. The Company uses its IRR test to ensure that anticipated revenues from an expansion project warrant the extent of investment required for the project, in accordance with its line extension tariff, as further explained below.

Second, the Company proposes to provide gas compression services to qualified commercial customers under separate, negotiated agreements with the customer. The compression services would be optional for the customer and conditioned upon arrangements mutually satisfactory to the customer and the Company for design, location, construction and operation of the required compression facilities. The compression facilities (*e.g.*, compressors, gas dryers, storage vessels and any other equipment required to supply enhanced gas pressure to the customer's facilities) would be owned, operated and maintained by the Company but located in appropriate areas on the customer's premises. No tariff change is required because each negotiated contract would be subject to separate Commission review, under the existing NCR rate schedule.

Third, the Company proposes a new program applicable to municipalities or incorporated towns (referred collectively as “towns”) seeking to extend gas distribution service into designated areas within the town limits. Pursuant to the rider, towns would submit an application to the Company describing the areas in which they require gas infrastructure. In evaluating the expansion project, the Company would estimate the construction costs and would agree to advance the town that amount to fund the construction of the gas main infrastructure expansion. The town would agree to pay back the amount advanced within a six (6) year period from the time of the installation of the mains. Any delivery service revenues received from customers that connect to the main for gas service within this six (6) year period would be applied toward the amount advanced by the Company. All of the Company’s carrying costs related to the advance for the particular municipal expansion project would be recorded as a regulatory asset and reviewed in the Company’s subsequent rate case for recovery in base rates.

Fourth, the Company proposes to revise its IRR economic test to allow for the costs of utilizing temporary gas storage tanks and equipment conversion costs to be included in the costs of a particular project when construction of the main extension will not be complete by the in-service date for the project. (The temporary gas storage tank typically will be for propane but could also be for compressed natural gas (“CNG”), if CNG is readily available.) The Company submits that a tariff change is not required for it to revise its economic test in this way because its current tariff, at Section 6.2 of the Rules and Regulations, provides that main extensions “are limited to the extent of new investment warranted by the anticipated revenues.” However, by revising its economic test as part of this rate case, the Company is seeking a finding that, moving forward, such costs (if reasonable in amount) may be capitalized as part of the expansion project and will be recoverable in rate base. By allowing recovery of the costs associated with temporary gas storage facilities, new residential developments or businesses will be able to benefit from gas even if the gas lines are not complete by the in-service date for the new construction.

Fifth, the Company proposes to make a modification to the eligibility criteria for Transportation services specifically for the growers within the poultry industry. The Company proposes to allow the poultry house grower accounts to transport if the sum of their consumption for all of their accounts is greater than 30,000 CCF per year.

Sixth, the Company is proposing minor changes to its tariff to enable it to sell or deliver natural gas to compressed natural gas (“CNG”) providers, without violating the general prohibition on “sales for resale” included in its tariff.

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. The proposed tariff changes are contained in the redlined tariff within this application. Specific tariff sheets are; Sheets No. 12.1 and 43.

Q. PLEASE EXPLAIN THE PROPOSED MULTI-FAMILY HOUSING PROGRAM.

A. The Company proposes to provide a per-unit financial contribution to the builders, developers, or owners of multi-family housing on a project-specific basis that would offset the initial cost of venting of gas appliances and gas piping to individually metered apartments or condominium units. The Company would provide the contribution only if the total investment required for the project, including any contribution, meets the Company's IRR economic test. In other words, the contribution will only be available when the project produces sufficient revenue to justify the total investment required, including the contribution, which will ensure that existing customers do not subsidize the multi-family housing project. The proposed tariff language establishing the program is included under the Rules and Regulations under the existing Section 6.2 Main Extensions – New Residential Development.

Q. AGAIN, PLEASE DESCRIBE THE COSTS TO WHICH THE CONTRIBUTION MAY BE APPLIED.

A. The contribution will only be permitted to offset the costs of: (1) venting gas appliances and (2) the associated gas piping of the multi-family unit under consideration. The contribution will not be applicable to any costs associated with the procurement of gas appliances.

Q. PLEASE EXPLAIN HOW THE PROPOSED MULTI-FAMILY HOUSING PROGRAM WILL OPERATE.

A. The Company will evaluate each multi-family housing project as it currently does; that is, using its IRR test to determine whether an extension project is "economic." A project is economic if the IRR test demonstrates that the anticipated revenues from the project produce a rate of return on the required investment for the project at least equal to the Company's authorized rate of return. Under the proposed tariff change, if the project's rate of return is determined to be greater than the Company's authorized rate of return, then the Company could provide a contribution toward the builder's cost of gas piping and venting in an amount up to, but not in excess of, the calculated overage. If the project fails to pass the IRR economic test, then no contribution can be provided. Any authorized contribution will only be provided once the Company has verified all costs associated with the project. For a housing project to be considered "multi-family housing" it must have a least four (4) individually metered dwelling units per building.

Q. WHAT MARKET PROBLEMS DOES THIS PROPOSAL ADDRESS?

A. Historically, multi-family housing developers have been reluctant to include gas within their new units due to the upfront costs associated with installing gas facilities in a building, which can be considerable. These costs are attributable to the extensive additional piping required throughout a multi-family building and the necessary venting related to the gas appliances. These upfront costs represent the primary impediment for multi-family unit developers that may want to provide units with gas.

Q. DOES THIS PROPOSAL PROVIDE OTHER BENEFITS TO CUSTOMERS?

A. Yes. This multi-family housing incentive will facilitate tenant access to a clean and low cost energy source when compared to electricity and other forms of energy. Given the abundance of natural gas, the cost advantages of natural gas are expected to continue for the foreseeable future. The multi-family housing sector provides a solution for many limited income households and first-time home buyers. The lower energy bills associated with natural gas will provide a particular economic benefit to this population. Furthermore, qualified income eligible customers may also have access to the Chesapeake Emergency Energy Recipient Program, also known as Sharing, which can provide grants to assist them with their energy bills in times of need.

Q. WILL THE MULTI-FAMILY HOUSING PROGRAM PROVIDE ANY BENEFITS TO EXISTING CUSTOMERS?

A. Yes. Growing the number of gas customers, within the parameters of the Company's IRR economic test, allows the fixed costs of the Company to be spread across a larger customer base. This should result in lower rates, over time, than otherwise would result from a stagnant or declining customer base. With only a limited number of multi-family units signing up for gas service, the Company's existing customers have a large untapped source of additional customers over which fixed costs can be allocated.

Q. HAS THE COMMISSION APPROVED ANY PROGRAM SIMILAR TO THE MULTI-FAMILY HOUSING PROGRAM?

A. Chesapeake is not aware of any similar programs in Delaware. In Maryland, however, in Case No. 9322, the Proposed Order of the Public Utility Law Judge (dated October 10, 2013) approved a similar multi-family housing program proposed by Washington Gas & Light Company. No party to that case objected to the program and no party appealed that part of the Proposed Order. (See ML# 150004, at pages 138-139.)

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO OFFER COMPRESSED NATURAL GAS SERVICE UNDER NEGOTIATED RATES.

A. The Company is proposing to offer a compression service under negotiated contract terms that will allow customers to realize the economic and environmental benefits of gas usage in lieu of other energy sources. Specifically, the Company is seeking authority to include in rate base the cost-effective construction costs of Company-owned and maintained compression facilities that may be used to support industrial compressors, gas dryers, storage vessels and any other equipment necessary to provide gas pressure to a commercial customer's facilities at the times and levels required by the customer.

Under the proposed NCR offering, The Company will construct, own and operate equipment associated with the compression of gas in order to meet the pressure demands specified by the customer. The terms of the particular arrangement with a compression service customer will be agreed upon in advance between the customer and the Company. The contract terms with the compression customer will include the rate components, compression requirements and payment terms.

Specifically, the Company and the compression customer will negotiate a rate structure based on the Company's expected cost of service over a period agreed upon by the parties. The rate structure shall be designed to recover costs including, but not limited to, depreciation, returns on capital, income taxes, property taxes, O&M expense, repair expense, A&G expense, franchise fees, uncollectibles and insurance. Upon early termination of the compression services agreement for any reason (other than the Company's default), the Company shall recover from the customer an amount based on the Company's unrecovered ownership and removal costs and any early-termination provisions in the Company's subcontracts.

The proposed tariff language establishing the program is included under the Rules and Regulations under the existing Section 6.2 Main Extensions – Commercial and Industrial Main Extensions.

Q. WHAT PROBLEM IS THE NEW COMPRESSION SERVICE DESIGNED TO ADDRESS?

A. This compression service offering is designed to address one of the most significant hurdles faced by commercial customers seeking gas service – the significant up-front costs of building and operating compression facilities.

Q. HOW DOES THE COMPANY'S COMPRESSION SERVICE NCR RELATE TO THE STANDARD IRR ECONOMIC TEST APPLIED TO NEW CUSTOMERS UNDER THE EXISTING TARIFF?

A. If the Company provides a facilities extension and the compression equipment needed to provide the required pressure, the Company would use the same IRR calculation as the economic test to examine whether to construct the extension. The Company's proposed new NCR offering would allow the customer to repay the costs (including carrying costs on the unpaid balance) of furnishing the compression and associated facilities over the agreed upon time period (*e.g.*, 10 years) rather than entirely upfront. Again, the application of the IRR economic test protects existing customers from subsidizing compression service customers.

Q. HAS THE COMMISSION APPROVED ANY PROGRAM SIMILAR TO THE COMPRESSION SERVICE OFFERING?

A. Chesapeake is not aware of any similar programs in Delaware. In Maryland, however, in Case No. 9322, the Proposed Order of the Public Utility Law Judge (dated October 10, 2013) approved a compression service offering proposed by Washington Gas & Light Company, including combined heat and power energy production services. (See ML# 150004, at pages 139-141.)

No party to that case objected to the compression service offering and no party appealed that part of the Proposed Order.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO IMPLEMENT A MUNICIPAL NATURAL GAS INFRASTRUCTURE EXPANSION PROGRAM.

A. The proposed program will provide a potential solution to those municipalities or incorporated towns (referred collectively as "towns") seeking to extend natural gas distribution service into designated areas within the town limits. Pursuant to the program, towns would have the option of submitting an application to the Company describing the areas in which they require natural gas infrastructure. In evaluating the expansion project, the Company would obtain a cost estimate to construct the facilities requested and would agree to advance the town that amount to fund the construction of the gas main infrastructure expansion. The town would agree to pay back the amount advanced within a six (6) year period from the time of the installation of the mains. Any Delivery Service Revenues received from customers that tie into the main for gas service within this six (6) year period would be applied toward the amount advanced by the Company. At the expiration of the six (6) year period, the Company will compare the amount advanced to the town (*i.e.*, six times the expected revenues) with the amount actually spent by the Company. If the actual investment exceeds the amount of the funds advanced, then the town will pay the difference.

Although the proposed advance and repayment structure already fits with existing tariff language of its Rules and Regulations, at Section 6.3 Financial Guarantees, the Company seeks Commission approval to create a regulatory asset for the Company's carrying costs related to the advance, which will be reviewed in the Company's subsequent rate case for recovery in delivery service rates.

Q. WHY IS THE COMPANY PROPOSING THE MUNICIPAL GAS INFRASTRUCTURE EXPANSION PROGRAM?

A. The program is designed to support economic development in towns and municipalities that seek natural gas service and to provide energy savings to their residents and businesses. The Company understands that the availability of natural gas in an area is a significant factor that new home developers and businesses consider when deciding where to locate. The program is completely voluntary on behalf of the towns. Moreover, the expansion program will allow the towns to provide low-cost natural gas to customers in areas that would otherwise not be served including those in urban areas with fixed or limited incomes or in assisted living facilities. In return, the town will receive the benefit of additional property taxes and potentially increased property values created by the introduction of natural gas to the area.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR A TEMPORARY GAS STORAGE TANK PROGRAM.

A. The Company proposes to include the costs of utilizing temporary propane (or CNG) gas storage tanks and associated equipment conversion costs related to a particular project when performing the applicable economic test under the

Company's line extension tariff. Equipment conversion costs can include the costs associated with switching the appliances from propane to natural gas when that appliance is temporarily setup to use propane during the interim time period after a new home or business has been constructed but before the natural gas infrastructure to the new home or business is complete. Under the proposal, the Company will only be allowed to proceed with a particular project if the anticipated revenues exceed the cost of the investment under the applicable economic test - inclusive of the additional costs for the temporary storage tanks and equipment conversions.

Q. WHY IS THE COMPANY PROPOSING THIS REVISION/CLARIFICATION?

A. As the Company has expanded into the lower eastern shore area, interest in, and the demand for, natural gas has increased significantly. Recently, the construction of new homes on the Delmarva Peninsula have increased and, in response, the Company is preparing to accelerate its main extension construction program. Moreover, construction and building restrictions in certain resort areas in Sussex County limit the periods during the calendar year which the Company is authorized to perform the roadwork necessary to install its mains. Since much of the potential expansion is located in the resort areas, this restriction further complicates the Company's ability to extend gas mains to these newly constructed homes in a timely manner.

Q. WHY SHOULD THE COMMISSION APPROVE THIS REQUEST?

A. Again, the costs for utilizing temporary gas storage tanks and the conversion of the equipment may only be included if their inclusion either meets the six (6) times net revenue test or the IRR test, depending on which test is applicable under the tariff. If the project meets the applicable economic test, then existing customers will not be subsidizing any of the costs for the particular extension project. In addition, the proposal is intended for those projects that the Company estimates completion of the main installation within one (1) year from the date of the request but may be delayed due to permitting, weather, or restrictions during the summer vacation period while the homes are being constructed. By revising its economic test in this manner as part of this rate case, the Company is seeking a finding that, moving forward, such costs (if reasonable in amount) will be recoverable in rate base.

While the Company does not believe that a tariff change is necessary to implement this program, the Main Extension Policies on file with the Commission, which originated as Exhibit A to the settlement agreement adopted in Docket No. 12-292, may need to be amended to specify that the temporary storage tank and equipment conversion costs are appropriate costs for inclusion in the economic analysis.

Q. PLEASE DESCRIBE YOUR PROPOSAL TO MODIFY THE TRANSPORTATION SERVICE CRITERIA FOR POULTRY HOUSE ACCOUNTS.

A. The Company is proposing to modify its transportation service criteria to allow the poultry houses that are set up under a common name for billing purposes to aggregate their consumption for purposes of meeting the 30,000 CCF usage requirement for eligibility for transportation service. The proposed tariff change is included on Section 1.1 of the Transportation and Balancing Rider, at Sheet 43.

Q. WHY IS THE COMPANY PROPOSING TO MAKE THIS CHANGE?

A. The poultry industry provides significant benefits to the regional economy encompassing Delaware and the Delmarva Peninsula. Several large poultry companies operate in the region including Perdue, Mountaire Farms, Allen Harim, Amick Farms and Tyson Foods. Over the past few years, the poultry companies located on the Delmarva Peninsula have converted nearly all of their large processing plants, feed mills and grain dryers to natural gas. The owners/operators of several poultry houses have contacted the Company requesting natural gas for their facilities. Per the Delmarva Poultry Industry there are over 1,700 growers on Delmarva with over 5,000 poultry houses. However, the poultry houses typically do not meet the current minimum usage requirements for qualification of transportation service. Modifying the criteria so that the poultry houses can transport allows the poultry industry to have longer term control over their costs. Currently a single poultry farm with multiple houses most likely will not meet the minimum volumetric requirement but allowing those under the same account name to aggregate will increase their ability to utilize transportation services.

Q. PLEASE DESCRIBE THE PROPOSED TARIFF CHANGES RELATING TO CNG SERVICES.

A. The current tariff permits “sales for resale” of natural gas when a customer makes a “retail sale as a fuel to natural gas vehicles.” This language appears in the Rate Schedules for all commercial and industrial classes under the “Special Terms and Conditions of Service.” This allowance for vehicle fuel is an exception to the general prohibition on “sales for resale” (appearing in Sections 10.3 and 16.1) and enables CNG providers to sell CNG as vehicle fuel. The Company proposes to expand this exception to include customers who transport or sell the natural gas as CNG to third parties.

If approved, the tariff change would enable owners or operators of CNG facilities (or CNG transportation providers) to be sales or transportation customers of the Company and to compress the natural gas and/or transport the CNG to third parties that are not connected to a natural gas transmission or distribution system. In addition to modifying the Special terms and Conditions for each commercial and industrial customer class to include CNG deliveries by truck to end users, the Company proposes to revise Section 10.3 of the Rules and Regulations of the Tariff to clarify that the prohibition on sales for resale only applies “unless otherwise specified in the Tariff.” The “unless otherwise specified in the Tariff” language also appears in Section 16.1 Definition of the Term “Customer” and, if added to Section 10.3, will clarify that resales of CNG as vehicle fuel or to end users are permitted.

Q. AS AN ENERGY SOURCE, DOES NATURAL GAS COMPARE FAVORABLY TO OTHER ENERGY SOURCES SUCH AS ELECTRICITY?

A. Yes. Generally, natural gas retains approximately 90% of its energy value during the process required to extract, process and deliver gas to the customer. On the other hand, electricity retains roughly 30% of its energy value from its source to end-use by the customer (due to its physical properties, a significant amount of energy is lost when transmitting electrical power over long distances). As a result, natural gas utilized for space or water heating is significantly more efficient than the use of electricity for the same purpose.

In addition, natural gas exhibits environmental advantages because it is clean burning. In fact, natural gas is significantly cleaner than carbon intense fossil fuels because it is composed chiefly of methane (the simple chemical composition of natural gas is one carbon atom and four hydrogen atoms). When methane is burned completely, the principal products of combustion are carbon dioxide and water vapor. The advantages of natural gas over other fuels include that it has fewer impurities and is less chemically complex, which results in a combustion process that generally produces less pollution. In most applications, using natural gas results in less of the following substances than oil or coal: carbon dioxide (CO_2) (which is the primary greenhouse gas); sulfur dioxide (which is the primary cause of acid rain); nitrogen oxides (which is the primary cause of smog); and particulate matter (which can affect health and visibility).[1] Advances in technology allow for cleaner energy production than

[1] Source: Energy Information Administration (www.eia.doe.gov).

ever before for all fuels, but the inherent cleanliness of natural gas demonstrates its worth as the preferred fuel option.

Due to the ability to harness supply resources such as the Marcellus Shale, natural gas is more abundant locally than ever before. This abundance is likely to keep gas commodity prices low for the foreseeable future. The advantages relating to energy efficiency, fewer environmental emissions and low prices support the Commission's approval of all of the programs, and related tariff changes, described herein.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

DATED: DECEMBER 21, 2015

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF SHANE BREAKIE

SHANE BREAKIE, being first duly sworn according to law, on oath deposes and says that he is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of Shane Breakie"; that, if asked the questions which appear in the text of the direct testimony, he would give the answers that are therein set forth; and that he adopts this testimony as his sworn direct testimony in these proceedings.

Shane Breakie

Then personally appeared this 21st day of December 2015 the above-named Shane Breakie and acknowledged the foregoing Testimony to be his free act and deed. Before me,

REBECCA K. GRIER NOTARY PUBLIC MY COMMISSION EXPIRES ON 07-17-18 STATE OF DELAWARE

Rebecca K. Grier
Notary Public
My Commission Expires: 7·17·18

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	**)**	
CHESAPEAKE UTILITIES CORPORATION	**)**	
FOR A GENERAL INCREASE IN ITS	**)**	**PSC DOCKET NO. 15-**
NATURAL GAS RATES AND FOR	**)**	
APPROVAL OF CERTAIN OTHER	**)**	
CHANGES TO ITS NATURAL GAS TARIFF	**)**	

DIRECT TESTIMONY OF KATHRYN G. McVAY

On Behalf of Chesapeake Utilities Corporation

Delaware Division

Submitted for filing: December 21, 2015

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

A. My name is Kathryn G. McVay and I am an independent consultant for Chesapeake Utilities Corporation (“Chesapeake”). My business address is 701 Spinnaker Street, Middletown, Delaware 19709.

Q. DESCRIBE BRIEFLY YOUR EDUCATION AND RELEVANT PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science Degree in Commerce (Accounting major) from the University of Virginia and a Masters of Business Administration from Virginia Commonwealth University. I am also a Certified Public Accountant. From 1978 to 1983 I was employed by Price Waterhouse in the Audit Department. From 1983 to 1989 I was employed as an Internal Audit Manager at Best Products, Inc. I worked as an accounting recruiter for Don Richard Associates during 1990 – 1991. I was hired by Chesapeake Utilities Corporation as Director of Internal Audit in April of 1991 and was promoted to Corporate Controller in 2001. In May 2005, I became an independent contractor and have been performing consulting work on a part-time basis.

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

A. The purpose of my testimony is to request authorization to use deferral accounting and to create a regulatory asset or regulatory liability to record charges or credits that would have otherwise been recorded in equity pursuant to the balance sheet treatment required by the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Section 715 Compensation – Retirement Benefits, ASC 715-30-25-1 and ASC 715-60-25-1 (formerly included in Statement of Financial Accounting Standards ("SFAS") No. 158). Additionally, Chesapeake Utilities Corporation respectfully requests that the Commission acknowledge that, if amounts represented by the establishment of regulatory assets or liabilities pursuant to this order were to be recognized in expense through a future curtailment, settlement or termination event under ASC 715-30 and ASC 715-60, the recognized costs would be includable as a cost of service for ratemaking purposes, subject to the Commission's normal ability to review the amounts for reasonableness.

Q. DO YOU SPONSOR ANY ATTACHMENTS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I do. Attachment KGM-1 displays the journal entries that are required in order to comply with ASC 715 and the journal entries that Chesapeake Utilities Corporation is seeking the Commission's approval to create in order to record the regulatory asset or regulatory liability for its Delaware Division related to the unfunded liability of Pension, Deferred Compensation and Other Post-Retirement Benefits.

Q. PLEASE EXPLAIN THE REASON YOU ARE REQUESTING APPROVAL FOR THE DEFERRAL ACCOUNTING AND REGULATORY TREATMENT OF PENSION, DEFERRED COMPENSATION AND OTHER POST RETIREMENT BENEFITS.

A. The Company's financial reporting is governed by Generally Accepted Accounting Principles ("GAAP"), of which the ASC is a part. ASC 715-30-25-1 requires employers to recognize a liability that equals the unfunded projected benefit obligation, if the projected benefit obligation exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation, the employer shall recognize an asset that equals the overfunded projected benefit obligation. At the time of Chesapeake's last rate case, interest rates were relatively stable. Since then, there has been significant volatility in interest rates, which impacts the discount rates used to calculate pension liabilities. This has created volatility in the Accumulated Other Comprehensive Income and Pension liability accounts. Looking forward, the recent increase in interest rates by the Federal Open Market Committee of the Federal Reserve and their comments surrounding future changes in rates, suggest that volatility will continue. Adopting deferral accounting would eliminate this volatility in the equity accounts.

Q. WHAT ARE THE REQUIREMENTS FOR ADOPTING DEFERRAL ACCOUNTING?

A. ASC 980 Regulated Operations (formerly Statement of Accounting Standards No. 71) allows regulated companies to defer costs and create regulatory assets provided the regulatory agency grants authority for such a deferral. As stated in ASC 980-10-05-5 and ASC 980-10-05-6:

"Regulators sometimes include costs in allowable costs in a period other than the period in which the costs would be charged to expense by an unregulated entity. For the regulated entity, that procedure can do any of the following:

a. create assets (future cash inflows that will result from the rate-making process)
b. reduce assets (reductions of future cash inflows that will result from the rate-making process)
c. create liabilities (futures cash outflows that will result from the rate-making process).

For general-purpose financial reporting, an incurred cost for which a regulator permits recovery in a future period is accounted for like an incurred cost that is reimbursable under a cost-reimbursement-type contract."

Additional qualification requirements are stated in ASC 980-340-25-1:

"Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:

a. It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes.

b. Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost."

Chesapeake Utilities Corporation is requesting approval of deferral accounting and acknowledgement of the likelihood of recovery of the previously incurred pension, deferred compensation and other post-retirement benefit costs in order to meet the requirements of ASC 980-340-25-1.

Q. WHAT ARE THE KEYCONSIDERATIONS IN CONCLUDING THAT PENSION DFERRAL MEETS THE REQUIREMENT OF ASC 980-340-25-1?

A. In order to demonstrate that pension deferral meets the requirements of ASC 980-340-25-1, Chesapeake must demonstrate that it is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes. In Chesapeake's prior rate filing, it included pension costs calculated in accordance with ASC 715 Compensation – Retirement Benefits. The Commission has not disallowed inclusion of pension costs in prior rate cases. At this time, we are asking the Commission to confirm that their current practice is to allow in rates pension costs calculated in accordance with ASC 715. Additionally we are asking for confirmation that, if amounts represented by the establishment of regulatory assets or liabilities pursuant to this order were to be recognized in expense through the operation of the pension expense calculation or a subsequent curtailment, settlement or termination event under ASC 715-30 and ASC 715-60, the Commission would allow these costs to be included in determining rates. Recovery of such costs would be subject to the Commission's normal ability to review the amounts for reasonableness.

Q. WILL ADOPTION OF DEFERRAL ACCOUNTING AND THE CREATION OF A REGULATORY ASSET OR REGULATORY LIABILITY CHANGE EXPENSE RECOGNITION FOR PENSION, DEFERRED COMPENSATION OR OTHER POST-RETIREMENT BENEFITS?

A. No, adoption of deferral accounting and the creation of a regulatory asset does not change expense recognition for pension, deferred compensation or other post-retirement benefits.

Q. WHAT DEFINED BENEFIT PLANS DOES CHESAPEAKE UTILITIES CORPORATION SPONSOR?

A. Chesapeake sponsors a defined benefit pension plan, a defined benefit deferred compensation plan and a postretirement health care and life insurance plan. The defined benefit pension plan and the defined benefit deferred compensation plans have been frozen since December 31, 2004 and future benefits under these plans are no longer increasing due to years of service or pay increases. The postretirement healthcare and life insurance plans were modified as of

January 1. 1994. At that time, employee contributions were increased for future participants. Employees who had achieved 20 years of service and attained age 55 on that date would be required to pay 25% of the insurance cost, employees who had achieved 20 years of service, but were not yet 55, would be required to pay 50% of the cost and employees who did not meet that criteria would be eligible to participate, but must pay 100% of the cost of the insurance. There was no change to the benefits of those who retired prior to January 1, 1994. Chesapeake's plan requires all retirees eligible for Medicare to use Medicare as their primary insurance. Participation in the retiree healthcare plan is optional.

Closing

Q. IS THE INFORMATION SET FORTH IN SCHEDULE KGM-1 TRUE AND CORRECT TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes, it is.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DATED: DECEMBER 21, 2015

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF KATHRYN G. MCVAY

KATHRYN G. MCVAY, being first duly sworn according to law, on oath deposes and says that she is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of Kathryn G. McVay"; that, if asked the questions which appear in the text of the direct testimony, she would give the answers that are therein set forth; and that she adopts this testimony as her sworn direct testimony in these proceedings.

Kathryn G. McVay

Kathryn G. McVay

Then personally appeared this 21st day of December 2015 the above-named Kathryn G. McVay and acknowledged the foregoing Testimony to be her free act and deed.

Before me,

REBECCA K. GRIER NOTARY PUBLIC MY COMMISSION EXPIRES ON 07-17-18 STATE OF DELAWARE

Rebecca K. Grier

Notary Public

My Commission Expires: 7·17·18

Attachment KGM-1

Proposed Accounting Entries

The following journal entries are required to record the unfunded liability for Pension, Deferred Compensation and Other Post-Retirement Benefits. These unfunded liabilities represent the excess of the Projected Benefit Obligation (for Pension and Deferred Compensation) and Accumulated Post-Retirement Benefit Obligation (for Other Post-Retirement Benefits) over the fair value of plan assets for the Pension and the recorded benefit liabilities for the Deferred Compensation and Other Post-Retirement Benefits Plans, which are unfunded.

		Dr.	Cr.
219	Accumulated Other Comprehensive Income (after tax)	X	
182	Regulatory tax asset – SFAS No. 158-related (tax effect)	X	
228	Liabilities for Pension & Deferred Compensation		X
228	Liability for Other Post-Retirement Benefits (SFAS No. 106)		X

The following journal entries would be made to reclassify the after-tax amounts charged from Accumulated Other Comprehensive Income to a Regulatory Asset.

		Dr.	Cr.
182	Regulatory asset – benefit related	X	
219	Accumulated Other Comprehensive Income		X

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
CHESAPEAKE UTILITIES CORPORATION	)	
FOR A GENERAL INCREASE IN ITS	)	PSC Docket No. 15-XXX
NATURAL GAS RATES AND FOR	)	
APPROVAL OF CERTAIN OTHER	)	
CHANGES TO ITS NATURAL GAS TARIFF	)	

DIRECT TESTIMONY OF JOHN D. TAYLOR

On Behalf of Chesapeake Utilities Corporation

Delaware Division

Submitted for filing: December 21, 2015

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. My name is John D. Taylor and my business address is 14401 Lamar Avenue, Overland Park, KS 66211.

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

A. I am employed by Black & Veatch Corporation ("Black & Veatch") as a Project Manager in the Finance & Regulatory Services Practice of Black & Veatch's Management Consulting group. Black & Veatch is a leading provider of consulting services to electric and gas utilities and other energy-related and network businesses.

Q. Please describe the firm of Black & Veatch.

A. Black & Veatch has provided comprehensive engineering and management services to utility, industrial, and governmental entities since 1915. Its Management Consulting Division delivers management consulting solutions in the energy and water sectors. Our services include broad-based strategic, regulatory, financial, and information systems consulting. In the energy sector, Black & Veatch Management Consulting delivers a variety of services for companies involved in the generation, transmission, and distribution of electricity and natural gas. From an industry-wide perspective, Black & Veatch has extensive experience in all aspects of the North American natural gas industry, including utility costing and pricing, gas supply and transportation planning, competitive market analysis and regulatory practices and policies gained through management and operating responsibilities at gas distribution, pipeline and other energy-related companies, and through a wide variety of client assignments. Black & Veatch has assisted numerous gas distribution companies located in the U.S. and Canada.

Q. Please describe your professional background and education.

A. As a Principal Consultant with Black and Veatch I am involved in a variety of energy and utility related projects regarding matters pertaining to economics, finance, and public policy. This includes: asset divestitures, allocated class cost of service studies, rate of return, cash working capital, tax litigation, rate design analysis, auction analysis, and affiliate cost allocation. Part of my role within these projects is to conduct various analyses which take into account both accounting and financial considerations and the particular operational configuration of a company's assets. This includes studies such as: allocated class cost of service studies; valuation modeling; affiliate cost allocation; and various cost of service analyses. I have filed testimony on class cost of service studies as well as statistical audit sampling. I have filed expert testimony in Indiana, Maine, Minnesota, Illinois, and Pennsylvania. I began my education studying electrical and mechanical engineering and worked for an industrial inspection company which provided me with hands on experience with utility assets and equipment. I received an undergraduate degree in Environmental Economics, with an emphasis in econometrics and regulatory policy. I also earned a Masters in Economics from American University in Washington, D.C. A copy of my resume is provided as Appendix A.

Q. What is your assignment in this proceeding?

A. Black & Veatch has been retained by Chesapeake Utilities Corporation's Delaware Division ("Chesapeake" or the "Company") as a consultant in the area of utility costing and rate design and related regulatory matters. Among the varied consulting support for Chesapeake's general rate case, Chesapeake has requested that we assist the Company by conducting an Allocated Cost of Service Study (ACOSS) for which I am sponsoring.

II. Purpose of Testimony

Q. What is the purpose of your direct testimony in this docket?

A. First, I will discuss various principles of cost allocation and factors that influence the cost allocation framework; as well as, general methods and approaches used to allocate costs to customer classes. Second, I will discuss the underlying methodology and basis used in the ACOSS studies I conducted and am sponsoring. I will describe the studies of relative costs and other analyses employed to apportion the various categories of plant and operation and maintenance ("O&M") expenses to the respective customer classes. I will present the class-by-class rate of return results and corresponding revenue surpluses or deficiencies from the ACOSS.

Q. Mr. Taylor, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Exhibits JDT-1, JDT-2, and JDT-3.

Q. Would you briefly describe the contents of Exhibits JDT-1, JDT-2, and JDT-3?

A. Exhibit JDT-1 contains the class-by-class rate of return results and corresponding revenue surpluses or deficiencies from the ACOSS for the test year and test period. The studies contained in Exhibit JDT-2 are based on costs and operating conditions for the test period ended March 31, 2016. This exhibit provides a summary of the results, a printout of the cost assignment and allocation detail, and supporting schedules showing functionalization of the costs and the cost allocation factors used. Exhibit JDT-3 provides additional descriptions and backup material used in the development of the functionalization of Distribution Mains and the development of allocation factors. The results of these studies were applied to expenses and plant balances for the test year and the test period.

III. Overview of ACOSS

Q. Please describe the general approach used to develop the ACOSS?

A. In this proceeding, the purpose of the ACOSS is to allocate Chesapeake's Delaware Division's overall adjusted revenues and costs to the various classes of service in a manner that reflects the relative costs of providing service to each class. This is accomplished through analyzing costs and assigning each customer or rate class its proportionate share of the utility's total revenues and costs within the historical test year and the partially forecasted test period. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility. In order to allocate costs to the various classes, I reviewed Chesapeake's expense and plant accounts and developed studies of the relative costs of providing facilities and services for each rate class and analyzed the key factors that cause the costs to vary.

Q. Please describe the model that was used in conducting the ACOSS filed in this proceeding.

A. I used the same model in this proceeding as was used in the Company's 2001 and 2007 rate filings; a Cost of Service Model purchased by Chesapeake from Navigant Consulting, Inc.

Q. Is the preparation of a cost allocation study an exact science?

A. No, it is not. The fundamental purpose of a cost allocation study is to aid in the design of rates to be charged by identifying all of the capital and operating costs incurred by a utility to provide service to all of its customers, and then assigning or allocating those costs to individual rate classes on the basis of how those rate classes cause the costs to be incurred. This process inherently requires a substantial level of judgment and can be more accurately described as engineering/accounting art, rather than science. Although there may be no single, absolutely perfect methodology for allocating costs, there are certain fundamental and foundational principles, i.e., cost causation and consistency that should be followed in order to produce more accurate and reasonable results. As described in further detail below, Chesapeake's cost allocation studies follow these principles.

Q. What is the guiding principle that should be followed when performing an ACOSS?

A. Cost causation is the fundamental principle applicable to all cost studies for purposes of allocating costs to customer groups. Cost causation addresses the question of which customer or group of customers causes the utility to incur particular types of costs. In order to answer this question, it is necessary to establish a relationship between the services used by a utility's customers and the particular costs incurred by the utility in serving those customers. In other words, the costs assigned or allocated to particular customers should be those costs that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service.

Q. What are the steps to performing an ACOSS?

A. In order to establish the cost responsibility of each customer class, a three step analysis of the utility's total operating costs must first be performed. The three steps which are the predicate for an ACOSS are: (1) cost functionalization; (2) cost classification; and (3) cost allocation. The first step, functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. The Company's functional cost categories associated with gas service include: production and gathering, transmission, distribution and general. Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost-defining characteristics previously discussed: (1) customer, (2) demand or capacity, and (3) commodity. The final step is the allocation of each functionalized and classified cost element to the individual customer class. Costs typically are allocated on customer, demand, commodity or revenue allocation factors.

Q. How does one establish the cost and utility service relationships you previously discussed?

A. To establish these relationships, the Company must analyze its gas system design and operations, its accounting records as well as its system and customer load data (e.g., annual and peak period gas consumption levels). From the results of those analyses, methods of direct assignment and "common" cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q. Please explain what you mean by the term "direct assignment."

A. The term "direct assignment" relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing an ACOSS, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups to avoid the need to rely upon other more generalized allocation methods.

Direct assignments of plant and expenses to particular customers or classes of customers are generally made on the basis of special studies wherever the necessary data are available. These assignments are developed by detailed analyses of the utility's maps and records, work order descriptions, property records and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint use plant.

Q. Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned?

A. No. The nature of utility operations is characterized by the existence of common or joint use facilities. Out of necessity, then, to the extent a utility's plant and expense cannot be directly assigned to customer groups, common allocation methods must be derived to assign or allocate the remaining costs to the customer classes.

Q. What is required to appropriately classify costs as Customer, Demand, and Commodity?

A. Usually a determination on the classification of costs can be made simply by knowing the type of expense related activities or utility plant assets that reside in a particular FERC account. In these instances the account as a whole can be classified. However, for some FERC account functions it is beneficial to conduct classification studies which determine which portion of an account is associated with each classification.

III. Black and Veatch's ACOSS

Q. What is the source of the cost data analyzed in Chesapeake's ACOSS?

A. All cost of service data have been extracted from the Company's total cost of service (i.e., basic rate revenue requirement) contained in this general rate case filing for the test year ending June 30, 2015, the partially forecasted test period ending March 31, 2016. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data was derived from the historical books and records of the Company and information provided by company personnel.

Q. How are the rate classes structured for purposes of the ACOSS?

A. The ACOSS evaluated eight rate classes: RS-1 (Residential Service-1), RS-2 (Residential Service-2), GS (General Service), MVS (Medium Volume Service), LVS (Large Volume Service), HLFS (High Load Factor Service), GLR (Gas Lighting Residential), and IS (Interruptible Transportation Service). For cost allocation purposes those customers within expansion areas were included in their corresponding rate (e.g., ERS-1, Expansion Area Residential Service-1 customers were included in RS-1). Further; GS, MVS, LVS, and HLFS included costs and revenues from both the sales and transportation customers.

Q. How were Production Plant costs treated in the ACOSS?

A. The plant related to Chesapeake's Liquid Petroleum assets were allocated to the customer classes on the basis of their respective contribution to peak day demand under system design weather conditions; on a "design day" basis.

Q. How did the Company's ACOSS classify and allocate investment in Distribution Mains?

A. The Company classified 57.5% of its investment in distribution mains as customer related and 42.5% of the investment as demand related. The customer related portion of the distribution mains investment was then allocated based on the number of customers on Chesapeake's system. The demand related investment was allocated to the customer classes on the basis of their respective contribution to peak day demand under system design weather conditions, in other words, on a "design day" basis.

Q. Was this similar to the study utilized in Chesapeake's 2007 general base rate filing?

A. Yes. The methodology is the same as the method utilized in the 2007 study. However the 2007 study assumed a minimum size main of 1¼ inch; which resulted in a 71.9% customer component. Whereas the study that is being relied upon in this proceeding utilized a 2 inch minimum sized main, resulting in a 57.5% customer component.

Q. Are there generally accepted methods for preparing classification studies?

A. It is widely accepted that distribution mains (FERC Account No. 376) are installed to meet both system peak period load requirements and to connect customers to the Local Distribution Company's ("LDC's") gas system. Therefore, to ensure that the rate classes that cause the Company to incur this plant investment or expense are charged with its cost, distribution mains should be allocated to the rate classes in proportion to their peak period load requirements and number of customers.

There are two cost factors that influence the level of distribution mains facilities installed by an LDC in expanding its gas distribution system. First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on the LDC's gas system by its customers. Secondly, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid to connect new customers to the system. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on both peak period demands and the number of customers served by the LDC.

Q. Is the method used by the Company to determine a customer cost component of distribution mains a generally accepted technique for determining customer costs?

A. Yes. The two most commonly used methods for determining the customer cost component of distribution mains facilities consist of the following: (1) the zero-intercept approach and (2) the most commonly installed, minimum-sized unit of plant investment. Under the minimum-sized unit approach, which is the method utilized in the Company's cost study, a customer cost component is developed through re-calculating the cost of a minimum size system by replacing all mains at the unit cost of a minimum diameter main (2 inch main in this study). The calculated cost of this minimum sized system is then divided into the total cost of the mains to determine the portion that is customer related and the remaining portion is classified as demand related. The analysis in support of this study is included in Exhibit JDT-3.

Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, Electric Utility Cost Allocation Manual, by John J. Doran et al, National Association of Regulatory Utility Commissioners ("NARUC"), and Gas Rate Fundamentals, American Gas Association, both describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities. The existence and utilization of a customer component of distribution facilities, specifically for distribution mains, is a fully supportable and commonly used approach in the gas industry.

Q. How were Distribution Plant costs treated in the ACOSS?

A. As indicated above, Distribution Mains were functionalized to customer and demand and allocated based on the customer count and design day allocator.

Where possible, costs were directly allocated to the customer classes based on the data contained in the Company plant records (i.e., FERC Account 383 - House Regulators. Special studies were conducted for the costs in FERC Account Nos. 380 (Services); 381 (Meters); 382 (Meter Installations); and 385 (Industrial M&R Equipment). Details on these studies are provided in JDT-3 including a narrative description of the process undertaken. The costs in FERC Account Nos. 378 (General M&R Equipment) and 379 (City Gate M&R Equipment) were allocated on a "Peak and Average" allocator; in this instance a 50/50 weighting of a class's contribution to the system's design day and the system's total annual throughput.

Q. How were the General Plant costs classified and allocated in the ACOSS?

A. General Plant costs were classified and allocated to the rate classes based on an internal allocation factor generated from the results of the classification and allocation of production and distribution plant costs.

Q. How were Operation and Maintenance expenses classified and allocated in the ACOSS?

A. Generally, the classification and allocation of the Operation and Maintenance ("O&M") expenses followed the treatment of the related plant accounts with the exception of Account Nos. 870 (Distribution Operations Supervision and Engineering), 871 (Distribution Load Dispatching), 880 (Distribution Office), and 881 (Distribution Rents). The distribution supervision, office and rent expenses were allocated on internal factors based on the classification and allocation of the directly allocated costs. Account No. 871 was allocated on total throughput.

Further, FERC Account No. 879 (Customer Installation Expenses) was directly assigned to those classes for which installations expense were incurred.

Q. Please describe the classification and allocation of Customer Accounts and Customer Service expenses in the ACOSS?

A. All of these expenses were classified as customer-related costs and allocated based on the number of customers by class. Exceptions to this treatment were Account Nos. 901 (Supervision) and 904 (Bad Debt Write-offs). Supervision expenses were allocated based on the other directly allocated costs in the category. Bad debt expenses were assigned to the classes based on the historical expense levels for each class.

Q. Please explain the treatment of Administrative and General expenses in the ACOSS?

A. The majority of the Administrative and General ("A&G") expenses were classified and allocated based on either labor or plant according to the nature of the underlying costs, that is, whether the particular A&G expense was labor-related or plant-related. Account 928 (Regulatory Commission) expenses, which consist of legal, consulting and other outside services fees related to the processing of the Company's general rate case, were allocated on the basis of rate base.

Q. Please explain how Depreciation expenses and Taxes Other Than Income were treated in the ACOSS?

A. The classification and allocation of Depreciation expenses followed the allocation of the plant to which these costs are related. Taxes Other Than Income were allocated on the basis of either labor (e.g., Payroll taxes) or plant (e.g., Property taxes) depending on the nature of the tax, that is, the basis upon which the tax or fee is assessed.

IV. ACOSS Results

Q. Please summarize the results of the ACOSS.

A. As shown on Exhibit JDT-1 page 3, the ACOSS indicates that at current rates the Company's overall rate of return is 6.20% for the test year, and 4.61% for the test period (page 4) which is below the proposed overall rate of return of 8.55% (page 5). For the test period, as detailed on page 4, the non-interruptible class rates of return vary from a negative 4.84% to a positive 23.76%.

Exhibit JDT-1 page 5 contains the revenue requirement at equal rates of return such that the company would recover its requested 8.55% return equally from all rate classes. Page 6 provides similar information at the proposed revenues by class as described in more detail by Company Witness Ronald Amen. The remaining pages of Exhibit JDT-1 provide the functional rate base and functional revenue requirement inclusive and exclusive of Miscellaneous Fee Revenue.

VI. Conclusion

Q. Does this conclude your testimony?

A. Yes.

John D. Taylor

Mr. Taylor has supported projects involving financial analysis, regulatory support and strategy, market assessment, litigation support, and organizational and operations reviews. Mr. Taylor's work often involves providing support for regulatory proceedings by conducting various studies and analyses related to revenue requirements, affiliate transactions, class cost of service, and cash working capital studies. He also has experience in asset and corporate valuation, the application of real options analysis, and various risk management techniques. Mr. Taylor has also been involved in the sale of generating assets, supporting due diligence efforts and regulatory approval processes. He has filed testimony as an expert witness on class cost of service studies and on the appropriate use of statistical analysis during audit testing.

REPRESENTATIVE PROJECT EXPERIENCE

Rate Design and Regulatory Proceedings

Mr. Taylor has worked on several electric and gas rate cases including the development of revenue requirements, class cost of service studies, and projects related to utility rate design issues. Specifically, he has:

- Supported the development of an allocated class cost of service study and rate design for a Midwest electric utility.
- Developed revenue requirement model to comply with a new performance based formula ratemaking process for a Midwest electric utility.
- Supported the developed of time of use rates.
- Assessed the consequences of a divestiture on the cost of service model for a New England gas distribution company.
- Analyzed and summarized allocation methodology for a shared services company.
- Constructed the cost of service model for a Texas electric distribution utility.
- Assessed the reasonableness of costs through various benchmarking efforts.
- Led the effort to collect and organize plant addition documentation for six Midwest utilities associated with the state commission's audit of rate base.
- Supported lead-lag analysis and testimony.
- Analyzed customer usage profiles to support reclassification of rate classes for a gas utility.
- Helped conduct a marginal cost analysis to support rate design testimony.
- Conducted research on performance-based ratemaking and applicable precedents.

PRINCIPAL CONSULTANT

Specialization:
Utility Costing and Pricing, Expert Witness Testimony, Transaction Facilitation, Revenue Requirements, Statistics, Valuation, Market Studies, Rate Case Management, Transaction Facilitation, Energy Litigation Support, Expert Testimony

Office Location
Richmond, VA

Education
- M.A., Economics, American University, 2005
- B.A., Environmental Economics, University of North Carolina at Asheville, 2004...

Year Career Started
2000

Year Started with B&V
2015

- Conducted a regression analysis to forecast use per customer to support a rate case for a gas utility.

Transaction Experience

Mr. Taylor has been involved with several generating asset transactions supporting both buy side and sell side analysis and due diligence. His work has included:

- Helped facilitate and manage processes for a nuclear plant auction by processing Q&A, collecting relevant documentation and managing the virtual data room for auction participants.
- Supported the auction process for steam and chilled water distribution and generation assets in the Midwest.
- Provided research on comparable transactions, previous mergers and acquisitions, and potential transaction opportunities for several clients.

Litigation Support and Expert Testimony

Mr. Taylor has testified in several cases on class cost of service studies and statistical audit methods. He has also supported numerous other expert testimonies. Specifically, he has:

- Filed testimony as an expert witness on allocated class cost of service studies.
- Filed testimony as an expert witness on the application of statistical analysis.
- Compared revenue recovery mechanisms in multiple jurisdictions in support of return on equity testimony.
- Supported affiliate cost testimony for a New England utility and for a Midwest utility.
- Supported testimony relating to the regulatory approval of assets sales and the recovery of shared services charges to regulated affiliates.
- Performed asset valuations associated with spent nuclear fuel litigation.
- Conducted research to support testimony associated with the decoupling of gas rates.
- Supported testimony and produced a discounted cash flow analysis relating to a ‘lease in lease out’ transaction in the Netherlands.
- Provided research on precedents and ratemaking theory regarding consolidated tax adjustments to support expert testimony.

Financial Analysis

Other financial analysis Mr. Taylor has conducted include:

- Modeling alternative mechanisms for the allocation of overhead costs to a nuclear plant.

- Analyzing the implications of a merchant power plant entering into a financial swap.
- Assisting with the creation of a replacement cost model used to value generation assets.
- Researching regulations associated with a foreign company establishing a U.S. natural gas marketing division.

Market Research Experience

Other market research activities Mr. Taylor has been involved with include:

- Developed distributed CNG/LNG market studies for two separate utilities and two separate competitive market participants.
- Participated in the development of a peak shaving service market study for a mid-Atlantic utility.
- Researching and creating summaries of recent pipeline projects and LNG receiving facilities.
- Conducting research on potential Caribbean investment opportunities.
- Researching market dynamics and analyzing incentive structures in several restructured states.

DATED: DECEMBER _21_, 2015

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF JOHN TAYLOR

JOHN TAYLOR, being first duly sworn according to law, on oath deposes and says that he is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of John Taylor"; that, if asked the questions which appear in the text of the direct testimony, he would give the answers that are therein set forth; and that he adopts this testimony as his sworn direct testimony in these proceedings.

John D. Taylor
John Taylor

Then personally appeared this _21st_ day of December 2015 the above-named John Taylor and acknowledged the foregoing Testimony to be his free act and deed. Before me,

REBECCA K. GRIER
NOTARY
PUBLIC
MY COMMISSION
EXPIRES ON
07-17-18
STATE OF DELAWARE

Rebecca K. Grier
Notary Public
My Commission Expires: 7·17·18

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

CHESAPEAKE UTILITIES CORPORATION

EXHIBIT JDT-1

COST ALLOCATION STUDY RESULTS

Witness: John D. Taylor

Docket No. 15-XXX

CHESAPEAKE UTILITIES CORPORATION

EXHIBIT JDT-1

COST ALLOCATION STUDY RESULTS – INDEX

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Current Revenue Summary
Test Year at Current Revenues

	System Total	Residential Service - 1	Residential Service - 2	General Service	Medium Volume Service	Large Volume Service	High Load Factor Service	Gas Lighting Residential	Interruptible Service
REVENUES	$ 23,989,324	$ 1,061,598	$ 14,661,975	$ 1,570,559	$ 897,520	$ 1,811,378	$ 3,821,311	$ 709	$ 164,272
EXPENSES									
O & M Expense	$ 5,260,300	$ 435,281	$ 3,843,387	$ 356,371	$ 154,442	$ 200,014	$ 265,923	$ 230	$ 4,653
A & G Expense	$ 8,445,364	$ 654,164	$ 5,994,950	$ 582,689	$ 280,488	$ 420,720	$ 503,152	$ 322	$ 8,879
Depreciation Expense	$ 2,402,831	$ 167,272	$ 1,610,697	$ 171,339	$ 96,831	$ 170,241	$ 183,210	$ 66	$ 3,175
Interest on Customer Deposits	$ 74,347	$ 7,070	$ 58,355	$ 6,632	$ 1,078	$ 454	$ 758	$ -	$ -
Taxes Other than Income	$ 1,807,906	$ 133,218	$ 1,258,923	$ 125,838	$ 64,797	$ 106,122	$ 117,016	$ 64	$ 1,929
Total Expenses	*$ 17,990,748*	*$ 1,397,005*	*$ 12,766,312*	*$ 1,242,868*	*$ 597,635*	*$ 897,550*	*$ 1,070,059*	*$ 683*	*$ 18,637*
OPERATING INCOME BEFORE INTEREST & TAXES	$ 5,998,576	$ (335,407)	$ 1,895,664	$ 327,691	$ 299,885	$ 913,828	$ 2,751,252	$ 27	$ 145,636
INCOME TAXES	$ 1,914,520	$ (169,991)	$ 420,874	$ 95,710	$ 99,673	$ 333,965	$ 1,075,960	$ (8)	$ 58,338
OPERATING INCOME	$ 4,084,056	$ (165,416)	$ 1,474,790	$ 231,981	$ 200,212	$ 579,864	$ 1,675,293	$ 34	$ 87,298
RATE BASE	$ 65,854,598	$ 4,477,783	$ 44,685,470	$ 4,748,331	$ 2,778,716	$ 4,547,753	$ 4,552,375	$ 2,400	$ 61,770
Earned Return	**6.20%**	**-3.69%**	**3.30%**	**4.89%**	**7.21%**	**12.75%**	**36.80%**	**1.44%**	**141.33%**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Current Revenue Summary
Test Period at Current Revenues

	System Total	Residential Service - 1	Residential Service - 2	General Service	Medium Volume Service	Large Volume Service	High Load Factor Service	Gas Lighting Residential	Interruptible Service
REVENUES	$ 22,965,902	$ 887,136	$ 14,369,772	$ 1,506,503	$ 905,193	$ 2,171,020	$ 2,960,465	$ 709	$ 165,105
EXPENSES									
O & M Expense	$ 5,612,851	$ 431,787	$ 4,184,528	$ 381,438	$ 166,684	$ 209,387	$ 234,800	$ 245	$ 3,983
A & G Expense	$ 7,976,825	$ 565,497	$ 5,712,251	$ 545,253	$ 267,853	$ 406,781	$ 470,120	$ 299	$ 8,770
Depreciation Expense	$ 2,654,050	$ 167,715	$ 1,788,664	$ 190,981	$ 111,685	$ 193,682	$ 197,829	$ 72	$ 3,422
Interest on Customer Deposits	$ 74,347	$ 6,440	$ 58,960	$ 6,618	$ 1,129	$ 477	$ 723	$ -	$ -
Taxes Other than Income	$ 2,039,883	$ 136,118	$ 1,425,868	$ 141,993	$ 75,643	$ 125,384	$ 132,603	$ 70	$ 2,206
Total Expenses	*$ 18,357,957*	*$ 1,307,558*	*$ 13,170,272*	*$ 1,266,283*	*$ 622,993*	*$ 935,711*	*$ 1,036,074*	*$ 685*	*$ 18,381*
OPERATING INCOME BEFORE INTEREST & TAXES	$ 4,607,945	$ (420,422)	$ 1,199,500	$ 240,220	$ 282,200	$ 1,235,308	$ 1,924,391	$ 24	$ 146,725
INCOME TAXES	$ 1,340,647	$ (207,845)	$ 114,019	$ 58,418	$ 92,003	$ 469,778	$ 754,326	$ (10)	$ 59,958
OPERATING INCOME	$ 3,267,298	$ (212,577)	$ 1,085,481	$ 181,802	$ 190,198	$ 765,530	$ 1,170,065	$ 33	$ 86,767
RATE BASE	$ 70,938,750	$ 4,392,927	$ 48,316,146	$ 5,155,528	$ 3,086,925	$ 4,995,536	$ 4,924,340	$ 2,447	$ 64,902
Earned Return	**4.61%**	**-4.84%**	**2.25%**	**3.53%**	**6.16%**	**15.32%**	**23.76%**	**1.35%**	**133.69%**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Revenue Requirement Summary
Revenue Requirement at Equal Rates of Return

	System Total	Residential Service - 1	Residential Service -2	General Service	Medium Volume Service	Large Volume Service	High Load Factor Service	Gas Lighting Residential	Interruptible Service
RATE BASE	$ 70,938,750	$ 4,392,969	$ 48,316,435	$ 5,155,441	$ 3,086,864	$ 4,995,449	$ 4,924,245	$ 2,447	$ 64,900
PROPOSED RATE OF RETURN	8.55%	8.55%	8.55%	8.55%	8.55%	8.55%	8.55%	8.55%	8.55%
RETURN ALLOWANCE	$ 6,065,263	$ 375,599	$ 4,131,055	$ 440,790	$ 263,927	$ 427,111	$ 421,023	$ 209	$ 5,549
INCOME TAXES	$ 3,257,426	$ 201,720	$ 2,218,635	$ 236,732	$ 141,745	$ 229,385	$ 226,116	$ 112	$ 2,980
EXPENSES									
O & M Expense	$ 5,625,697	$ 433,005	$ 4,195,675	$ 381,822	$ 166,732	$ 209,404	$ 234,832	$ 245	$ 3,982
A & G Expense	$ 7,976,825	$ 565,511	$ 5,712,354	$ 545,199	$ 267,825	$ 406,766	$ 470,102	$ 299	$ 8,770
Depreciation Expense	$ 2,654,050	$ 167,715	$ 1,788,664	$ 190,981	$ 111,685	$ 193,682	$ 197,829	$ 72	$ 3,422
Interest on Customer Deposits	$ 74,347	$ 6,440	$ 58,960	$ 6,618	$ 1,129	$ 477	$ 723	$ -	$ -
Taxes Other than Income	$ 2,054,108	$ 137,001	$ 1,435,568	$ 143,021	$ 76,259	$ 126,384	$ 133,588	$ 70	$ 2,219
Total Expenses	*$ 18,385,028*	*$ 1,309,672*	*$ 13,191,221*	*$ 1,267,640*	*$ 623,631*	*$ 936,712*	*$ 1,037,074*	*$ 685*	*$ 18,393*
REVENUE REQUIREMENT									
Total Expenses	$ 18,385,028	$ 1,309,672	$ 13,191,221	$ 1,267,640	$ 623,631	$ 936,712	$ 1,037,074	$ 685	$ 18,393
Total Income Taxes	$ 3,257,426	$ 201,720	$ 2,218,635	$ 236,732	$ 141,745	$ 229,385	$ 226,116	$ 112	$ 2,980
Total Return on Rate Base	$ 6,065,263	$ 375,599	$ 4,131,055	$ 440,790	$ 263,927	$ 427,111	$ 421,023	$ 209	$ 5,549
Total Revenue Requirement	***$ 27,707,717***	***$ 1,886,991***	***$ 19,540,911***	***$ 1,945,162***	***$ 1,029,303***	***$ 1,593,208***	***$ 1,684,212***	***$ 1,007***	***$ 26,923***
less: Miscellaneous Fee Revenue	***$ (742,783)***	***$ (62,248)***	***$ (470,704)***	***$ (36,880)***	***$ (14,564)***	***$ (56,336)***	***$ (99,579)***	***$ (4)***	***$ (2,469)***
Remaining Revenue Requirement	***$ 26,964,933***	***$ 1,824,743***	***$ 19,070,207***	***$ 1,908,282***	***$ 1,014,739***	***$ 1,536,872***	***$ 1,584,634***	***$ 1,003***	***$ 24,454***

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Revenue Requirement at Proposed Rates of Return

REVENUES									
Base Rate Margins	$ 26,964,933	$ 1,189,216	$ 17,713,486	$ 1,908,282	$ 1,014,740	$ 2,114,683	$ 2,860,886	$ 1,003	$ 162,637
Miscellaneous Fee Revenue	$ 742,783	$ 62,248	$ 470,704	$ 36,880	$ 14,564	$ 56,336	$ 99,579	$ 4	$ 2,469
Total Revenues	$ 27,707,717	$ 1,251,464	$ 18,184,190	$ 1,945,162	$ 1,029,304	$ 2,171,020	$ 2,960,465	$ 1,007	$ 165,105
EXPENSES									
O & M Expense	$ 5,625,697	$ 433,005	$ 4,195,675	$ 381,822	$ 166,732	$ 209,404	$ 234,832	$ 245	$ 3,982
A & G Expense	$ 7,976,825	$ 565,511	$ 5,712,354	$ 545,199	$ 267,825	$ 406,766	$ 470,102	$ 299	$ 8,770
Depreciation Expense	$ 2,654,050	$ 167,715	$ 1,788,664	$ 190,981	$ 111,685	$ 193,682	$ 197,829	$ 72	$ 3,422
Interest on Customer Deposits	$ 74,347	$ 6,440	$ 58,960	$ 6,618	$ 1,129	$ 477	$ 723	$ -	$ -
Taxes Other than Income	$ 2,054,108	$ 137,001	$ 1,435,568	$ 143,021	$ 76,259	$ 126,384	$ 133,588	$ 70	$ 2,219
Total Expenses	*$ 18,385,028*	*$ 1,309,672*	*$ 13,191,221*	*$ 1,267,640*	*$ 623,631*	*$ 936,712*	*$ 1,037,074*	*$ 685*	*$ 18,393*
Interest Expense	$ (1,354,930)	$ (83,906)	$ (922,844)	$ (98,469)	$ (58,959)	$ (95,413)	$ (94,053)	$ (47)	$ (1,240)
INCOME PRIOR TO TAXES	*$ 7,967,759*	*$ (204,362)*	*$ 3,599,421*	*$ 542,174*	*$ 332,150*	*$ 1,082,558*	*$ 1,729,760*	*$ 271*	*$ 143,004*
Total Income Taxes	$ 3,257,426	$ (58,100)	$ 1,663,973	$ 236,732	$ 141,746	$ 465,609	$ 747,881	$ 112	$ 59,473
OPERATING INCOME	$ 6,065,263	$ (108)	$ 3,328,997	$ 440,790	$ 263,927	$ 768,698	$ 1,175,511	$ 209	$ 87,239
RATE BASE	$ 70,938,750	$ 4,392,969	$ 48,316,435	$ 5,155,441	$ 3,086,864	$ 4,995,449	$ 4,924,245	$ 2,447	$ 64,900
Proposed Return	***8.55%***	***0.00%***	***6.89%***	***8.55%***	***8.55%***	***15.39%***	***23.87%***	***8.55%***	***134.42%***

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functional Rate Base

	System Total	Residential Service - 1	Residential Service -2	General Service	Medium Volume Service	Large Volume Service	High Load Factor Service	Gas Lighting Residential	Interruptible Service
Gas Supply									
Demand	$ 1,525,623	$ 19,692	$ 736,957	$ 97,051	$ 105,268	$ 285,530	$ 281,125	$ -	$ -
Commodity	$ 1,807,272	$ 27,479	$ 1,240,718	$ 137,403	$ 141,776	$ 141,314	$ 118,562	$ 20	$ -
Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 3,332,895*	*$ 47,171*	*$ 1,977,675*	*$ 234,454*	*$ 247,044*	*$ 426,844*	*$ 399,687*	*$ 20*	*$ -*
Distribution									
Demand	$ 17,144,528	$ 219,195	$ 8,222,690	$ 1,080,160	$ 1,174,119	$ 3,216,532	$ 3,228,291	$ 4	$ 3,537
Commodity	$ (27,933)	$ (206)	$ (9,128)	$ (1,003)	$ (1,272)	$ (5,806)	$ (10,255)	$ (0)	$ (262)
Customer	$ 51,970,082	$ 4,252,032	$ 39,270,445	$ 3,978,434	$ 1,689,530	$ 1,367,313	$ 1,348,307	$ 2,407	$ 61,614
Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 69,086,677*	*$ 4,471,021*	*$ 47,484,007*	*$ 5,057,591*	*$ 2,862,377*	*$ 4,578,038*	*$ 4,566,343*	*$ 2,411*	*$ 64,890*
Customer Acct/Billing									
Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	$ (1,531,204)	$ (129,805)	$ (1,187,228)	$ (139,640)	$ (22,988)	$ (9,528)	$ (42,042)	$ 15	$ 11
Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ (1,531,204)*	*$ (129,805)*	*$ (1,187,228)*	*$ (139,640)*	*$ (22,988)*	*$ (9,528)*	*$ (42,042)*	*$ 15*	*$ 11*
Customer Services									
Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	$ 50,382	$ 4,582	$ 41,981	$ 3,036	$ 431	$ 95	$ 256	$ -	$ -
Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 50,382*	*$ 4,582*	*$ 41,981*	*$ 3,036*	*$ 431*	*$ 95*	*$ 256*	*$ -*	*$ -*
~									
~ ~	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
~ ~	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
~ ~	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
~ ~	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
~ ~	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*
~									
TOTAL									
Demand	$ 18,670,151	$ 238,887	$ 8,959,647	$ 1,177,211	$ 1,279,388	$ 3,502,062	$ 3,509,416	$ 4	$ 3,537
Commodity	$ 1,779,339	$ 27,273	$ 1,231,590	$ 136,400	$ 140,504	$ 135,508	$ 108,307	$ 20	$ (262)
Customer	$ 50,489,259	$ 4,126,809	$ 38,125,198	$ 3,841,830	$ 1,666,973	$ 1,357,879	$ 1,306,522	$ 2,423	$ 61,625
Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL RATE BASE	***$ 70,938,750***	***$ 4,392,969***	***$ 48,316,435***	***$ 5,155,441***	***$ 3,086,864***	***$ 4,995,449***	***$ 4,924,245***	***$ 2,447***	***$ 64,900***

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functional Revenue Requirement (Inclusive of Miscellaneous Fee Revenue)
Revenue Requirement at Equal Rates of Return

	System Total	Residential Service - 1	Residential Service -2	General Service	Medium Volume Service	Large Volume Service	High Load Factor Service	Gas Lighting Residential	Interruptible Service
Gas Supply									
Demand	$ 592,273	$ 7,645	$ 286,099	$ 37,677	$ 40,867	$ 110,848	$ 109,138	$ -	$ -
Commodity	$ 292,612	$ 4,348	$ 191,901	$ 21,699	$ 22,538	$ 27,690	$ 24,434	$ 3	$ -
Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 884,884*	*$ 11,992*	*$ 478,000*	*$ 59,375*	*$ 63,405*	*$ 138,537*	*$ 133,572*	*$ 3*	*$ -*
Distribution									
Demand	$ 4,506,490	$ 56,545	$ 2,131,154	$ 278,565	$ 304,088	$ 849,479	$ 883,917	$ 3	$ 2,740
Commodity	$ 368,397	$ 2,714	$ 120,390	$ 13,223	$ 16,780	$ 76,579	$ 135,257	$ 4	$ 3,450
Customer	$ 15,576,086	$ 1,262,234	$ 11,654,227	$ 1,189,432	$ 524,293	$ 468,184	$ 456,827	$ 605	$ 20,284
Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 20,450,972*	*$ 1,321,493*	*$ 13,905,770*	*$ 1,481,220*	*$ 845,161*	*$ 1,394,241*	*$ 1,476,001*	*$ 612*	*$ 26,474*
Customer Acct/Billing									
Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	$ 4,409,500	$ 375,029	$ 3,521,980	$ 286,309	$ 103,951	$ 56,737	$ 64,652	$ 392	$ 449
Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 4,409,500*	*$ 375,029*	*$ 3,521,980*	*$ 286,309*	*$ 103,951*	*$ 56,737*	*$ 64,652*	*$ 392*	*$ 449*
Customer Services									
Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	$ 1,962,361	$ 178,477	$ 1,635,161	$ 118,257	$ 16,786	$ 3,693	$ 9,988	$ -	$ -
Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 1,962,361*	*$ 178,477*	*$ 1,635,161*	*$ 118,257*	*$ 16,786*	*$ 3,693*	*$ 9,988*	*$ -*	*$ -*
~									
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~ ~	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
~ ~	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*
~									
TOTAL									
Demand	$ 5,098,763	$ 64,190	$ 2,417,253	$ 316,242	$ 344,955	$ 960,327	$ 993,054	$ 3	$ 2,740
Commodity	$ 661,008	$ 7,062	$ 312,291	$ 34,921	$ 39,318	$ 104,268	$ 159,691	$ 7	$ 3,450
Customer	$ 21,947,946	$ 1,815,739	$ 16,811,367	$ 1,593,999	$ 645,030	$ 528,614	$ 531,467	$ 997	$ 20,733
Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Revenue Requirement	***$ 27,707,717***	***$ 1,886,991***	***$ 19,540,911***	***$ 1,945,162***	***$ 1,029,303***	***$ 1,593,208***	***$ 1,684,212***	***$ 1,007***	***$ 26,923***

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functional Revenue Requirement (Exclusive of Miscellaneous Fee Revenue)

Revenue Requirement at Equal Rates of Return

	System Total	Residential Service - 1	Residential Service -2	General Service	Medium Volume Service	Large Volume Service	High Load Factor Service	Gas Lighting Residential	Interruptible Service
Gas Supply									
Demand	$ 573,464	$ 7,392	$ 279,208	$ 36,962	$ 40,289	$ 106,928	$ 102,685	$ -	$ -
Commodity	$ 284,691	$ 4,204	$ 187,279	$ 21,287	$ 22,219	$ 26,710	$ 22,989	$ 3	$ -
Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 858,156*	*$ 11,597*	*$ 466,486*	*$ 58,250*	*$ 62,508*	*$ 133,638*	*$ 125,674*	*$ 3*	*$ -*
Distribution									
Demand	$ 4,361,155	$ 54,680	$ 2,079,818	$ 273,283	$ 299,785	$ 819,441	$ 831,655	$ 3	$ 2,489
Commodity	$ 353,898	$ 2,625	$ 117,490	$ 12,972	$ 16,543	$ 73,871	$ 127,260	$ 4	$ 3,133
Customer	$ 15,178,322	$ 1,220,595	$ 11,373,498	$ 1,166,881	$ 516,875	$ 451,629	$ 429,817	$ 603	$ 18,424
Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 19,893,374*	*$ 1,277,899*	*$ 13,570,806*	*$ 1,453,136*	*$ 833,203*	*$ 1,344,940*	*$ 1,388,733*	*$ 610*	*$ 24,046*
Customer Acct/Billing									
Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	$ 4,299,520	$ 362,658	$ 3,437,142	$ 280,881	$ 102,480	$ 54,731	$ 60,829	$ 391	$ 408
Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 4,299,520*	*$ 362,658*	*$ 3,437,142*	*$ 280,881*	*$ 102,480*	*$ 54,731*	*$ 60,829*	*$ 391*	*$ 408*
Customer Services									
Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	$ 1,913,884	$ 172,589	$ 1,595,773	$ 116,015	$ 16,548	$ 3,562	$ 9,397	$ -	$ -
Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 1,913,884*	*$ 172,589*	*$ 1,595,773*	*$ 116,015*	*$ 16,548*	*$ 3,562*	*$ 9,397*	*$ -*	*$ -*
~									
~ ~	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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~ ~	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
~ ~	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*
~									
TOTAL									
Demand	$ 4,934,619	$ 62,072	$ 2,359,026	$ 310,246	$ 340,074	$ 926,369	$ 934,340	$ 3	$ 2,489
Commodity	$ 638,589	$ 6,829	$ 304,768	$ 34,259	$ 38,762	$ 100,581	$ 150,250	$ 7	$ 3,133
Customer	$ 21,391,725	$ 1,755,841	$ 16,406,413	$ 1,563,777	$ 635,903	$ 509,922	$ 500,044	$ 993	$ 18,832
Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Revenue Requirement	***$ 26,964,933***	***$ 1,824,743***	***$ 19,070,207***	***$ 1,908,282***	***$ 1,014,739***	***$ 1,536,872***	***$ 1,584,634***	***$ 1,003***	***$ 24,454***

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

	System Total	Residential Service - 1	Residential Service -2	General Service	Medium Volume Service	Large Volume Service	High Load Factor Service	Gas Lighting Residential	Interruptible Service
Transportation and Sales	*7,763,775*	*57,200*	*2,537,154*	*278,664*	*353,638*	*1,613,856*	*2,850,480*	*84*	*72,699*
Sales (in Mcf)	*3,637,221*	*57,200*	*2,537,154*	*269,796*	*284,167*	*235,908*	*252,912*	*84*	*0*
*Average Customers * 12*	*565,236*	*51,036*	*467,580*	*34,416*	*5,868*	*2,472*	*3,780*	*60*	*24*

Unit Cost - Customer Basis

	System Total	Residential Service - 1	Residential Service -2	General Service	Medium Volume Service	Large Volume Service	High Load Factor Service	Gas Lighting Residential	Interruptible Service
Gas Supply	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution	$ 26.85	$ 23.92	$ 24.32	$ 33.91	$ 88.08	$ 182.70	$ 113.71	$ 10.04	$ 767.69
Customer Acct/Billing	$ 7.61	$ 7.11	$ 7.35	$ 8.16	$ 17.46	$ 22.14	$ 16.09	$ 6.51	$ 16.99
Customer Services	$ 3.39	$ 3.38	$ 3.41	$ 3.37	$ 2.82	$ 1.44	$ 2.49	$ -	$ -
~	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Unit Cost	***$ 37.85***	***$ 34.40***	***$ 35.09***	***$ 45.44***	***$ 108.37***	***$ 206.28***	***$ 132.29***	***$ 16.55***	***$ 784.67***

Unit Cost - Usage Basis

	System Total	Residential Service - 1	Residential Service -2	General Service	Medium Volume Service	Large Volume Service	High Load Factor Service	Gas Lighting Residential	Interruptible Service
Gas Supply - Demand	$ 0.07	$ 0.13	$ 0.11	$ 0.13	$ 0.11	$ 0.07	$ 0.04	$ -	$ -
Gas Supply - Commodity	$ 0.04	$ 0.07	$ 0.07	$ 0.08	$ 0.06	$ 0.02	$ 0.01	$ 0.03	$ -
Distribution - Demand	$ 0.56	$ 0.96	$ 0.82	$ 0.98	$ 0.85	$ 0.51	$ 0.29	$ 0.04	$ 0.03
Distribution - Commodity	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.04	$ 0.05	$ 0.04
Total Unit Cost	***$ 0.72***	***$ 1.20***	***$ 1.05***	***$ 1.24***	***$ 1.07***	***$ 0.64***	***$ 0.38***	***$ 0.12***	***$ 0.08***

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

CHESAPEAKE UTILITIES CORPORATION

EXHIBIT JDT-2

ALLOCATED CLASS COST OF SERVICE STUDY

TEST PERIOD

Witness: John D. Taylor

Docket No. 15-XXX

CHESAPEAKE UTILITIES CORPORATION

EXHIBIT JDT-2

ALLOCATED CLASS COST OF SERVICE STUDY

TEST YEAR – INDEX

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

Account Factor Choice
Test Period at Proposed Revenues

No. Account Description	Amount	Function	Classifier	DEM	COM	CUS	REV	Internal
RATE BASE								
Plant-in Service								
Intangible Plant								
Organization Expense	6,038							PD_PLANT
Franchise and Consent	248							PD_PLANT
Misc. Intangible Plant	3,000							PD_PLANT
Sub-total	***9,286***							
Production Plant								
Land and Land Rights	1,236,589	F_PRODU	DEM	DD				
Depreciable Land Rights	-	F_PRODU	DEM	DD				
Structures and Improvements	224,540	F_PRODU	DEM	DD				
Liquid Petroleum Gas Equipment	3,346,977	F_PRODU	DEM	DD				
Sub-total	***4,808,105***							
Distribution Plant								
Mains	63,275,399	F_DISTR	MIN	DD		CUST		
M & R Stations - General	209,392	F_DISTR	DEM	PAVG				
M & R Stations - City Gate	1,042,889	F_DISTR	DEM	PAVG				
Services	32,773,250	F_DISTR	CUS			SERVICE		
Meters	11,037,872	F_DISTR	CUS			MET		
Meter Installations	5,901,032	F_DISTR	CUS			MET		
Regulating Equipment	2,143,325	F_DISTR	CUS			REG		
M & R Stations - Industrial	1,727,660	F_DISTR	CUS			MNR		
Other Equipment	363,074							DIS_PLANT
Sub-total	***118,473,894***							
General Plant								
Structures and Improvements	287,023							PD_PLANT
Office Equipment	1,052,106							PD_PLANT
Vax System Equipment	-							PD_PLANT
Transportation Equipment	2,040,017							PD_PLANT
Tools and Work Equipment	434,368							PD_PLANT
Laboratory Equipment	-							PD_PLANT
Power Operated Equipment	674,971							PD_PLANT
Communication Equipment	-							PD_PLANT
Miscellaneous Equipment	248,188							PD_PLANT
Other Intangible Property	-							PD_PLANT
Plant Leased to Others	-							PD_PLANT
Sub-total	***4,736,673***							
TOTAL PLANT-IN-SERVICE	**128,027,958**							

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

Account Factor Choice
Test Period at Proposed Revenues

No.	Account Description	Amount	Function	Classifier	DEM	COM	CUS	REV	Internal
	Accumulated Reserve for Depreciation								
	Intangible Plant								
	Organization Expense	-							PD_PLANT
	Franchise and Consent	-							PD_PLANT
	Misc. Intangible Plant	-							PD_PLANT
	Sub-total	**-**							
	Production Plant								
	Land and Land Rights	(101,996)	F_PRODU	DEM	DD				
	Depreciable Land Rights	-	F_PRODU	DEM	DD				
	Structures and Improvements	(143,206)	F_PRODU	DEM	DD				
	Liquid Petroleum Gas Equipment	(1,757,693)	F_PRODU	DEM	DD				
	Sub-total	***(2,002,895)***							
	Distribution Plant								
	Mains	(15,193,054)	F_DISTR	MIN	DD		CUST		
	M & R Stations - General	(50,311)	F_DISTR	DEM	PAVG				
	M & R Stations - City Gate	(482,002)	F_DISTR	DEM	PAVG				
	Services	(11,632,528)	F_DISTR	CUS			SERVICE		
	Meters	(301,233)	F_DISTR	CUS			MET		
	Meter Installations	(1,869,000)	F_DISTR	CUS			MET		
	Regulating Equipment	(573,834)	F_DISTR	CUS			REG		
	M & R Stations - Industrial	(649,227)	F_DISTR	CUS			MNR		
	Other Equipment	(54,182)							DIS_PLANT
	Sub-total	***(30,805,372)***							
	General Plant								
	Structures and Improvements	(285,944)							PD_PLANT
	Office Equipment	7,441							PD_PLANT
	Vax System Equipment	-							PD_PLANT
	Transportation Equipment	(1,140,185)							PD_PLANT
	Tools and Work Equipment	(36,706)							PD_PLANT
	Laboratory Equipment	-							PD_PLANT
	Power Operated Equipment	(371,658)							PD_PLANT
	Communication Equipment	57,843							PD_PLANT
	Miscellaneous Equipment	(170,666)							PD_PLANT
	Other Intangible Property	-							PD_PLANT
	Plant Leased to Others	-							PD_PLANT
	Sub-total	***(1,939,874)***							
	Retirement Work in Process	10,942							PD_PLANT
	TOTAL DEPRECIATION ACCRUAL	**(34,737,200)**							

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

Account Factor Choice
Test Period at Proposed Revenues

No. Account Description	Amount	Function	Classifier	DEM	COM	CUS	REV	Internal
Rate Base Adjustments and Working Capital								
Accumulated Deferred Income Tax								
Accelerated Depreciation	(23,689,863)							DEP
Bad Debts	47,610	F_DISTR	CUS			BADDEBT		
Capital Interest & Overheads	176,551							DIS_PLANT
Pension	196,895							LABOR
Incentive Compenstation	207,781							LABOR
Other Post Retirement Benefits	210,778							LABOR
Insurance Reserves	(60,896)							DIS_PLANT
Self-Insurance	214,028							LABOR
Regulatory Asset	59,148							OM
Real Property and Repairs	(300,581)							DIS_PLANT
Sub-total	***(22,938,550)***							
Other Rate Base Adjustments								
Customer Deposits	(1,698,560)	F_CBILL	CUS			CUSDEP		
Customer Advances	(27,692)	F_CBILL	CUS			CUSADV		
Operating Reserves	(1,547,011)							LABOR
Nat. Gas in Storage	1,538,611	F_PRODU	COM		SSALES			
Propane in Storage	264,685	F_PRODU	COM		CDD			
Plant M&S	365,301							PD_PLANT
Cash Working Capital	1,028,566							OM
CWIP	662,641							MAINS
Sub-total	***586,541***							
TOTAL OTHER RATE BASE	**(22,352,008)**							
TOTAL RATE BASE	**70,938,750**							

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

Account Factor Choice
Test Period at Proposed Revenues

No. Account Description	Amount	Function	Classifier	DEM	COM	CUS	REV	Internal
EXPENSES								
O & M Expenses								
Production Ops								
Liquefied Petroleum Gas Expenses	29,966	F_PRODU	COM		CDD			
Liquefied Petroleum Gas	-	F_PRODU	COM		CDD			
Operation Labor & Expense	30,718	F_PRODU	DEM	DD				
Sub-total	***60,684***							
Purchased Gas Expense								
-	-							
-	-							
-	-							
-	-							
-	-							
-	-							
-	-							
Sub-total	***-***							
Distribution Ops								
Operation Supervision & Engineering	471,559							DIS_LABOR
Distribution Load Dispatching - Direct	-							
Distribution Load Dispatching	0	F_DISTR	COM		THRU			
Mains & Services Expenses	490,800							M_S
M & R Station Expense - General	14,144	F_DISTR	DEM	PAVG				
M & R Station Expense - Industrial	20,867	F_DISTR	CUS			MNR		
M & R Station Expenses - City Gate	10,523	F_DISTR	DEM	PAVG				
Meter and House Regulator Expense	378,244							M_HR
Customer Installation Expenses	66,046	F_DISTR	CUS			CINSTALL		
Other Expenses - Distribution	3,236							DIS_PLANT
Rents - Distribution	5,881							DIS_PLANT
Negative Salvage Value	-							
Sub-total	***1,461,299***							
Customer Service Ops								
Supervision - Customer Accounting	268,386							C_LABOR
Meter Reading Expenses	271,965	F_CBILL	CUS			CMET		
Customer Records & Collection Expenses	1,702,321	F_CBILL	CUS			CREC		
Uncollectible Accounts	141,823	F_CBILL	CUS			BADDEBT		
Info & Instructional Exp	64,633	F_CBILL	CUS			SCUSTS		
Sub-total	***2,449,128***							
Sales Ops								
-	-							
Demonstrating & Selling Expenses	791,955	F_CSERV	CUS			SCUSTS		
Advertising Expenses	144,614	F_CSERV	CUS			SCUSTS		
Sub-total	***936,569***							

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

Account Factor Choice
Test Period at Proposed Revenues

No.	Account Description	Amount	Function	Classifier	DEM	COM	CUS	REV	Internal
	Production Maintenance								
	Maintenance of Structures & Improvements	-							P_PLANT
	Maintenance of Production Equipment	47,461							P_PLANT
	Sub-total	***47,461***							
	Distribution Maintenance								
	Structures & Improvements	-							DIS_PLANT
	Mains & Services Expenses	315,432							M_S
	M & R Station Equipment - General	28,701	F_DISTR	DEM	PAVG				
	M & R Station Equipment - Industrial	65,713	F_DISTR	CUS			MNR		
	M & R Station Equipment - City Gate	4,898	F_DISTR	DEM	PAVG				
	Services	138,657	F_DISTR	CUS			SERVICE		
	Meters & House Regulators	100,120							M_HR
	Other Equipment	17,035							DIS_PLANT
	Sub-total	***670,556***							
	TOTAL O & M EXPENSES	**5,625,697**							

Labor Expense

No.	Account Description	Amount	Function	Classifier	DEM	COM	CUS	REV	Internal
	Production Ops								
	Liquefied Petroleum Gas Expenses	9,377	F_PRODU	COM		CDD			
	Liquefied Petroleum Gas	-	F_PRODU	COM		CDD			
	Operation Labor & Expense	-	F_PRODU	DEM	DD				
	Sub-total	***9,377***							
	Distribution Ops								
	Operation Supervision & Engineering	407,188							DIS_LABOR
	Distribution Load Dispatching	152,294	F_DISTR	COM		THRU			
	Mains & Services Expenses	317,881							M_S
	M & R Station Expense - General	778	F_DISTR	DEM	PAVG				
	M & R Station Expense - Industrial	10,600	F_DISTR	CUS			MNR		
	M & R Station Expenses - City Gate	5,612	F_DISTR	DEM	PAVG				
	Meter and House Regulator Expense	283,521							M_HR
	Customer Installation Expenses	110,223	F_DISTR	CUS			CINSTALL		
	Other Expenses - Distribution	153							DIS_PLANT
	Rents - Distribution	-							DIS_PLANT
	Sub-total	***1,288,251***							
	Customer Service Ops								
	Supervision - Customer Accounting	218,064							C_LABOR
	Meter Reading Expenses	222,802	F_CBILL	CUS			CMET		
	Customer Records & Collection Expenses	995,377	F_CBILL	CUS			CREC		
	Uncollectible Accounts	-	F_CBILL	CUS			BADDEBT		
	Customer Assistance Expenses	-	F_CBILL	CUS			SCUSTS		
	Sub-total	***1,436,243***							

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

Account Factor Choice
Test Period at Proposed Revenues

No.	Account Description	Amount	Function	Classifier	DEM	COM	CUS	REV	Internal
	Sales Ops								
	Demonstrating & Selling Expenses	674,073	F_CSERV	CUS			SCUSTS		
	Advertising Expenses	-	F_CSERV	CUS			SCUSTS		
	Sub-total	***674,073***							
	Distribution Maintenance								
	Structures & Improvements	-							DIS_PLANT
	Mains & Services Expenses	125,645							M_S
	M & R Station Equipment - General	28,095	F_DISTR	DEM	PAVG				
	M & R Station Equipment - Industrial	17,790	F_DISTR	CUS			MNR		
	M & R Station Equipment - City Gate	4,009	F_DISTR	DEM	PAVG				
	Services	88,852	F_DISTR	CUS			SERVICE		
	Meters & House Regulators	20,024							M_HR
	Other Equipment	-							DIS_PLANT
	Sub-total	***284,415***							
	Production Maintenance								
	Maintenance of Structures & Improvements	-							P_PLANT
	Maintenance of Production Equipment	8,194							P_PLANT
	Sub-total	***8,194***							
	TOTAL LABOR EXPENSE	**3,700,554**							

A & G Expenses

No.	Account Description	Amount	Function	Classifier	DEM	COM	CUS	REV	Internal
	Administrative & General Ops								
	Administrative & General Salaries	3,341,431							LABOR
	Office Supplies & Expenses	852,815							PD_PLANT
	Outside Services	1,032,630							PD_PLANT
	Property Insurance	25,719							PD_PLANT
	Injuries & Damages	335,053							PD_PLANT
	Employee Pensions & Benefits	1,409,073							LABOR
	Regulatory Commission Expenses	247,134							BASE
	General Advertising - A & G	21,979							PD_PLANT
	Misc. General Expenses	259,469							PD_PLANT
	Rents - A & G	331,663							LABOR
	Sub-total	***7,856,967***							
	Administrative & General Maintenance								
	General Plant	119,858							PD_PLANT
	Sub-total	***119,858***							
	TOTAL A&G EXPENSES	**7,976,825**							

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

Account Factor Choice
Test Period at Proposed Revenues

No. Account Description	Amount	Function	Classifier	DEM	COM	CUS	REV	Internal
Depreciation & Amortization Expense								
Intangible Plant								
Organization Expense	-							PD_PLANT
Franchise and Consent	-							PD_PLANT
Misc. Intangible Plant	-							PD_PLANT
UtiliCIS	-	F_CSERV	CUS			CUST		
Sub-total	**-**							
Production Plant								
Land and Land Rights	-	F_PRODU	DEM	DD				
Depreciable Land Rights	14,812	F_PRODU	DEM	DD				
Structures and Improvements	4,090	F_PRODU	DEM	DD				
Liquid Petroleum Gas Equipment	110,841	F_PRODU	DEM	DD				
Sub-total	***129,743***							
Distribution Plant								
Mains	1,076,974	F_DISTR	MIN	DD		CUST		
M & R Stations - General	7,910	F_DISTR	DEM	PAVG				
M & R Stations - City Gate	39,734	F_DISTR	DEM	PAVG				
Services	712,438	F_DISTR	CUS			SERVICE		
Meters	268,755	F_DISTR	CUS			MET		
Meter Installations	138,926	F_DISTR	CUS			MET		
Regulating Equipment	38,489	F_DISTR	CUS			REG		
M & R Stations - Industrial	73,721	F_DISTR	CUS			MNR		
Other Equipment	15,319							DIS_PLANT
Sub-total	***2,372,266***							
General Plant								
Structures and Improvements	57,405							PD_PLANT
Office Equipment	43,182							PD_PLANT
Vax System Equipment	-							PD_PLANT
Transportation Equipment	(15,426)							PD_PLANT
Tools and Work Equipment	11,165							PD_PLANT
Laboratory Equipment	-							PD_PLANT
Power Operated Equipment	44,696							PD_PLANT
Communication Equipment	-							PD_PLANT
Miscellaneous Equipment	11,020							PD_PLANT
Other Intangible Property	-							PD_PLANT
Plant Leased to Others	-							PD_PLANT
Sub-total	***152,042***							
TOTAL DEPRECIATION EXPENSE	**2,654,050**							
TOTAL EXPENSES	**16,256,572**							

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

Account Factor Choice
Test Period at Proposed Revenues

No.	Account Description	Amount	Function	Classifier	DEM	COM	CUS	REV	Internal
	Interest on Customer Deposits								
	Interest on Customer Deposits	74,347	F_DISTR	CUS			CUSDEP		
	Sub-total	***74,347***							
	TOTAL INTEREST ON CUSTOMER DEPOSITS	**74,347**							
	TAXES (other than Income)								
	Taxes (other than Income)								
	Payroll	511,237							LABOR
	Property	1,359,722							PD_PLANT
	Revenue Related	157,057							BASE
	Other Taxes	26,092							BASE
	Sub-total	***2,054,108***							
	TOTAL TAXES OTHER THAN INCOME	**2,054,108**							
	Income Taxes								
	Income Taxes	3,257,426							BASE
	Sub-total	***3,257,426***							
	TOTAL INCOME TAXES	**3,257,426**							
	REVENUE								
	Base Revenue	22,223,119	REV_BASE						
	Other Revenue	455,585	REV_OTHER						
	Unbilled	3,518	REV_UNBILLED						
	NGV Revenue	2,606	REV_BASE						
	Rent from Gas Property	21,600	REV_RENT						
	Margin Sharing	186,628	REV_THRU						
	Revenue Related Taxes	72,846	REV_THRU						
	-	-							
	-	-							
	-	-							
	-	-							
	TOTAL REVENUE	**22,965,902**							

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functionalization

Test Period at Proposed Revenues

No.	Account Descriptior	Amount	4 F_PRODU_DD	5 F_DISTR_DD	6 F_DISTR_PAVG	7 F_PRODU_SSALES	8 F_PRODU_CDD	9 F_DISTR_THRU	10 F_DISTR_CUST	11 F_DISTR_SERVICE	12 F_DISTR_MET	13 F_DISTR_REG	14 F_DISTR_MNR
Plant-in Service													
	Intangible Plant												
	Organization Expense	6,038	235	1,321	62	-	-	-	1,787	1,610	832	105	85
	Franchise and Consent	248	10	54	3	-	-	-	73	66	34	4	3
	Misc. Intangible Plant	3,000	117	656	31	-	-	-	888	800	413	52	42
	~	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***9,286***	***362***	***2,032***	***95***	***-***	***-***	***-***	***2,749***	***2,476***	***1,280***	***162***	***131***
	Production Plant												
	Land and Land Rights	1,236,589	1,236,589	-	-	-	-	-	-	-	-	-	-
	Depreciable Land Rights	-	-	-	-	-	-	-	-	-	-	-	-
	Structures and Improvements	224,540	224,540	-	-	-	-	-	-	-	-	-	-
	Liquid Petroleum Gas Equipment	3,346,977	3,346,977	-	-	-	-	-	-	-	-	-	-
	Sub-total	***4,808,105***	***4,808,105***	***-***	***-***	***-***	***-***	***-***	***-***	***-***	***-***	***-***	***-***
	Distribution Plant												
	Mains	63,275,399	-	26,892,045	-	-	-	-	36,383,355	-	-	-	-
	M & R Stations - General	209,392	-	-	209,392	-	-	-	-	-	-	-	-
	M & R Stations - City Gate	1,042,889	-	-	1,042,889	-	-	-	-	-	-	-	-
	Services	32,773,250	-	-	-	-	-	-	-	32,773,250	-	-	-
	Meters	11,037,872	-	-	-	-	-	-	-	-	11,037,872	-	-
	Meter Installations	5,901,032	-	-	-	-	-	-	-	-	5,901,032	-	-
	Regulating Equipment	2,143,325	-	-	-	-	-	-	-	-	-	2,143,325	-
	M & R Stations - Industrial	1,727,660	-	-	-	-	-	-	-	-	-	-	1,727,660
	Other Equipment	363,074	-	82,667	3,850	-	-	-	111,843	100,745	52,070	6,589	5,311
	Sub-total	***118,473,894***	***-***	***26,974,711***	***1,256,130***	***-***	***-***	***-***	***36,495,198***	***32,873,996***	***16,990,975***	***2,149,913***	***1,732,971***
	General Plant												
	Structures and Improvements	287,023	11,194	62,802	2,925	-	-	-	84,967	76,537	39,558	5,005	4,035
	Office Equipment	1,052,106	41,033	230,206	10,720	-	-	-	311,455	280,551	145,003	18,348	14,789
	Vax System Equipment	-	-	-	-	-	-	-	-	-	-	-	-
	Transportation Equipment	2,040,017	79,562	446,366	20,786	-	-	-	603,907	543,984	281,159	35,576	28,676
	Tools and Work Equipment	434,368	16,941	95,042	4,426	-	-	-	128,586	115,827	59,865	7,575	6,106
	Laboratory Equipment	-	-	-	-	-	-	-	-	-	-	-	-
	Power Operated Equipment	674,971	26,324	147,687	6,877	-	-	-	199,812	179,986	93,026	11,771	9,488
	Communication Equipment	-	-	-	-	-	-	-	-	-	-	-	-
	Miscellaneous Equipment	248,188	9,680	54,305	2,529	-	-	-	73,471	66,181	34,206	4,328	3,489
	Other Intangible Property	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Leased to Others	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***4,736,673***	***184,734***	***1,036,407***	***48,262***	***-***	***-***	***-***	***1,402,198***	***1,263,067***	***652,818***	***82,603***	***66,583***
	TOTAL PLANT-IN-SERVICE	**128,027,958**	**4,993,202**	**28,013,151**	**1,304,487**	**-**	**-**	**-**	**37,900,145**	**34,139,538**	**17,645,072**	**2,232,678**	**1,799,685**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functionalization
Test Period at Proposed Revenues

No.	Account Descriptior	Amount	15 F_DISTR_BADDEBT	16 F_CBILL_CUSDEP	17 F_CBILL_CUSADV	18 F_DISTR_CINSTALL	19 F_CBILL_CMET	20 F_CBILL_CREC	21 F_CBILL_BADDEBT	22 F_CBILL_SCUSTS	23 F_CSERV_SCUSTS	24 F_CSERV_CUST	25 F_DISTR_CUSDEP
Plant-in Service													
	Intangible Plant												
	Organization Expense	6,038	-	-	-	-	-	-	-	-	-	-	-
	Franchise and Consent	248	-	-	-	-	-	-	-	-	-	-	-
	Misc. Intangible Plant	3,000	-	-	-	-	-	-	-	-	-	-	-
	~	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***9,286***	-	-	-	-	-	-	-	-	-	-	-
	Production Plant												
	Land and Land Rights	1,236,589	-	-	-	-	-	-	-	-	-	-	-
	Depreciable Land Rights	-	-	-	-	-	-	-	-	-	-	-	-
	Structures and Improvements	224,540	-	-	-	-	-	-	-	-	-	-	-
	Liquid Petroleum Gas Equipment	3,346,977	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***4,808,105***	-	-	-	-	-	-	-	-	-	-	-
	Distribution Plant												
	Mains	63,275,399	-	-	-	-	-	-	-	-	-	-	-
	M & R Stations - General	209,392	-	-	-	-	-	-	-	-	-	-	-
	M & R Stations - City Gate	1,042,889	-	-	-	-	-	-	-	-	-	-	-
	Services	32,773,250	-	-	-	-	-	-	-	-	-	-	-
	Meters	11,037,872	-	-	-	-	-	-	-	-	-	-	-
	Meter Installations	5,901,032	-	-	-	-	-	-	-	-	-	-	-
	Regulating Equipment	2,143,325	-	-	-	-	-	-	-	-	-	-	-
	M & R Stations - Industrial	1,727,660	-	-	-	-	-	-	-	-	-	-	-
	Other Equipment	363,074	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***118,473,894***	-	-	-	-	-	-	-	-	-	-	-
	General Plant												
	Structures and Improvements	287,023	-	-	-	-	-	-	-	-	-	-	-
	Office Equipment	1,052,106	-	-	-	-	-	-	-	-	-	-	-
	Vax System Equipment	-	-	-	-	-	-	-	-	-	-	-	-
	Transportation Equipment	2,040,017	-	-	-	-	-	-	-	-	-	-	-
	Tools and Work Equipment	434,368	-	-	-	-	-	-	-	-	-	-	-
	Laboratory Equipment	-	-	-	-	-	-	-	-	-	-	-	-
	Power Operated Equipment	674,971	-	-	-	-	-	-	-	-	-	-	-
	Communication Equipment	-	-	-	-	-	-	-	-	-	-	-	-
	Miscellaneous Equipment	248,188	-	-	-	-	-	-	-	-	-	-	-
	Other Intangible Property	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Leased to Others	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***4,736,673***	-	-	-	-	-	-	-	-	-	-	-
	TOTAL PLANT-IN-SERVICE	**128,027,958**	-	-	-	-	-	-	-	-	-	-	-

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functionalization

Test Period at Proposed Revenues

			4	5	6	7	8	9	10	11	12	13	14
No.	**Account Descriptior**	**Amount**	**F_PRODU_DD**	**F_DISTR_DD**	**F_DISTR_PAVG**	**F_PRODU_SSALES**	**F_PRODU_CDD**	**F_DISTR_THRU**	**F_DISTR_CUST**	**F_DISTR_SERVICE**	**F_DISTR_MET**	**F_DISTR_REG**	**F_DISTR_MNR**
Accumulated Reserve for Depreciation													
	Intangible Plant												
	Organization Expense	-	-	-	-	-	-	-	-	-	-	-	-
	Franchise and Consent	-	-	-	-	-	-	-	-	-	-	-	-
	Misc. Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-
	~	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	-	-	-	-	-	-	-	-	-	-	-	-
	Production Plant												
	Land and Land Rights	(101,996)	(101,996)	-	-	-	-	-	-	-	-	-	-
	Depreciable Land Rights	-	-	-	-	-	-	-	-	-	-	-	-
	Structures and Improvements	(143,206)	(143,206)	-	-	-	-	-	-	-	-	-	-
	Liquid Petroleum Gas Equipment	(1,757,693)	(1,757,693)	-	-	-	-	-	-	-	-	-	-
	Sub-total	***(2,002,895)***	***(2,002,895)***	-	-	-	-	-	-	-	-	-	-
	Distribution Plant												
	Mains	(15,193,054)	-	(6,457,048)	-	-	-	-	(8,736,006)	-	-	-	-
	M & R Stations - General	(50,311)	-	-	(50,311)	-	-	-	-	-	-	-	-
	M & R Stations - City Gate	(482,002)	-	-	(482,002)	-	-	-	-	-	-	-	-
	Services	(11,632,528)	-	-	-	-	-	-	-	(11,632,528)	-	-	-
	Meters	(301,233)	-	-	-	-	-	-	-	-	(301,233)	-	-
	Meter Installations	(1,869,000)	-	-	-	-	-	-	-	-	(1,869,000)	-	-
	Regulating Equipment	(573,834)	-	-	-	-	-	-	-	-	-	(573,834)	-
	M & R Stations - Industrial	(649,227)	-	-	-	-	-	-	-	-	-	-	(649,227)
	Other Equipment	(54,182)	-	(12,336)	(574)	-	-	-	(16,690)	(15,034)	(7,771)	(983)	(793)
	Sub-total	***(30,805,372)***	-	***(6,469,384)***	***(532,888)***	-	-	-	***(8,752,696)***	***(11,647,562)***	***(2,178,004)***	***(574,817)***	***(650,020)***
	General Plant												
	Structures and Improvements	(285,944)	(11,152)	(62,566)	(2,914)	-	-	-	(84,648)	(76,249)	(39,409)	(4,987)	(4,020)
	Office Equipment	7,441	290	1,628	76	-	-	-	2,203	1,984	1,025	130	105
	Vax System Equipment	-	-	-	-	-	-	-	-	-	-	-	-
	Transportation Equipment	(1,140,185)	(44,468)	(249,478)	(11,617)	-	-	-	(337,529)	(304,038)	(157,143)	(19,884)	(16,028)
	Tools and Work Equipment	(36,706)	(1,432)	(8,031)	(374)	-	-	-	(10,866)	(9,788)	(5,059)	(640)	(516)
	Laboratory Equipment	-	-	-	-	-	-	-	-	-	-	-	-
	Power Operated Equipment	(371,658)	(14,495)	(81,321)	(3,787)	-	-	-	(110,022)	(99,105)	(51,223)	(6,481)	(5,224)
	Communication Equipment	57,843	2,256	12,656	589	-	-	-	17,123	15,424	7,972	1,009	813
	Miscellaneous Equipment	(170,666)	(6,656)	(37,343)	(1,739)	-	-	-	(50,522)	(45,509)	(23,522)	(2,976)	(2,399)
	Other Intangible Property	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Leased to Others	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***(1,939,874)***	***(75,657)***	***(424,454)***	***(19,766)***	-	-	-	***(574,261)***	***(517,281)***	***(267,357)***	***(33,829)***	***(27,269)***
	Retirement Work in Process	10,942	427	2,394	111	-	-	-	3,239	2,918	1,508	191	154
	TOTAL DEPRECIATION ACCRUAL	**(34,737,200)**	**(2,078,125)**	**(6,891,444)**	**(552,542)**	-	-	-	**(9,323,719)**	**(12,161,926)**	**(2,443,853)**	**(608,456)**	**(677,135)**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functionalization

Test Period at Proposed Revenues

Accumulated Reserve for Depreciation

No.	Account Description	Amount	15 F_DISTR_BADDEBT	16 F_CBILL_CUSDEP	17 F_CBILL_CUSADV	18 F_DISTR_CINSTALL	19 F_CBILL_CMET	20 F_CBILL_CREC	21 F_CBILL_BADDEBT	22 F_CBILL_SCUSTS	23 F_CSERV_SCUSTS	24 F_CSERV_CUST	25 F_DISTR_CUSDEP
	Intangible Plant												
	Organization Expense	-	-	-	-	-	-	-	-	-	-	-	-
	Franchise and Consent	-	-	-	-	-	-	-	-	-	-	-	-
	Misc. Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-
	~	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Production Plant												
	Land and Land Rights	(101,996)	-	-	-	-	-	-	-	-	-	-	-
	Depreciable Land Rights	-	-	-	-	-	-	-	-	-	-	-	-
	Structures and Improvements	(143,206)	-	-	-	-	-	-	-	-	-	-	-
	Liquid Petroleum Gas Equipment	(1,757,693)	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***(2,002,895)***	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution Plant												
	Mains	(15,193,054)	-	-	-	-	-	-	-	-	-	-	-
	M & R Stations - General	(50,311)	-	-	-	-	-	-	-	-	-	-	-
	M & R Stations - City Gate	(482,002)	-	-	-	-	-	-	-	-	-	-	-
	Services	(11,632,528)	-	-	-	-	-	-	-	-	-	-	-
	Meters	(301,233)	-	-	-	-	-	-	-	-	-	-	-
	Meter Installations	(1,869,000)	-	-	-	-	-	-	-	-	-	-	-
	Regulating Equipment	(573,834)	-	-	-	-	-	-	-	-	-	-	-
	M & R Stations - Industrial	(649,227)	-	-	-	-	-	-	-	-	-	-	-
	Other Equipment	(54,182)	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***(30,805,372)***	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	General Plant												
	Structures and Improvements	(285,944)	-	-	-	-	-	-	-	-	-	-	-
	Office Equipment	7,441	-	-	-	-	-	-	-	-	-	-	-
	Vax System Equipment	-	-	-	-	-	-	-	-	-	-	-	-
	Transportation Equipment	(1,140,185)	-	-	-	-	-	-	-	-	-	-	-
	Tools and Work Equipment	(36,706)	-	-	-	-	-	-	-	-	-	-	-
	Laboratory Equipment	-	-	-	-	-	-	-	-	-	-	-	-
	Power Operated Equipment	(371,658)	-	-	-	-	-	-	-	-	-	-	-
	Communication Equipment	57,843	-	-	-	-	-	-	-	-	-	-	-
	Miscellaneous Equipment	(170,666)	-	-	-	-	-	-	-	-	-	-	-
	Other Intangible Property	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Leased to Others	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***(1,939,874)***	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Retirement Work in Process	10,942	-	-	-	-	-	-	-	-	-	-	-
	TOTAL DEPRECIATION ACCRUAL	**(34,737,200)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functionalization

Test Period at Proposed Revenues

No.	Account Descriptior	Amount	4 F_PRODU_DD	5 F_DISTR_DD	6 F_DISTR_PAVG	7 F_PRODU_SSALES	8 F_PRODU_CDD	9 F_DISTR_THRU	10 F_DISTR_CUST	11 F_DISTR_SERVICE	12 F_DISTR_MET	13 F_DISTR_REG	14 F_DISTR_MNR
Rate Base Adjustments and Working Capital													
	Accumulated Deferred Income Ta>												
	Accelerated Depreciation	(23,689,863)	(1,417,227)	(4,699,785)	(376,819)	-	-	-	(6,358,533)	(8,294,116)	(1,666,644)	(414,951)	(461,788)
	Bad Debts	47,610	-	-	-	-	-	-	-	-	-	-	-
	Capital Interest & Overheads	176,551	-	40,198	1,872	-	-	-	54,386	48,989	25,320	3,204	2,582
	Pension	196,895	436	8,918	2,764	-	499	10,934	12,066	17,248	19,347	2,448	2,039
	Incentive Compenstation	207,781	460	9,411	2,917	-	527	11,539	12,733	18,201	20,417	2,583	2,151
	Other Post Retirement Benefits	210,778	467	9,547	2,959	-	534	11,705	12,916	18,464	20,711	2,621	2,182
	Insurance Reserves	(60,896)	-	(13,865)	(646)	-	-	-	(18,759)	(16,897)	(8,733)	(1,105)	(891)
	Self-Insurance	214,028	474	9,694	3,004	-	542	11,886	13,116	18,749	21,031	2,661	2,216
	Regulatory Asset	59,148	822	2,964	779	-	315	648	4,011	5,448	5,650	715	1,035
	Real Property and Repairs	(300,581)	-	(68,438)	(3,187)	-	-	-	(92,592)	(83,405)	(43,108)	(5,455)	(4,397)
	Sub-total	***(22,938,550)***	***(1,414,569)***	***(4,701,355)***	***(366,357)***	***-***	***2,417***	***46,711***	***(6,360,657)***	***(8,267,319)***	***(1,606,009)***	***(407,279)***	***(454,870)***
	Other Rate Base Adjustments												
	Customer Deposits	(1,698,560)	-	-	-	-	-	-	-	-	-	-	-
	Customer Advances	(27,692)	-	-	-	-	-	-	-	-	-	-	-
	Operating Reserves	(1,547,011)	(3,426)	(70,070)	(21,715)	-	(3,920)	(85,910)	(94,801)	(135,516)	(152,011)	(19,234)	(16,017)
	Nat. Gas in Storage	1,538,611	-	-	-	1,538,611	-	-	-	-	-	-	-
	Propane in Storage	264,685	-	-	-	-	264,685	-	-	-	-	-	-
	Plant M&S	365,301	14,247	79,930	3,722	-	-	-	108,140	97,410	50,347	6,370	5,135
	Cash Working Capital	1,028,566	14,294	51,549	13,551	-	5,479	11,266	69,743	94,746	98,257	12,433	18,000
	CWIP	662,641	-	281,623	-	-	-	-	381,019	-	-	-	-
	Sub-total	***586,541***	***25,115***	***343,031***	***(4,442)***	***1,538,611***	***266,244***	***(74,644)***	***464,101***	***56,641***	***(3,407)***	***(431)***	***7,118***
	TOTAL OTHER RATE BASE	**(22,352,008)**	**(1,389,453)**	**(4,358,324)**	**(370,799)**	**1,538,611**	**268,661**	**(27,933)**	**(5,896,556)**	**(8,210,678)**	**(1,609,416)**	**(407,710)**	**(447,752)**
TOTAL RATE BASE		**70,938,750**	**1,525,623**	**16,763,382**	**381,146**	**1,538,611**	**268,661**	**(27,933)**	**22,679,870**	**13,766,935**	**13,591,803**	**1,216,512**	**674,798**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functionalization

Test Period at Proposed Revenues

Rate Base Adjustments and Working Capital

No.	Account Description	Amount	15 F_DISTR_BADDEBT	16 F_CBILL_CUSDEP	17 F_CBILL_CUSADV	18 F_DISTR_CINSTALL	19 F_CBILL_CMET	20 F_CBILL_CREC	21 F_CBILL_BADDEBT	22 F_CBILL_SCUSTS	23 F_CSERV_SCUSTS	24 F_CSERV_CUST	25 F_DISTR_CUSDEP
	Accumulated Deferred Income Ta												
	Accelerated Depreciation	(23,689,863)	-	-	-	-	-	-	-	-	-	-	-
	Bad Debts	47,610	47,610	-	-	-	-	-	-	-	-	-	-
	Capital Interest & Overheads	176,551	-	-	-	-	-	-	-	-	-	-	-
	Pension	196,895	-	-	-	7,914	13,302	62,018	755	344	35,865	-	-
	Incentive Compenstation	207,781	-	-	-	8,351	14,037	65,447	796	363	37,848	-	-
	Other Post Retirement Benefits	210,778	-	-	-	8,472	14,239	66,391	808	368	38,394	-	-
	Insurance Reserves	(60,896)	-	-	-	-	-	-	-	-	-	-	-
	Self-Insurance	214,028	-	-	-	8,602	14,459	67,415	820	374	38,986	-	-
	Regulatory Asset	59,148	-	-	-	1,163	3,211	20,101	1,675	763	9,847	-	-
	Real Property and Repairs	(300,581)	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***(22,938,550)***	***47,610***	***-***	***-***	***34,502***	***59,248***	***281,371***	***4,853***	***2,212***	***160,941***	***-***	***-***
	Other Rate Base Adjustments												
	Customer Deposits	(1,698,560)	-	(1,698,560)	-	-	-	-	-	-	-	-	-
	Customer Advances	(27,692)	-	-	(27,692)	-	-	-	-	-	-	-	-
	Operating Reserves	(1,547,011)	-	-	-	(62,177)	(104,511)	(487,278)	(5,929)	(2,702)	(281,795)	-	-
	Nat. Gas in Storage	1,538,611	-	-	-	-	-	-	-	-	-	-	-
	Propane in Storage	264,685	-	-	-	-	-	-	-	-	-	-	-
	Plant M&S	365,301	-	-	-	-	-	-	-	-	-	-	-
	Cash Working Capital	1,028,566	-	-	-	20,229	55,844	349,546	29,121	13,271	171,236	-	-
	CWIP	662,641	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***586,541***	***-***	***(1,698,560)***	***(27,692)***	***(41,948)***	***(48,667)***	***(137,732)***	***23,193***	***10,570***	***(110,559)***	***-***	***-***
	TOTAL OTHER RATE BASE	**(22,352,008)**	**47,610**	**(1,698,560)**	**(27,692)**	**(7,446)**	**10,581**	**143,639**	**28,046**	**12,781**	**50,382**	**-**	**-**
TOTAL RATE BASE		**70,938,750**	**47,610**	**(1,698,560)**	**(27,692)**	**(7,446)**	**10,581**	**143,639**	**28,046**	**12,781**	**50,382**	**-**	**-**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functionalization

Test Period at Proposed Revenues

No. / Account Descriptior	Amount	4 F_PRODU_DD	5 F_DISTR_DD	6 F_DISTR_PAVG	7 F_PRODU_SSALES	8 F_PRODU_CDD	9 F_DISTR_THRU	10 F_DISTR_CUST	11 F_DISTR_SERVICE	12 F_DISTR_MET	13 F_DISTR_REG	14 F_DISTR_MNR
EXPENSES												
O & M Expenses												
Production Ops												
Liquefied Petroleum Gas Expenses	29,966	-	-	-	-	29,966	-	-	-	-	-	-
Liquefied Petroleum Gas	-	-	-	-	-	-	-	-	-	-	-	-
Operation Labor & Expense	30,718	30,718	-	-	-	-	-	-	-	-	-	-
Sub-total	***60,684***	***30,718***	-	-	-	***29,966***	-	-	-	-	-	-
Purchased Gas Expense												
-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-total	-	-	-	-	-	-	-	-	-	-	-	-
Distribution Ops												
Operation Supervision & Engineering	471,559	-	50,258	15,576	-	-	61,619	67,996	97,199	109,030	13,796	11,488
Distribution Load Dispatching - Direct	-	-	-	-	-	-	-	-	-	-	-	-
Distribution Load Dispatching	0	-	-	-	-	-	0	-	-	-	-	-
~	-	-	-	-	-	-	-	-	-	-	-	-
Mains & Services Expenses	490,800	-	137,416	-	-	-	-	185,916	167,469	-	-	-
M & R Station Expense - General	14,144	-	-	14,144	-	-	-	-	-	-	-	-
M & R Station Expense - Industrial	20,867	-	-	-	-	-	-	-	-	-	-	20,867
M & R Station Expenses - City Gate	10,523	-	-	10,523	-	-	-	-	-	-	-	-
Meter and House Regulator Expense	378,244	-	-	-	-	-	-	-	-	335,759	42,485	-
Customer Installation Expenses	66,046	-	-	-	-	-	-	-	-	-	-	-
Other Expenses - Distribution	3,236	-	737	34	-	-	-	997	898	464	59	47
Rents - Distribution	5,881	-	1,339	62	-	-	-	1,812	1,632	843	107	86
Negative Salvage Value	-	-	-	-	-	-	-	-	-	-	-	-
Sub-total	***1,461,299***	-	***189,750***	***40,338***	-	-	***61,619***	***256,720***	***267,197***	***446,097***	***56,446***	***32,489***
Customer Service Ops												
Supervision - Customer Accounting	268,386	-	-	-	-	-	-	-	-	-	-	-
Meter Reading Expenses	271,965	-	-	-	-	-	-	-	-	-	-	-
Customer Records & Collection Expenses	1,702,321	-	-	-	-	-	-	-	-	-	-	-
~	-	-	-	-	-	-	-	-	-	-	-	-
Uncollectible Accounts	141,823	-	-	-	-	-	-	-	-	-	-	-
Info & Instructional Exp	64,633	-	-	-	-	-	-	-	-	-	-	-
Sub-total	***2,449,128***	-	-	-	-	-	-	-	-	-	-	-
Sales Ops												
-	-	-	-	-	-	-	-	-	-	-	-	-
Demonstrating & Selling Expenses	791,955	-	-	-	-	-	-	-	-	-	-	-
Advertising Expenses	144,614	-	-	-	-	-	-	-	-	-	-	-
Sub-total	***936,569***	-	-	-	-	-	-	-	-	-	-	-
Production Maintenance												
Maintenance of Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-
Maintenance of Production Equipment	47,461	47,461	-	-	-	-	-	-	-	-	-	-
Sub-total	***47,461***	***47,461***	-	-	-	-	-	-	-	-	-	-
Distribution Maintenance												
Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-
Mains & Services Expenses	315,432	-	88,316	-	-	-	-	119,486	107,630	-	-	-
M & R Station Equipment - General	28,701	-	-	28,701	-	-	-	-	-	-	-	-
M & R Station Equipment - Industrial	65,713	-	-	-	-	-	-	-	-	-	-	65,713
M & R Station Equipment - City Gate	4,898	-	-	4,898	-	-	-	-	-	-	-	-
Services	138,657	-	-	-	-	-	-	-	138,657	-	-	-
Meters & House Regulators	100,120	-	-	-	-	-	-	-	-	88,874	11,246	-
Other Equipment	17,035	-	3,879	181	-	-	-	5,248	4,727	2,443	309	249
Sub-total	***670,556***	-	***92,194***	***33,780***	-	-	-	***124,734***	***251,014***	***91,317***	***11,555***	***65,962***
TOTAL O & M EXPENSES	**5,625,697**	**78,179**	**281,944**	**74,118**	-	**29,966**	**61,619**	**381,454**	**518,211**	**537,414**	**68,000**	**98,451**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functionalization
Test Period at Proposed Revenues

No.	Account Descriptior	Amount	15 F_DISTR_BADDEBT	16 F_CBILL_CUSDEP	17 F_CBILL_CUSADV	18 F_DISTR_CINSTALL	19 F_CBILL_CMET	20 F_CBILL_CREC	21 F_CBILL_BADDEBT	22 F_CBILL_SCUSTS	23 F_CSERV_SCUSTS	24 F_CSERV_CUST	25 F_DISTR_CUSDEP
EXPENSES													
O & M Expenses													
	Production Ops												
	Liquefied Petroleum Gas Expenses	29,966	-	-	-	-	-	-	-	-	-	-	-
	Liquefied Petroleum Gas	-	-	-	-	-	-	-	-	-	-	-	-
	Operation Labor & Expense	30,718	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***60,684***	-	-	-	-	-	-	-	-	-	-	-
	Purchased Gas Expense												
	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution Ops												
	Operation Supervision & Engineering	471,559	-	-	-	44,597	-	-	-	-	-	-	-
	Distribution Load Dispatching - Direct	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution Load Dispatching	0	-	-	-	-	-	-	-	-	-	-	-
	~	-	-	-	-	-	-	-	-	-	-	-	-
	Mains & Services Expenses	490,800	-	-	-	-	-	-	-	-	-	-	-
	M & R Station Expense - General	14,144	-	-	-	-	-	-	-	-	-	-	-
	M & R Station Expense - Industrial	20,867	-	-	-	-	-	-	-	-	-	-	-
	M & R Station Expenses - City Gate	10,523	-	-	-	-	-	-	-	-	-	-	-
	Meter and House Regulator Expense	378,244	-	-	-	-	-	-	-	-	-	-	-
	Customer Installation Expenses	66,046	-	-	-	66,046	-	-	-	-	-	-	-
	Other Expenses - Distribution	3,236	-	-	-	-	-	-	-	-	-	-	-
	Rents - Distribution	5,881	-	-	-	-	-	-	-	-	-	-	-
	Negative Salvage Value	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***1,461,299***	-	-	-	***110,643***	-	-	-	-	-	-	-
	Customer Service Ops												
	Supervision - Customer Accounting	268,386	-	-	-	-	33,471	209,506	17,454	7,954	-	-	-
	Meter Reading Expenses	271,965	-	-	-	-	271,965	-	-	-	-	-	-
	Customer Records & Collection Expenses	1,702,321	-	-	-	-	-	1,702,321	-	-	-	-	-
	~	-	-	-	-	-	-	-	-	-	-	-	-
	Uncollectible Accounts	141,823	-	-	-	-	-	-	141,823	-	-	-	-
	Info & Instructional Exp	64,633	-	-	-	-	-	-	-	64,633	-	-	-
	Sub-total	***2,449,128***	-	-	-	-	***305,436***	***1,911,827***	***159,277***	***72,587***	-	-	-
	Sales Ops												
	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demonstrating & Selling Expenses	791,955	-	-	-	-	-	-	-	-	791,955	-	-
	Advertising Expenses	144,614	-	-	-	-	-	-	-	-	144,614	-	-
	Sub-total	***936,569***	-	-	-	-	-	-	-	-	***936,569***	-	-
	Production Maintenance												
	Maintenance of Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-
	Maintenance of Production Equipment	47,461	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***47,461***	-	-	-	-	-	-	-	-	-	-	-
	Distribution Maintenance												
	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-
	Mains & Services Expenses	315,432	-	-	-	-	-	-	-	-	-	-	-
	M & R Station Equipment - General	28,701	-	-	-	-	-	-	-	-	-	-	-
	M & R Station Equipment - Industrial	65,713	-	-	-	-	-	-	-	-	-	-	-
	M & R Station Equipment - City Gate	4,898	-	-	-	-	-	-	-	-	-	-	-
	Services	138,657	-	-	-	-	-	-	-	-	-	-	-
	Meters & House Regulators	100,120	-	-	-	-	-	-	-	-	-	-	-
	Other Equipment	17,035	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***670,556***	-	-	-	-	-	-	-	-	-	-	-
	TOTAL O & M EXPENSES	**5,625,697**	-	-	-	**110,643**	**305,436**	**1,911,827**	**159,277**	**72,587**	**936,569**	-	-

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functionalization

Test Period at Proposed Revenues

No.	Account Descriptior	Amount	4 F_PRODU_DD	5 F_DISTR_DD	6 F_DISTR_PAVG	7 F_PRODU_SSALES	8 F_PRODU_CDD	9 F_DISTR_THRU	10 F_DISTR_CUST	11 F_DISTR_SERVICE	12 F_DISTR_MET	13 F_DISTR_REG	14 F_DISTR_MNR
Labor Expense													
	Production Ops												
	Liquefied Petroleum Gas Expenses	9,377	-	-	-	-	9,377	-	-	-	-	-	-
	Liquefied Petroleum Gas	-	-	-	-	-	-	-	-	-	-	-	-
	Operation Labor & Expense	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***9,377***	-	-	-	-	***9,377***	-	-	-	-	-	-
	Distribution Ops												
	Operation Supervision & Engineering	407,188	-	43,397	13,449	-	-	53,208	58,714	83,931	94,147	11,913	9,920
	Distribution Load Dispatching	152,294	-	-	-	-	-	152,294	-	-	-	-	-
	~	-	-	-	-	-	-	-	-	-	-	-	-
	Mains & Services Expenses	317,881	-	89,001	-	-	-	-	120,414	108,466	-	-	-
	M & R Station Expense - General	778	-	-	778	-	-	-	-	-	-	-	-
	M & R Station Expense - Industrial	10,600	-	-	-	-	-	-	-	-	-	-	10,600
	M & R Station Expenses - City Gate	5,612	-	-	5,612	-	-	-	-	-	-	-	-
	Meter and House Regulator Expense	283,521	-	-	-	-	-	-	-	-	251,676	31,845	-
	Customer Installation Expenses	110,223	-	-	-	-	-	-	-	-	-	-	-
	Other Expenses - Distribution	153	-	35	2	-	-	-	47	42	22	3	2
	Rents - Distribution	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***1,288,251***	-	***132,434***	***19,840***	-	-	***205,502***	***179,175***	***192,439***	***345,845***	***43,761***	***20,522***
	Customer Service Ops												
	Supervision - Customer Accounting	218,064	-	-	-	-	-	-	-	-	-	-	-
	Meter Reading Expenses	222,802	-	-	-	-	-	-	-	-	-	-	-
	Customer Records & Collection Expenses	995,377	-	-	-	-	-	-	-	-	-	-	-
	Uncollectible Accounts	-	-	-	-	-	-	-	-	-	-	-	-
	Customer Assistance Expenses	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***1,436,243***	-	-	-	-	-	-	-	-	-	-	-
	Sales Ops												
	Demonstrating & Selling Expenses	674,073	-	-	-	-	-	-	-	-	-	-	-
	Advertising Expenses	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***674,073***	-	-	-	-	-	-	-	-	-	-	-
	Distribution Maintenance												
	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-
	Mains & Services Expenses	125,645	-	35,179	-	-	-	-	47,594	42,872	-	-	-
	M & R Station Equipment - General	28,095	-	-	28,095	-	-	-	-	-	-	-	-
	M & R Station Equipment - Industrial	17,790	-	-	-	-	-	-	-	-	-	-	17,790
	M & R Station Equipment - City Gate	4,009	-	-	4,009	-	-	-	-	-	-	-	-
	Services	88,852	-	-	-	-	-	-	-	88,852	-	-	-
	Meters & House Regulators	20,024	-	-	-	-	-	-	-	-	17,775	2,249	-
	Other Equipment	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***284,415***	-	***35,179***	***32,105***	-	-	-	***47,594***	***131,724***	***17,775***	***2,249***	***17,790***
	Production Maintenance												
	Maintenance of Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-
	Maintenance of Production Equipment	8,194	8,194	-	-	-	-	-	-	-	-	-	-
	Sub-total	***8,194***	***8,194***	-	-	-	-	-	-	-	-	-	-
	TOTAL LABOR EXPENSE	**3,700,554**	**8,194**	**167,612**	**51,945**	**-**	**9,377**	**205,502**	**226,770**	**324,163**	**363,619**	**46,010**	**38,313**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functionalization

Test Period at Proposed Revenues

No.	Account Descriptior	Amount	15 F_DISTR_BADDEBT	16 F_CBILL_CUSDEP	17 F_CBILL_CUSADV	18 F_DISTR_CINSTALL	19 F_CBILL_CMET	20 F_CBILL_CREC	21 F_CBILL_BADDEBT	22 F_CBILL_SCUSTS	23 F_CSERV_SCUSTS	24 F_CSERV_CUST	25 F_DISTR_CUSDEP
Labor Expense													
	Production Ops												
	Liquefied Petroleum Gas Expenses	9,377	-	-	-	-	-	-	-	-	-	-	-
	Liquefied Petroleum Gas	-	-	-	-	-	-	-	-	-	-	-	-
	Operation Labor & Expense	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***9,377***	-	-	-	-	-	-	-	-	-	-	-
	Distribution Ops												
	Operation Supervision & Engineering	407,188	-	-	-	38,509	-	-	-	-	-	-	-
	Distribution Load Dispatching	152,294	-	-	-	-	-	-	-	-	-	-	-
	~	-	-	-	-	-	-	-	-	-	-	-	-
	Mains & Services Expenses	317,881	-	-	-	-	-	-	-	-	-	-	-
	M & R Station Expense - General	778	-	-	-	-	-	-	-	-	-	-	-
	M & R Station Expense - Industrial	10,600	-	-	-	-	-	-	-	-	-	-	-
	M & R Station Expenses - City Gate	5,612	-	-	-	-	-	-	-	-	-	-	-
	Meter and House Regulator Expense	283,521	-	-	-	-	-	-	-	-	-	-	-
	Customer Installation Expenses	110,223	-	-	-	110,223	-	-	-	-	-	-	-
	Other Expenses - Distribution	153	-	-	-	-	-	-	-	-	-	-	-
	Rents - Distribution	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***1,288,251***	-	-	-	***148,733***	-	-	-	-	-	-	-
	Customer Service Ops												
	Supervision - Customer Accounting	218,064	-	-	-	-	27,195	170,224	14,182	6,463	-	-	-
	Meter Reading Expenses	222,802	-	-	-	-	222,802	-	-	-	-	-	-
	Customer Records & Collection Expenses	995,377	-	-	-	-	-	995,377	-	-	-	-	-
	Uncollectible Accounts	-	-	-	-	-	-	-	-	-	-	-	-
	Customer Assistance Expenses	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***1,436,243***	-	-	-	-	***249,997***	***1,165,601***	***14,182***	***6,463***	-	-	-
	Sales Ops												
	Demonstrating & Selling Expenses	674,073	-	-	-	-	-	-	-	-	674,073	-	-
	Advertising Expenses	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***674,073***	-	-	-	-	-	-	-	-	***674,073***	-	-
	Distribution Maintenance												
	Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-
	Mains & Services Expenses	125,645	-	-	-	-	-	-	-	-	-	-	-
	M & R Station Equipment - General	28,095	-	-	-	-	-	-	-	-	-	-	-
	M & R Station Equipment - Industrial	17,790	-	-	-	-	-	-	-	-	-	-	-
	M & R Station Equipment - City Gate	4,009	-	-	-	-	-	-	-	-	-	-	-
	Services	88,852	-	-	-	-	-	-	-	-	-	-	-
	Meters & House Regulators	20,024	-	-	-	-	-	-	-	-	-	-	-
	Other Equipment	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***284,415***	-	-	-	-	-	-	-	-	-	-	-
	Production Maintenance												
	Maintenance of Structures & Improvements	-	-	-	-	-	-	-	-	-	-	-	-
	Maintenance of Production Equipment	8,194	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***8,194***	-	-	-	-	-	-	-	-	-	-	-
	TOTAL LABOR EXPENSE	**3,700,554**	-	-	-	**148,733**	**249,997**	**1,165,601**	**14,182**	**6,463**	**674,073**	-	-

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functionalization

Test Period at Proposed Revenues

No.	Account Descriptior	Amount	4 F_PRODU_DD	5 F_DISTR_DD	6 F_DISTR_PAVG	7 F_PRODU_SSALES	8 F_PRODU_CDD	9 F_DISTR_THRU	10 F_DISTR_CUST	11 F_DISTR_SERVICE	12 F_DISTR_MET	13 F_DISTR_REG	14 F_DISTR_MNR
A & G Expenses													
	Administrative & General Ops												
	Administrative & General Salaries	3,341,431	7,399	151,346	46,904	-	8,467	185,559	204,763	292,704	328,332	41,545	34,595
	Office Supplies & Expenses	852,815	33,261	186,600	8,689	-	-	-	252,459	227,409	117,537	14,872	11,988
	Outside Services	1,032,630	40,273	225,945	10,522	-	-	-	305,690	275,358	142,319	18,008	14,516
	Property Insurance	25,719	1,003	5,627	262	-	-	-	7,613	6,858	3,545	449	362
	Injuries & Damages	335,053	13,067	73,311	3,414	-	-	-	99,186	89,344	46,178	5,843	4,710
	Employee Pensions & Benefits	1,409,073	3,120	63,822	19,779	-	3,571	78,250	86,348	123,433	138,457	17,519	14,589
	Regulatory Commission Expenses	247,134	5,315	58,400	1,328	5,360	936	(97)	79,011	47,961	47,351	4,238	2,351
	General Advertising - A & G	21,979	857	4,809	224	-	-	-	6,507	5,861	3,029	383	309
	Misc. General Expenses	259,469	10,120	56,773	2,644	-	-	-	76,811	69,189	35,761	4,525	3,647
	Rents - A & G	331,663	734	15,022	4,656	-	840	18,418	20,324	29,053	32,590	4,124	3,434
	Sub-total	***7,856,967***	***115,150***	***841,656***	***98,421***	***5,360***	***13,814***	***282,130***	***1,138,711***	***1,167,170***	***895,096***	***111,506***	***90,499***
	Administrative & General Maintenance												
	General Plant	119,858	4,675	26,226	1,221	-	-	-	35,482	31,961	16,519	2,090	1,685
	Sub-total	***119,858***	***4,675***	***26,226***	***1,221***	***-***	***-***	***-***	***35,482***	***31,961***	***16,519***	***2,090***	***1,685***
	TOTAL A&G EXPENSES	**7,976,825**	**119,824**	**867,882**	**99,642**	**5,360**	**13,814**	**282,130**	**1,174,193**	**1,199,131**	**911,615**	**113,596**	**92,184**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functionalization
Test Period at Proposed Revenues

No.	Account Descriptior	Amount	15 F_DISTR_BADDEBT	16 F_CBILL_CUSDEP	17 F_CBILL_CUSADV	18 F_DISTR_CINSTALL	19 F_CBILL_CMET	20 F_CBILL_CREC	21 F_CBILL_BADDEBT	22 F_CBILL_SCUSTS	23 F_CSERV_SCUSTS	24 F_CSERV_CUST	25 F_DISTR_CUSDEP
A & G Expenses													
	Administrative & General Ops												
	Administrative & General Salaries	3,341,431	-	-	-	134,299	225,736	1,052,485	12,805	5,836	608,657	-	-
	Office Supplies & Expenses	852,815	-	-	-	-	-	-	-	-	-	-	-
	Outside Services	1,032,630	-	-	-	-	-	-	-	-	-	-	-
	Property Insurance	25,719	-	-	-	-	-	-	-	-	-	-	-
	Injuries & Damages	335,053	-	-	-	-	-	-	-	-	-	-	-
	Employee Pensions & Benefits	1,409,073	-	-	-	56,633	95,192	443,830	5,400	2,461	256,669	-	-
	Regulatory Commission Expenses	247,134	166	(5,917)	(96)	(26)	37	500	98	45	176	-	-
	General Advertising - A & G	21,979	-	-	-	-	-	-	-	-	-	-	-
	Misc. General Expenses	259,469	-	-	-	-	-	-	-	-	-	-	-
	Rents - A & G	331,663	-	-	-	13,330	22,406	104,467	1,271	579	60,414	-	-
	Sub-total	***7,856,967***	***166***	***(5,917)***	***(96)***	***204,237***	***343,371***	***1,601,283***	***19,574***	***8,920***	***925,916***	***-***	***-***
	Administrative & General Maintenance												
	General Plant	119,858	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***119,858***	***-***	***-***	***-***	***-***	***-***	***-***	***-***	***-***	***-***	***-***	***-***
	TOTAL A&G EXPENSES	**7,976,825**	**166**	**(5,917)**	**(96)**	**204,237**	**343,371**	**1,601,283**	**19,574**	**8,920**	**925,916**	**-**	**-**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functionalization

Test Period at Proposed Revenues

No.	Account Description	Amount	4 F_PRODU_DD	5 F_DISTR_DD	6 F_DISTR_PAVG	7 F_PRODU_SSALES	8 F_PRODU_CDD	9 F_DISTR_THRU	10 F_DISTR_CUST	11 F_DISTR_SERVICE	12 F_DISTR_MET	13 F_DISTR_REG	14 F_DISTR_MNR
Depreciation & Amortization Expense													
	Intangible Plant												
	Organization Expense	-	-	-	-	-	-	-	-	-	-	-	-
	Franchise and Consent	-	-	-	-	-	-	-	-	-	-	-	-
	Misc. Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-
	UtiliCIS	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	-	-	-	-	-	-	-	-	-	-	-	-
	Production Plant												
	Land and Land Rights	-	-	-	-	-	-	-	-	-	-	-	-
	Depreciable Land Rights	14,812	14,812	-	-	-	-	-	-	-	-	-	-
	Structures and Improvements	4,090	4,090	-	-	-	-	-	-	-	-	-	-
	Liquid Petroleum Gas Equipment	110,841	110,841	-	-	-	-	-	-	-	-	-	-
	Sub-total	***129,743***	***129,743***	-	-	-	-	-	-	-	-	-	-
	Distribution Plant												
	Mains	1,076,974	-	457,714	-	-	-	-	619,260	-	-	-	-
	M & R Stations - General	7,910	-	-	7,910	-	-	-	-	-	-	-	-
	M & R Stations - City Gate	39,734	-	-	39,734	-	-	-	-	-	-	-	-
	Services	712,438	-	-	-	-	-	-	-	712,438	-	-	-
	Meters	268,755	-	-	-	-	-	-	-	-	268,755	-	-
	Meter Installations	138,926	-	-	-	-	-	-	-	-	138,926	-	-
	Regulating Equipment	38,489	-	-	-	-	-	-	-	-	-	38,489	-
	M & R Stations - Industrial	73,721	-	-	-	-	-	-	-	-	-	-	73,721
	Other Equipment	15,319	-	3,488	162	-	-	-	4,719	4,251	2,197	278	224
	Sub-total	***2,372,266***	-	***461,202***	***47,807***	-	-	-	***623,979***	***716,689***	***409,877***	***38,767***	***73,945***
	General Plant												
	Structures and Improvements	57,405	2,239	12,560	585	-	-	-	16,993	15,307	7,912	1,001	807
	Office Equipment	43,182	1,684	9,448	440	-	-	-	12,783	11,515	5,951	753	607
	Vax System Equipment	-	-	-	-	-	-	-	-	-	-	-	-
	Transportation Equipment	(15,426)	(602)	(3,375)	(157)	-	-	-	(4,567)	(4,113)	(2,126)	(269)	(217)
	Tools and Work Equipment	11,165	435	2,443	114	-	-	-	3,305	2,977	1,539	195	157
	Laboratory Equipment	-	-	-	-	-	-	-	-	-	-	-	-
	Power Operated Equipment	44,696	1,743	9,780	455	-	-	-	13,231	11,919	6,160	779	628
	Communication Equipment	-	-	-	-	-	-	-	-	-	-	-	-
	Miscellaneous Equipment	11,020	430	2,411	112	-	-	-	3,262	2,938	1,519	192	155
	Other Intangible Property	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Leased to Others	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***152,042***	***5,930***	***33,267***	***1,549***	-	-	-	***45,009***	***40,543***	***20,955***	***2,651***	***2,137***
	TOTAL DEPRECIATION EXPENSE	**2,654,050**	**135,672**	**494,469**	**49,356**	-	-	-	**668,988**	**757,232**	**430,832**	**41,419**	**76,082**
TOTAL EXPENSES		**16,256,572**	**333,676**	**1,644,295**	**223,117**	**5,360**	**43,780**	**343,749**	**2,224,635**	**2,474,574**	**1,879,862**	**223,015**	**266,717**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functionalization

Test Period at Proposed Revenues

No. / Account Description	Amount	15 F_DISTR_BADDEBT	16 F_CBILL_CUSDEP	17 F_CBILL_CUSADV	18 F_DISTR_CINSTALL	19 F_CBILL_CMET	20 F_CBILL_CREC	21 F_CBILL_BADDEBT	22 F_CBILL_SCUSTS	23 F_CSERV_SCUSTS	24 F_CSERV_CUST	25 F_DISTR_CUSDEP
Depreciation & Amortization Expense												
Intangible Plant												
Organization Expense	-	-	-	-	-	-	-	-	-	-	-	-
Franchise and Consent	-	-	-	-	-	-	-	-	-	-	-	-
Misc. Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-
UtiliCIS	-	-	-	-	-	-	-	-	-	-	-	-
Sub-total	-	-	-	-	-	-	-	-	-	-	-	-
Production Plant												
Land and Land Rights	-	-	-	-	-	-	-	-	-	-	-	-
Depreciable Land Rights	14,812	-	-	-	-	-	-	-	-	-	-	-
Structures and Improvements	4,090	-	-	-	-	-	-	-	-	-	-	-
Liquid Petroleum Gas Equipment	110,841	-	-	-	-	-	-	-	-	-	-	-
Sub-total	***129,743***	-	-	-	-	-	-	-	-	-	-	-
Distribution Plant												
Mains	1,076,974	-	-	-	-	-	-	-	-	-	-	-
M & R Stations - General	7,910	-	-	-	-	-	-	-	-	-	-	-
M & R Stations - City Gate	39,734	-	-	-	-	-	-	-	-	-	-	-
Services	712,438	-	-	-	-	-	-	-	-	-	-	-
Meters	268,755	-	-	-	-	-	-	-	-	-	-	-
Meter Installations	138,926	-	-	-	-	-	-	-	-	-	-	-
Regulating Equipment	38,489	-	-	-	-	-	-	-	-	-	-	-
M & R Stations - Industrial	73,721	-	-	-	-	-	-	-	-	-	-	-
Other Equipment	15,319	-	-	-	-	-	-	-	-	-	-	-
Sub-total	***2,372,266***	-	-	-	-	-	-	-	-	-	-	-
General Plant												
Structures and Improvements	57,405	-	-	-	-	-	-	-	-	-	-	-
Office Equipment	43,182	-	-	-	-	-	-	-	-	-	-	-
Vax System Equipment	-	-	-	-	-	-	-	-	-	-	-	-
Transportation Equipment	(15,426)	-	-	-	-	-	-	-	-	-	-	-
Tools and Work Equipment	11,165	-	-	-	-	-	-	-	-	-	-	-
Laboratory Equipment	-	-	-	-	-	-	-	-	-	-	-	-
Power Operated Equipment	44,696	-	-	-	-	-	-	-	-	-	-	-
Communication Equipment	-	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous Equipment	11,020	-	-	-	-	-	-	-	-	-	-	-
Other Intangible Property	-	-	-	-	-	-	-	-	-	-	-	-
Plant Leased to Others	-	-	-	-	-	-	-	-	-	-	-	-
Sub-total	***152,042***	-	-	-	-	-	-	-	-	-	-	-
TOTAL DEPRECIATION EXPENSE	**2,654,050**	-	-	-	-	-	-	-	-	-	-	-
TOTAL EXPENSES	**16,256,572**	**166**	**(5,917)**	**(96)**	**314,879**	**648,808**	**3,513,110**	**178,852**	**81,507**	**1,862,485**	-	-

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functionalization

Test Period at Proposed Revenues

No.	Account Descriptior	Amount	4 F_PRODU_DD	5 F_DISTR_DD	6 F_DISTR_PAVG	7 F_PRODU_SSALES	8 F_PRODU_CDD	9 F_DISTR_THRU	10 F_DISTR_CUST	11 F_DISTR_SERVICE	12 F_DISTR_MET	13 F_DISTR_REG	14 F_DISTR_MNR
Interest on Customer Deposits													
	Interest on Customer Deposits	74,347	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	***74,347***	-	-	-	-	-	-	-	-	-	-	-
	TOTAL INTEREST ON CUSTOMER DEPOSITS	**74,347**	-	-	-	-	-	-	-	-	-	-	-
TAXES (other than Income)													
	Taxes (other than Income												
	Payroll	511,237	1,132	23,156	7,176	-	1,295	28,390	31,329	44,784	50,235	6,356	5,293
	Property	1,359,722	53,030	297,514	13,854	-	-	-	402,519	362,579	187,400	23,712	19,114
	Revenue Related	157,057	3,378	37,114	844	3,406	595	(62)	50,213	30,480	30,092	2,693	1,494
	Other Taxes	26,092	561	6,166	140	566	99	(10)	8,342	5,064	4,999	447	248
	Sub-total	***2,054,108***	***58,101***	***363,949***	***22,015***	***3,972***	***1,989***	***28,318***	***492,402***	***442,906***	***272,725***	***33,209***	***26,149***
	TOTAL TAXES OTHER THAN INCOME	**2,054,108**	**58,101**	**363,949**	**22,015**	**3,972**	**1,989**	**28,318**	**492,402**	**442,906**	**272,725**	**33,209**	**26,149**
Income Taxes													
	0												
	Income Taxes	3,257,426	70,055	769,755	17,502	70,651	12,337	(1,283)	1,041,434	632,162	624,120	55,861	30,986
	Sub-total	***3,257,426***	***70,055***	***769,755***	***17,502***	***70,651***	***12,337***	***(1,283)***	***1,041,434***	***632,162***	***624,120***	***55,861***	***30,986***
	TOTAL INCOME TAXES	**3,257,426**	**70,055**	**769,755**	**17,502**	**70,651**	**12,337**	**(1,283)**	**1,041,434**	**632,162**	**624,120**	**55,861**	**30,986**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Functionalization

Test Period at Proposed Revenues

No.	Account Description	Amount	15 F_DISTR_BADDEBT	16 F_CBILL_CUSDEP	17 F_CBILL_CUSADV	18 F_DISTR_CINSTALL	19 F_CBILL_CMET	20 F_CBILL_CREC	21 F_CBILL_BADDEBT	22 F_CBILL_SCUSTS	23 F_CSERV_SCUSTS	24 F_CSERV_CUST	25 F_DISTR_CUSDEP
Interest on Customer Deposits													
	Interest on Customer Deposits	74,347	-	-	-	-	-	-	-	-	-	-	74,347
	Sub-total	***74,347***	-	-	-	-	-	-	-	-	-	-	***74,347***
	TOTAL INTEREST ON CUSTOMER DEPOSITS	**74,347**	-	-	-	-	-	-	-	-	-	-	**74,347**
TAXES (other than Income)													
	Taxes (other than Income												
	Payroll	511,237	-	-	-	20,548	34,538	161,030	1,959	893	93,124	-	-
	Property	1,359,722	-	-	-	-	-	-	-	-	-	-	-
	Revenue Related	157,057	105	(3,761)	(61)	(16)	23	318	62	28	112	-	-
	Other Taxes	26,092	18	(625)	(10)	(3)	4	53	10	5	19	-	-
	Sub-total	***2,054,108***	***123***	***(4,385)***	***(71)***	***20,528***	***34,565***	***161,400***	***2,032***	***926***	***93,254***	-	-
	TOTAL TAXES OTHER THAN INCOME	**2,054,108**	**123**	**(4,385)**	**(71)**	**20,528**	**34,565**	**161,400**	**2,032**	**926**	**93,254**	-	-
Income Taxes													
	0												
	Income Taxes	3,257,426	2,186	(77,996)	(1,272)	(342)	486	6,596	1,288	587	2,313	-	-
	Sub-total	***3,257,426***	***2,186***	***(77,996)***	***(1,272)***	***(342)***	***486***	***6,596***	***1,288***	***587***	***2,313***	-	-
	TOTAL INCOME TAXES	**3,257,426**	**2,186**	**(77,996)**	**(1,272)**	**(342)**	**486**	**6,596**	**1,288**	**587**	**2,313**	-	-

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Class Allocation

Test Period at Proposed Revenues

Function	Class	Func/Class	Allocator	Line Ref. Total	5 RS-1	6 RS-2	7 GS	8 MVS	9 LVS	10 HLFS	11 GLR	12 IS
RATE BASE												
F_PRODU	DEM	F_PRODU_DEM	DD	1,525,623	19,692	736,957	97,051	105,268	285,530	281,125	-	-
F_DISTR	DEM	F_DISTR_DEM	DD	16,763,382	216,368	8,097,603	1,066,385	1,156,679	3,137,373	3,088,974	-	-
F_DISTR	DEM	F_DISTR_DEM	PAVG	381,146	2,827	125,087	13,775	17,441	79,158	139,317	4	3,537
F_PRODU	COM	F_PRODU_COM	SSALES	1,538,611	24,011	1,110,940	120,312	123,238	91,033	69,056	20	-
F_PRODU	COM	F_PRODU_COM	CDD	268,661	3,468	129,778	17,091	18,538	50,282	49,506	-	-
F_DISTR	COM	F_DISTR_COM	THRU	(27,933)	(206)	(9,128)	(1,003)	(1,272)	(5,806)	(10,255)	(0)	(262)
F_DISTR	CUS	F_DISTR_CUS	CUST	22,679,870	2,047,799	18,761,462	1,380,928	235,451	99,188	151,671	2,407	963
F_DISTR	CUS	F_DISTR_CUS	SERVICE	13,766,935	1,236,117	11,298,384	847,179	157,681	77,158	112,304	-	38,111
F_DISTR	CUS	F_DISTR_CUS	MET	13,591,803	856,654	8,188,719	1,583,142	1,167,150	930,698	844,445	-	20,996
F_DISTR	CUS	F_DISTR_CUS	REG	1,216,512	107,690	986,826	90,245	15,433	6,459	9,858	-	-
F_DISTR	CUS	F_DISTR_CUS	MNR	674,798	-	456	75,612	113,590	253,716	229,879	-	1,544
F_DISTR	CUS	F_DISTR_CUS	BADDEBT	47,610	4,467	40,975	1,603	271	115	179	-	-
F_CBILL	CUS	F_CBILL_CUS	CUSDEP	(1,698,560)	(147,137)	(1,347,032)	(151,196)	(25,789)	(10,889)	(16,517)	-	-
F_CBILL	CUS	F_CBILL_CUS	CUSADV	(27,692)	-	(343)	-	-	-	(27,349)	-	-
F_DISTR	CUS	F_DISTR_CUS	CINSTALL	(7,446)	(696)	(6,377)	(276)	(47)	(20)	(30)	-	-
F_CBILL	CUS	F_CBILL_CUS	CMET	10,581	569	6,537	1,096	1,041	641	693	-	5
F_CBILL	CUS	F_CBILL_CUS	CREC	143,639	12,969	118,822	8,746	1,491	628	961	15	6
F_CBILL	CUS	F_CBILL_CUS	BADDEBT	28,046	2,631	24,138	944	160	67	105	-	-
F_CBILL	CUS	F_CBILL_CUS	SCUSTS	12,781	1,162	10,650	770	109	24	65	-	-
F_CSERV	CUS	F_CSERV_CUS	SCUSTS	50,382	4,582	41,981	3,036	431	95	256	-	-
F_CSERV	CUS	F_CSERV_CUS	CUST	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	F_DISTR_CUS	CUSDEP	-	-	-	-	-	-	-	-	-

	Func/Class	Total	RS-1	RS-2	GS	MVS	LVS	HLFS	GLR	IS
F_PRODU										
	DEM	1,525,623	19,692	736,957	97,051	105,268	285,530	281,125	-	-
	COM	1,807,272	27,479	1,240,718	137,403	141,776	141,314	118,562	20	-
	CUS	-	-	-	-	-	-	-	-	-
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***3,332,895***	***47,171***	***1,977,675***	***234,454***	***247,044***	***426,844***	***399,687***	***20***	***-***
F_DISTR										
	DEM	17,144,528	219,195	8,222,690	1,080,160	1,174,119	3,216,532	3,228,291	4	3,537
	COM	(27,933)	(206)	(9,128)	(1,003)	(1,272)	(5,806)	(10,255)	(0)	(262)
	CUS	51,970,082	4,252,032	39,270,445	3,978,434	1,689,530	1,367,313	1,348,307	2,407	61,614
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***69,086,677***	***4,471,021***	***47,484,007***	***5,057,591***	***2,862,377***	***4,578,038***	***4,566,343***	***2,411***	***64,890***
F_CBILL										
	DEM	-	-	-	-	-	-	-	-	-
	COM	-	-	-	-	-	-	-	-	-
	CUS	(1,531,204)	(129,805)	(1,187,228)	(139,640)	(22,988)	(9,528)	(42,042)	15	11
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***(1,531,204)***	***(129,805)***	***(1,187,228)***	***(139,640)***	***(22,988)***	***(9,528)***	***(42,042)***	***15***	***11***
F_CSERV										
	DEM	-	-	-	-	-	-	-	-	-
	COM	-	-	-	-	-	-	-	-	-
	CUS	50,382	4,582	41,981	3,036	431	95	256	-	-
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***50,382***	***4,582***	***41,981***	***3,036***	***431***	***95***	***256***	***-***	***-***
RATE BASE										
	DEM	18,670,151	238,887	8,959,647	1,177,211	1,279,388	3,502,062	3,509,416	4	3,537
	COM	1,779,339	27,273	1,231,590	136,400	140,504	135,508	108,307	20	(262)
	CUS	50,489,259	4,126,809	38,125,198	3,841,830	1,666,973	1,357,879	1,306,522	2,423	61,625
	REV	-	-	-	-	-	-	-	-	-
	TOTAL	**70,938,750**	**4,392,969**	**48,316,435**	**5,155,441**	**3,086,864**	**4,995,449**	**4,924,245**	**2,447**	**64,900**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Class Allocation

Test Period at Proposed Revenues

Function	Class	Func/Class	Allocator	Line Ref. Total	5 RS-1	6 RS-2	7 GS	8 MVS	9 LVS	10 HLFS	11 GLR	12 IS
O & M EXPENSES												
F_PRODU	DEM	F_PRODU_DEM	DD	78,179	1,009	37,765	4,973	5,394	14,632	14,406	-	-
F_DISTR	DEM	F_DISTR_DEM	DD	281,944	3,639	136,194	17,936	19,454	52,768	51,954	-	-
F_DISTR	DEM	F_DISTR_DEM	PAVG	74,118	550	24,325	2,679	3,392	15,393	27,092	1	688
F_PRODU	COM	F_PRODU_COM	SSALES	-	-	-	-	-	-	-	-	-
F_PRODU	COM	F_PRODU_COM	CDD	29,966	387	14,475	1,906	2,068	5,608	5,522	-	-
F_DISTR	COM	F_DISTR_COM	THRU	61,619	454	20,137	2,212	2,807	12,809	22,624	1	577
F_DISTR	CUS	F_DISTR_CUS	CUST	381,454	34,442	315,550	23,226	3,960	1,668	2,551	40	16
F_DISTR	CUS	F_DISTR_CUS	SERVICE	518,211	46,530	425,291	31,889	5,935	2,904	4,227	-	1,435
F_DISTR	CUS	F_DISTR_CUS	MET	537,414	33,872	323,779	62,597	46,149	36,799	33,389	-	830
F_DISTR	CUS	F_DISTR_CUS	REG	68,000	6,020	55,162	5,045	863	361	551	-	-
F_DISTR	CUS	F_DISTR_CUS	MNR	98,451	-	67	11,031	16,572	37,016	33,539	-	225
F_DISTR	CUS	F_DISTR_CUS	BADDEBT	-	-	-	-	-	-	-	-	-
F_CBILL	CUS	F_CBILL_CUS	CUSDEP	-	-	-	-	-	-	-	-	-
F_CBILL	CUS	F_CBILL_CUS	CUSADV	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	F_DISTR_CUS	CINSTALL	110,643	10,336	94,759	4,105	696	300	448	-	-
F_CBILL	CUS	F_CBILL_CUS	CMET	305,436	16,419	188,681	31,638	30,056	18,502	20,010	-	130
F_CBILL	CUS	F_CBILL_CUS	CREC	1,911,827	172,622	1,581,520	116,407	19,848	8,361	12,785	203	81
F_CBILL	CUS	F_CBILL_CUS	BADDEBT	159,277	14,944	137,081	5,364	907	383	598	-	-
F_CBILL	CUS	F_CBILL_CUS	SCUSTS	72,587	6,602	60,484	4,374	621	137	369	-	-
F_CSERV	CUS	F_CSERV_CUS	SCUSTS	936,569	85,181	780,407	56,440	8,011	1,763	4,767	-	-
F_CSERV	CUS	F_CSERV_CUS	CUST	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	F_DISTR_CUS	CUSDEP	-	-	-	-	-	-	-	-	-

Function	Class	Total	RS-1	RS-2	GS	MVS	LVS	HLFS	GLR	IS
F_PRODU										
	DEM	78,179	1,009	37,765	4,973	5,394	14,632	14,406	-	-
	COM	29,966	387	14,475	1,906	2,068	5,608	5,522	-	-
	CUS	-	-	-	-	-	-	-	-	-
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***108,146***	***1,396***	***52,240***	***6,880***	***7,462***	***20,240***	***19,928***	***-***	***-***
F_DISTR										
	DEM	356,063	4,189	160,519	20,614	22,846	68,161	79,045	1	688
	COM	61,619	454	20,137	2,212	2,807	12,809	22,624	1	577
	CUS	1,714,173	131,199	1,214,606	137,893	74,175	79,049	74,705	40	2,506
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***2,131,855***	***135,842***	***1,395,262***	***160,719***	***99,827***	***160,019***	***176,374***	***42***	***3,771***
F_CBILL										
	DEM	-	-	-	-	-	-	-	-	-
	COM	-	-	-	-	-	-	-	-	-
	CUS	2,449,128	210,586	1,967,766	157,783	51,432	27,383	33,764	203	211
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***2,449,128***	***210,586***	***1,967,766***	***157,783***	***51,432***	***27,383***	***33,764***	***203***	***211***
F_CSERV										
	DEM	-	-	-	-	-	-	-	-	-
	COM	-	-	-	-	-	-	-	-	-
	CUS	936,569	85,181	780,407	56,440	8,011	1,763	4,767	-	-
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***936,569***	***85,181***	***780,407***	***56,440***	***8,011***	***1,763***	***4,767***	***-***	***-***
O & M EXPENSES										
	DEM	434,242	5,198	198,283	25,588	28,240	82,793	93,452	1	688
	COM	91,585	841	34,612	4,118	4,874	18,417	28,145	1	577
	CUS	5,099,870	426,966	3,962,779	352,116	133,618	108,194	113,235	243	2,718
	REV	-	-	-	-	-	-	-	-	-
	TOTAL	**5,625,697**	**433,005**	**4,195,675**	**381,822**	**166,732**	**209,404**	**234,832**	**245**	**3,982**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Class Allocation

Test Period at Proposed Revenues

Function	Class	Func/Class	Allocator	Line Ref. Total	5 RS-1	6 RS-2	7 GS	8 MVS	9 LVS	10 HLFS	11 GLR	12 IS
A & G EXPENSES												
F_PRODU	DEM	F_PRODU_DEM	DD	119,824	1,547	57,881	7,622	8,268	22,426	22,080	-	-
F_DISTR	DEM	F_DISTR_DEM	DD	867,882	11,202	419,233	55,209	59,884	162,430	159,924	-	-
F_DISTR	DEM	F_DISTR_DEM	PAVG	99,642	739	32,701	3,601	4,560	20,694	36,421	1	925
F_PRODU	COM	F_PRODU_COM	SSALES	5,360	84	3,870	419	429	317	241	0	-
F_PRODU	COM	F_PRODU_COM	CDD	13,814	178	6,673	879	953	2,585	2,545	-	-
F_DISTR	COM	F_DISTR_COM	THRU	282,130	2,079	92,198	10,126	12,851	58,646	103,584	3	2,642
F_DISTR	CUS	F_DISTR_CUS	CUST	1,174,193	106,020	971,327	71,494	12,190	5,135	7,852	125	50
F_DISTR	CUS	F_DISTR_CUS	SERVICE	1,199,131	107,669	984,115	73,791	13,734	6,721	9,782	-	3,320
F_DISTR	CUS	F_DISTR_CUS	MET	911,615	57,457	549,225	106,183	78,282	62,423	56,638	-	1,408
F_DISTR	CUS	F_DISTR_CUS	REG	113,596	10,056	92,148	8,427	1,441	603	921	-	-
F_DISTR	CUS	F_DISTR_CUS	MNR	92,184	-	62	10,329	15,518	34,660	31,404	-	211
F_DISTR	CUS	F_DISTR_CUS	BADDEBT	166	16	143	6	1	0	1	-	-
F_CBILL	CUS	F_CBILL_CUS	CUSDEP	(5,917)	(513)	(4,693)	(527)	(90)	(38)	(58)	-	-
F_CBILL	CUS	F_CBILL_CUS	CUSADV	(96)	-	(1)	-	-	-	(95)	-	-
F_DISTR	CUS	F_DISTR_CUS	CINSTALL	204,237	19,079	174,916	7,577	1,284	554	826	-	-
F_CBILL	CUS	F_CBILL_CUS	CMET	343,371	18,458	212,115	35,567	33,789	20,800	22,496	-	146
F_CBILL	CUS	F_CBILL_CUS	CREC	1,601,283	144,582	1,324,629	97,499	16,624	7,003	10,709	170	68
F_CBILL	CUS	F_CBILL_CUS	BADDEBT	19,574	1,837	16,846	659	111	47	74	-	-
F_CBILL	CUS	F_CBILL_CUS	SCUSTS	8,920	811	7,433	538	76	17	45	-	-
F_CSERV	CUS	F_CSERV_CUS	SCUSTS	925,916	84,212	771,531	55,798	7,920	1,742	4,713	-	-
F_CSERV	CUS	F_CSERV_CUS	CUST	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	F_DISTR_CUS	CUSDEP	-	-	-	-	-	-	-	-	-
	F_PRODU											
		DEM		119,824	1,547	57,881	7,622	8,268	22,426	22,080	-	-
		COM		19,174	262	10,543	1,298	1,383	2,903	2,786	0	-
		CUS		-	-	-	-	-	-	-	-	-
		REV		-	-	-	-	-	-	-	-	-
		Sub-total		***138,998***	***1,809***	***68,425***	***8,920***	***9,650***	***25,328***	***24,866***	***0***	***-***
	F_DISTR											
		DEM		967,524	11,941	451,934	58,810	64,444	183,124	196,345	1	925
		COM		282,130	2,079	92,198	10,126	12,851	58,646	103,584	3	2,642
		CUS		3,695,121	300,296	2,771,936	277,807	122,450	110,096	107,423	125	4,989
		REV		-	-	-	-	-	-	-	-	-
		Sub-total		***4,944,775***	***314,315***	***3,316,069***	***346,744***	***199,744***	***351,866***	***407,353***	***129***	***8,555***
	F_CBILL											
		DEM		-	-	-	-	-	-	-	-	-
		COM		-	-	-	-	-	-	-	-	-
		CUS		1,967,135	165,176	1,556,329	133,736	50,511	27,829	33,170	170	214
		REV		-	-	-	-	-	-	-	-	-
		Sub-total		***1,967,135***	***165,176***	***1,556,329***	***133,736***	***50,511***	***27,829***	***33,170***	***170***	***214***
	F_CSERV											
		DEM		-	-	-	-	-	-	-	-	-
		COM		-	-	-	-	-	-	-	-	-
		CUS		925,916	84,212	771,531	55,798	7,920	1,742	4,713	-	-
		REV		-	-	-	-	-	-	-	-	-
		Sub-total		***925,916***	***84,212***	***771,531***	***55,798***	***7,920***	***1,742***	***4,713***	***-***	***-***
	A & G EXPENSES											
		DEM		1,087,348	13,488	509,816	66,433	72,712	205,550	218,425	1	925
		COM		301,304	2,341	102,741	11,424	14,233	61,549	106,370	3	2,642
		CUS		6,588,172	549,683	5,099,796	467,341	180,880	139,667	145,306	295	5,203
		REV		-	-	-	-	-	-	-	-	-
		TOTAL		**7,976,825**	**565,511**	**5,712,354**	**545,199**	**267,825**	**406,766**	**470,102**	**299**	**8,770**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Class Allocation

Test Period at Proposed Revenues

Depreciation Expense

Function	Class	Func/Class	Allocator	Line Ref. Total	5 RS-1	6 RS-2	7 GS	8 MVS	9 LVS	10 HLFS	11 GLR	12 IS
F_PRODU	DEM	F_PRODU_DEM	DD	135,672	1,751	65,537	8,631	9,361	25,392	25,000	-	-
F_DISTR	DEM	F_DISTR_DEM	DD	494,469	6,382	238,855	31,455	34,119	92,543	91,115	-	-
F_DISTR	DEM	F_DISTR_DEM	PAVG	49,356	366	16,198	1,784	2,258	10,251	18,041	1	458
F_PRODU	COM	F_PRODU_COM	SSALES	-	-	-	-	-	-	-	-	-
F_PRODU	COM	F_PRODU_COM	CDD	-	-	-	-	-	-	-	-	-
F_DISTR	COM	F_DISTR_COM	THRU	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	F_DISTR_CUS	CUST	668,988	60,404	553,407	40,733	6,945	2,926	4,474	71	28
F_DISTR	CUS	F_DISTR_CUS	SERVICE	757,232	67,991	621,452	46,598	8,673	4,244	6,177	-	2,096
F_DISTR	CUS	F_DISTR_CUS	MET	430,832	27,154	259,565	50,182	36,996	29,501	26,767	-	666
F_DISTR	CUS	F_DISTR_CUS	REG	41,419	3,667	33,599	3,073	525	220	336	-	-
F_DISTR	CUS	F_DISTR_CUS	MNR	76,082	-	51	8,525	12,807	28,606	25,918	-	174
F_DISTR	CUS	F_DISTR_CUS	BADDEBT	-	-	-	-	-	-	-	-	-
F_CBILL	CUS	F_CBILL_CUS	CUSDEP	-	-	-	-	-	-	-	-	-
F_CBILL	CUS	F_CBILL_CUS	CUSADV	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	F_DISTR_CUS	CINSTALL	-	-	-	-	-	-	-	-	-
F_CBILL	CUS	F_CBILL_CUS	CMET	-	-	-	-	-	-	-	-	-
F_CBILL	CUS	F_CBILL_CUS	CREC	-	-	-	-	-	-	-	-	-
F_CBILL	CUS	F_CBILL_CUS	BADDEBT	-	-	-	-	-	-	-	-	-
F_CBILL	CUS	F_CBILL_CUS	SCUSTS	-	-	-	-	-	-	-	-	-
F_CSERV	CUS	F_CSERV_CUS	SCUSTS	-	-	-	-	-	-	-	-	-
F_CSERV	CUS	F_CSERV_CUS	CUST	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	F_DISTR_CUS	CUSDEP	-	-	-	-	-	-	-	-	-

		Total	RS-1	RS-2	GS	MVS	LVS	HLFS	GLR	IS
F_PRODU										
	DEM	135,672	1,751	65,537	8,631	9,361	25,392	25,000	-	-
	COM	-	-	-	-	-	-	-	-	-
	CUS	-	-	-	-	-	-	-	-	-
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***135,672***	***1,751***	***65,537***	***8,631***	***9,361***	***25,392***	***25,000***	***-***	***-***
F_DISTR										
	DEM	543,825	6,748	255,053	33,239	36,377	102,794	109,156	1	458
	COM	-	-	-	-	-	-	-	-	-
	CUS	1,974,553	159,216	1,468,075	149,111	65,947	65,497	63,672	71	2,964
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***2,518,378***	***165,964***	***1,723,127***	***182,350***	***102,324***	***168,290***	***172,828***	***72***	***3,422***
F_CBILL										
	DEM	-	-	-	-	-	-	-	-	-
	COM	-	-	-	-	-	-	-	-	-
	CUS	-	-	-	-	-	-	-	-	-
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***-***	***-***	***-***	***-***	***-***	***-***	***-***	***-***	***-***
F_CSERV										
	DEM	-	-	-	-	-	-	-	-	-
	COM	-	-	-	-	-	-	-	-	-
	CUS	-	-	-	-	-	-	-	-	-
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***-***	***-***	***-***	***-***	***-***	***-***	***-***	***-***	***-***
Depreciation Expense										
	DEM	679,498	8,499	320,590	41,870	45,738	128,186	134,156	1	458
	COM	-	-	-	-	-	-	-	-	-
	CUS	1,974,553	159,216	1,468,075	149,111	65,947	65,497	63,672	71	2,964
	REV	-	-	-	-	-	-	-	-	-
	TOTAL	**2,654,050**	**167,715**	**1,788,664**	**190,981**	**111,685**	**193,682**	**197,829**	**72**	**3,422**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Class Allocation

Test Period at Proposed Revenues

Function	Class	Func/Class	Allocator	Line Ref. Total	5 RS-1	6 RS-2	7 GS	8 MVS	9 LVS	10 HLFS	11 GLR	12 IS
TIMING DIFFERENCES												
F_PRODU	DEM	F_PRODU_DEM	DD	70,055	904	33,840	4,456	4,834	13,111	12,909	-	-
F_DISTR	DEM	F_DISTR_DEM	DD	769,755	9,935	371,833	48,967	53,113	144,065	141,842	-	-
F_DISTR	DEM	F_DISTR_DEM	PAVG	17,502	130	5,744	633	801	3,635	6,397	0	162
F_PRODU	COM	F_PRODU_COM	SSALES	70,651	1,103	51,013	5,525	5,659	4,180	3,171	1	-
F_PRODU	COM	F_PRODU_COM	CDD	12,337	159	5,959	785	851	2,309	2,273	-	-
F_DISTR	COM	F_DISTR_COM	THRU	(1,283)	(9)	(419)	(46)	(58)	(267)	(471)	(0)	(12)
F_DISTR	CUS	F_DISTR_CUS	CUST	1,041,434	94,033	861,505	63,411	10,812	4,555	6,965	111	44
F_DISTR	CUS	F_DISTR_CUS	SERVICE	632,162	56,761	518,809	38,901	7,241	3,543	5,157	-	1,750
F_DISTR	CUS	F_DISTR_CUS	MET	624,120	39,337	376,017	72,696	53,594	42,737	38,776	-	964
F_DISTR	CUS	F_DISTR_CUS	REG	55,861	4,945	45,314	4,144	709	297	453	-	-
F_DISTR	CUS	F_DISTR_CUS	MNR	30,986	-	21	3,472	5,216	11,650	10,556	-	71
F_DISTR	CUS	F_DISTR_CUS	BADDEBT	2,186	205	1,882	74	12	5	8	-	-
F_CBILL	CUS	F_CBILL_CUS	CUSDEP	(77,996)	(6,756)	(61,854)	(6,943)	(1,184)	(500)	(758)	-	-
F_CBILL	CUS	F_CBILL_CUS	CUSADV	(1,272)	-	(16)	-	-	-	(1,256)	-	-
F_DISTR	CUS	F_DISTR_CUS	CINSTALL	(342)	(32)	(293)	(13)	(2)	(1)	(1)	-	-
F_CBILL	CUS	F_CBILL_CUS	CMET	486	26	300	50	48	29	32	-	0
F_CBILL	CUS	F_CBILL_CUS	CREC	6,596	596	5,456	402	68	29	44	1	0
F_CBILL	CUS	F_CBILL_CUS	BADDEBT	1,288	121	1,108	43	7	3	5	-	-
F_CBILL	CUS	F_CBILL_CUS	SCUSTS	587	53	489	35	5	1	3	-	-
F_CSERV	CUS	F_CSERV_CUS	SCUSTS	2,313	210	1,928	139	20	4	12	-	-
F_CSERV	CUS	F_CSERV_CUS	CUST	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	F_DISTR_CUS	CUSDEP	-	-	-	-	-	-	-	-	-

	Func/Class	Total	RS-1	RS-2	GS	MVS	LVS	HLFS	GLR	IS
F_PRODU										
	DEM	70,055	904	33,840	4,456	4,834	13,111	12,909	-	-
	COM	82,988	1,262	56,972	6,309	6,510	6,489	5,444	1	-
	CUS	-	-	-	-	-	-	-	-	-
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***153,043***	***2,166***	***90,813***	***10,766***	***11,344***	***19,600***	***18,353***	***1***	***-***
F_DISTR										
	DEM	787,257	10,065	377,576	49,600	53,914	147,699	148,239	0	162
	COM	(1,283)	(9)	(419)	(46)	(58)	(267)	(471)	(0)	(12)
	CUS	2,386,406	195,248	1,803,254	182,685	77,581	62,785	61,913	111	2,829
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***3,172,381***	***205,304***	***2,180,411***	***232,239***	***131,437***	***210,218***	***209,681***	***111***	***2,980***
F_CBILL										
	DEM	-	-	-	-	-	-	-	-	-
	COM	-	-	-	-	-	-	-	-	-
	CUS	(70,311)	(5,960)	(54,516)	(6,412)	(1,056)	(438)	(1,931)	1	0
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***(70,311)***	***(5,960)***	***(54,516)***	***(6,412)***	***(1,056)***	***(438)***	***(1,931)***	***1***	***0***
F_CSERV										
	DEM	-	-	-	-	-	-	-	-	-
	COM	-	-	-	-	-	-	-	-	-
	CUS	2,313	210	1,928	139	20	4	12	-	-
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***2,313***	***210***	***1,928***	***139***	***20***	***4***	***12***	***-***	***-***
TIMING DIFFERENCES										
	DEM	857,312	10,969	411,417	54,056	58,748	160,811	161,148	0	162
	COM	81,705	1,252	56,553	6,263	6,452	6,222	4,973	1	(12)
	CUS	2,318,409	189,498	1,750,665	176,412	76,545	62,352	59,994	111	2,830
	REV	-	-	-	-	-	-	-	-	-
	TOTAL	**3,257,426**	**201,720**	**2,218,635**	**236,732**	**141,745**	**229,385**	**226,116**	**112**	**2,980**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Class Allocation

Test Period at Proposed Revenues

Function	Class	Func/Class	Allocator	Line Ref. Total	5 RS-1	6 RS-2	7 GS	8 MVS	9 LVS	10 HLFS	11 GLR	12 IS
Interest on Customer Deposits												
F_PRODU	DEM	F_PRODU_DEM	DD	-	-	-	-	-	-	-	-	-
F_DISTR	DEM	F_DISTR_DEM	DD	-	-	-	-	-	-	-	-	-
F_DISTR	DEM	F_DISTR_DEM	PAVG	-	-	-	-	-	-	-	-	-
F_PRODU	COM	F_PRODU_COM	SSALES	-	-	-	-	-	-	-	-	-
F_PRODU	COM	F_PRODU_COM	CDD	-	-	-	-	-	-	-	-	-
F_DISTR	COM	F_DISTR_COM	THRU	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	F_DISTR_CUS	CUST	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	F_DISTR_CUS	SERVICE	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	F_DISTR_CUS	MET	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	F_DISTR_CUS	REG	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	F_DISTR_CUS	MNR	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	F_DISTR_CUS	BADDEBT	-	-	-	-	-	-	-	-	-
F_CBILL	CUS	F_CBILL_CUS	CUSDEP	-	-	-	-	-	-	-	-	-
F_CBILL	CUS	F_CBILL_CUS	CUSADV	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	F_DISTR_CUS	CINSTALL	-	-	-	-	-	-	-	-	-
F_CBILL	CUS	F_CBILL_CUS	CMET	-	-	-	-	-	-	-	-	-
F_CBILL	CUS	F_CBILL_CUS	CREC	-	-	-	-	-	-	-	-	-
F_CBILL	CUS	F_CBILL_CUS	BADDEBT	-	-	-	-	-	-	-	-	-
F_CBILL	CUS	F_CBILL_CUS	SCUSTS	-	-	-	-	-	-	-	-	-
F_CSERV	CUS	F_CSERV_CUS	SCUSTS	-	-	-	-	-	-	-	-	-
F_CSERV	CUS	F_CSERV_CUS	CUST	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	F_DISTR_CUS	CUSDEP	74,347	6,440	58,960	6,618	1,129	477	723	-	-
	F_PRODU											
		DEM		-	-	-	-	-	-	-	-	-
		COM		-	-	-	-	-	-	-	-	-
		CUS		-	-	-	-	-	-	-	-	-
		REV		-	-	-	-	-	-	-	-	-
		Sub-total		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	F_DISTR											
		DEM		-	-	-	-	-	-	-	-	-
		COM		-	-	-	-	-	-	-	-	-
		CUS		74,347	6,440	58,960	6,618	1,129	477	723	-	-
		REV		-	-	-	-	-	-	-	-	-
		Sub-total		***74,347***	***6,440***	***58,960***	***6,618***	***1,129***	***477***	***723***	**-**	**-**
	F_CBILL											
		DEM		-	-	-	-	-	-	-	-	-
		COM		-	-	-	-	-	-	-	-	-
		CUS		-	-	-	-	-	-	-	-	-
		REV		-	-	-	-	-	-	-	-	-
		Sub-total		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	F_CSERV											
		DEM		-	-	-	-	-	-	-	-	-
		COM		-	-	-	-	-	-	-	-	-
		CUS		-	-	-	-	-	-	-	-	-
		REV		-	-	-	-	-	-	-	-	-
		Sub-total		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Interest on Customer Deposits											
		DEM		-	-	-	-	-	-	-	-	-
		COM		-	-	-	-	-	-	-	-	-
		CUS		74,347	6,440	58,960	6,618	1,129	477	723	-	-
		REV		-	-	-	-	-	-	-	-	-
		TOTAL		**74,347**	**6,440**	**58,960**	**6,618**	**1,129**	**477**	**723**	**-**	**-**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Class Allocation
Test Period at Proposed Revenues

TAXES (other than Income)

Function	Class	Func/Class	Allocator	Line Ref. Total	5 RS-1	6 RS-2	7 GS	8 MVS	9 LVS	10 HLFS	11 GLR	12 IS
F_PRODU	DEM	F_PRODU_DEM	DD	58,101	750	28,066	3,696	4,009	10,874	10,706	-	-
F_DISTR	DEM	F_DISTR_DEM	DD	363,949	4,698	175,807	23,152	25,113	68,115	67,065	-	-
F_DISTR	DEM	F_DISTR_DEM	PAVG	22,015	163	7,225	796	1,007	4,572	8,047	0	204
F_PRODU	COM	F_PRODU_COM	SSALES	3,972	62	2,868	311	318	235	178	0	-
F_PRODU	COM	F_PRODU_COM	CDD	1,989	26	961	127	137	372	367	-	-
F_DISTR	COM	F_DISTR_COM	THRU	28,318	209	9,254	1,016	1,290	5,887	10,397	0	265
F_DISTR	CUS	F_DISTR_CUS	CUST	492,402	44,460	407,330	29,981	5,112	2,153	3,293	52	21
F_DISTR	CUS	F_DISTR_CUS	SERVICE	442,906	39,768	363,489	27,255	5,073	2,482	3,613	-	1,226
F_DISTR	CUS	F_DISTR_CUS	MET	272,725	17,189	164,310	31,766	23,419	18,675	16,944	-	421
F_DISTR	CUS	F_DISTR_CUS	REG	33,209	2,940	26,939	2,464	421	176	269	-	-
F_DISTR	CUS	F_DISTR_CUS	MNR	26,149	-	18	2,930	4,402	9,832	8,908	-	60
F_DISTR	CUS	F_DISTR_CUS	BADDEBT	123	12	106	4	1	0	0	-	-
F_CBILL	CUS	F_CBILL_CUS	CUSDEP	(4,385)	(380)	(3,478)	(390)	(67)	(28)	(43)	-	-
F_CBILL	CUS	F_CBILL_CUS	CUSADV	(71)	-	(1)	-	-	-	(71)	-	-
F_DISTR	CUS	F_DISTR_CUS	CINSTALL	20,528	1,918	17,581	762	129	56	83	-	-
F_CBILL	CUS	F_CBILL_CUS	CMET	34,565	1,858	21,352	3,580	3,401	2,094	2,264	-	15
F_CBILL	CUS	F_CBILL_CUS	CREC	161,400	14,573	133,515	9,827	1,676	706	1,079	17	7
F_CBILL	CUS	F_CBILL_CUS	BADDEBT	2,032	191	1,749	68	12	5	8	-	-
F_CBILL	CUS	F_CBILL_CUS	SCUSTS	926	84	771	56	8	2	5	-	-
F_CSERV	CUS	F_CSERV_CUS	SCUSTS	93,254	8,481	77,705	5,620	798	175	475	-	-
F_CSERV	CUS	F_CSERV_CUS	CUST	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	F_DISTR_CUS	CUSDEP	-	-	-	-	-	-	-	-	-

		Total	RS-1	RS-2	GS	MVS	LVS	HLFS	GLR	IS
F_PRODU										
	DEM	58,101	750	28,066	3,696	4,009	10,874	10,706	-	-
	COM	5,961	88	3,829	437	455	607	545	0	-
	CUS	-	-	-	-	-	-	-	-	-
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***64,063***	***838***	***31,895***	***4,133***	***4,464***	***11,481***	***11,251***	***0***	***-***
F_DISTR										
	DEM	385,964	4,861	183,032	23,948	26,120	72,688	75,111	0	204
	COM	28,318	209	9,254	1,016	1,290	5,887	10,397	0	265
	CUS	1,288,043	106,286	979,772	95,162	38,557	33,375	33,111	52	1,728
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***1,702,325***	***111,355***	***1,172,058***	***120,127***	***65,967***	***111,949***	***118,619***	***53***	***2,198***
F_CBILL										
	DEM	-	-	-	-	-	-	-	-	-
	COM	-	-	-	-	-	-	-	-	-
	CUS	194,466	16,326	153,909	13,142	5,030	2,778	3,243	17	22
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***194,466***	***16,326***	***153,909***	***13,142***	***5,030***	***2,778***	***3,243***	***17***	***22***
F_CSERV										
	DEM	-	-	-	-	-	-	-	-	-
	COM	-	-	-	-	-	-	-	-	-
	CUS	93,254	8,481	77,705	5,620	798	175	475	-	-
	REV	-	-	-	-	-	-	-	-	-
	Sub-total	***93,254***	***8,481***	***77,705***	***5,620***	***798***	***175***	***475***	***-***	***-***
TAXES (other than Income)										
	DEM	444,065	5,611	211,098	27,644	30,129	83,562	85,818	0	204
	COM	34,280	296	13,083	1,454	1,745	6,494	10,942	0	265
	CUS	1,575,763	131,094	1,211,387	113,924	44,384	36,328	36,828	69	1,750
	REV	-	-	-	-	-	-	-	-	-
	TOTAL	**2,054,108**	**137,001**	**1,435,568**	**143,021**	**76,259**	**126,384**	**133,588**	**70**	**2,219**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis

Class Allocation

Test Period at Proposed Revenues

Function Class	Func/Class	Allocator	Line Ref. Total	5 RS-1	6 RS-2	7 GS	8 MVS	9 LVS	10 HLFS	11 GLR	12 IS
REVENUE											
Base Revenue	REV_BASE		22,223,119	824,887	13,899,066	1,469,623	890,630	2,114,684	2,860,887	705	162,637
Other Revenue	REV_OTHER		455,585	58,572	366,540	25,706	1,680	622	2,464	-	-
Unbilled	REV_UNBILLED		3,518	330	3,028	118	20	8	13	-	-
NGV Revenue	REV_BASE		2,606	97	1,630	172	104	248	336	0	19
Rent from Gas Property	REV_RENT		21,600	1,338	14,712	1,570	940	1,521	1,499	1	20
Margin Sharing	REV_THRU		186,628	1,375	60,989	6,699	8,501	38,794	68,521	2	1,748
Revenue Related Taxes	REV_THRU		72,846	537	23,806	2,615	3,318	15,142	26,746	1	682
TOTAL REVENUE			**22,965,902**	**887,136**	**14,369,770**	**1,506,503**	**905,194**	**2,171,020**	**2,960,465**	**709**	**165,105**

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

External Allocators

Test Period at Proposed Revenues

Name	Description	Classifier	Total	RS-1	RS-2	GS	MVS	LVS	HLFS	GLR	IS
DD	Design Day	DEM		1.29%	48.31%	6.36%	6.90%	18.72%	18.43%	0.00%	0.00%
	Test Year		66,338	1,023	32,809	4,052	4,348	12,053	12,053	-	-
	Test Period		69,806	901	33,720	4,441	4,817	13,065	12,863	-	-
PAVG	Peak and Average	DEM		0.74%	32.82%	3.61%	4.58%	20.77%	36.55%	0.00%	0.93%
	Test Year		4,050,955	42,817	1,384,494	163,808	187,405	640,824	1,595,217	42	36,350
	Test Period		3,916,790	29,051	1,285,437	141,552	179,227	813,460	1,431,672	42	36,350
CUST	Average Customers	CUS		9.03%	82.72%	6.09%	1.04%	0.44%	0.67%	0.01%	0.00%
	Test Year		46,138	4,579	37,767	2,813	456	193	323	5	2
	Test Period		47,103	4,253	38,965	2,868	489	206	315	5	2
SCUSTS	Sales Customers	CUS		9.09%	83.33%	6.03%	0.86%	0.19%	0.51%	0.00%	0.00%
	Test Year		45,810	4,579	37,767	2,765	369	83	247	-	-
	Test Period		46,762	4,253	38,965	2,818	400	88	238	-	-
ACUST	Average Customers * 12	CUS		9.03%	82.72%	6.09%	1.04%	0.44%	0.67%	0.01%	0.00%
	Test Year		553,656	54,948	453,204	33,756	5,472	2,316	3,876	60	24
	Test Period		565,236	51,036	467,580	34,416	5,868	2,472	3,780	60	24
MET	Meters	CUS		6.30%	60.25%	11.65%	8.59%	6.85%	6.21%	0.00%	0.15%
	Test Year		65,828	4,579	39,404	7,709	5,403	4,329	4,299	-	104
	Test Period		67,479	4,253	40,654	7,860	5,795	4,621	4,192	-	104
SERVICE	Services	CUS		8.98%	82.07%	6.15%	1.15%	0.56%	0.82%	0.00%	0.28%
	Test Year		46,398	4,579	37,678	2,859	506	249	396	-	131
	Test Period		47,367	4,253	38,873	2,915	543	265	386	-	131
REG	Regulators	CUS		8.85%	81.12%	7.42%	1.27%	0.53%	0.81%	0.00%	0.00%
	Test Year		47,060	4,579	37,775	3,497	569	240	400	-	-
	Test Period		48,044	4,253	38,973	3,564	610	255	389	-	-
CMET	Meter Reading	CUS		5.38%	61.77%	10.36%	9.84%	6.06%	6.55%	0.00%	0.04%
	Test Year		77,088	4,579	47,372	8,038	7,260	4,490	5,315	-	34
	Test Period		79,118	4,253	48,874	8,195	7,785	4,793	5,183	-	34

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

External Allocators

Test Period at Proposed Revenues

Name	Description	Classifier	Total	RS-1	RS-2	GS	MVS	LVS	HLFS	GLR	IS
MNR	Industrial M&R	CUS		0.00%	0.07%	11.21%	16.83%	37.60%	34.07%	0.00%	0.23%
	Test Year		1,707,413	-	1,154	191,317	287,413	641,968	581,654	-	3,906
	Test Period		1,707,413	-	1,154	191,317	287,413	641,968	581,654	-	3,906
BADDEBT	Bad Debts	CUS		9.38%	86.06%	3.37%	0.57%	0.24%	0.38%	0.00%	0.00%
	Test Year		44,368	4,579	37,774	1,500	240	102	173	-	-
	Test Period		45,330	4,253	39,013	1,527	258	109	170	-	-
CASSIST	Customer Assistance	CUS		9.23%	84.55%	6.22%	0.00%	0.00%	0.00%	0.00%	0.00%
	Test Year		45,159	4,579	37,767	2,813	-	-	-	-	-
	Test Period		46,086	4,253	38,965	2,868	-	-	-	-	-
CREC	Customer Records	CUS		9.03%	82.72%	6.09%	1.04%	0.44%	0.67%	0.01%	0.00%
	Test Year		46,138	4,579	37,767	2,813	456	193	323	5	2
	Test Period		47,103	4,253	38,965	2,868	489	206	315	5	2
CINSTALL	Customer Installations	CUS		9.34%	85.64%	3.71%	0.63%	0.27%	0.40%	0.00%	0.00%
	Test Year		44,585	4,579	37,776	1,659	268	111	192	-	-
	Test Period		45,527	4,253	38,991	1,689	286	123	184	-	-
CUSADV	Customer Advances for Construction	CUS		0.00%	1.24%	0.00%	0.00%	0.00%	98.76%	0.00%	0.00%
	Test Year		3,221,968	-	37,767	-	-	-	3,184,201	-	-
	Test Period		3,144,300	-	38,965	-	-	-	3,105,335	-	-
CUSDEP	Customer Deposits	CUS		8.66%	79.30%	8.90%	1.52%	0.64%	0.97%	0.00%	0.00%
	Test Year		48,149	4,579	37,792	4,295	698	294	491	-	-
	Test Period		49,097	4,253	38,936	4,370	745	315	477	-	-
CDD	Commodity Design Day	COM		1.29%	48.31%	6.36%	6.90%	18.72%	18.43%	0.00%	0.00%
	Test Year		66,338	1,023	32,809	4,052	4,348	12,053	12,053	-	-
	Test Period		69,806	901	33,720	4,441	4,817	13,065	12,863	-	-

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

External Allocators

Test Period at Proposed Revenues

Name	Description	Classifier	Total	RS-1	RS-2	GS	MVS	LVS	HLFS	GLR	IS
SALES	Sales (in Mcf)	COM		1.57%	69.76%	7.42%	7.81%	6.49%	6.95%	0.00%	0.00%
	Test Year		3,932,518	84,611	2,736,178	313,409	300,358	235,633	262,245	84	-
	Test Period		3,637,221	57,200	2,537,154	269,796	284,167	235,908	252,912	84	-
SSALES	Seasonal Sales	COM		1.56%	72.20%	7.82%	8.01%	5.92%	4.49%	0.00%	0.00%
	Test Year		2,986,366	65,807	2,146,523	251,664	235,973	162,077	124,287	35	-
	Test Period		2,685,918	41,916	1,939,344	210,026	215,134	158,913	120,550	35	-
THRU	Transportation and Sales	COM		0.74%	32.68%	3.59%	4.55%	20.79%	36.72%	0.00%	0.94%
	Test Year		8,035,573	84,611	2,736,178	323,565	370,461	1,269,594	3,178,382	84	72,699
	Test Period		7,763,775	57,200	2,537,154	278,664	353,638	1,613,856	2,850,480	84	72,699
REV_BASE	Delivery Revenue	REV		3.71%	62.54%	6.61%	4.01%	9.52%	12.87%	0.00%	0.73%
	Test Year		23,201,048	985,967	14,106,715	1,531,552	885,978	1,780,878	3,746,615	707	162,637
	Test Period		22,223,119	824,887	13,899,066	1,469,623	890,630	2,114,684	2,860,887	705	162,637
REV_OTHER	Other Revenue	REV		12.86%	80.45%	5.64%	0.37%	0.14%	0.54%	0.00%	0.00%
	Test Year		455,545	58,567	366,508	25,704	1,680	622	2,464	-	-
	Test Period		455,545	58,567	366,508	25,704	1,680	622	2,464	-	-
REV_UNBILLED	Bad Debt	REV		9.38%	86.06%	3.37%	0.57%	0.24%	0.38%	0.00%	0.00%
	Test Year		44,368	4,579	37,774	1,500	240	102	173	-	-
	Test Period		45,330	4,253	39,013	1,527	258	109	170	-	-
REV_RENT	Rate Base	REV		6.19%	68.11%	7.27%	4.35%	7.04%	6.94%	0.00%	0.09%
	Test Year		65,854,598	4,477,783	44,685,470	4,748,331	2,778,716	4,547,753	4,552,375	2,400	61,770
	Test Period		70,938,750	4,392,927	48,316,146	5,155,528	3,086,925	4,995,536	4,924,340	2,447	64,902
REV_THRU	Throughput	REV		0.74%	32.68%	3.59%	4.55%	20.79%	36.72%	0.00%	0.94%
	Test Year		8,035,573	84,611	2,736,178	323,565	370,461	1,269,594	3,178,382	84	72,699
	Test Period		7,763,775	57,200	2,537,154	278,664	353,638	1,613,856	2,850,480	84	72,699
ROR	Rate of Return			100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Test Period		8.55%	8.55%	8.55%	8.55%	8.55%	8.55%	8.55%	8.55%	8.55%

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

Internal Allocators

Test Period at Proposed Revenues

		Line Ref.	4	5	6	7	8	9
Name	**Description**	**Total**	**F_PRODU_DD**	**F_DISTR_DD**	**F_DISTR_PAVG**	**F_PRODU_SSALES**	**F_PRODU_CDD**	**F_DISTR_THRU**
PD_PLANT	Production & Distribution Plant	123,281,999	4,808,105	26,974,711	1,256,130	-	-	-
			3.90%	21.88%	1.02%	0.00%	0.00%	0.00%
DEP	Depreciation Accruals	(34,737,200)	(2,078,125)	(6,891,444)	(552,542)	-	-	-
			5.98%	19.84%	1.59%	0.00%	0.00%	0.00%
DIS_PLANT	Distribution Plant	118,110,820	-	26,892,045	1,252,281	-	-	-
			0.00%	22.77%	1.06%	0.00%	0.00%	0.00%
OM	O & M Expenses	5,625,697	78,179	281,944	74,118	-	29,966	61,619
			1.39%	5.01%	1.32%	0.00%	0.53%	1.10%
LABOR	Labor Expense	3,700,554	8,194	167,612	51,945	-	9,377	205,502
			0.22%	4.53%	1.40%	0.00%	0.25%	5.55%
OMXG	O & M excel Gas	5,517,552	-	281,944	74,118	-	-	61,619
			0.00%	5.11%	1.34%	0.00%	0.00%	1.12%
DIS_LABOR	Distribution Labor	1,165,478	-	124,215	38,496	-	-	152,294
			0.00%	10.66%	3.30%	0.00%	0.00%	13.07%
MAINS	Mains	63,275,399	-	26,892,045	-	-	-	-
			0.00%	42.50%	0.00%	0.00%	0.00%	0.00%
M_S	Mains and Services	96,048,650	-	26,892,045	-	-	-	-
			0.00%	28.00%	0.00%	0.00%	0.00%	0.00%
M_HR	Meter and House Regulators	19,082,229	-	-	-	-	-	-
			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C_LABOR	Customer Account Labor	2,180,742	-	-	-	-	-	-
			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
BASE	Rate Base	70,938,750	1,525,623	16,763,382	381,146	1,538,611	268,661	(27,933)
			2.15%	23.63%	0.54%	2.17%	0.38%	-0.04%
P_PLANT	Production Plant	4,808,105	4,808,105	-	-	-	-	-
			100.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

Internal Allocators

Test Period at Proposed Revenues

Name	Description	Line Ref. Total	10 F_DISTR_CUST	11 F_DISTR_SERVICE	12 F_DISTR_MET	13 F_DISTR_REG	14 F_DISTR_MNR	15 F_DISTR_BADDEBT	16 F_CBILL_CUSDEP	17 F_CBILL_CUSADV	18 F_DISTR_CINSTALL
PD_PLANT	Production & Distribution Plant	123,281,999	36,495,198	32,873,996	16,990,975	2,149,913	1,732,971	-	-	-	-
			29.60%	26.67%	13.78%	1.74%	1.41%	0.00%	0.00%	0.00%	0.00%
DEP	Depreciation Accruals	(34,737,200)	(9,323,719)	(12,161,926)	(2,443,853)	(608,456)	(677,135)	-	-	-	-
			26.84%	35.01%	7.04%	1.75%	1.95%	0.00%	0.00%	0.00%	0.00%
DIS_PLANT	Distribution Plant	118,110,820	36,383,355	32,773,250	16,938,904	2,143,325	1,727,660	-	-	-	-
			30.80%	27.75%	14.34%	1.81%	1.46%	0.00%	0.00%	0.00%	0.00%
OM	O & M Expenses	5,625,697	381,454	518,211	537,414	68,000	98,451	-	-	-	110,643
			6.78%	9.21%	9.55%	1.21%	1.75%	0.00%	0.00%	0.00%	1.97%
LABOR	Labor Expense	3,700,554	226,770	324,163	363,619	46,010	38,313	-	-	-	148,733
			6.13%	8.76%	9.83%	1.24%	1.04%	0.00%	0.00%	0.00%	4.02%
OMXG	O & M excel Gas	5,517,552	381,454	518,211	537,414	68,000	98,451	-	-	-	110,643
			6.91%	9.39%	9.74%	1.23%	1.78%	0.00%	0.00%	0.00%	2.01%
DIS_LABOR	Distribution Labor	1,165,478	168,055	240,232	269,472	34,097	28,393	-	-	-	110,223
			14.42%	20.61%	23.12%	2.93%	2.44%	0.00%	0.00%	0.00%	9.46%
MAINS	Mains	63,275,399	36,383,355	-	-	-	-	-	-	-	-
			57.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
M_S	Mains and Services	96,048,650	36,383,355	32,773,250	-	-	-	-	-	-	-
			37.88%	34.12%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
M_HR	Meter and House Regulators	19,082,229	-	-	16,938,904	2,143,325	-	-	-	-	-
			0.00%	0.00%	88.77%	11.23%	0.00%	0.00%	0.00%	0.00%	0.00%
C_LABOR	Customer Account Labor	2,180,742	-	-	-	-	-	-	-	-	-
			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
BASE	Rate Base	70,938,750	22,679,870	13,766,935	13,591,803	1,216,512	674,798	47,610	(1,698,560)	(27,692)	(7,446)
			31.97%	19.41%	19.16%	1.71%	0.95%	0.07%	-2.39%	-0.04%	-0.01%
P_PLANT	Production Plant	4,808,105	-	-	-	-	-	-	-	-	-
			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

Internal Allocators
Test Period at Proposed Revenues

Name	Description	Line Ref. Total	19 F_CBILL_CMET	20 F_CBILL_CREC	21 F_CBILL_BADDEBT	22 F_CBILL_SCUSTS	23 F_CSERV_SCUSTS	24 F_CSERV_CUST	25 F_DISTR_CUSDEP
PD_PLANT	Production & Distribution Plant	123,281,999	-	-	-	-	-	-	-
			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DEP	Depreciation Accruals	(34,737,200)	-	-	-	-	-	-	-
			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DIS_PLANT	Distribution Plant	118,110,820	-	-	-	-	-	-	-
			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OM	O & M Expenses	5,625,697	305,436	1,911,827	159,277	72,587	936,569	-	-
			5.43%	33.98%	2.83%	1.29%	16.65%	0.00%	0.00%
LABOR	Labor Expense	3,700,554	249,997	1,165,601	14,182	6,463	674,073	-	-
			6.76%	31.50%	0.38%	0.17%	18.22%	0.00%	0.00%
OMXG	O & M excel Gas	5,517,552	305,436	1,911,827	159,277	72,587	936,569	-	-
			5.54%	34.65%	2.89%	1.32%	16.97%	0.00%	0.00%
DIS_LABOR	Distribution Labor	1,165,478	-	-	-	-	-	-	-
			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
MAINS	Mains	63,275,399	-	-	-	-	-	-	-
			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
M_S	Mains and Services	96,048,650	-	-	-	-	-	-	-
			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
M_HR	Meter and House Regulators	19,082,229	-	-	-	-	-	-	-
			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C_LABOR	Customer Account Labor	2,180,742	271,965	1,702,321	141,823	64,633	-	-	-
			12.47%	78.06%	6.50%	2.96%	0.00%	0.00%	0.00%
BASE	Rate Base	70,938,750	10,581	143,639	28,046	12,781	50,382	-	-
			0.01%	0.20%	0.04%	0.02%	0.07%	0.00%	0.00%
P_PLANT	Production Plant	4,808,105	-	-	-	-	-	-	-
			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

CHESAPEAKE UTILITIES CORPORATION

EXHIBIT JDT-3

FUNCTIONALIZATION AND ALLOCATION FACTOR STUDIES

Witness: John D. Taylor

Docket No. 15-XXX

CHESAPEAKE UTILITIES CORPORATION

EXHIBIT JDT-3

FUNCTIONALIZATION AND ALLOCATION FACTOR STUDIES – INDEX

CHESAPEAKE UTILITIES CORPORATION

EXHIBIT JDT-4

DISTRIBUTION MAINS MINIMUM SYSTEM STUDY

The below pages provide the results of the minimum system study used to functionalize Chesapeake's Distribution Mains between the customer and demand classifications. The studies are based on data as of June 30,2015. The results of these studies were applied to distribution plant data for the test year and the test period in the ACOSS model. The first step in the process was to price adjust the installed costs to get all years of installed mains on a 2015 real dollar basis. The Handy Whitman Index was used to do so, utilizing the Plastic Mains and Steel Mains price adjustment factors for plastic and steel mains on the Chesapeake system. The total inflated investment was then calculated. The total footage was then multiplied by the per foot cost for a minimum sized main, a 2 inch main. The resulting costs of this calculated minimum system was then divided into the total inflated costs to develop the customer related percentage of total costs. The remainder of the system is the demand related portion.

DEVELOPMENT OF ALLOCATORS FOR CUSTOMERS

The first part of this section provides a listing of all the allocators used for the test year/test period and the values associated with each rate class. Details are then provided for the development of the allocation of meter costs and services. A summary of the methods employed to develop these calculations is provided below.

Services (Account 380)

Chesapeake provided a count of services by size for each of the rate classes. Information was gathered on the present replacement cost for each size for an average distance between 120 feet and 170 feet. The multiplication of the replacement costs for services size by the number of service of that size within each rate class resulted in total replacement costs for each rate class. This was then used to develop an average costs per service and ultimately a relative cost factor reflecting the relative cost of providing a service to each of the classes (e.g., 1.00 is RS-1 and 1.29 is HLFS so that it costs 1.29 times the costs of residential for HLFS).

Meters (Account 381)

Chesapeake provided a count of meters by size for each of the rate classes. The average cost for each of these meter sizes was then multiplied by the count resulting in a total costs for each rate class. This was then used to develop an average costs per meter and ultimately a relative cost factor reflecting the relative cost of providing a service to each of the classes (e.g., 1.00 is RS-1 and 15.31 is HLFS so that it costs 15.31 times the costs of residential for HLFS).

Industrial M&R Equipment (Account 385)

An allocation of this plant to the various customer classes was facilitated by research of property records conducted by Chesapeake's personnel to identify specific equipment with individual customers. The remaining M&R equipment in Account No. 385 that could not be identified with individual customers were allocated to the classes based on the assignment of the identifiable M&R equipment costs.

Meter Reading (Account 902)

Thought interviews and the review of data it was determined that there is a total of 90 man days in an average month spent on meter reading. Six of these man days are solely spent during one day, Industrial Day, reading certain industrial meters. This information allowed us to allocate 6.67% of effort (6 man days of 90) to those classes read during Industrial Day. The remaining 93.33% of effort was allocated to all other customers and was weighted based on the ratio of Encoder Receiver Transmitter ("ERT" or remote read) to Non-ERT for each class (this takes into account the fact that ERTs are read much quicker than non-ERTs). As a result the total days of effort (for an average) month was calculated for each rate class and ultimately a relative amount of effort (e.g., 1.00 is RS-1 and 16.49 is HLFS so that it takes 16.49 times longer, on average, to read a HLFS meter than a RS-1 meter).

Chesapeake Utilities Corporation
Delaware Division
Analysis of Mains - Account 376
Test Year: Twelve Months Ended June 30, 2015

Line. No.	Size of Main		Footage	Actual Investment	Inflated Investment	Inflated Investment per Foot
1	3/4"	Steel	3,403	$11,265	$74,816	$21.99
2	1 1/4"	Steel	30,600	$37,453	$446,011	$14.58
3	2"	Steel	199,149	$655,400	$5,599,949	$28.12
4	3"	Steel	39,288	$78,596	$1,005,383	$25.59
5	4"	Combined	1,368,293	$14,078,790	$28,964,112	$21.17
6	6"	Combined	906,348	$18,028,148	$29,643,971	$32.71
7	8"	Steel	129,709	$5,331,773	$6,674,018	$51.45
8	10"	Steel	22,180	$759,529	$922,251	$41.58
9	12"	Steel	500	$26,784	$28,952	$57.90
10	2 1/2"	Steel	17,401	$13,815	$181,502	$10.43
11	2"	Combined	99,621	$682,691	$2,088,094	$20.96
12	1 1/4"	Plastic	13,167	$116,743	$209,741	$15.93
13	2"	Plastic	2,419,402	$19,987,519	$27,344,867	$11.30
14	3/4"	Plastic	703	$4,449	$7,646	$10.88
15	1"	Plastic	1,490	$7,479	$30,836	$20.70
16						
17	**Total**		**5,251,254**	**$59,820,434**	**$103,222,149**	**$19.66**

Line. No.				
18				
19			Inflated	Inflated
20	Minimum System	Footage	Investment	Invest/ Foot
21	2" Plastic	2,419,402	$27,344,867	$11.30
22				
23	Minimum System	5,251,254	$59,339,170	$11.30
24	Total Inflated Investment		$103,222,149	
25	Customer Related Percentage		57.49%	

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

Line No.		Name	Description Classifier	Total	Residential Service -1 RS-1	Residential Service - 2 RS-2	General Service GS	Medium Volume Service MVS	Large Volume Service LVS	High Load Factor Service HLFS	Gas Lighting Residential GLR	Interruptible Service IS
1	DD	Design Day	DEM									
2	DD_Test Year	Test Year		66,338	1,023	32,809	4,052	4,348	12,053	12,053	-	-
3	DD_Test Period	Test Period		69,806	901	33,720	4,441	4,817	13,065	12,863	-	-
4	PAVG	Peak and Average	DEM									
5	PAVG_Test Year	Test Year	(50% DD & 50% Throughput)	4,050,955	42,817	1,384,494	163,808	187,405	640,824	1,595,217	42	36,350
6	PAVG_Test Period	Test Period	(50% DD & 50% Throughput)	3,916,790	29,051	1,285,437	141,552	179,227	813,460	1,431,672	42	36,350

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

Line No.		Name	Description Classifier	Total	Residential Service -1 RS-1	Residential Service - 2 RS-2	General Service GS	Medium Volume Service MVS	Large Volume Service LVS	High Load Factor Service HLFS	Gas Lighting Residential GLR	Interruptible Service IS
	CUSTOMER ALLOCATORS											
7	CUST	Average Customers	CUS									
8	CUST_Test Year	Test Year		46,138	4,579	37,767	2,813	456	193	323	5	2
9	CUST_Test Period	Test Period		47,103	4,253	38,965	2,868	489	206	315	5	2
10	SCUSTS	Sales Customers	CUS									
11	SCUSTS_Test Year	Test Year		45,810	4,579	37,767	2,765	369	83	247	-	-
12	SCUSTS_Test Period	Test Period		46,762	4,253	38,965	2,818	400	88	238	-	-
13	ACUST	Average Customers * 12	CUS									
14	ACUST_Test Year	Test Year		553,656	54,948	453,204	33,756	5,472	2,316	3,876	60	24
15	ACUST_Test Period	Test Period		565,236	51,036	467,580	34,416	5,868	2,472	3,780	60	24
16	MET	Meters	CUS									
17		Meter Cost Per Meter			$ 67.07	$ 69.98	$ 183.81	$ 794.80	$ 1,504.46	$ 892.69	$ -	$ 3,495.79
18		Relative Weighting Factor			1.00	1.04	2.74	11.85	22.43	13.31	-	52.12
19	MET_Test Year	Test Year	Weighted Customers	65,828	4,579	39,404	7,709	5,403	4,329	4,299	-	104
20	MET_Test Period	Test Period	Weighted Customers	67,479	4,253	40,654	7,860	5,795	4,621	4,192	-	104
21	SERVICE	Services	CUS									
22		Service Cost per Service			$ 2,858.69	$ 2,851.97	$ 2,905.36	$ 3,171.57	$ 3,683.96	$ 3,506.63	$ -	$ 187,425.00
23		Relative Weighting Factor			1.00	1.00	1.02	1.11	1.29	1.23	-	65.56
24	SERVICE_Test Year	Test Year	Weighted Customers	46,398	4,579	37,678	2,859	506	249	396	-	131
25	SERVICE_Test Period	Test Period	Weighted Customers	47,367	4,253	38,873	2,915	543	265	386	-	131

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

Line No.		Name	Description Classifier	Total	Residential Service -1 RS-1	Residential Service - 2 RS-2	General Service GS	Medium Volume Service MVS	Large Volume Service LVS	High Load Factor Service HLFS	Gas Lighting Residential GLR	Interruptible Service IS
21	REG	Regulators	CUS									
26		House Regulators Per Customer	Test Year		$ 44.93	$ 44.94	$ 55.84	$ 56.10	$ 55.87	$ 55.64	$ -	$ -
27		Relative Weighting Factor	Test Year		1.00	1.00	1.24	1.25	1.24	1.24	-	-
28		House Regulators Per Customer	Test Period		$ 44.68	$ 44.69	$ 55.52	$ 55.69	$ 55.32	$ 55.22	$ -	$ -
29		Relative Weighting Factor	Test Period		1.00	1.00	1.24	1.25	1.24	1.24	-	-
30	REG_Test Year	Test Year	Weighted Customers	47,060	4,579	37,775	3,497	569	240	400	-	-
31	REG_Test Period	Test Period	Weighted Customers	48,044	4,253	38,973	3,564	610	255	389	-	-
32	CMET	Meter Reading	CUS									
		Weighting Factor			1.00	1.25	2.86	15.92	23.26	16.46	-	16.87
33	CMET_Test Year	Test Year		77,088	4,579	47,372	8,038	7,260	4,490	5,315	-	34
34	CMET_Test Period	Test Period		79,118	4,253	48,874	8,195	7,785	4,793	5,183	-	34
35	MNR	Industrial M&R	CUS									
36	MNR_Test Year	Test Year		1,707,413	-	1,154	191,317	287,413	641,968	581,654	-	3,906
37	MNR_Test Period	Test Period		1,707,413	-	1,154	191,317	287,413	641,968	581,654	-	3,906
38	BADDEBT	Bad Debts	CUS									
39		Bad Debt Per Customer	Test Year		$ 3.23	$ 3.23	$ 1.72	$ 1.70	$ 1.70	$ 1.73	$ -	$ -
40		Relative Weighting Factor	Test Year		1.00	1.00	0.53	0.53	0.53	0.54	-	-
41		Bad Debt Per Customer	Test Period		$ 3.20	$ 3.20	$ 1.70	$ 1.69	$ 1.69	$ 1.73	$ -	$ -
42		Relative Weighting Factor	Test Period		1.00	1.00	0.53	0.53	0.53	0.54	-	-
43	BADDEBT_Test Year	Test Year	Weighted Customers	44,368	4,579	37,774	1,500	240	102	173	-	-
44	BADDEBT_Test Period	Test Period	Weighted Customers	45,330	4,253	39,013	1,527	258	109	170	-	-
45	CASSIST	Customer Assistance	CUS									
		Weighting Factor			1.00	1.00	1.00	-	-	-	-	-
46	CASSIST_Test Year	Test Year		45,159	4,579	37,767	2,813	-	-	-	-	-
47	CASSIST_Test Period	Test Period		46,086	4,253	38,965	2,868	-	-	-	-	-

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

Line No.		Name	Description Classifier	Total	Residential Service -1 RS-1	Residential Service - 2 RS-2	General Service GS	Medium Volume Service MVS	Large Volume Service LVS	High Load Factor Service HLFS	Gas Lighting Residential GLR	Interruptible Service IS
48	CREC	Customer Records	CUS									
		Weighting Factor			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
49	CREC_Test Year	Test Year		46,138	4,579	37,767	2,813	456	193	323	5	2
50	CREC_Test Period	Test Period		47,103	4,253	38,965	2,868	489	206	315	5	2
51	CINSTALL	Customer Installations	CUS									
52		Customer Installs Per Customer	Test Year		$ 1.32	$ 1.32	$ 0.78	$ 0.77	$ 0.76	$ 0.78	$ -	$ -
53		Relative Weighting Factor	Test Year		1.00	1.00	0.59	0.59	0.58	0.59	-	-
54		Customer Installs Per Customer	Test Period		$ 1.35	$ 1.35	$ 0.80	$ 0.79	$ 0.81	$ 0.79	$ -	$ -
55		Relative Weighting Factor	Test Period		1.00	1.00	0.59	0.59	0.60	0.58	-	-
56	CINSTALL_Test Year	Test Year	Weighted Customers	44,585	4,579	37,776	1,659	268	111	192	-	-
57	CINSTALL_Test Period	Test Period	Weighted Customers	45,527	4,253	38,991	1,689	286	123	184	-	-
58	CUSADV	Customer Advances for Construction	CUS									
59		Customer Advances per Customer	Test Year		$ -	$ 0.04	$ -	$ -	$ -	$ 442.96	$ -	$ -
60		Weighting Factor			-	1.00	-	-	-	9,858.21	-	-
61	CUSADV_Test Year	Test Year		3,221,968	-	37,767	-	-	-	3,184,201	-	-
62	CUSADV_Test Period	Test Period		3,144,300	-	38,965	-	-	-	3,105,335	-	-
63	CUSDEP	Customer Deposits	CUS									
64		Customer Deposits Per Customer	Test Year		$ 53.45	$ 53.49	$ 81.61	$ 81.84	$ 81.34	$ 81.28	$ -	$ -
65		Relative Weighting Factor	Test Year		1.00	1.00	1.53	1.53	1.52	1.52	-	-
66		Customer Deposits Per Customer	Test Period		$ 34.65	$ 34.62	$ 52.80	$ 52.82	$ 52.94	$ 52.52	$ -	$ -
67		Relative Weighting Factor	Test Period		1.00	1.00	1.52	1.52	1.53	1.52	-	-
68	CUSDEP_Test Year	Test Year	Weighted Customers	48,149	4,579	37,792	4,295	698	294	491	-	-
69	CUSDEP_Test Period	Test Period	Weighted Customers	49,097	4,253	38,936	4,370	745	315	477	-	-

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

Line No.		Name	Description Classifier	Total	Residential Service -1 RS-1	Residential Service - 2 RS-2	General Service GS	Medium Volume Service MVS	Large Volume Service LVS	High Load Factor Service HLFS	Gas Lighting Residential GLR	Interruptible Service IS
	COMMODITY ALLOCATORS											
70	CDD	Commodity Design Day	COM									
71	CDD_Test Year	Test Year		66,338	1,023	32,809	4,052	4,348	12,053	12,053	-	-
72	CDD_Test Period	Test Period		69,806	901	33,720	4,441	4,817	13,065	12,863	-	-
73	SALES	Sales Mcf	COM									
74	SALES_Test Year	Test Year		3,932,518	84,611	2,736,178	313,409	300,358	235,633	262,245	84	-
75	SALES_Test Period	Test Period		3,637,221	57,200	2,537,154	269,796	284,167	235,908	252,912	84	-
76	SSALES	Sales Seasonal Mcf	COM									
77	SSALES_Test Year	Test Year		2,986,366	65,807	2,146,523	251,664	235,973	162,077	124,287	35	-
78	SSALES_Test Period	Test Period		2,685,918	41,916	1,939,344	210,026	215,134	158,913	120,550	35	-
79	THRU	Transportation and Sales	COM									
80	THRU_Test Year	Test Year		8,035,573	84,611	2,736,178	323,565	370,461	1,269,594	3,178,382	84	72,699
81	THRU_Test Period	Test Period		7,763,775	57,200	2,537,154	278,664	353,638	1,613,856	2,850,480	84	72,699

Chesapeake Utilities - Delaware Division
Cost of Service Analysis - Inputs

Line No.		Name	Description Classifier	Total	Residential Service -1 RS-1	Residential Service - 2 RS-2	General Service GS	Medium Volume Service MVS	Large Volume Service LVS	High Load Factor Service HLFS	Gas Lighting Residential GLR	Interruptible Service IS
	REVENUE ALLOCATORS											
82	REV_BASE	Delivery Revenue	REV									
83	REV_BASE_Test Year	Test Year		23,201,048	985,967	14,106,715	1,531,552	885,978	1,780,878	3,746,615	707	162,637
84	REV_BASE_Test Period	Test Period		22,223,119	824,887	13,899,066	1,469,623	890,630	2,114,684	2,860,887	705	162,637
85	REV_OTHER	Other Revenue	REV									
86	REV_OTHER_Test Year	Test Year		455,545	58,567	366,508	25,704	1,680	622	2,464	-	-
87	REV_OTHER_Test Period	Test Period		455,545	58,567	366,508	25,704	1,680	622	2,464	-	-
88	REV_UNBILLED	Bad Debt	REV									
89	REV_UNBILLED_Test Year	Test Year		44,368	4,579	37,774	1,500	240	102	173	-	-
90	REV_UNBILLED_Test Period	Test Period		45,330	4,253	39,013	1,527	258	109	170	-	-
91	REV_RENT	Rate Base	REV									
92	REV_RENT_Test Year	Test Year		65,854,598	4,477,783	44,685,470	4,748,331	2,778,716	4,547,753	4,552,375	2,400	61,770
93	REV_RENT_Test Period	Test Period		70,938,750	4,392,927	48,316,146	5,155,528	3,086,925	4,995,536	4,924,340	2,447	64,902
94	REV_THRU	Throughput	REV									
95	REV_THRU_Test Year	Test Year		8,035,573	84,611	2,736,178	323,565	370,461	1,269,594	3,178,382	84	72,699
96	REV_THRU_Test Period	Test Period		7,763,775	57,200	2,537,154	278,664	353,638	1,613,856	2,850,480	84	72,699

Chesapeake Utilities Corporation
Delaware Division
Analysis of Services - Account 380
Twelve Months Ended June 30, 2015

Service Size	Replacement Cost	RS-1	RS-2	GS	MVS	LVS	HLFS	IS *	Grand Total
0.25	$ 2,850		4				1		5
0.5	$ 2,850	132	503	14	1				650
0.75	$ 2,850	2,802	32,991	1,627	174	39	101	1	37735
1	$ 2,950	7	46	5	1		4		63
1.25	$ 2,950	197	321	320	98	43	51		1030
1.5	$ 2,950			1					1
1.75	$ 2,950		1						1
2	$ 6,300	2	11	20	25	23	13		94
2.5	$ 6,300		1						1
3	$ 7,600					1			1
4	$ 8,900						9		9
6	$ 11,300			1			2		3
Grand Total		3,140	33,878	1,988	299	106	181	2	39,593
	Total Cost	$ 8,976,300	$ 96,619,100	$ 5,775,850	$ 948,300	$ 390,500	$ 634,700	$ 374,850	
	Average Cost	$ 2,859	$ 2,852	$ 2,905	$ 3,172	$ 3,684	$ 3,507	$ 187,425	
	Relative Cost	1.00	1.00	1.02	1.11	1.29	1.23	65.56	

5100 feet of 6 inch	
6 inch at 170	$ 12,400
Cost Per Foot	$ 72.94
Feet	5,100
Total Cost	$ 372,000

* One of the two IS customer has 6 inch service at 5100 feet.

Chesapeake Utilities Corporation
Delaware Division
Analysis of Meters - Account 381
Twelve Months Ended June 30, 2015

VENDOR NAME	METER SIZE	Count	Investment	Average Cost	RS-1	RS-2	GS	MVS	LVS	HLFS	IS	Grand Total
AMERICAN METER CO	250	27,971	$ 2,021,600	$ 72	2,620	19,365	1,222	7		3		23,217
AMERICAN METER CO	425	850	199,491	235	11	348	255	45	1	12		672
AMERICAN METER CO	630	521	226,910	436	2	154	126	48	2	22		354
AMERICAN METER CO	800	388	332,445	857	1	43	84	48	5	38		219
AMERICAN METER CO	1000	190	153,523	808		9	45	50	1	28		133
AMERICAN METER CO	1400	82	89,444	1,091		2	11	16	5	8		42
AMERICAN METER CO	1.5M	11	10,006	910			1	1	1	1		4
AMERICAN METER CO	3.5M	15	12,536	836			1		1			2
AMERICAN METER CO	5.5m	11	16,167	1,470					1			1
AMERICAN METER CO	5B	3,355	103,355	31	124	1,157	51					1,332
AMERICAN METER CO	GT4 [1]			5,660			1					1
AMERICAN METER CO	GT6 [2]			4,857					1			1
EQUIMETER	275	2,467	197,813	80	285	2,034	118	1		1		2,439
EQUIMETER	TB18	2	1,776	888					2			2
METRIS	250	6,296	334,027	53	411	3,814	134			1		4,360
ROCKWELL	250	429	22,189	52	42	492	16					550
ROCKWELL	275	18,256	1,059,704	58	1,224	11,949	602	5		3		13,783
ROCKWELL	415	427	71,042	166	4	183	124	12		7		330
ROCKWELL	750	250	120,900	484		16	41	12		6		75
ROCKWELL	1000	21	18,676	889			6	6	1	6		19
ROCKWELL	3000	4	3,645	911			1					1

Chesapeake Utilities Corporation
Delaware Division
Analysis of Meters - Account 381
Twelve Months Ended June 30, 2015

VENDOR NAME	METER SIZE	Count	Investment	Average Cost	RS-1	RS-2	GS	MVS	LVS	HLFS	IS	Grand Total
ROOTS-CONNERVILLE	1.5M	63	48,143	764			18	36	7	26		87
ROOTS-CONNERVILLE	11m	52	104,440	2,008			1	1	19	4		25
ROOTS-CONNERVILLE	15c	223	218,833	981			30	53	10	18		111
ROOTS-CONNERVILLE	16M	46	129,510	2,815			1	1	18		2	22
ROOTS-CONNERVILLE	2m	34	43,257	1,272		1	4	9	2	4		20
ROOTS-CONNERVILLE	3M	370	383,436	1,036			23	95	79	49		246
ROOTS-CONNERVILLE	5m	185	243,512	1,316		1	9	24	64	17		115
ROOTS-CONNERVILLE	7m	66	126,400	1,915				2	40	2		44
ROOTS-CONNERVILLE	8c	23	22,715	988		1	17	4		2		24
SENSYS	275 [3]			69	29	144	17					190
SENSYS	T27	2	10,889	5,444					1			1
SENSYS	T35	1	4,857	4,857					2	1	1	4
SENSYS	t57	2	16,662	8,331					1	1		2
SENSYS	T90	8	28,338	3,542					1	1		2
SONIX	215	120	23,264	194	6		40					46
SONIX	600	40	23,550	589		20	3	1				24
SONIX	880	38	$ 24,452	$ 643		4	9	3		2		18
Grand Total		62,819		Count	4,759	39,737	3,011	480	265	263	3	48,518
				Total Cost	$ 319,202	$ 2,780,840	$ 553,466	$ 381,504	$ 398,682	$ 234,777	$ 10,487	
				Average Cost	$ 67.07	$ 69.98	$ 183.81	$ 794.80	$ 1,504.46	$ 892.69	$ 3,495.79	
				Relative Cost	1.00	1.04	2.74	11.85	22.43	13.31	52.12	

Notes
[1] Assumed replacement with T18 meter
[2] Assumed replacement with T35 meter
[3] Used average of other 275s

Chesapeake Utilities Corporation
Delaware Division
Analysis of Industrial M&R - Account 385
Twelve Months Ended June 30, 2015

Row Labels	Test Year Industrial M&R
RS-1	$ -
RS-2	$ 1,154
GS	$ 191,317
MVS	$ 287,413
LVS	$ 641,968
HLFS	$ 581,654
GLR	$ -
IS	$ 3,906
Grand Total	**$ 1,707,413**

The above table represents the total invested plant that was determined to directly serve individual customers, summed by rate class.

Chesapeake Utilities Corporation
Delaware Division
Analysis of Meter Reading - Account 902
Twelve Months Ended June 30, 2015

Rate Classes	ERT Meter Count	Non-ERT Meter Count	Total Meter Count	ERT Read on Industrial Day (Count)	Non ERT Read on Industrial Day (Count)	Read on Industrial Day (Count)	Read on Industrial Day (%)
RS-1	4130	655	4,785	-	1	1	0.34%
RS-2	33516	6677	40,193	1	-	1	0.34%
GS	2297	722	3,019	118	88	206	69.36%
MVS	143	340	483	56	128	184	61.95%
LVS	13	190	203	10	162	172	57.91%
HLFS	75	258	333	16	106	122	41.08%
IS		3	3	-	3	3	1.01%
Grand Total	**40,174**	**8,845**	**49,019**	**201**	**488**	**297**	**100.00%**

Man Days Reading Industrial	6
Man Days Reading All Other Meters	84
Total	90

Rate Classes	Read on Industrial Day (Days of Effort)	Not Read on Industrial Day (Count)	ERT (Not Read on Industrial Day)	Non-ERT (Not Read on Industrial Day)	Non-ERT to ERT Ratio	Ratio Weighted Customer Count
RS-1	0.02	4,784	4,130	654	0.16	758
RS-2	0.02	40,192	33,515	6,677	0.20	8,007
GS	4.16	2,813	2,179	634	0.29	818
MVS	3.72	299	87	212	2.44	729
LVS	3.47	31	3	28	9.33	289
HLFS	2.46	211	59	152	2.58	544
IS	0.06	-	-	-	1.00	-
Grand Total	**6.00**	**48,330**	**39,973**	**8,357**		**11,145**

Rate Classes	Not Read on Industrial Day (%)	Not Read on Industrial Day (Days of Effort)	Total Days of Effort	Days of Effort per Meter	Relative Effort to Read
RS-1	6.80%	5.71	5.73	0.0012	1.00
RS-2	71.85%	60.35	60.37	0.0015	1.25
GS	7.34%	6.17	10.33	0.0034	2.86
MVS	6.54%	5.49	9.21	0.0191	15.92
LVS	2.60%	2.18	5.66	0.0279	23.26
HLFS	4.88%	4.10	6.56	0.0197	16.46
IS	0.00%	-	0.06	0.0202	16.87
Grand Total	**7.47%**	**84**	**98**		

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
CHESAPEAKE UTILITIES CORPORATION	)	
FOR AN INCREASE IN ITS NATURAL GAS	)	PSC Docket No. 15-XXX
RATES AND SERVICES AND FOR CERTAIN	)	
OTHER CHANGES TO ITS NATURAL GAS	)	
TARIFF (FILED December 21, 2015)	)	

DIRECT TESTIMONY OF RONALD J. AMEN

On Behalf of Chesapeake Utilities Corporation

Delaware Division

Submitted for filing: December 21, 2015

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. My name is Ronald J. Amen. My business address is 17806 NE 109th Court, Redmond, WA 98052.

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

A. I am employed by Black & Veatch Corporation ("Black & Veatch") as a Director in the Finance & Regulatory Services Practice of Black & Veatch's Management Consulting group. Black & Veatch is a leading nationwide provider of consulting services to electric and gas utilities and other energy-related and network businesses.

Q. Please describe the firm of Black & Veatch.

A. Black & Veatch has provided comprehensive engineering and management services to utility, industrial, and governmental entities since 1915. Its Management Consulting Division delivers management consulting solutions in the energy and water sectors. Our services include broad-based strategic, regulatory, financial, and information systems consulting. In the energy sector, Black & Veatch Management Consulting delivers a variety of services for companies involved in the generation, transmission, and distribution of electricity and natural gas. From an industry-wide perspective, Black & Veatch has extensive experience in all aspects of the North American natural gas industry, including utility costing and pricing, gas supply and transportation planning, competitive market analysis and regulatory practices and policies gained through management and operating responsibilities at gas distribution, pipeline and other energy-related companies, and through a wide variety of client assignments. Black & Veatch has assisted numerous gas distribution companies located in the U.S. and Canada.

Q. What has been the nature of your work in the utility consulting field?

A. I have over thirty-seven (37) years of experience in the utility industry, the last eighteen (18) years of which have been in the field of utility management and economic consulting. Specializing in the gas industry, I have advised and assisted utility management, industry trade organizations and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, gas resource planning issues, strategic business planning, organizational restructuring, new business development, and load research studies. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included as Appendix A.

Q. Mr. Amen, have you previously testified before this Commission or any other regulatory authority?

A. Yes. I have presented expert testimony before the Federal Energy Regulatory Commission ("FERC") and numerous state and provincial regulatory commissions, including the Delaware Public Service Commission (the "Commission"). My expert testimony has dealt with the costing and pricing of energy-related products and services for gas and electric distribution and gas pipeline companies.

In addition to traditional utility costing and rate design concepts and issues, my testimony has addressed revenue decoupling concepts and other innovative ratemaking approaches, gas transportation rates, gas supply planning issues and activities, market-based rates, Performance-Based Regulation ("PBR") concepts and plans, competitive market analysis, gas merchant service issues, market power assessment, multi-jurisdictional utility cost allocation issues, inter-affiliate cost separation and transfer pricing issues, seasonal rates, time-of-use rates, and pipeline ratemaking issues.

Q. For what purpose has Black & Veatch been retained by Chesapeake Utilities Corporation's Delaware Division ("Chesapeake" or the "Company")?

A. Black & Veatch has been retained by Chesapeake as a consultant in the area of utility costing and rate design and related regulatory matters. Among the varied consulting support for Chesapeake's general rate case, Chesapeake has requested that we assist the Company by conducting a cost of service study, used to determine the embedded costs of serving the Company's customers. In addition, we have performed various statistical, costing and pricing analyses related to the provision of gas distribution services on Chesapeake's system. We also provided analysis to the Company on the various forms of revenue decoupling mechanisms utilized by the utilities industry in order to determine the mechanism most appropriate to Chesapeake's Delaware Division.

II. Purpose of Testimony

Q. What is the purpose of your direct testimony in this docket?

A. First, I will be supporting the level of revenue responsibility between customer classes as a result of the revenue requirement proposed by Chesapeake in this proceeding and as supported by the Allocated Cost of Service Study (ACOSS). I will discuss the use of cost of service results as a guide to be incorporated into the rate design process. Because the results of the ACOSS suggest shifts in revenue responsibility between customer classes, I will discuss proposed changes in the rates of the Company's rate schedules that reflect the ACOSS results.

Second, I will discuss the Company's proposals for changes to the various rate components, in particular, the monthly customer charges for Residential and General Service customers.

Finally, I will present and discuss, from an industry-wide and utility-specific perspective, the reasons that support the ratemaking proposals presented in this proceeding by Chesapeake. Specifically, my testimony will discuss: (1) the business conditions and key challenges facing both regulators and the gas distribution utility industry today; (2) how these challenges have led regulators, utilities, and other key stakeholders to explore and implement innovative ratemaking approaches for gas distribution utilities; (3) the nature of these innovative approaches to rate design for gas distribution utilities; (4) the specific industry-wide activities that are occurring with regard to revenue decoupling mechanisms; (5) conceptual support for the implementation of revenue decoupling mechanisms by gas distribution utilities such as Chesapeake; and (6) the specific decoupling proposal by Chesapeake in this proceeding.

Q. Are you sponsoring any attachments to your testimony?

A. Yes.

Exhibit RJA-1 – Rate Apportionment
Exhibit RJA-2 – Rate Design
Exhibit RJA-3 – Average Monthly Bill Impacts for Residential and General Service Customers

Exhibit RJA-4 – Typical Bill Impacts at Various Consumption Levels
Exhibit RJA-5 – AGA Customer Charge Table
Exhibit RJA-6 – Map of Rate Recovery Mechanisms and Table
Exhibit RJA-7 – Historical Data – Use per Customer, Margin per Customer, and Operating Income
Exhibit RJA-8 – Rate Normalization Mechanism Example
Exhibit RJA-9 – Summary of Rate Normalization Simulation

III. Principles of Sound Rate Design

Q. Please identify the principles of rate design you have relied upon as the basis for Chesapeake's rate design proposals.

A. A number of rate design principles or objectives find broad acceptance in utility regulatory and policy literature. These include:

1. Efficiency;
2. Cost of Service;
3. Value of Service;
4. Stability;
5. Non-Discrimination;
6. Administrative Simplicity; and
7. Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates. Each of these principles plays an important role in analyzing the rate design proposals of Chesapeake.

Q. Please discuss the principle of efficiency.

A. The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by gas producers and consumers, fosters efficient expansion of delivery capacity, results in efficient capital investment in customer facilities, and facilitates the efficient use of existing gas pipeline, storage, transmission, and distribution resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service. Technical efficiency means that the development of the gas utility system is designed and constructed to meet the design day requirements of customers using the most economic equipment and technology consistent with design standards.

Q. Please discuss the cost of service and value of service principles.

A. These principles each relate to designing rates that recover the utility's total revenue requirement without causing inefficient choices by consumers. The cost of service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by the embedded cost of service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service.

Q. Please discuss the principle of stability.

A. The principle of stability typically applies to utility revenues and customer rates alike. Revenue stability and predictability for utilities will provide a minimum of unexpected changes that are seriously adverse to their fiscal condition. This principle also suggests that reasonably stable and predictable prices are important objectives of a proper rate design. In this regard, employing the concept of “gradualism” by moderating rate increases in order to minimize adverse bill impacts on customers is consistent with this principle.

Q. Please discuss the concept of non-discrimination.

A. The concept of non-discrimination requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers within the same class or across different classes of customers.

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, considerations such as the location, type of meter and service, demand characteristics, size, and a variety of other factors are often recognized in the design of utility rates to properly distribute the total cost of service to and within customer classes. This concept is also directly related to the concepts of vertical and horizontal equity. The principle of horizontal equity requires that “equals should be treated equally” and vertical equity requires that “unequals should be treated unequally.” Specifically, these principles of equity require that where cost of service is equal—rates should be equal and, where costs are different—rates should be different.

Q. Please discuss the principle of administrative simplicity.

A. The principle of administrative simplicity as it relates to rate design requires prices be reasonably simple to administer and understand. This concept includes price transparency within the constraints of the ratemaking process. Prices are transparent when customers are able to reasonably calculate and predict bill levels and interpret details about the charges resulting from the application of the tariff.

Q. Please discuss the principle of the balanced budget.

A. This principle permits the utility a reasonable opportunity to recover its allowed revenue requirement based on the cost of service. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective that I previously discussed from the perspective of customer rates.

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes, like most principles that have broad application, these principles can compete with each other. This competition or tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension.

IV. Proposed Revenue Allocation

Q. Please describe the approach generally followed to allocate Chesapeake's proposed revenue increase of $4.74 million to its customer classes.

A. As just described, the apportionment of revenues among customer classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. These criteria were evaluated for Chesapeake's rate classes to facilitate the development of the proposed class revenue targets. The first step in this process is to analyze the current return and revenue to cost ratios by each customer class (i.e., the amount of revenue Chesapeake is receiving in comparison to the costs to serve each customer class).

Q. What insight is gained from reviewing the current return and revenue to cost ratios for each customer class?

A. As a result of the ACOSS, the current return and revenue-to-cost ratio can be seen for each customer class on Table 1 below. For instance, RS-1 is providing a negative return of 4.84% with a revenue-to-cost ratio of 0.45. RS-2 is providing a return of 2.25% with a revenue-to-cost ratio of 0.73. The two residential customer classes are providing revenue far below Chesapeake's cost to serve these classes. In contrast the LVS and HLFS classes are providing revenues higher than Chesapeake's cost to serve these classes. In short, there is an interclass subsidy whereby some of the larger commercial and industrial customers are subsidizing the service of other customer classes; namely Residential and General Service.

Table 1 – Return and Revenue to Cost Ratio

	A	B	C	D	E	F	G
Line	**Class**		**Pro Forma Delivery Revenue**	**Proposed Revenue for Equal Rates of Return**	**Revenue to Cost Ratio**	**ROR at Current**	**Relative Rate of Return**
1	**System Total**		**$ 22,223,119**	**$ 26,964,933**	**0.82**	**4.61%**	**1.00**
2	Residential Service -1	RS-1	824,888	1,824,742	0.45	-4.84%	-1.05
3	Residential Service - 2	RS-2	13,899,067	19,070,205	0.73	2.25%	0.49
4	General Service	GS	1,469,623	1,908,282	0.77	3.53%	0.77
5	Medium Volume Service	MVS	890,630	1,014,740	0.88	6.16%	1.34
6	Large Volume Service	LVS	2,114,683	1,536,873	1.38	15.32%	3.33
7	High Load Factor Service	HLFS	2,860,886	1,584,634	1.81	23.76%	5.16
8	Gas Lighting Residential	GLR	705	1,003	0.70	1.35%	0.29
10	Interruptible Service	IS	162,637	24,454	6.65	133.69%	29.03

Q. How does this interclass subsidy affect the ability to move the classes to their fully allocated cost of service?

A. The first option that I evaluated under Chesapeake's proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost for each class was equal to 1.00. As a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass subsidy issue. The rate impact of moving the two residential classes to their fully allocated cost of service would be in direct contrast with Bonbright's principal of stability as the rate impacts would be very large for those classes. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective.

Q. How did you balance the competing needs of reducing the interclass subsidy with principles of rate stability and gradualism?

A. First I did not provide rate decreases to any of the classes. Providing a rate decrease to those classes providing more revenues than their costs would result in even more costs needing to be recovered from the residential classes, who are already far below their cost of service. Secondly, I developed a band around Chesapeake's proposed overall system increase, which is 21.34%, of 1.5x and 2x to assess the reasonableness of rate increases. The resulting increase target at 1.5x the overall system increase is 32.01% and at 2x the increase is 42.67%. I was able to move RS-2 and GS closer to their cost of service but kept them below the 1.5x increase band. For RS-1, I set their target revenue-to-cost ratio at a level that would result in a 0.00% return for that class. This resulted in the proposed increase for RS-1 slightly above the 2x band. As a result every class except LVS and HLFS (which did not receive a revenue decrease) moved closer to a revenue-to-cost ratio of 1.00. This resulted in the relative rate of return among the classes tightening (i.e., the large disparity of returns among the classes is no longer as large). Table 2 below provides details on this outcome. This information is also provided in Exhibit RJA-1.

Table 2 – Proposed Revenue Increase and Resulting Return

	A	B	C	D	E	F
Line	**Class**		**Target Revenue to Cost**	**Proposed Increase (Decrease)**	**ROR @ Proposed Increase**	**Relative Rate of Return**
1	**System Total**			**$ 4,741,815**	8.55%	1.00
2	Residential Service -1	RS-1	0.65	364,328	0.00%	(0.00)
3	Residential Service - 2	RS-2	0.93	3,814,419	6.89%	0.81
4	General Service	GS	1.00	438,660	8.55%	1.00
5	Medium Volume Service	MVS	1.00	124,110	8.55%	1.00
6	Large Volume Service	LVS	1.38	-	15.39%	1.80
7	High Load Factor Service	HLFS	1.81	-	23.87%	2.79
8	Gas Lighting Residential	GLR	1.00	298	8.55%	1.00
10	Interruptible Service	IS	-	-	134.42%	15.72

V. Proposed Rate Design

Q. Please summarize the rate design changes Chesapeake has proposed in this rate proceeding.

A. I will present the specific rate design changes and supporting rationale for Chesapeake's rate design proposals. Chesapeake is not making any changes to the rate block cut-offs and rate schedule availability for each of the rate schedules.

Further, Chesapeake is proposing to increase the monthly customer charge for each of the rate schedules to reflect the underlying costs of providing basic customer service to those rate schedules, with the exception of the customer charges for the communities served under the Company's expansion tariffs. Those customer charges were determined in a recent Chesapeake proceeding and will be reviewed according to the schedule set in that docket.[1]

Q. Please summarize the reasons why the Company is proposing to increase the customer charge levels and the relationship to the rate design principles you discussed earlier.

A. The Company has proposed monthly residential customer charges at levels that more closely approximate their full customer cost responsibility. The $15.00 Residential RS-1 customer charge would bring this charge to approximately 44% of its full customer cost level, while the $17.00 customer charge for the Residential RS-2 class will approach 52% of full cost, and the $34.00 for the General Service class will approach 75% of full cost. These proposed customer charges reduce customer bill volatility, alleviate some of the instability in the Company's margin recovery, are fair to customers within the Residential and General Service classes, are easily understood, do not place a greater burden on low income customers than rates that have a more volumetric weighting, and

[1] [Order No. 8479 dated November 5, 2013, in Delaware PSC Docket No. 12-292.]

convey more appropriate price signals with respect to recovery of fixed distribution costs.

Q. Please elaborate.

A. Establishing higher monthly customer charges helps to equalize the contribution each customer within a class makes towards recovery of customer costs attributable to this class. This method of customer cost recovery is preferable to including such costs in the commodity block prices, which has the effect of causing some customers to pay too much while others pay too little.

The customer charges provide for recovery of a portion of the Company's fixed customer costs, which are incurred solely because of the existence of customers connected to the system. These costs, such as the expense of reading meters and billing, occur regardless of whether gas is consumed and are not related to demands placed on the system. The proposed customer charge increases will also help to ensure recovery by the Company of a greater portion of its fixed costs of providing service. Inasmuch as customer costs are not related to usage, they should be recovered to the extent possible through a tariff mechanism that does not depend upon volumetric billing.

In terms of understandability, customers should easily understand a full customer cost based charge. A full customer cost based charge is easily explained since the rate is based on customer costs. Because these costs do not vary with the customer's usage, it is perfectly understandable that the charge should not vary as well. It is intuitively obvious that a customer should not pay more for being a customer when the weather is cold, and conversely should not pay less when the weather is warm.

Q. Have you provided an Exhibit that depicts the proposed rates for all classes of service?

A. Yes. Exhibit RJA-2 shows the derivation of each rate component for each of Chesapeake's rate schedules.

Q. Please describe the bill impacts prepared to illustrate Chesapeake's rate design proposal impact on the various rate schedules.

A. Monthly bill impacts across a typical year of average monthly consumption are shown for Residential and General Service customers on Exhibit RJA-3. The average monthly increase for a Residential RS-2 customer under the Company's proposed rate design is $8.27 or 12.15%. Further, monthly bill impacts for customers over a range of monthly consumption levels are shown on Exhibit RJA-4.

VI. Revenue Decoupling

A. Changes to the Traditional Ratemaking Process

Q. Can you please describe the business conditions and key challenges that have faced both regulators and the gas distribution utility industry over the last several years?

A. Yes. The major business challenges faced by gas distribution utilities operating in North America over the past several years have included:

- Weather variability and warming temperatures;
- Declining use per customer;
- Increased impact and promotion of energy efficiency and conservation measures;

- Rising costs of labor and materials for expansion and growth; and
- Increasing requirements applicable to heightened regulatory oversight over safety issues and due to maintenance and improvement of aging infrastructure and system reliability.

These challenges, in turn, create stresses and challenges for regulators such as managing more frequent and larger rate case filings or developing new regulatory tools for encouraging energy conservation without requiring still more general rate case filings.

Q. How do the business challenges you have described impact a gas utility's delivery service costs and its ability to recover these costs through base rates?

A. The business challenges I just described have a combined effect of introducing elements of considerable and recurring variability, unpredictability and uncontrollability related to a gas utility's costs of delivery service and the gas usage factors used to set its base rates to recover such costs.

Q. Please explain this phenomenon.

A. Very simply, these elements of variability are not well accommodated within the context of the traditional utility ratemaking process. First, the traditional volumetric structure of a utility's base rates does not allow for the full recovery of a utility's non-gas cost of service approved by its utility regulator whenever a decline is experienced in the level of its billing determinants (i.e., customers' gas consumption levels are lower than the level used to establish base rates). Second, the static nature of how a utility's revenue requirement is determined precludes the recognition and timely recovery of additional costs incurred by the utility in providing delivery service that is necessitated by unpredictable or uncontrollable business conditions that the utility has to accommodate.

Q. Have these business conditions and associated challenges caused utilities, regulators, and stakeholders to explore more innovative natural gas rate design approaches?

A. Yes. In my experience, it is widely recognized by industry participants, regulators, and other key stakeholders including energy conservation advocates that innovative approaches to utility ratemaking can actually align all the various interests in a way that creates opportunities out of these challenges. In addition, the fixed cost nature of the gas distribution business warrants new approaches to the traditional ratemaking process in order that a utility be given a reasonable opportunity to recover its fixed costs of providing gas delivery service, and that its customers pay for that service in an appropriate and equitable manner. With the associated changes to key industry drivers - such as the gas supply/demand balance, marketplace price dynamics, and customer usage characteristics - the policy objectives of stakeholders pertaining to utility ratemaking also are changing. At the same time, there is a growing recognition that the current rate design approaches may not be working as intended as evidenced by stakeholder impacts and original rate design objectives not being satisfied. These impacts have included the inability of gas distribution utilities to fully recover their approved revenue requirements and customers paying more or less than expected for gas service due to fluctuations in weather from “normal” conditions.

Q. Please explain some of these innovative approaches to rate design for gas distribution utilities.

A. The above-described business conditions and challenges have led to fundamental changes in the ratemaking approaches traditionally relied upon by gas distribution utilities, and approved by utility regulators. These changes are reflected in the growing and widespread approval of various innovative ratemaking approaches by gas distribution utilities. These approaches can be characterized in broad terms as follows:

1. Revenue decoupling mechanisms,
2. Rate design utilizing a single, fixed monthly charge.
3. Automatic adjustment rate mechanisms or rate trackers that address items such as the recovery of bad debt expenses, infrastructure replacement costs, energy efficiency program costs, and margin revenue losses due to warmer-than-normal weather.
4. Revenue (return) stabilization mechanisms.

Q. In your expert opinion, what current business challenges are having the greatest impact upon the gas distribution industry?

A. The combination of increasing fixed costs associated with increased investments to replace aging infrastructure and to address increased regulatory requirements, combined with conservation efforts, weather variability, and the uncertain ability of gas distribution utilities to recover their approved level of margin revenues has been the greatest, and a continuing, challenge to the gas distribution utility segment of the energy industry. And although this serious challenge has been addressed, or at least partially mitigated, for a growing number of gas utilities in recent years through innovative ratemaking approaches, it continues to impact many utilities' financial performance.

Q. How has the gas distribution utility industry addressed the challenge of under recovery of fixed costs?

A. The revenue shortfall challenge for gas distribution utilities has received much attention from state regulators in recent times. To effectively mitigate the variability in revenues caused primarily by weather and declining use per customer, and to align utility objectives with key public policy goals such as energy conservation, regulators have implemented a number of ratemaking solutions, including:

1. Revenue decoupling mechanisms that adjust rates for changes in usage caused primarily by weather and energy conservation;
2. Straight Fixed-Variable ("SFV") rate structures;
3. Weather Normalization Adjustment ("WNA") mechanisms that adjust rates for changes in usage caused by weather; and
4. Monthly customer charges that more fully reflect the gas utility's fixed costs of providing gas delivery service.

Q. Are the ratemaking solutions that you just described mutually exclusive for a gas distribution utility?

A. No. There are numerous examples of gas distribution utilities that have received approval from regulators to implement more than one of these ratemaking solutions recognizing that they work together to address the business challenges that I described earlier.

Q. Can you provide an overall picture of the degree to which utility regulators have implemented these types of ratemaking solutions for gas distribution utilities?

A. Yes. Exhibit RJA-6, Schedule 1 presents a map of the U.S. which depicts the extent to which revenue decoupling mechanisms, SFV rate structures, WNA mechanisms, and revenue (return) stabilization mechanisms have been approved, or are currently being addressed, in the various states.[2] This information clearly shows the widespread regulatory acceptance of these types of ratemaking solutions. Based on this information, there are 27 states that have approved, or have pending, one or more types of the non-volumetric ratemaking approaches that I just presented. Therefore, only 23 states have not yet experienced any meaningful activity related to these types of innovative ratemaking solutions. Finally, I should add that WNA mechanisms have been a part of the utility ratemaking process for the natural gas industry since the 1980s, while revenue decoupling mechanisms and SFV rate design has appeared more recently, with the majority having been approved by utility regulators between 2005 and 2010.

Regarding the industry-wide trends observed in the level of monthly customer charges, it is has been common practice on the part of gas distribution utilities in recent years to adjust their monthly customer charges[3] to levels that are much closer to the customer-related fixed costs of gas delivery service. Interestingly, a number of the gas utilities that have pursued this ratemaking approach also have implemented revenue decoupling mechanisms. To the extent a gas utility is allowed by the regulator to adjust its monthly customer

[2] Compiled from American Gas Association and Black & Veatch data – as of September 2015. Schedule 3 of this Exhibit provides a table with additional details on the decoupling mechanisms approved throughout the United States.

[3] This is especially true in the utility's residential and small general service markets where the majority of its non-gas revenues are designed to be collected.

charges in each rate case towards the underlying cost of service, all other things being equal, the periodic rate adjustments under the utility's revenue decoupling mechanism will decrease in magnitude.

An American Gas Association ("AGA)" analysis[4] addressing the customer charge component of gas utility rates noted that gas utilities have sought to increase their monthly customer charges to better capture the actual fixed costs of serving smaller residential and general service customers, citing the following customer and utility benefits:

- Moderates volatility in customer bills;
- Encourages gas utilities to promote energy conservation by customers;
- Reduces winter bills for high use customers;
- Reduces the need for future rate cases;
- Makes utility earnings less dependent on sales volumes;
- Improves cash flow, mitigating the need for working capital; and
- Is a more appropriate way to recover fixed costs.[5]

There were some important conclusions reached in the analysis, including:

- The monthly customer charge was typically $11.25 per month for residential customers (the median value), with the corresponding charge of $15.53 per month in the third quartile of the research population[6].

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[4] Natural Gas Utility Rate Structure: The Customer Charge Component – 2015 Update, American Gas Association, Energy Analysis EA-2015-3, dated May 28, 2015.

[5] Compared to recovery through volumetric delivery charges.

[6] The AGA analysis is based on a February 2015 internet search of natural gas utility tariffs and AGA surveys, representing 237 rate jurisdictions in all states and the District of Columbia. Black & Veatch conducted an update to the basic numerical results of the above-described AGA analysis to reflect the level of monthly customer charges currently billed to residential customers by gas utilities in the U.S. This supplemental research was conducted in September 2015.

- The customer charge represented about nineteen (19) percent of a customer's annual gas bill.
- The customer charges typically recovered forty-six (46) percent of a gas utility's actual fixed costs of delivery service.
- A gas utility's monthly customer charge would have to be set at $24.00 per month for the residential sector, on average, in order to recover all of utility's typical fixed costs.
- The median monthly residential customer charge has increased from $10.00 in the AGA's 2010 study to the present studies' result of $11.25.

Importantly, more than 57% of the monthly customer charges surveyed in the residential sector are above Chesapeake's current Residential RS-1 customer charge of $10.50 per month for its residential class. Page 1 of Exhibit RJA-5, presents a graphical representation of this result. Pages 2-7 of the Exhibit present the current residential monthly customer charges by individual gas utility, and state.

B. Industry-Wide Activities Related to Revenue Decoupling

Q. Please discuss the nationwide trends related to revenue decoupling mechanisms for gas distribution utilities.

A. Overall, there is a strong recognition and endorsement throughout the utility industry of ratemaking approaches that "decouple" a utility's sales from its revenues. In my opinion, such a ratemaking approach has become widespread as its conceptual underpinnings have gained acceptance by a number of utility regulators as the challenges in the utility industry become more evident and pronounced.

In 2002, there were only three (3) states that had approved revenue decoupling mechanisms for gas utilities – and currently there are twenty-two (22) states that have approved revenue decoupling, and five (5) additional states that have approved SFV rate design (another form of revenue decoupling). ExhibitRJA-6, Schedule 2 presents a map of the U.S. which depicts the extent to which revenue decoupling has been approved in the various states.[7]

Q. What is the overall structure of revenue decoupling mechanisms approved by utility regulators in the U.S.?

A. Exhibit RJA-6, Schedule 3 presents a tabular listing of all the revenue decoupling mechanisms approved for gas utilities in the U.S. This Schedule includes the name of the gas utility, the state in which the utility is located, the year the revenue decoupling mechanism was approved, the type of mechanism, whether the mechanism applies to all rate classes, and the inclusion of any revenue/rate restrictions or caps. The vast majority of revenue decoupling mechanisms approved in the U.S. are designed on a "full" decoupled basis. This means that the ratemaking mechanism addresses all factors (including variations in weather) that impact use per customer. It should be noted that in the states where a single ratemaking mechanism is not used to achieve "full" revenue decoupling, the utility regulators also have approved companion WNA mechanisms for those utilities to specifically address the impact of weather upon their gas volumes and non-gas revenues. This ratemaking approach effectively provides the gas utility with "full" revenue decoupling.

[7] Reflects states where revenue decoupling mechanisms or SFV rate structures has been approved since both "decouple" a utility's sales from its revenues.

Q. In your opinion, what are the factors driving this level of interest in revenue decoupling?

A. I believe there are two key factors driving this interest in revenue decoupling. First, it is widely acknowledged by utilities, regulators, legislators, and other stakeholders that utilities have an inherent disincentive to promote energy efficiency. This is caused by the prevalence of volumetric-based rate structures for gas utilities that create a decline in margin revenues with a decline in customers' gas usage. Revenue decoupling removes this inherent disincentive as a necessary prerequisite to utilities offering energy efficiency and conservation programs to their customers.

Second, as a result of an ongoing decline in use per customer, most gas utilities have experienced an under-recovery of margin revenues.[8] This serious financial impact can be mitigated with revenue decoupling.

Q. Have other participants in the gas industry endorsed the concept of revenue decoupling to address the inherent disincentive that a utility has to promote energy efficiency?

A. Yes. Over the last ten years or so, many energy industry groups have been publicly advocating a renewed focus on promoting cost-effective energy efficiency measures to help relieve consumer burdens associated with the price of natural gas. These groups have included the AGA, the Edison Electric Institute ("EEI"), the Natural Resources Defense Council ("NRDC"), the Alliance to Save

[8] On average, natural gas use per customer in the U.S. has been declining by about one percent per year since 1980. See the American Gas Association Energy Analysis entitled, "Forecasted Patterns in Residential Natural Gas Consumption," 2001-2020, EA 2004-04 (dated September 24, 2004).

Energy, and the American Council for an Energy Efficient Economy ("ACEEE"). These groups realized that a fundamental change must be made to the utility ratemaking process in order to achieve these consumer benefits. They have endorsed the concept of revenue decoupling as their solution to the problem.[9]

The NRDC and the Edison Electric Institute issued a particularly pointed statement. It noted that:

> *To eliminate a powerful disincentive for energy efficiency and distributed-resource investment, we both support the use of modest, regular true-ups in rates to ensure that any fixed costs recovered in kilowatt-hour charges are not held hostage to sales volumes.*[10]

Q. Has any other industry organization recognized revenue decoupling as a viable ratemaking concept to address this issue?

A. Yes. NARUC has recognized that revenue decoupling as a ratemaking concept provides earnings stability for utilities and removes the disincentives for promoting energy conservation. In particular, NARUC made reference to the above-mentioned groups and stated that:

> *Among the mechanisms supported by these groups are the use of automatic rate true-ups to ensure the utility's opportunity to recover*

[9] Joint Statement of the American Gas Association and the Natural Resources Defense Council submitted to the National Association of Regulatory Utility Commissioners ("NARUC"), July 2004.

[10] Joint recommendation submitted in November 2003 to the NARUC by the NRDC and the Edison Electric Institute.

> *authorized fixed costs is not held hostage to fluctuations on (sic) retail sales.*[11]

In its 2005 Fall Meeting, NARUC's Board of Directors adopted the "Resolution on Energy Efficiency and Innovative Rate Design," dated November 16, 2005. As set forth in this second resolution:

> *[NARUC]…encourages State commissions and other policy makers to review the rate designs they have previously approved to determine whether they should be reconsidered in order to implement innovative rate designs that will encourage energy conservation and energy efficiency that will assist in moderating natural gas demand and reducing upward pressure on natural gas prices…* [12]

The NARUC resolution recognized that the traditional volume driven approach to regulating the rates that utilities charge to deliver natural gas might tend to misalign the interests of natural gas utilities and the goals of energy efficiency and energy conservation.[13] As part of this review, NARUC further encouraged state utility regulators and other policy makers to consider in their review innovative rate designs including "energy efficiency tariffs" and "decoupling

[11] NARUC Resolution on Gas and Electric Efficiency, Sponsored by NARUC Natural Gas Task Force, Committee on Gas, Committee on Consumer Affairs, Committee on Electricity, Committee on Energy Resources and the Environment, adopted by the NARUC Board of Directors on July 14, 2004.

[12] NARUC Resolution on Energy Efficiency and Innovative Rate Design, Sponsored by the Committee on Gas, recommended by the NARUC Board of Directors on November 15, 2005, adopted by the NARUC on November 16, 2005.

[13] Ibid.

tariffs."[14] The resolution recognized several utilities that have received approval of revenue decoupling mechanisms, fixed-variable rates and other innovative rate design approaches.

In July of 2008, NARUC issued a second resolution[15] in response to the Second Joint Statement of the AGA and NRDC[16] again encouraging state commissions and other policymakers to review and give strong consideration to favorably approving gas distribution proposals consistent with the principles and recommendations made in the AGA/NRDC Statement.

Q. Have any national policy initiatives been undertaken to address the deficiencies in traditional utility ratemaking?

A. Yes. The National Action Plan for Energy Efficiency[17] ("Action Plan") emphasizes the need to eliminate ratemaking and regulatory disincentives or barriers through its recommendation that utility regulators "modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments." Specifically, the Action Plan states that, "removing the throughput incentive is one way to remove a disincentive to invest in efficiency." It is widely recognized that a revenue

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[14] Ibid.

[15] NARUC Resolution on Second Joint Statement of the American Gas Association and the Natural Resources Defense Council in Support of Measures to Promote Increased Energy Efficiency and reduction in Greenhouse Gas Emissions, Sponsored by the Committee on Gas and Energy Resources and the Environment, adopted by the NARUC Board of Directors on July 23, 2008.

[16] Second Joint Statement of the American Gas Association and the Natural Resources Defense Council, May 2008.

[17] Issued in July 2005, the "Action Plan" was facilitated by the U.S. Department of Energy and U.S. Environmental Protection Agency with the participation of over 50 utilities, public utility commissions, energy consumers, and non-governmental groups to set a broad course for encouraging greater energy efficiency investment in the United States.

decoupling mechanism is a ratemaking approach that can address the "Throughput Incentive" utilities have when their rates are designed so that fixed costs are recovered through volumetrically-based energy charges.

I would also note that in NARUC's "Resolution Supporting the National Action Plan on Energy Efficiency" ("NARUC Resolution") it endorsed "the principal objectives and recommendations of the Action Plan, and commends to its member commissions a state-specific, or where appropriate, regional review of the elements and potential applicability of energy efficiency policy recommendations outlined in the Action Plan, in an effort to identify potential improvements in energy efficiency policy nationwide."[18] The NARUC Resolution cites five key elements of the Action Plan, including the modification of ratemaking practices to align utility incentives with the delivery of cost effective energy efficiency and to promote energy efficiency investments.

Q. Has Federal legislation in the last ten years addressed revenue decoupling?

A. Yes. The Energy Independence and Security Act of 2007 addresses revenue decoupling in conjunction with the Act's directives on utility energy efficiency programs. Section 532(b)(6)(A) of the Act states that "(t)he rates allowed to be charged by a natural gas utility shall align utility incentives with the deployment of cost-effective energy efficiency." Further, from a policy perspective, the Act directs each state regulatory authority to consider, "separating fixed-cost revenue

[18] NARUC Resolution Supporting the National Action Plan for Energy Efficiency, Sponsored by the Executive Committee and the Committees on Consumer Affairs, Electricity, Energy Resources and the Environment, and Gas, adopted by the NARUC Board of Directors August 2, 2006.

recovery from the volume of transportation or sales service provided to the customer. Clearly, revenue decoupling mechanisms and SFV rate design are two ratemaking approaches that do achieve this policy objective.

Similarly, the American Recovery and Reinvestment Act of 2009 addresses the concept of revenue decoupling within the context of the energy efficiency initiatives delineated in the Act. Section 410 (a) (1) of the Act specifically states that the applicable State regulatory authority will seek to implement a general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently. As I discussed earlier, this alignment can be achieved by a utility and its stakeholders through the implementation of a revenue decoupling mechanism.

Q. Has the financial community recognized the value of ratemaking solutions to address the conditions faced by gas utilities?

A. Yes. The financial community has discussed the impact of energy conservation and usage on gas utilities. It has acknowledged that rate design solutions such as revenue decoupling favorably address the financial consequences of reduced usage on gas utility systems. For example, Moody's Investor Service issued a Special Comment report that specifically addressed this topic. The Moody's report stated:

> *Moody's believes that having utility rate designs that compensate the gas LDCs for margin losses caused by variations in gas consumption due to conservation as with variations due to weather, would serve to stabilize*

the utility's credit metrics and credit ratings. Utilities having these ratemaking mechanisms also tend to carry 'A' credit ratings.[19]

In addition, Standard & Poor's presented its views on the characteristics of credit-supportive regulation during a recent AGA Financial Forum, which included: (1) consistency and predictability of decisions; (2) timeliness of rate orders; (3) use of forward-looking measures; (4) use of adjustment clauses/trackers; (5) pre-approval processes; and (6) support during times of economic or financial stress.[20]

C. Conceptual Support for the Implementation of Revenue Decoupling Mechanisms

Q. Please indicate the business challenges that have most influenced the decisions by gas distribution utilities to propose revenue decoupling mechanisms.

A. Some of the business challenges mentioned earlier that have most influenced the decisions by gas distribution utilities to propose revenue decoupling mechanisms have included weather variability, declining use per customer, and the ongoing energy efficiency and conservation efforts of their customers. Based on my discussions with Chesapeake staff, I understand that each of these factors has impacted Chesapeake's past financial performance and its customers' bills.

Q. Please explain how weather influences the ratemaking process for a gas utility.

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[19] "Impact of Conservation on Gas Margins and Financial Stability in the Gas LDC Sector," Special Comment Report, Moody's Investor Service, June 2005.

[20] "Understanding the Ratings Process and What it Means to the Cost of Capital," presented by Ken Farer, Director – Standard & Poor's, at the AGA Financial Forum, May 17, 2010.

A. As part of the ratemaking process, both test period costs and revenues of a gas utility are established based on normal weather. The test period used by the utility is designed to be a reasonable picture of the operating conditions expected to occur during the period in which the utility's approved rates will be in effect. The process of computing revenue under normal weather conditions consists of either increasing or decreasing actual gas volumes, in relative terms, based on the difference between normal temperatures established for the utility's service area and actual temperatures experienced during the actual year.

Q. How are weather-normalized gas volumes used to derive a gas utility's base rates?

A. While the following explanation is somewhat over-simplified, essentially the utility's unit rates and charges for gas service are derived by dividing the appropriate costs, to be recovered through rates, by the weather-normalized gas volumes. These rates and charges are designed to provide the utility with an opportunity to recover the significant level of fixed costs it incurs to provide utility service, at the levels determined in the utility's last completed rate case. Fixed costs are costs incurred by a utility that do not vary with the amount of gas delivered to customers. For Chesapeake, these costs are composed of fixed operation and maintenance ("O&M") expenses, administrative and general expenses, depreciation, certain taxes, a portion of working capital requirements, and return on investment. These costs also do not vary in the short-term with changes in temperature. If actual temperatures are normal, the utility has a reasonable opportunity to fully recover its fixed costs of service at established sales levels. Unfortunately, normal temperatures seldom, if ever, occur.

Therefore, as a result of abnormal weather, the margin revenues and resulting earnings of a utility such as Chesapeake can vary widely from the levels authorized by its regulator.

Q. Please explain more specifically what you mean by "margin revenues".

A. "Margin revenues" consist of a utility's total cost of service, exclusive of purchased gas expenses and any other expenses that are treated as "flow-through" items in rates (e.g., revenue taxes). A utility generates margin revenues through base rates for delivering gas to its customers. A utility's margin revenues reflect its overall costs of operations (exclusive of flow-through items), with most of it fixed, including a fair and reasonable return on its utility assets. A portion of margin revenues are typically recovered through fixed charges such as a monthly customer charge, leaving the remaining portion of margin revenues to be recovered through volumetric distribution charges.

Q. What is the significance of any portion of margin revenues being recovered through a volumetric charge?

A. To the extent any margin revenue is subject to recovery in a volumetric charge, the full recovery of such a margin revenue amount is entirely dependent upon the volumes of gas usage experienced by the utility. Therefore, the recovery of margin revenue in a volumetric component of rates puts full recovery at risk.

Q. What portion of Chesapeake's fixed costs is recovered through its current volumetric distribution charges?

A. For Chesapeake's primary Residential, General Service, Medium Volume Service, Large Volume Service, and High Load Factor Service classes, approximately 56 percent (56%) of the current margin revenue is currently designed to be recovered through its volumetric distribution charges (see page 4 of Exhibit RJA-2).

Q. Is it important that a utility such as Chesapeake realizes the margin revenue that was allowed by the regulator in the utility's most recent rate case?

A. Yes. The utility's financial health is directly tied to its ability to recover the total cost of service (excluding purchased costs) approved by its regulator through the margin revenues upon which its base rates were previously established.

Q. Please explain how fluctuations in weather over time impact a gas utility's temperature-sensitive customers and the utility's financial performance.

A. Since the bills of gas customers are largely based on the level of gas usage, temperature-sensitive customers' monthly bills can vary widely due to changing weather conditions. Under traditional ratemaking methods, if actual temperatures were colder than normal, the typical gas customer would use more gas, pay more for service, and potentially overpay its share of fixed costs. This occurs because the unit rates used to recover fixed costs are not reduced to recognize the higher gas volumes used by customers during colder weather. Since the gas utility's level of fixed costs does not change, the higher gas volumes applied against the same unit rate would generate comparatively higher non-gas revenues than the level of fixed costs established for ratemaking purposes. Conversely, in warmer than normal weather, the reverse situation will occur. Customers' gas usage decreases with warmer temperatures, thus generating comparatively lower non-gas revenues than required to recover the gas utility's total fixed costs that do not decrease due to warm weather.

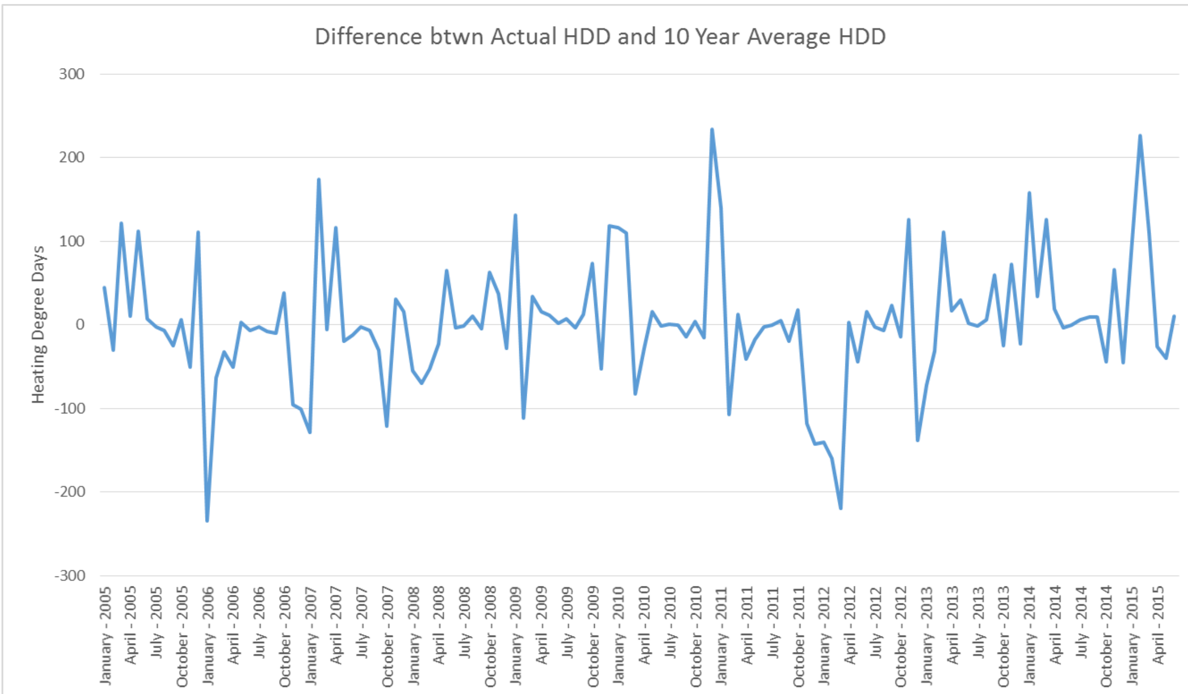
Q. What is your understanding of Chesapeake's historical weather patterns?

A. Based on my review of the weather data from the last eleven years (2005 – 2015), winter period temperatures during the months of January through March have averaged colder than normal in eight of those years and have been increasing over the past three years. Based on the weather data for Chesapeake of the last ten calendar years (2005 through 2014), six have been colder than normal based on the most recent 30-year average of Heating Degree-Days ("HDDs"). This weather average is the basis upon which Chesapeake's current base rates were set.

Q. Have you prepared a graphical depiction of the historical weather pattern experienced by Chesapeake?

A. Yes. The historical weather pattern is presented in Table 3 below. The weather is presented on an annual and monthly basis as the change in heating-degree days ("HDDs") from Chesapeake's normal weather (and its monthly components). As described in the testimony of Chesapeake witness Sarah E. Hardy, the Company's current normal HDD level is based on the 10-year average, calculated from weather data maintained by Eastern Shore Natural Gas Company, an interstate pipeline wholly-owned by Chesapeake Utilities Corporation . Clearly, there is a significant variation in actual weather compared to normal weather. The variability of weather has very significant implications for Chesapeake's ability to achieve its authorized margin revenue per customer level, which is premised upon normal weather.

Table 3 – Historical Weather



Q. Historically, what has Chesapeake's experience with gas use per customer?

A. Exhibit RJA-7 demonstrates that over the last six (6) years, the annual average use per customer has fluctuated in Chesapeake's Residential and General Service classes.

Q. What reference point should be used to review Chesapeake's volatility in use per customer?

A. The reference point should be the use per customer levels established in Chesapeake's past rate case. Referring to Page 1 of Exhibit RJA-7, the annual "baseline" use per customer for the Residential R-2 class established in Docket No. 07-186 to design Chesapeake's base rates was approximately 700 ccf per customer, respectively. One can readily see that over the succeeding years since that rate case was completed, Chesapeake's R-2 class experienced an approximate annual use per customer greater than this level only once.

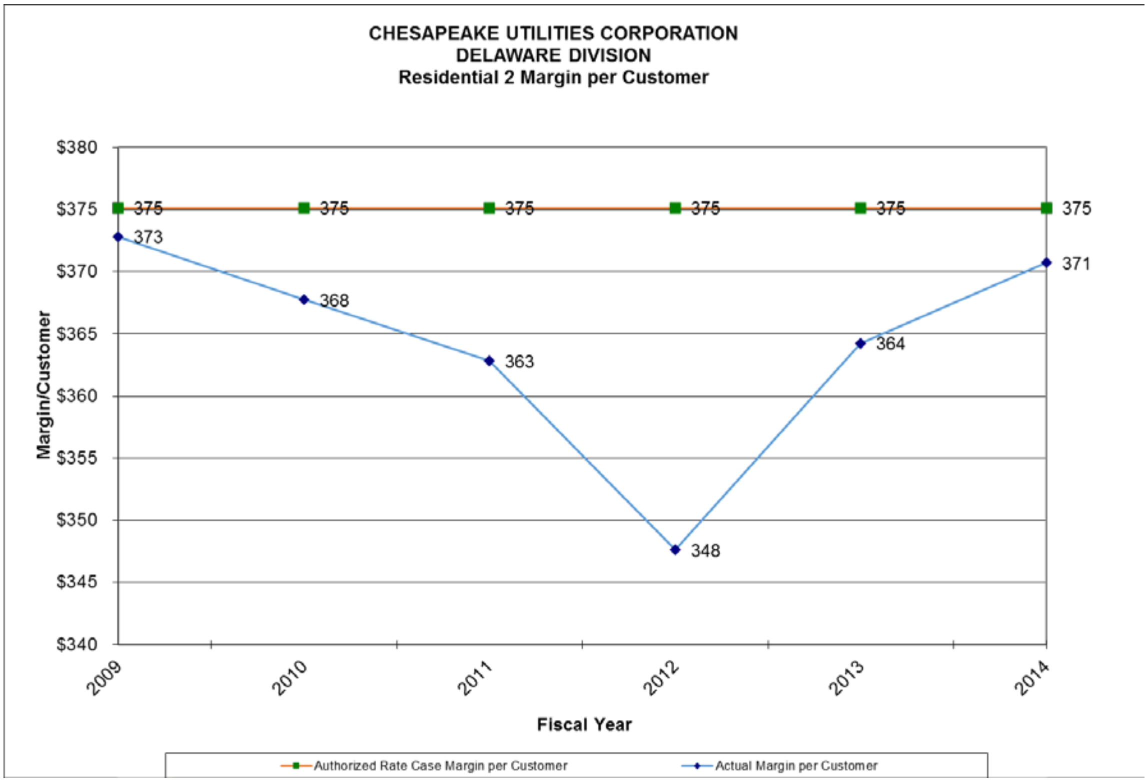
Q. What conclusion do you reach from this assessment?

A. Chesapeake's "baseline" use per customer level established in its prior rate cases was not representative of the actual use per customer it experienced in subsequent years. In fact, the data in Exhibit RJA-7 demonstrates that the baseline use per customer levels for the R-2 class were high relative to the actual amounts, and that trend is expected to continue without a resetting of Chesapeake's baseline use per customer levels. To the extent the baseline use per customer level is not representative of Chesapeake's expected future trends, its base rates will not properly recover from customers the fixed costs incurred to provide them with gas delivery service.

Q. Have you examined the variability in the margin revenues per customer collected historically by Chesapeake?

A. Yes. Exhibit RJA-7 presents the margin revenue per customer impact experienced by Chesapeake in its Residential (RS-1 and RS-2) and General Service classes due to fluctuations in gas volumes caused primarily by variations in weather from normal levels and non-weather related changes in use per customer. Between 2009 and 2014, Chesapeake incurred margin per customer deficiencies for all three classes in the two warmer than normal years, while the Residential RS-2 class experienced margin per customer deficiencies in all six years, despite the colder than normal weather experience, as shown on Table 4 below.

Table 4 – Residential Customer Margin per Customer



Q. How has Chesapeake's historical experience with the variability in its margin per customer recovery been reflected in the Company's achieved rate of return levels?

A. The Table 5 below provides a comparison of the Company's actual versus Commission authorized rates of return for its gas business, as shown in the Company's Annual PSC Reports. While recognizing that the Company's actual results of operations also reflects its ability to effectively manage those aspects of its business that are under its control, the trend in actual rate of return ("ROR") since 2009 tracks the net operating income (NOI) deficiency shown in Exhibit RJA-7 for the same period. The Company experienced achieved NOI levels less than the corresponding return requirement in each of the six full calendar years and in the first six months of 2015, both on a contemporaneous rate base level and the base year of 2009. The total NOI deficiency for the seven year period totaled approximately $6.1 million.

Table 5 - Net Operating Income

Adjusted Twelve Months Ended	Overall ROR	Return on Equity	Approved ROR	Total Rate Base	Return Requirement	Achieved NOI	Return Excess / (Deficiency)	Revenue Excess / (Deficiency)
								1.66871
30-Jun-2015	5.52%	5.70%	8.91%	$65,427,754	$ 5,829,613	$ 3,614,198	$ (2,215,415)	$ (3,696,885)
31-Dec-2014	5.42%	5.57%	8.91%	$63,392,476	$ 5,648,270	$ 3,435,127	$ (2,213,143)	$ (3,693,093)
31-Dec-2013	8.26%	8.95%	8.91%	$57,847,779	$ 5,154,237	$ 4,776,925	$ (377,312)	$ (629,624)
31-Dec-2012	8.87%	9.83%	8.91%	$53,623,281	$ 4,777,834	$ 4,758,718	$ (19,116)	$ (31,900)
31-Dec-2011	8.73%	9.75%	8.91%	$53,396,661	$ 4,757,643	$ 4,661,772	$ (95,870)	$ (159,980)
31-Dec-2010	8.16%	9.05%	8.91%	$52,705,256	$ 4,696,038	$ 4,301,571	$ (394,467)	$ (658,252)
31-Dec-2009	7.48%	7.95%	8.91%	$54,008,985	$ 4,812,201	$ 4,041,476	$ (770,724)	$ (1,286,116)
							$ (6,086,048)	$ (10,155,850)

Q. Company Witness Mr Christopher Redd's direct testimony discusses the increasing fixed costs and the associated concern over Chesapeake's ability to fully recover the appropriate level of revenue. Is the Company's concern unusual in the gas distribution industry?

A. No. Gas utilities across the U.S. continue to address their growing infrastructure requirements as a major part of their ongoing effort to provide safe, reliable, and cost-effective gas delivery service to their customers. From a regulatory perspective, this business initiative is facilitated through various ratemaking efforts that focus on achieving the full and timely recovery of such capital investment costs, as evidenced by the increased number of innovative ratemaking mechanisms[21] approved by regulators that are designed to satisfy those ratemaking objectives. With increased capital expenditures related to infrastructure a certainty for gas utilities, these concerns will only grow over time.

[21] Including infrastructure cost recovery mechanisms, formula rates, and multi-year rate plans.

Q. How will the revenue decoupling mechanism proposed by Chesapeake address weather, increasing conservation efforts, and the revenue variability, which it has experienced?

A. Chesapeake's proposed revenue decoupling mechanism will minimize the impact of weather on the volatility of its customers' bills and on its financial condition. The proposed mechanism represents the required fundamental change to the utility ratemaking process to recognize that a utility such as Chesapeake has difficulty in establishing a reasonable level of volumes in a rate case that can accurately represent its volumes in future periods. As a consequence of this process, the volumetric base rates or distribution charges that Chesapeake would derive in its rate case, and that the Commission would approve, are unlikely to reflect the level of base rates required in future periods to fully recover its approved level of fixed operating costs.

Q. In what other manner will the proposed revenue decoupling mechanism impact Chesapeake?

A. As described above the proposed revenue decoupling mechanism will align the interests of Chesapeake with the interests of policymakers, conservation advocates, and others with respect to energy conservation and efficiency programs for Chesapeake's customers. It will place Chesapeake in a much stronger position to offer to its customers various energy conservation and efficiency programs to help offset the volatility and unpredictability of high gas prices.

Q. Please explain the importance of "breaking the link" between Chesapeake's sales and earnings to achieve enhanced energy efficiency and conservation goals.

A. Breaking this link is important because it eliminates Chesapeake's "Throughput Incentive" that is inherent in the way its gas rates have been historically designed. The "Throughput Incentive" financially motivates a utility such as Chesapeake to increase sales of natural gas (relative to historical levels which underlie base rates) and to maximize the "throughput" of natural gas across its utility system. Under the traditional utility ratemaking structure, a utility is financially motivated to increase its sales levels in a future period above that established in its previous rate case because its rates are designed to recover most fixed costs on a volumetric basis – causing the utility's revenues to increase as its sales increase. With volumetric pricing for gas delivery service, an increase in the recovery of fixed costs will occur (compared to the level approved in the utility's most recently completed rate case) when sales are higher than assumed in the design of the utility's rates. Conversely, a decrease in the recovery of fixed costs will occur when sales are low relative to assumed levels. This situation creates an automatic disincentive for utilities to promote conservation or energy efficiency initiatives because such actions will reduce the utility's revenues and resulting earnings. Chesapeake's proposed revenue decoupling mechanism will adjust its rates on a periodic basis to offset the revenue impact of increases or decreases in use per customer and therefore margin revenue per customer. By doing so, its proposed revenue decoupling mechanism would effectively eliminate the link between sales and earnings. Hence, it would encourage

Chesapeake to be supportive of measures which would promote decreased energy usage, conservation, or other energy efficiency initiatives.

Q. Please explain the mechanics of revenue decoupling in utility ratemaking.

A. While such a ratemaking mechanism can take several forms, the basic approach consists of defining a target for the utility's margin revenues and placing over- and under-collections of revenue with reference to that target in a deferred account for refund or recovery in a subsequent period. Under these mechanisms, the gas utility cannot increase its earnings by increasing its sales volumes because any over-collected margin revenues are refunded to customers.

Q. Is it necessary to continue to use some measure of sales volumes to compute a gas utility's unit rates?

A. Yes, it is. Under a revenue decoupling mechanism, however, the sales level assumed in the utility's last rate case upon which its base rates were designed is not blindly adhered to for purposes of representing the level of sales the utility actually achieves in a future 12-month period. By utilizing customers' actual sales levels and relating that amount to the utility's approved level of distribution margin revenues, rates can be adjusted to recover the appropriate level of revenues to produce the margin authorized by the regulator. In other words, the utility's realized distribution margins are no longer inextricably linked to its rate case sales level.

The de-emphasis of sales volumes in the operation of a revenue decoupling mechanism better recognizes the way consumers actually perceive, value, and purchase services offered by gas and electric utilities. A consumer does not look at utility services and consciously make a decision to purchase a certain number of ccfs of gas or kilowatt-hours of electricity. Instead, the consumer purchases utility services to acquire light, heat, air conditioning and a wide range of other consumer needs and conveniences. Therefore, we should not continue to hold the financial health of utilities hostage to the fluctuating sales levels resulting from such consumer choices (or from weather). If over time consumers are able to utilize energy commodities more efficiently, through adoption of energy conservation and energy efficiency techniques promoted by utilities and others, the utilities should not be penalized for these beneficial societal actions.

Q. Does the implementation of a revenue decoupling mechanism provide the utility with a guarantee that it will achieve the financial performance previously approved by the regulator?

A. No. In order to achieve its financial expectations, the utility must still actively manage its costs relative to the levels approved in its last rate case to achieve its financial expectations. The re-establishment of the utility's sales levels that I just described only takes gas volumes out of the ratemaking equation. It does not eliminate any of the utility's responsibilities to prudently manage the business factors that are under its control.

D. Recent Activities in Delaware Related to Revenue Decoupling

Q. What has been the recent experience in Delaware with regard to revenue decoupling for gas utilities?

A. In March 2007, the Commission initiated Regulation Docket No. 59 to consider whether to implement a revenue decoupling mechanism for the electric and natural gas distribution utilities, and if so, the design of such a revenue decoupling mechanism. In July 2007, Chesapeake proposed a Revenue Normalization Mechanism (RNM) as an element of its base rate filing in PSC Docket No. 07-186. Under the settlement in that proceeding, the Company's proposed revenue normalization, conservation programs, and conservation cost recovery mechanisms would not then be implemented. Rather, Chesapeake deferred the pursuit of an RNM pending the outcome of the revenue decoupling issues being explored by the Commission in Regulation Docket No. 59.

Q. What was the outcome of Regulation Docket No. 59?

A. In the initial set of comments filed in 2007, all parties agreed that the Commission was authorized to depart from traditional rate base regulation pursuant to 26 Del. C. § 201(d) if such departure is found to promote just and reasonable rates. In Order No. 7420, issued in September 2008, the Commission adopted the recommendations of the proceeding's Hearing Examiner, which among other policy matters, recommended that the Commission should investigate the potential implementation of a revenue decoupling mechanism for each utility in the context of the respective company's next base rate case proceeding. Consistent with the Commission's findings in Order No. 7420, Chesapeake has now included its current RNA proposal in the instant base rate filing.

E. <u>Chesapeake's Proposed Revenue Normalization Adjustment ("RNA") Mechanism</u>

Q. Please summarize the structure of the Company's decoupling proposal.

A. The Company's decoupling proposal, the RNA mechanism, is designed to stabilize the level of margin revenues that are provided by customers to the Company on an annual basis. The proposal will periodically adjust the

Company's distribution service rates to recover the margin revenues per customer, as established in this general rate case, that fluctuate due to variances in gas volumes caused primarily by weather, energy efficiency gains and conservation efforts by its customers. The RNA mechanism will apply to the Residential Service Rate Schedules RS-1 and RS-2, and General Service Rate Schedule GS; as well as the relative expansion tariffed rates for those three schedules; RS-1 Expansion, RS-2 Expansion, and GS Expansion. These are the customer classes that have exhibited weather sensitivity and volatility in use per customer, as shown earlier in Exhibit RJA-7. The Company proposes to identify the RNA as a separate line item on the bill as either a credit or a surcharge.

Q. How will the Revenue Normalization Adjustment be determined?

A. The target margin revenues will consist of the Commission authorized margin revenue per customer levels determined in this general rate case for each of the applicable classes. Each Quarter the company will file a worksheet comparing the targeted margin per customer with the actual margin per customer and calculate the over or under collection that resulted for each class, which will then be combined into an overall over or under collection. In the case of an over collection this amount will be credited to the customers in those six classes through a negative RNA Rate. Alternatively, in the case of an under collection a surcharge will be assessed through a positive RNA Rate. The aim of either is to match the actual margin per customer with the authorized margin per customer set in this rate proceeding.

Mechanically, the RNA Adjustment is determined through the following series of calculations:

1. Actual Margin per Customer for $Month_n$ and Rate $Class_i$ **–** Targeted Normalized Margin per Customer for $Month_n$ and Rate $Class_i$ **=** Difference per Customer for $Month_n$ and Rate $Class_i$
2. Difference per Customer for $Month_n$ and Rate $Class_i$ **x** Customer Count for $Month_n$ and Rate $Class_i$ **=** Over or Under Collection for $Month_n$ and Rate $Class_i$
3. Total Over or Under Collection for Quarter **=** Sum of Over or Under Collection for All Six Rate Classes for Three Months of the Quarter
4. Current Quarter RNA Adjustment **=** Total Over or Under Collection for Quarter **/** Projected Sales Volume Over Next 12 Months for All Six Rate Classes
5. Total RNA Adjustment **=** Current Quarter RNA Adjustment **+** Last Three Quarters RNA Adjustment **+** Annual True-Up
6. Annual True-Up **=** Difference between Projected RNA Collection and Actual RNA Collection for Past 12 Months / Projected Sales Volume Over 12 Months for All Six Rate Classes

Q. Have you prepared an example Exhibit that demonstrates these calculations?

A. Yes. Exhibit RJA-8 provides an example that is based on a hypothetical 2014 2nd Quarter filing utilizing some actual data from 2014. The quarterly filing is depicted on page 1 of the Exhibit. The first section (lines 1 through 3) provides the current RNA Adjustment, which is the combination of the current quarter, the last three quarters, and the previous year's annual true-up. The second section (lines 4 through 8) provides the reconciliation of the past quarters third month between estimated and actual.[22] The third section (lines 9 through13) provides details on targeted versus actual margin per customer for all six rate classes for the current quarter's three months; with the first two being actual and the last being estimated. Lastly, the fourth section (lines 14 through 28) details the projected 12 months of sales volume that is used as the denominator in the quarterly RNA Adjustment calculation. Page 2 of the Exhibit also includes a schedule showing a hypothetical annual true-up filing based on data from 2012 and 2013. As described above, the annual true-up simply compares the projected surcharge or credit for the 12 months to the actual amounts credited or collected. The resulting 12 months over or under is then divided into 12 months of projected volume sales to develop the annual true-up RNA adjustment.

Q. Have you evaluated the expected performance of the proposed RNA adjustment mechanism based on the Company's recent experience with weather variability and use per customer?

A. Yes. Exhibit RJA-9 illustrates the results of a simulation of the operation of the RNA Adjustment Account and the determination of the RNA rates for Rate Schedule Nos. RS-1, RS-2, and GS during the six-year period 2009 - 2014. Customer billing adjustments under the RNA were computed for the average customer in each of these rate classes as if the RNA was in effect during this six-year period. The simulation used as a base the margin and customer levels for these classes that were authorized in the Company's last general rate case and

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[22] This is needed due to the last month of data for each quarter being estimated as part of the filing rather than being based on actual (i.e., accounts for the one month lag needed for collection of data and filing of this quarterly report).

the actual margin revenue per customer by class from the Company's results of operations.

Q. Please describe the results of your analysis for the Company's Rate Schedule Nos. RS-1, RS-2 and GS.

A. The analysis summarized on Exhibit RJA-9 presents the combined results of a simulation of the monthly deferrals in the RNA Deferral Account under RNA for these customers and the resulting quarterly RNA adjustments (column H). The resulting quarterly RNA rate adjustments in year one (2009) ranged from $0.033 per ccf in the 2nd Quarter, $0.020 per ccf in the 3rd Quarter and $0.038 per ccf in the 4th Quarter. At the end of year one, the balance in the Deferral Adjustment Account was an over-collection of $370,514 (column K). When spread over the projected ccf for the eligible customer classes over the succeeding twelve month period, the adjustment would be –$0.016 per ccf. As a point of reference, the average monthly gas bill of the average-sized RS-2 customer is approximately $68.05, at current rates.

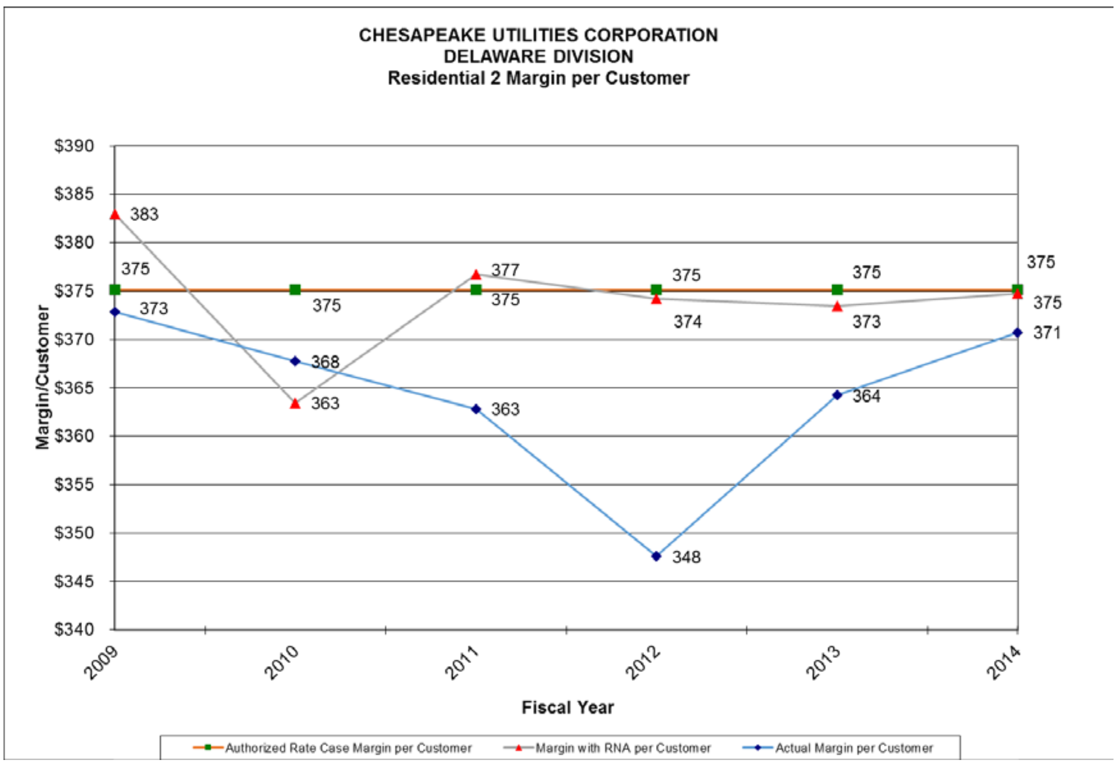
Continuing with the simulation, the quarterly adjustments over the entire six-year simulation period ranged from $0.066 per ccf to –$0.008 per ccf (column H).

Q. What were the year-end balances in the RNA Adjustment Account for the remaining years of the six-year simulation?

A. The balances in the RNA Adjustment Account for the annual "true-up" at the end of years two through six were $381,227 (2010), –$12,780 (2011), $84,751 (2012), $18,672 (2013), and –$41,005 (2014), respectively. These deferral balances translate into RNA per ccf annual true-up adjustments of $0.016, –

$0.001, $0.003, $0.001, and –$0.001, respectively (see Exhibit RJA-9, column B, Annual Summary section). The following graph from Exhibit RJA-7 includes the impact of the RNA on the recovery of the Commission authorized margin per customer from the Residential RS-2 class. As can be seen after the initial rolling in of the mechanism during 2009 and 2010 the margin per customer more closely matches the target set in the Company's past rate case.

Table 6 – Margin per Customer with RNA



Q. What has been Chesapeake's experience with revenue decoupling in its Maryland natural gas service territory?

A. As part of Chesapeake Utilities Corporation – Maryland Division's (" the Maryland Division") 2006 base rate case, the Maryland Public Service Commission authorized the Maryland Division to implement a revenue normalization adjustment mechanism similar in structure to that now proposed by the Company in its Delaware base rate filing.[23] The revenue normalization adjustment has since been included in the calculation of the Maryland Division's quarterly Gas Sales Service Rate (Rate Schedule GSR).

VII. Conclusion

Q. Please summarize how the interests of Chesapeake and its customers are served by implementing the Company's RNA proposal?

A. There are significant benefits to both Chesapeake and its customers from implementing the Company's proposed RNA, including:

1. The RNA will break the link between the gas consumption of the Company's customers and its margin recovery and result in a better alignment of the interests of Chesapeake and its customers.
2. The RNA will address factors beyond the Company's control that contribute to under recovery of costs and the inability to achieve the level of returns that have been authorized by the Commission.
3. Under the RNA, Chesapeake will be able to promote energy efficiency programs for its customers, without the real margin losses associated with the resulting decline in gas use per customer.
4. With the implementation of the RNA, customers will pay each year approximately the same amount for gas delivery service as if the Company had experienced normal weather, which is the same basis upon which the Commission establishes Chesapeake's base rates. Ultimately, the RNA will result in a customer's annual bill more accurately reflecting

[23] Maryland PSC Order in Case No. 9062, dated September 26, 2006.

the margin recovery amounts approved by the Commission in this rate case, while customers will recognize the results of their energy conservation efforts in the amount they pay for the gas commodity.

Q. Does this conclude your direct testimony?

A. Yes.

Ronald J. Amen

Mr. Amen has over thirty-five years of combined experience in utility management and consulting in the areas of regulatory affairs, resource planning, organizational development, distribution operations and customer service, marketing and sales, and systems administration. He has particular expertise in the following areas: regulatory policy, strategy and analysis; resource strategy, planning and financial analysis; cost allocation and pricing issues; business process design and organizational structures; and expert witness testimony. Prior to joining Black & Veatch, Mr. Amen's consulting experience included Concentric Energy Advisors, Inc. and Navigant Consulting, Inc. His prior utility experience includes Manager of Federal Regulatory Affairs at Puget Sound Energy, Inc., Director of Rates at Washington Natural Gas Company, Regional Director - Operations and Director – Rates for Indiana Energy (now Vectren), and management positions in Information Systems and Distribution Operations at Ohio Valley Gas Corporation.

DIRECTOR

Specialization:
Financial, regulatory, strategic, operations and litigation support

Office Location
Redmond, WA

Education
- B.S., Business Administration (Finance and Economics), College of Business Administration, University of Nebraska, 1978

Professional Associations
- American Gas Association
- Southern Gas Association

Year Career Started
1978

Year Started with B&V
2013

PROJECT EXPERIENCE

REGULATORY POLICY, STRATEGY AND ANALYSIS

Southwestern Electric/Gas Utility

Provided case management, revenue requirement, cost of service and rate design support for a general rate cases in the utility's two State regulatory jurisdictions. Issue management and policy development included an electric fuel and purchased power cost mechanism, recovery of environmental remediation costs for a coal-fired power plant, and the valuation of renewable energy credits related to a wind power facility.

Confidential Energy Company

Provided due diligence on behalf of client related to the purchase of a gas/electric utility, including a review of the regulatory and market related assumptions underlying the client's valuation model, resulting in the validation of the model and identification of key business risks and opportunities.

Confidential Energy Company

Provided regulatory due diligence support for client related to a proposed merger with a multi-jurisdictional gas/electric company, including an evaluation of the regulatory landscape in the various applicable State jurisdictions, recent regulatory decisions, and current regulatory issues.

Confidential Energy Company

Performed due diligence on behalf of a confidential energy company client related to the acquisition of a U.S. interstate pipeline, involving a market assessment related to its customer contracts and their prospective alternatives.

Eastern Electric/Gas Utility

Provided management with an evaluation of its line extension practices for both its gas and electric services and an earnings impact assessment using a proprietary evaluation model. Conducted a workshop for management on the results of the evaluation and recommendations for consideration in the areas of revenue enhancements, modification of internal policies and procedures and construction cost control areas.

Eastern Gas Utility

Provided management with an evaluation of the policies, procedures and tools presently used in its new customer addition process, an assessment of the impact of new customer growth on NOI, and regulatory solutions to accelerate recovery of new customer costs that best meet the regulatory requirements of its three state jurisdictions.

Canadian Gas Utility

Engaged to assist with the development of a Gas Transmission asset ownership strategy. The project included researching examples from other jurisdictions in North America for transmission ownership structures, the supporting rationale, and the resulting regulatory treatment.

Eastern Gas Utility |

Provided expert witness testimony on the subject of new area expansion programs in the U.S. for the client’s general rate case proceeding. As part of a negotiated settlement of the case, the client was permitted to establish a new area expansion pilot program.

Pacific Northwest Electric/Gas Utility

Redesigned gas line extension policy based on financial investment criteria, standardized construction costs, and revenue contributions derived from the client’s residential end-use data (building type/size/vintage, appliance type, etc.). Introduced a new customer rate option for customers whose facilities extensions did not meet the target rate of return requirement, which significantly reduced earnings attrition caused by rapid customer growth. In a later general rate proceeding, testimony support was provided regarding the modifications and revisions to the facilities extension program.

RESOURCE PLANNING, STRATEGY AND FINANCIAL ANALYSIS

Western Canadian Gas Utility

Retained to help develop a gas supply incentive mechanism in cooperation with the BCUC staff and the Company’s other stakeholders. Provided an independent analysis of the utility’s management of pipeline and storage capacity and supply. Part of this work entailed a review of the major markets in which the utility transacted, reviewing the size of trading activity at the major market hubs and reviewing the price indices for these markets.

Western Electric Utility

Engaged as a member of a consultant team that served as the independent evaluator in a competitive solicitation for non-intermittent generation resources. Jointly recommended by the utility client, the staff of the utility commission, and the state attorney general, the consulting team acted as an agent of the public utility commission monitoring and overseeing the solicitation, which included reviewing the request for proposals and solicitation process, including provisions of the PPA, preliminary review (economic and contractual) of bids received from the request for proposals, initial modeling of bids for screening, selection of bidders with whom to conduct negotiations and oversight of the negotiation process, and the ultimate selection of the winning bid. Provided due diligence review of all input data, preliminary and final model output, and output summaries. The team produced bi-weekly confidential reports to the commission regarding the process and its results.

Pacific Northwest Gas Utility

Assisted with the development of its long-term Integrated Resource Plan (IRP) for its Oregon and Washington service territories. The IRP includes the evaluation of incremental inter- and intra-state pipeline capacity, underground storage, and two proposed LNG plants under development in the region.

Pacific Northwest Electric/Gas Utility

Engaged to assist the client with the development of a natural gas resource efficiency and direct end-use strategy, an interdepartmental initiative focused on preparing a natural gas resource efficiency plan that optimizes customers' end-use energy consumption while furthering corporate customer, financial, environmental, and social responsibilities.

Pacific Northwest Electric/Gas Utility

As part of a review of a gas procurement strategy and hedging analytics, provided gas LDC case studies for gas procurement and risk management practices, including identification of risk management best practices across the industry.

Pacific Northwest Electric/Gas Utility

Provided resource planning strategy and analysis for the Company's Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts.

Pacific Northwest Electric/Gas Utility

Engaged as a member of a consulting team serving as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multi-track solicitation process for and evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition in a subsequent power cost rate proceeding.

Midwestern Electric/Gas Utility

Provided an evaluation of the functions provided by the utility's underground storage facilities for the purpose of assigning cost responsibility to the various customer groups, which had been challenged by parties in the company's general rate proceeding.

Southwestern Electric/Gas Utility

Conducted an evaluation of two gas operating subsidiaries, their capital planning, asset management strategy, and customer growth practices. Formulated a strategy for improving the profitability of the entities, with regulatory strategies for its two jurisdictions that included a special cost recovery mechanism for accelerated infrastructure replacement programs.

Midwestern Municipal Electric Utility

Engaged as a member of three-consultant team that established a self-sustaining energy services business to replace its rebate-based, demand-side management programs. Area of focus included the finance and administrative functions as well as the employee evaluation and recruitment process.

European Electric Utility

Provided strategy and analysis support, including a review of the natural gas value chain in the U.S., as part of an overall project scope focusing on the evaluation of retail multi-energy strategies for the client.

COST ALLOCATION, PRICING ISSUES AND RATE DESIGN

Southwestern Electric Utility

Retained to conduct a study to estimate the conservation effect of replacing its existing electric residential rate design with an alternative rate design such as an inverted block rate design. Reviewed inclining block rate structures that have actively been employed in other jurisdictions and also reviewed technical and academic literature to assess the elasticity of electricity demand for residential customers in the U.S. Southwest. Analyzed 2009-2011 residential data to determine what sort of conservation effect the Company may expect by implementing an inclining block rate structure. Provided an overview of alternative rate structures which may also promote conservation effects, such as seasonal rates, three-part rates and time-of-use ("TOU") rates, and considered the competing incentives of promoting conservation and cost recovery, without specific rate mechanisms to address this conflict.

Northeastern Electric Utility

Supported utility in its decoupling proposal for the Company's general rate case. Work included: (1) research on the financial implications of decoupling; (2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; (3) identification of rate adjustment mechanisms that would work together with the Company's proposed decoupling mechanism; and (4) preparing pre-filed testimony and testifying at hearings in support of the Company's decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism based on a statistical analysis, and a capital spending mechanism to recover the costs associated with capital plant investment targeted to improving service reliability.

Northeastern Electric/Gas Utility

Conducted class allocated cost of service studies for the client's New England natural gas operations. This included combined gas cost of service studies for the consolidation of four gas service territories into two gas utility subsidiaries. During interrogatories, performed four separate allocated cost of service studies for each gas service territory. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Served as an expert witness on behalf of the client in consolidated general rate cases before the Massachusetts Department of Public Utilities.

Midwestern Energy Company

Conducted class allocated cost of service studies for the client's natural gas (including two other affiliate gas utilities) and electric operations. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Rate design was modernized to recover a greater portion of fixed costs via fixed monthly customer and demand based charges, a transition to a "Straight-Fixed Variable" form of rate design. Industry research was provided on alternative rate designs for the electric service, including Time-of-Use rates and Critical Peak Pricing. Served as an expert witness on behalf of the client in three general rate cases before the Indiana Utility Regulatory Commission.

Midwestern Electric Utility |

Conducted class allocated cost of service studies for a Midwestern electric utility's Minnesota electric operations. Work included reconfiguring the Company's customer classes for cost of service purposes to collapse end-use based classes with the classes to which they would be eligible. Cost of service studies were performed on a before-and-after basis for the existing and proposed classes. The cost of service studies included a Fixed/Variable study for Production costs, and a Primary – Secondary study for poles, transformers and conductors. Performed a Time of Use analysis to determine the appropriate rate differentials for its Peak and Off-peak rates. Served as an expert witness on behalf of the client in a general rate case before the Minnesota Public Service Commission.

Midwestern Gas Utility

Provided cost of service and rate design support for the Company's general rate case filings in its two State jurisdictions and in support of a Section 311 transportation filing before the Federal Energy Regulatory Commission (FERC).

Provided related research, design and expert witness testimony in support of a Revenue Decoupling mechanism in one jurisdiction and a Weather Normalization Adjustment (WNA) mechanism in the other jurisdiction, along with a significant increase in fixed charges and the introduction of demand charges for the Company's largest customer classes. Conducted a pre-filing "Decoupling" workshop for the utility commission staff.

Pacific Northwest Gas Utility

Provided Cost of Service and Rate Design support for the utility's general rate case, including expert witness testimony. Assisted the client with an earlier revenue neutral reconfiguration of its Commercial / Industrial sales and transportation service offerings. The earlier initiative included collaborative work with an industrial customer stakeholder group.

Midwestern Energy Company

Assisted the client with the pursuit of alternative regulatory initiatives in conjunction with company's expansion of its energy efficiency and conservation programs. Supported the research, design, and selection of Revenue Decoupling mechanisms for its two regulated gas utility subsidiaries. Served as the cost of service witness in two general rate case filings.

Pacific Northwest Electric/Gas Utility

In two general rate proceedings, provided Cost of Service and Rate Design support, including expert witness testimony in support of the utility's proposed gas Revenue Decoupling mechanism. Conducted research on accelerated cost recovery mechanisms for Infrastructure Replacement, Electric Power Cost Adjustment mechanisms and Gas Supply Pricing Options of utilities in North America.

U.S. Energy Company

Engagement director for Cost of Service and Rate Design support for the general rate proceedings of the Company's Midwestern and Northeastern gas utilities, including expert witness testimony on cost of service, rate design and declining use-per-customer. Rate design support included a proposed ten-year weather normal, and the introduction of straight-fixed variable rates (Midwestern LDC). This was the third consecutive rate case engagement for the Northeastern LDC.

Midwestern Electric/Gas Utility

Assisted the Company with the preparation of a retail customer choice filing for one of its gas distribution jurisdictions. Provided support for the development ancillary service costs, the design of program cost recovery mechanisms, and tariff structure for service offerings.

Western Canadian Gas Utility

Served as engagement manager for cost of service and rate design support. Represented the client in its capital investment recovery proceeding for a major pipeline project, a cross-provincial transmission pipeline. The three-phase project included regulatory strategy support for executive management regarding the integration of the pipeline proposal with the utility's PBR and unbundling initiatives and a global rate design proceeding. Cost of service support included a review of its gas cost portfolio allocation to firm sales customer classes, a survey of the trends in gas cost allocations and incentive mechanisms in North America, and serving as a facilitator for an all-party cost allocation and rate design workshop.

Northeastern Gas Utility

Served as engagement manager for cost of service and rate design support, including expert witness testimony, for the client's participation in a state-wide gas unbundling proceeding. Subsequent projects included analysis of the client's demand forecasting capability, implementation of an algorithm-based balancing service and a cost of service studies related to transportation related administrative costs, resources supporting system reliability and recovery of potentially stranded costs.

Midwestern Gas Transmission/Distribution Utility

Engagement manager for cost of service and rate design support, including expert witness testimony, for client's asset separation and unbundling proceeding as well as a subsequent general rate case. Integrated gas utility (wellhead to burner-tip) unbundled upstream services (production and gathering, storage, and intra-state transmission) from its distribution business.

South American Gas Utility

For an affiliate of a major U.S. energy company, conducted a cost of service and rate design training for management personnel engaged in the planned restructuring of the rate-setting processes for three gas utilities in Brazil.

Canadian Energy Marketer

Provided consulting support and position paper on cost allocation and pricing issues for Canadian gas marketer's participation in a restructuring collaborative sponsored by the intra-provincial pipeline and local distribution utility in Saskatchewan.

Pacific Northwest Gas Utility

Negotiated and obtained regulatory approval of a 20-year contract with the company's largest industrial customer, which avoided bypass of 14 primary plant facilities within the service territory, prevented loss of annual throughput, and maintained contribution to system costs.

Pacific Northwest Gas Utility

Obtained regulatory approval of unbundled, cost-based transportation services to meet large commercial and industrial customer needs and re-designed rates of other classes to better align with new cost of service methodology. The project required the facilitation of a collaborative working group of key industrial customers, customer associations, commission staff, and consumer advocacy agencies.

Western Energy Company

Provided case strategy and cost of service support for the biennial cost allocation proceedings of two utility subsidiaries of the Company.

UTILITY SYSTEM OPERATIONS AND ORGANIZATIONAL DEVELOPMENT

Pacific Northwest Electric/Gas Utility

Engaged to perform a review of its project management and capital spending authorization processes (CSA). The overall project objectives were to educate project management (PM) staff as to the importance and relevance of regulatory prudence standards; evaluate existing PM processes along with newly introduced corporate CSA processes; and propose PM and corporate process and documentation efficiencies. This was accomplished through 1) a situational assessment and risk review; 2) analysis of project management practices; and 3) development of common documentation for the CSA and PM processes.

Pacific Northwest Electric/Gas Utility

Engaged to perform a review of how the company compares to similarly-situated utilities in the areas of the underlying capitalized costs related to new customer additions ("New Business Investment") and the management policies and practices that influence the new business capital investment. Examined the inter-relationships of our client's management policies and practices in the functional areas related to New Business Investment and developed an understanding of the nature of the costs captured by the New Business Investment process. Benchmarked those costs relative to peers' cost factors and management capital expenditure practices and performed targeted peer group interviews on our client's behalf. The review identified certain trends and/or inter-relationships between management policies and practices, as well as other exogenous factors, and the resulting impact on New Business Investment.

Pacific Northwest Electric/Gas Utility

Engaged to perform a review of its electric transmission planning and project prioritization process. The emphasis of the review was to determine if the process implemented by the client could be expected to meet the regulatory standard of prudence, as adopted by the state regulatory commission. Reviewed the prudence standard adopted by the commission in several recent regulatory proceedings, supplemented by our knowledge of the prudence standard adopted at a national level and in other states. The engagement included two phases: 1) an initial situation assessment of the existing process employed by the client, and 2) a review of the historic implementation of that process by reviewing a sampling of transmission projects. Compiled and provided examples of capital planning documents and procedures, viewed as "Best Practices," from other electric utilities and other relevant transmission entities.

Midwestern Energy Company

Provided audit support for one of the Company's gas and electric utilities during a management audit ordered by one of its two regulatory jurisdictions. Conducted a pre-audit of distribution operations and resource planning process to provide the client with potential audit issues. Assisted the client throughout the audit process in responding to information requests, preparing Company executives and management personnel for audit interviews, and management of preliminary audit issues and findings by the independent audit firm.

Midwestern Energy Company

Performed a number of benchmark analyses to compare each of the client's A&G and O&M expenses, on a per-customer basis, to various peer groups conducted for the client's natural gas and electric operations. Analyses were performed for natural gas utilities, electric utilities, and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Served as an expert witness on behalf of the client in a consolidated general rate case proceeding of its three utility subsidiaries before the Illinois Commerce Commission.

Western Multi-state Water Utility

Engaged to manage the implementation of a new revenue decoupling mechanism into its 24 separate rate areas. Changes to the following processes and related procedures were required: rate setting, meter reading, billing, revenue and financial reporting. Microsoft Project was used to manage and track the implementation throughout the following organizations: Rates, Accounting, Information systems, Communications, and Customer Service.

Northwestern Electric/Gas Utility

Conducted an evaluation of the Company's key accounts (Top 100) and business account services organization. Work included compilation of "best practices" from peer group utilities, recommendations related to staffing levels, roles and responsibilities, and the interrelationships with the customer service (call center), revenue management and community relations organizations of the utility.

Eastern Gas Utility

Provided market monitoring strategies and action plans based on an analysis of competitive threats and discussions with the client's customers and other utilities facing similar issues. Intent of recommended monitoring strategies and corresponding action plans to result in increased customer growth (meters) and/or customer retention, including a prioritized implementation approach to the monitoring strategies and action plans, based on benefits to the client and time to implement.

Southern Electric/Gas Utility

Conducted an evaluation of two gas operating subsidiaries, their capital planning, asset management strategy, and customer growth practices. Formulated a strategy for improving the profitability of the entities, with regulatory strategies for its two jurisdictions that included a special cost recovery mechanism for accelerated infrastructure replacement programs.

Midwestern Municipal Electric Utility

Engaged as a member of three-consultant team that established a self-sustaining energy services business to replace its rebate-based, demand-side management programs. Area of focus included the finance and administrative functions as well as the employee evaluation and recruitment process, which involved establishing the organization structure, span of control, job descriptions, qualifications, and salary ranges. We worked closely with the head of new organization, the municipal utility management, and the relevant municipal government agencies; and facilitated numerous management and stakeholder meetings.

Midwestern Electric/Gas Utility

Provided research and consulting support to establish performance metrics and benchmarks from peer group companies for the client's performance management system.

Midwestern Energy Company

For a Midwestern energy company, Mr. Amen was responsible for marketing, customer service, gas distribution system construction, operation and maintenance, for a regional operating service territory of the company's gas utility. Among other gas operations responsibilities, Mr. Amen managed a field sales force responsible for sales plan development, including market analysis, program design, and cost-effectiveness evaluations for the following customer segments and/or trade alley groups: residential home builders and commercial developers; HVAC contractors; large commercial and industrial key accounts; public institutions; and governmental facilities.

Business Process Redesign and Organizational Restructuring – While serving in the aforementioned utility management capacity as Regional Director, Mr. Amen managed the successful integration of an acquired gas utility company into a regional operation.

Re-engineering Operations – Mr. Amen was a member of a management team that restructured the company's field organization into six regional operations (reduced from 26 district offices) resulting in a streamlined organization, which provided enhanced customer service while substantially reducing operating costs. The nine core management team members facilitated the work of over forty individual study groups during the eighteen-month transition period. This same management team redesigned the capital budgeting process and established new standards governing the use of construction contractors.

EXPERT WITNESS TESTIMONY PRESENTATION

- Arkansas Public Service Commission
- British Columbia Utility Commission (Canada)
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission
- Federal Energy Regulatory Commission

PROFESSIONAL HISTORY

Black & Veatch Corporation (Present)

Director

Concentric Energy Advisors, Inc. (2007 – 2013)

Vice President

Navigant Consulting, Inc. (1997 – 2007)

Director

Puget Sound Energy, Inc. (1997)

Manager – Federal Regulatory Affairs

Washington Natural Gas Company (1993 – 1997)

(merged with Puget Power and Light to form Puget Sound Energy in 1997)
Director – Rates and Tariffs

Indiana Energy (now Vectren) (1984 – 1993)

Regional Director – Distribution Operations
Director – Rates

Ohio Valley Gas Corporation (1978 – 1984)

Data Processing Manager
Assistant District Manager – Distribution Operations

SELECTED PUBLICATIONS/PRESENTATIONS

"Enhancing the Profitability of Growth," American Gas Association, Rate and Regulatory Issues Seminar, April 4 - 7, 2004

"Regulatory Treatment of New Generation Resource Acquisition: Key Aspects of Resource Policy, Procurement and New Resource Acquisition," Law Seminars International, Managing the Modern Utility Rate Case, February 17 - 18, 2005

"Managing Regulatory Risk – The Risk Associated with Uncertain Regulatory Outcomes," Western Energy Institute, Spring Energy Management Meeting, May 18 - 20, 2005

"Capital Asset Optimization – An Integrated Approach to Optimizing Utilization and Return on Utility Assets," Southern Gas Association, July 18 - 20, 2005

"Resource Planning as a Cost Recovery Tool," Law Seminars International, Utility Rate Case Issues & Strategies, February 22 - 23, 2007

"Natural Gas Infrastructure Development and Regulatory Challenges," Southeastern Association of Regulatory Utility Commissioners, Annual Conference, June 4 – 6, 2007

"Resource Planning in a Changing Regulatory Environment," Law Seminars International, Utility Rate Cases – Current Issues & Strategies, February 7 - 8, 2008

"Natural Gas Distribution Infrastructure Replacement," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 11 – 13, 2010

"Building a T&D Investment Program to Satisfy Customers, Regulators and Shareholders," SNL Webinar, March 27, 2014

"Utility Infrastructure Replacement; Trends in Aging Infrastructure, Replacement Programs and Rate Treatment," Large Public Power Council, Rates Committee Meeting, August 14, 2014

DATED: DECEMBER 21, 2015

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF RONALD AMEN

RONALD AMEN, being first duly sworn according to law, on oath deposes and says that he is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of Ronald Amen"; that, if asked the questions which appear in the text of the direct testimony, he would give the answers that are therein set forth; and that he adopts this testimony as his sworn direct testimony in these proceedings.

Ronald Amen

Ronald Amen

Then personally appeared this 21st day of December 2015 the above-named Ronald Amen and acknowledged the foregoing Testimony to be his free act and deed. Before me,

Rebecca K. Grier

Notary Public
My Commission Expires: 7.17.18

REBECCA K. GRIER NOTARY PUBLIC MY COMMISSION EXPIRES ON 07-17-18 STATE OF DELAWARE

Chesapeake Utilities
Delaware Division
Test Period Ended March 31, 2016

Exhibit RJA-1
Apportionment of
Revenue Requirement

	A	B	C	D	E	F	G	H	I
Line	**Class**		**Pro Forma Delivery Revenue**	**Proposed Revenue for Equal Rates of Return**	**Revenue to Cost Ratio**	**ROR at Current**	**Relative Rate of Return**	**ACOSS Proposed Increase (Decrease) @ 8.55% ROR**	**ACOSS Rate Increase**
1	**System Total**		**$ 22,223,119**	**$ 26,964,933**	**0.82**	**4.61%**	**1.00**	**$ 4,741,815**	**21.34%**
2	Residential Service -1	RS-1	824,888	1,824,742	0.45	-4.84%	-1.05	999,855	121.21%
3	Residential Service - 2	RS-2	13,899,067	19,070,205	0.73	2.25%	0.49	5,171,138	37.20%
4	General Service	GS	1,469,623	1,908,282	0.77	3.53%	0.77	438,660	29.85%
5	Medium Volume Service	MVS	890,630	1,014,740	0.88	6.16%	1.34	124,110	13.94%
6	Large Volume Service	LVS	2,114,683	1,536,873	1.38	15.32%	3.33	(577,811)	-27.32%
7	High Load Factor Service	HLFS	2,860,886	1,584,634	1.81	23.76%	5.16	(1,276,253)	-44.61%
8	Gas Lighting Residential	GLR	705	1,003	0.70	1.35%	0.29	298	42.29%
10	Interruptible Service	IS	162,637	24,454	6.65	133.69%	29.03	(138,183)	-84.96%

Note: Column C, D, and N from ACOSS Results (See Exhibit JDT-1)

Chesapeake Utilities
Delaware Division
Test Period Ended March 31, 2016

Exhibit RJA-1
Apportionment of
Revenue Requirement

	A	B	J	K	L	M	N	O
Line	**Class**		**Target Revenue to Cost**	**Proposed Increase (Decrease)**	**ROR @ Proposed Increase**	**Relative Rate of Return**	**Rate Increase @ Proposed Increase**	**Proposed Apportioned Revenue**
1	**System Total**			**$ 4,741,815**	8.55%	1.00	**21.34%**	**$ 26,964,933**
2	Residential Service -1	RS-1	0.65	364,328	0.00%	(0.00)	44.17%	1,189,216
3	Residential Service - 2	RS-2	0.93	3,814,419	6.89%	0.81	27.44%	17,713,486
4	General Service	GS	1.00	438,660	8.55%	1.00	29.85%	1,908,282
5	Medium Volume Service	MVS	1.00	124,110	8.55%	1.00	13.94%	1,014,740
6	Large Volume Service	LVS	1.38	-	15.39%	1.80	0.00%	2,114,683
7	High Load Factor Service	HLFS	1.81	-	23.87%	2.79	0.00%	2,860,886
8	Gas Lighting Residential	GLR	1.00	298	8.55%	1.00	42.29%	1,003
10	Interruptible Service	IS	-	-	134.42%	15.72	0.00%	162,637
			Total	$ 4,741,815	150% System Increase=		32.01%	
			Difference	$ -	200% System Increase=		42.67%	

Chesapeake Utilities
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Test Period Ended March 31, 2016

Exhibit RJA-2
Rate Design

Line No.	Customer Class	Proforma Test Period Revenue: Billing Units	Present Rate	Revenue	Proposed Revenues: Proposed Rates	Revenue	Difference: $ Amount	% Amount
	Residential Service 1							
1	Customer Charge	49,764	$10.50	$ 522,522	$15.00	$ 746,460	$ 223,938	43%
2	First 20	371,454	$0.607	$ 225,473	$0.852	$ 316,632		
3	Next 30	143,691	$0.280	$ 40,234	$0.525	$ 75,497		
4	Over 50	36,385	$0.170	$ 6,185	$0.415	$ 15,115		
5	Volumetric Charge	551,531		$ 271,892		$ 407,243	$ 135,352	50%
6	**Total RS1 Revenue**			**$ 794,414**		**$ 1,153,703**	**$ 359,290**	45%
	Residential Service 1 - Expansion							
7	Customer Charge	1,272	$16.50	$ 20,988	$16.50	$ 20,988	$ -	0%
8	First 20	12,049	$0.607	$ 7,314	$0.852	$ 10,270		
9	Next 30	6,868	$0.280	$ 1,923	$0.525	$ 3,609		
10	Over 50	1,553	$0.170	$ 264	$0.415	$ 645		
11	Volumetric Charge	20,470		$ 9,501		$ 14,524	$ 5,024	53%
12	**Total RS1-E Revenue**			**$ 30,489**		**$ 35,512**	**$ 5,024**	16%
13	**RS1 Revenue**			**$ 824,902**		**$ 1,189,216**		
	Residential Service 2							
14	Customer Charge	462,000	$13.00	$ 6,006,000	$17.00	$ 7,854,000	$ 1,848,000	31%
15	First 20	6,972,534	$0.578	$ 4,030,124	$0.656	$ 4,570,542		
16	Next 30	6,467,626	$0.319	$ 2,063,173	$0.397	$ 2,564,457		
17	Over 50	11,628,211	$0.132	$ 1,534,924	$0.210	$ 2,436,188		
18	Volumetric Charge	25,068,371		$ 7,628,221		$ 9,571,187	$ 1,942,966	25%
19	**Total RS2 Revenue**			**$ 13,634,221**		**$ 17,425,187**	**$ 3,790,966**	28%
	Residential Service 2 - Expansion							
20	Customer Charge	5,580	$31.75	$ 177,165	$31.75	$ 177,165	$ -	0%
21	First 20	72,951	$0.578	$ 42,166	$0.656	$ 47,820		
22	Next 30	80,653	$0.319	$ 25,728	$0.397	$ 31,979		
23	Over 50	149,562	$0.132	$ 19,742	$0.210	$ 31,334		
24	Volumetric Charge	303,167		$ 87,636		$ 111,134	$ 23,497	27%
25	**Total RS2-E Revenue**			**$ 264,801**		**$ 288,299**	**$ 23,497**	9%
26	**RS2 Revenue**			**$ 13,899,022**		**$ 17,713,486**		

Chesapeake Utilities
Delaware Division
Test Period Ended March 31, 2016

Exhibit RJA-2
Rate Design

	General Service								
27	Customer Charge	34,206	$26.00	$ 889,356	$34.00	$ 1,163,004	$	273,648	31%
28	First 20	383,908	$0.447	$ 171,607	$0.506	$ 194,391			
29	Next 30	420,300	$0.278	$ 116,844	$0.337	$ 141,788			
30	Over 50	1,961,018	$0.140	$ 274,542	$0.199	$ 390,926			
31	Volumetric Charge	2,765,226		$ 562,993		$ 727,105	$	164,112	29%
32	**Total GS Revenue**			**$ 1,452,349**		**$ 1,890,109**	**$**	**437,760**	30%
	General Service - Expansion								
33	Customer Charge	176	$56.00	$ 9,856	$56.00	$ 9,856	$	-	0%
34	First 20	1,724	$0.447	$ 771	$0.506	$ 873			
35	Next 30	2,053	$0.278	$ 571	$0.337	$ 693			
36	Over 50	10,225	$0.140	$ 1,432	$0.199	$ 2,038			
37	Volumetric Charge	14,003		$ 2,773		$ 3,604	$	831	30%
38	**Total GS-E Revenue**			**$ 12,629**		**$ 13,460**	**$**	**831**	7%
	General Service - Negotiated								
39	Customer Charge	24	$26.00	$ 624	$34.00	$ 816	$	192	31%
40	First 20	332	$0.525	$ 174	$0.525	$ 174			
41	Next 30	461	$0.525	$ 242	$0.525	$ 242			
42	Over 50	6,630	$0.525	$ 3,481	$0.525	$ 3,481			
43	Volumetric Charge	7,423		$ 3,897		$ 3,897	$	-	0%
44	**Total GS Negotiated Revenue**			**$ 4,521**		**$ 4,713**	**$**	**192**	4%
45	**GS Revenue**			**$ 1,469,499**		**$ 1,908,282**			
	Medium Volume Service								
46	Customer Charge	5,813	$65.00	$ 377,845	$80.00	$ 465,040	$	87,195	23%
47	First 200	842,712	$0.227	$ 191,296	$0.237	$ 200,050			
48	Over 200	2,661,839	$0.115	$ 306,111	$0.125	$ 333,763			
49	Volumetric Charge	3,504,551		$ 497,407		$ 533,813	$	36,406	7%
50	**Total MVS Revenue**			**$ 875,252**		**$ 998,853**	**$**	**123,601**	14%
	Medium Volume Service - Expansion								
51	Customer Charge	40	$158.75	$ 6,350	$158.75	$ 6,350	$	-	0%
52	First 200	4,733	$0.227	$ 1,074	$0.237	$ 1,124			
53	Over 200	19,347	$0.115	$ 2,225	$0.125	$ 2,426			
54	Volumetric Charge	24,080		$ 3,299		$ 3,549	$	250	8%
55	**Total MVS Negotiated Revenue**			**$ 9,649**		**$ 9,899**	**$**	**250**	3%
	Medium Volume Service - Negotiated								
56	Customer Charge	24	$65.00	$ 1,560	$80.00	$ 1,920	$	360	23%
57	First 200	2,667	$0.525	$ 1,400	$0.525	$ 1,400			
58	Over 200	5,081	$0.525	$ 2,668	$0.525	$ 2,668			
59	Volumetric Charge	7,748		$ 4,068		$ 4,068	$	-	0%
60	**Total MVS Negotiated Revenue**			**$ 5,628**		**$ 5,988**	**$**	**360**	6%
61	**Total MVS Revenue**			**$ 890,529**		**$ 1,014,740**	**$**	**124,211**	14%

Chesapeake Utilities
Delaware Division
Test Period Ended March 31, 2016

Exhibit RJA-2
Rate Design

	Large Volume Service						
62	Customer Charge	2,467	$125.00	$ 308,375	$175.00	$ 431,725	$ 123,350	40%
63	First 1000	1,862,828	$0.326	$ 607,282	$0.218	$ 406,436		
64	Over 1000	14,247,133	$0.083	$ 1,182,512	$0.088	$ 1,257,307		
65	Volumetric Charge	16,109,961		$ 1,789,794		$ 1,663,743	$ (126,051)	-7%
66	**Total LVS Revenue**			**$ 2,098,169**		**$ 2,095,468**	**$ (2,701)**	0%
	Large Volume Service - Negotiated							
67	Customer Charge	24	$125.00	$ 3,000	$175.00	$ 4,200	$ 1,200	40%
68	First 1000	28,600	$0.525	$ 15,015	$0.525	$ 15,015		
69	Over 1000	-	$0.525	$ -	$0.525	$ -		
70	Volumetric Charge	28,600		$ 15,015		$ 15,015	$ -	0%
71	**Total LVS Negotiated Revenue**			**$ 18,015**		**$ 19,215**	**$ 1,200**	7%
72	**Total LVS Revenue**			**$ 2,116,184**		**$ 2,114,683**		
	High Load Factor Service							
73	Customer Charge	3,718	$75.00	$ 278,850	$125.00	$ 464,750	$ 185,900	67%
74	All Consumption	28,284,815	$0.087	$ 2,460,779	$0.080	$ 2,269,209	$ (191,570)	-8%
75	Volumetric Charge	28,284,815		$ 2,460,779		$ 2,269,209	$ (191,570)	-8%
76	**Total HLFS Revenue**			**$ 2,739,629**		**$ 2,733,959**	**$ (5,670)**	0%
	High Load Factor Service - Negotiated							
77	Customer Charge	24	$75.00	$ 1,800	$125.00	$ 3,000	$ 1,200	67%
78	All Consumption	161,254	$0.525	$ 84,658	$0.525	$ 84,658	$ -	0%
79	Volumetric Charge	161,254		$ 84,658		$ 84,658	$ -	0%
80	Customer Charge	12	$75.00	$ 900	$125.00	$ 1,500	$ 600	67%
81	All Consumption	26,231	$0.960	$ 25,182	$0.960	$ 25,182	$ -	0%
82	Volumetric Charge	26,231		$ 25,182		$ 25,182	$ -	0%
83	Customer Charge	12	$75.00	$ 900	$125.00	$ 1,500	$ 600	67%
84	All Consumption	15,000	$0.295	$ 4,425	$0.295	$ 4,425	$ -	0%
85	Volumetric Charge	15,000		$ 4,425		$ 4,425	$ -	0%
86	Customer Charge	12	$75.00	$ 900	$125.00	$ 1,500	$ 600	67%
87	All Consumption	17,500	$0.295	$ 5,163	$0.295	$ 5,163	$ -	0%
88	Volumetric Charge	17,500		$ 5,163		$ 5,163	$ -	0%
89	**Total HLFS Negotiated Revenue**			**$ 123,928**		**$ 126,928**	**$ 3,000**	2%
90	**Total HLFS Negotiated Revenue**			**$ 2,863,557**		**$ 2,860,886**	**$ (2,670)**	0%

Chesapeake Utilities — **Exhibit RJA-2**
Delaware Division — **Rate Design**
Test Period Ended March 31, 2016

	Gas Lighting Residential									
91	Customer Charge	60	$11.75	$	705	$16.72	$	1,003	$ 298	42%
92	**Total GLR Revenue**			**$**	**705**		**$**	**1,003**	**$ 298**	42%
	Interruptible Service									
93	Customer Charge	12	$935.00	$	11,220	$935.00	$	11,220	$ -	0%
94	Consumed (July-Dec)	166,540	$0.099	$	16,487	$0.099	$	16,487		
95	Consumed (Jan-June)	108,630	$0.099	$	10,754	$0.099	$	10,754		
96	Volumetric Charge	275,170		$	27,242		$	27,242	$ 0	0%
97	Customer Charge	12	$935.00	$	11,220	$935.00	$	11,220	$ -	0%
98	All Consumption	451,820	$0.250	$	112,955	$0.250	$	112,955	$ 0	0%
99	Volumetric Charge	451,820		$	112,955		$	112,955	$ 0	0%
100	**Total IS Revenue**			**$**	**162,637**		**$**	**162,637**	**$ 0**	0%

101	Fixed Charge Revenue	$ 11,377,217
	Revenue Requirement:	
102	Customer	20,313,847
103	Demand	5,860,027
104	Total Fixed Costs	26,173,874
105	Percentage of Fixed Charges to Fixed Costs	43.5%
106	Remaining Fixed Costs Recoverd via Volumetric Rates	14,796,657
107	Percentage of Fixed Costs in Volumetric Rates	56.5%

Chesapeake Utilities
Delaware Division
Test Period Ended March 31, 2016

Exhibit RJA-3
Bill Impacts
Average Monthly Impact

Residential 1

Line No.	(a)	(b)	(c)	(d)	(e)	(f)
			Present Rates	Proposed Rates		
1		Customer Charge	$10.50	$15.00		
		Volumetric Charge				
2		20	$0.607	$0.852		
3		30	$0.280	$0.525		
4		50	$0.170	$0.415		
5		GSR Rate	$0.681	$0.681		
6		AVERAGE	REVENUE AT	REVENUE AT	MONTHLY BILL CHANGE	
7		CCF PER	PRESENT	PROPOSED		
8		CUSTOMER	RATES	RATES	AMOUNT	PERCENT
9	Jan	30.65	$46.50	$58.52	$12.02	25.86%
10	Feb	37.81	$53.37	$67.15	$13.78	25.82%
11	Mar	31.40	$47.21	$59.42	$12.20	25.85%
12	Apr	16.80	$32.13	$40.75	$8.62	26.83%
13	May	7.90	$20.67	$27.11	$6.44	31.15%
14	Jun	3.60	$15.13	$20.51	$5.38	35.57%
15	Jul	3.36	$14.83	$20.15	$5.32	35.91%
16	Aug	2.98	$14.34	$19.58	$5.23	36.48%
17	Sep	2.96	$14.31	$19.53	$5.23	36.52%
18	Oct	3.85	$15.46	$20.90	$5.44	35.22%
19	Nov	9.12	$22.25	$28.99	$6.74	30.29%
20	Dec	20.77	$37.00	$46.60	$9.60	25.94%
21	Total	171.19	$333.20	$429.21	$96.01	28.81%
22	Monthly Average		$27.77	$35.77	$8.00	28.81%

Residential 1 Expansion

Line No.	(a)	(b)	(c)	(d)	(e)	(f)
			Present Rates	Proposed Rates		
1		Customer Charge	$16.50	$16.50		
		Volumetric Charge				
2		20	$0.607	$0.852		
3		30	$0.280	$0.525		
4		50	$0.170	$0.415		
5		GSR Rate	$0.681	$0.681		
6		AVERAGE	REVENUE AT	REVENUE AT	MONTHLY BILL CHANGE	
7		CCF PER	PRESENT	PROPOSED		
8		CUSTOMER	RATES	RATES	AMOUNT	PERCENT
9	Jan	34.32	$56.02	$64.44	$8.42	15.03%
10	Feb	41.88	$63.28	$73.56	$10.28	16.24%
11	Mar	19.20	$41.23	$45.94	$4.71	11.43%
12	Apr	5.92	$24.13	$25.58	$1.45	6.02%
13	May	3.45	$20.94	$21.79	$0.85	4.04%
14	Jun	1.81	$18.84	$19.28	$0.44	2.36%
15	Jul	0.86	$17.61	$17.83	$0.21	1.20%
16	Aug	0.43	$17.05	$17.16	$0.11	0.62%
17	Sep	0.14	$16.69	$16.72	$0.04	0.21%
18	Oct	3.49	$20.99	$21.85	$0.86	4.08%
19	Nov	20.17	$42.43	$47.38	$4.95	11.67%
20	Dec	24.52	$46.61	$52.62	$6.02	12.91%
21	Total	156.20	$385.81	$424.14	$38.33	9.94%
22	Monthly Average		$32.15	$35.35	$3.19	9.94%

Chesapeake Utilities
Delaware Division
Test Period Ended March 31, 2016

Exhibit RJA-3
Bill Impacts
Average Monthly Impact

Residential 2

Line No.	(a)	(b)	(c)	(d)	(e)	(f)
			Present Rates	Proposed Rates		
23		Customer Charge	$13.00	$17.00		
		Volumetric Charge				
24		20	$0.578	$0.656		
25		30	$0.319	$0.397		
26		50	$0.132	$0.210		
27		GSR Rate	$0.681	$0.681		
28		AVERAGE	REVENUE AT	REVENUE AT	MONTHLY BILL CHANGE	
29		CCF PER	PRESENT	PROPOSED		
30		CUSTOMER	RATES	RATES	AMOUNT	PERCENT
31	Jan	122.76	$127.33	$140.85	$13.51	10.61%
32	Feb	138.70	$140.29	$155.04	$14.75	10.51%
32	Mar	111.99	$118.58	$131.26	$12.68	10.69%
33	Apr	65.24	$80.57	$89.63	$9.06	11.24%
34	May	31.06	$49.24	$55.65	$6.41	13.01%
35	Jun	13.42	$29.90	$34.94	$5.04	16.86%
36	Jul	10.65	$26.41	$31.23	$4.83	18.27%
37	Aug	9.25	$24.65	$29.37	$4.72	19.14%
38	Sep	9.11	$24.47	$29.18	$4.71	19.23%
39	Oct	16.01	$33.16	$38.40	$5.24	15.80%
40	Nov	44.34	$62.52	$69.96	$7.44	11.89%
41	Dec	88.43	$99.43	$110.28	$10.85	10.92%
42	Total	660.98	$816.55	$915.78	$99.23	12.15%
43	Monthly Average		$68.05	$76.32	$8.27	12.15%

Residential 2 Expansion

Line No.	(a)	(b)	(c)	(d)	(e)	(f)
			Present Rates	Proposed Rates		
23		Customer Charge	$31.75	$31.75		
		Volumetric Charge				
24		20	$0.578	$0.656		
25		30	$0.319	$0.397		
26		50	$0.132	$0.210		
27		GSR Rate	$0.681	$0.681		
28		AVERAGE	REVENUE AT	REVENUE AT	MONTHLY BILL CHANGE	
29		CCF PER	PRESENT	PROPOSED		
30		CUSTOMER	RATES	RATES	AMOUNT	PERCENT
31	Jan	112.12	$137.44	$146.13	$8.69	6.32%
32	Feb	130.79	$152.62	$162.75	$10.14	6.64%
32	Mar	81.40	$112.46	$118.77	$6.31	5.61%
33	Apr	34.81	$71.74	$74.44	$2.70	3.76%
34	May	18.71	$55.30	$56.75	$1.45	2.62%
35	Jun	11.56	$46.31	$47.20	$0.90	1.94%
36	Jul	4.79	$37.78	$38.15	$0.37	0.98%
37	Aug	4.02	$36.81	$37.13	$0.31	0.85%
38	Sep	4.11	$36.92	$37.24	$0.32	0.86%
39	Oct	14.88	$50.49	$51.64	$1.15	2.28%
40	Nov	55.93	$91.75	$96.08	$4.33	4.72%
41	Dec	82.24	$113.14	$119.51	$6.37	5.63%
42	Total	555.36	$942.75	$985.79	$43.04	4.57%
43	Monthly Average		$78.56	$82.15	$3.59	4.57%

Chesapeake Utilities
Delaware Division
Test Period Ended March 31, 2016

Exhibit RJA-3
Bill Impacts
Average Monthly Impact

General Service

Line No.	(a)	(b)	(c)	(d)	(e)	(f)
			Present Rates	Proposed Rates		
44		Customer Charge	$26.00	$34.00		
		Volumetric Charge				
45		20	$0.447	$0.506		
46		30	$0.278	$0.337		
47		50	$0.140	$0.199		
48		GSR Rate	$0.681	$0.681		
49		AVERAGE	REVENUE AT	REVENUE AT	MONTHLY BILL CHANGE	
50		CCF PER	PRESENT	PROPOSED		
51		CUSTOMER	RATES	RATES	AMOUNT	PERCENT
52	Jan	194.06	$195.60	$215.12	$19.52	9.98%
53	Feb	231.42	$226.28	$248.01	$21.73	9.61%
53	Mar	203.07	$203.00	$223.05	$20.05	9.88%
54	Apr	99.95	$118.33	$132.27	$13.93	11.77%
55	May	43.24	$70.85	$81.41	$10.57	14.91%
56	Jun	18.70	$47.09	$56.20	$9.11	19.34%
57	Jul	14.62	$42.49	$51.36	$8.87	20.87%
58	Aug	12.25	$39.81	$48.54	$8.73	21.92%
59	Sep	13.37	$41.08	$49.87	$8.79	21.41%
60	Oct	21.23	$49.74	$59.00	$9.26	18.62%
61	Nov	50.24	$77.53	$88.51	$10.98	14.16%
62	Dec	129.30	$142.44	$158.11	$15.67	11.00%
63	Total	1031.44	$1,254.24	$1,411.46	$157.21	12.53%
64	Monthly Average		$104.52	$117.62	$13.10	12.53%

General Service Expansion

Line No.	(a)	(b)	(c)	(d)	(e)	(f)
			Present Rates	Proposed Rates		
44		Customer Charge	$56.00	$56.00		
		Volumetric Charge				
45		20	$0.447	$0.506		
46		30	$0.278	$0.337		
47		50	$0.140	$0.199		
48		GSR Rate	$0.681	$0.681		
49		AVERAGE	REVENUE AT	REVENUE AT	MONTHLY BILL CHANGE	
50		CCF PER	PRESENT	PROPOSED		
51		CUSTOMER	RATES	RATES	AMOUNT	PERCENT
52	Jan	163.49	$200.50	$210.20	$9.70	4.84%
53	Feb	225.97	$251.80	$265.21	$13.41	5.33%
53	Mar	113.08	$159.12	$165.83	$6.71	4.22%
54	Apr	53.21	$109.96	$113.12	$3.16	2.87%
55	May	48.75	$106.13	$109.02	$2.89	2.73%
56	Jun	34.90	$92.85	$94.92	$2.07	2.23%
57	Jul	3.87	$60.37	$60.60	$0.23	0.38%
58	Aug	1.48	$57.66	$57.75	$0.09	0.15%
59	Sep	3.56	$60.02	$60.23	$0.21	0.35%
60	Oct	12.38	$69.96	$70.70	$0.73	1.05%
61	Nov	54.59	$111.10	$114.34	$3.24	2.92%
62	Dec	94.69	$144.02	$149.64	$5.62	3.90%
63	Total	809.95	$1,423.49	$1,471.56	$48.07	3.38%
64	Monthly Average		$118.62	$122.63	$4.01	3.38%

Chesapeake Utilities
Delaware Division
Test Period Ended March 31, 2016

Exhibit RJA-4
Typical Bill Impacts

CHESAPEAKE UTILITIES CORPORATION - Delaware Division
Estimated Monthly Bill Impacts
Residential Service 1

Line No.	(a)		(b) Present Rates	(c) Proposed Rates	(d)	(e)
1	Customer Charge		$10.50	$15.00		
	Volumetric Charge					
2		20	$0.607	$0.852		
3		30	$0.280	$0.525		
4		50	$0.170	$0.415		
5	GSR Rate		$0.681	$0.681		

Line No.	MONTHLY CONSUMPTION (Ccf)	REVENUE AT PRESENT RATES	REVENUE AT PROPOSED RATES	REVENUE CHANGE AMOUNT	REVENUE CHANGE PERCENT
9	0	$10.50	$15.00	$4.50	42.86%
10	25	$41.07	$51.70	$10.64	25.90%
11	30	$45.87	$57.73	$11.86	25.86%
12	35	$50.68	$63.76	$13.09	25.83%
13	40	$55.48	$69.80	$14.32	25.80%
14	45	$60.29	$75.83	$15.54	25.78%
15	50	$65.09	$81.86	$16.77	25.77%
16	60	$73.60	$92.82	$19.22	26.12%
17	70	$82.11	$103.79	$21.68	26.40%
18	80	$90.62	$114.75	$24.13	26.63%
19	90	$99.13	$125.72	$26.59	26.82%
20	100	$107.64	$136.68	$29.04	26.98%
21	110	$116.15	$147.65	$31.50	27.12%
22	120	$124.66	$158.61	$33.95	27.23%
23	130	$133.17	$169.57	$36.40	27.34%
24	140	$141.68	$180.54	$38.86	27.43%
25	150	$150.19	$191.50	$41.31	27.51%
26	160	$158.70	$202.47	$43.77	27.58%
27	170	$167.21	$213.43	$46.22	27.64%
28	180	$175.72	$224.39	$48.67	27.70%
29	190	$184.23	$235.36	$51.13	27.75%
30	200	$192.74	$246.32	$53.58	27.80%
31	210	$201.25	$257.29	$56.04	27.84%
32	220	$209.76	$268.25	$58.49	27.88%
33	230	$218.27	$279.21	$60.94	27.92%
34	240	$226.78	$290.18	$63.40	27.96%

Chesapeake Utilities **Exhibit RJA-4**
Delaware Division **Typical Bill Impacts**
Test Period Ended March 31, 2016

Residential Service 1 - Expansion

Line No.	(a)		(c)	(d)	(e)	(f)
			Present Rates	Proposed Rates		
35	Customer Charge		$16.50	$16.50		
	Volumetric Charge					
36		20	$0.607	$0.852		
37		30	$0.280	$0.525		
38		50	$0.170	$0.415		
39	GSR Rate		$0.681	$0.681		
40	MONTHLY		REVENUE AT	REVENUE AT	REVENUE CHANGE	
41	CONSUMPTION		PRESENT	PROPOSED		
42	(Ccf)		RATES	RATES	AMOUNT	PERCENT
43	0		$16.50	$16.50	$0.00	0.00%
44	25		$47.07	$53.20	$6.14	13.04%
45	30		$51.87	$59.23	$7.36	14.19%
46	35		$56.68	$65.26	$8.59	15.16%
47	40		$61.48	$71.30	$9.82	15.97%
48	45		$66.29	$77.33	$11.04	16.66%
49	50		$71.09	$83.36	$12.27	17.26%
50	60		$79.60	$94.32	$14.72	18.50%
51	70		$88.11	$105.29	$17.18	19.50%
52	80		$96.62	$116.25	$19.63	20.32%
53	90		$105.13	$127.22	$22.09	21.01%
54	100		$113.64	$138.18	$24.54	21.60%
55	110		$122.15	$149.15	$27.00	22.10%
56	120		$130.66	$160.11	$29.45	22.54%
57	130		$139.17	$171.07	$31.90	22.92%
58	140		$147.68	$182.04	$34.36	23.26%
59	150		$156.19	$193.00	$36.81	23.57%
60	160		$164.70	$203.97	$39.27	23.84%
61	170		$173.21	$214.93	$41.72	24.09%
62	180		$181.72	$225.89	$44.17	24.31%
63	190		$190.23	$236.86	$46.63	24.51%
64	200		$198.74	$247.82	$49.08	24.70%
65	210		$207.25	$258.79	$51.54	24.87%
66	220		$215.76	$269.75	$53.99	25.02%
67	230		$224.27	$280.71	$56.44	25.17%
68	240		$232.78	$291.68	$58.90	25.30%

Chesapeake Utilities
Delaware Division
Test Period Ended March 31, 2016

Exhibit RJA-4
Typical Bill Impacts

Residential Service 2

Line No.	(a)		(b)	(c)
			Present Rates	Proposed Rates
69	Customer Charge		$13.00	$17.00
	Volumetric Charge			
70		20	$0.578	$0.656
71		30	$0.319	$0.397
72		50	$0.132	$0.210
73	GSR Rate		$0.681	$0.681

Line No.	(a)	(b)	(c)	(d)	(e)
74	MONTHLY	REVENUE AT	REVENUE AT	REVENUE CHANGE	
75	CONSUMPTION	PRESENT	PROPOSED		
76	(Ccf)	RATES	RATES	AMOUNT	PERCENT
77	240	$222.65	$245.25	$22.60	10.15%
78	250	$230.78	$254.16	$23.38	10.13%
79	260	$238.91	$263.06	$24.15	10.11%
80	270	$247.04	$271.97	$24.93	10.09%
81	280	$255.17	$280.87	$25.70	10.07%
82	290	$263.30	$289.78	$26.48	10.06%
83	300	$271.43	$298.68	$27.25	10.04%
84	310	$279.56	$307.59	$28.03	10.03%
85	320	$287.69	$316.49	$28.80	10.01%
86	330	$295.82	$325.40	$29.58	10.00%
87	340	$303.95	$334.30	$30.35	9.99%
88	350	$312.08	$343.21	$31.13	9.97%
89	360	$320.21	$352.11	$31.90	9.96%
90	370	$328.34	$361.02	$32.68	9.95%
91	380	$336.47	$369.92	$33.45	9.94%
92	390	$344.60	$378.83	$34.23	9.93%
93	400	$352.73	$387.73	$35.00	9.92%
94	410	$360.86	$396.64	$35.78	9.91%
95	420	$368.99	$405.54	$36.55	9.91%
96	430	$377.12	$414.45	$37.33	9.90%
97	440	$385.25	$423.35	$38.10	9.89%
98	450	$393.38	$432.26	$38.88	9.88%
99	460	$401.51	$441.16	$39.65	9.88%
100	470	$409.64	$450.07	$40.43	9.87%
101	480	$417.77	$458.97	$41.20	9.86%
102	490	$425.90	$467.88	$41.98	9.86%

Chesapeake Utilities
Delaware Division
Test Period Ended March 31, 2016

Exhibit RJA-4
Typical Bill Impacts

Residential Service 2 - Expansion

Line No.	(a)		(c)	(d)	(e)	(f)
			Present Rates	Proposed Rates		
103	Customer Charge		$31.75	$31.75		
	Volumetric Charge					
104		20	$0.578	$0.656		
105		30	$0.319	$0.397		
106		50	$0.132	$0.210		
107	GSR Rate		$0.681	$0.681		

Line No.	MONTHLY CONSUMPTION (Ccf)	REVENUE AT PRESENT RATES	REVENUE AT PROPOSED RATES	REVENUE CHANGE AMOUNT	REVENUE CHANGE PERCENT
108-110					
111	240	$241.40	$260.00	$18.60	7.71%
112	250	$249.53	$268.91	$19.38	7.77%
113	260	$257.66	$277.81	$20.15	7.82%
114	270	$265.79	$286.72	$20.93	7.87%
115	280	$273.92	$295.62	$21.70	7.92%
116	290	$282.05	$304.53	$22.48	7.97%
117	300	$290.18	$313.43	$23.25	8.01%
118	310	$298.31	$322.34	$24.03	8.05%
119	320	$306.44	$331.24	$24.80	8.09%
120	330	$314.57	$340.15	$25.58	8.13%
121	340	$322.70	$349.05	$26.35	8.17%
122	350	$330.83	$357.96	$27.13	8.20%
123	360	$338.96	$366.86	$27.90	8.23%
124	370	$347.09	$375.77	$28.68	8.26%
125	380	$355.22	$384.67	$29.45	8.29%
126	390	$363.35	$393.58	$30.23	8.32%
127	400	$371.48	$402.48	$31.00	8.35%
128	410	$379.61	$411.39	$31.78	8.37%
129	420	$387.74	$420.29	$32.55	8.40%
130	430	$395.87	$429.20	$33.33	8.42%
131	440	$404.00	$438.10	$34.10	8.44%
132	450	$412.13	$447.01	$34.88	8.46%
133	460	$420.26	$455.91	$35.65	8.48%
134	470	$428.39	$464.82	$36.43	8.50%
135	480	$436.52	$473.72	$37.20	8.52%
136	490	$444.65	$482.63	$37.98	8.54%

Chesapeake Utilities **Exhibit RJA-4**
Delaware Division **Typical Bill Impacts**
Test Period Ended March 31, 2016

General Service

Line No.	(a)		(c)	(d)	(e)	(f)
			Present Rates	Proposed Rates		
137	Customer Charge		$26.00	$34.00		
	Volumetric Charge					
138		20	$0.447	$0.506		
139		30	$0.278	$0.337		
140		50	$0.140	$0.199		
141	GSR Rate		$0.681	$0.681		
142	MONTHLY		REVENUE AT	REVENUE AT	REVENUE CHANGE	
143	CONSUMPTION		PRESENT	PROPOSED		
144	(Ccf)		RATES	RATES	AMOUNT	PERCENT
145	240		$233.32	$255.56	$22.24	9.53%
146	250		$241.53	$264.37	$22.84	9.46%
147	260		$249.74	$273.17	$23.43	9.38%
148	270		$257.95	$281.97	$24.02	9.31%
149	280		$266.16	$290.78	$24.62	9.25%
150	290		$274.37	$299.58	$25.21	9.19%
151	300		$282.58	$308.38	$25.80	9.13%
152	310		$290.79	$317.19	$26.40	9.08%
153	320		$299.00	$325.99	$26.99	9.03%
154	330		$307.21	$334.80	$27.59	8.98%
155	340		$315.42	$343.60	$28.18	8.93%
156	350		$323.63	$352.40	$28.77	8.89%
157	360		$331.84	$361.21	$29.37	8.85%
158	370		$340.05	$370.01	$29.96	8.81%
159	380		$348.26	$378.81	$30.55	8.77%
160	390		$356.47	$387.62	$31.15	8.74%
161	400		$364.68	$396.42	$31.74	8.70%
162	410		$372.89	$405.22	$32.33	8.67%
163	420		$381.10	$414.03	$32.93	8.64%
164	430		$389.31	$422.83	$33.52	8.61%
165	440		$397.52	$431.63	$34.11	8.58%
166	450		$405.73	$440.44	$34.71	8.55%
167	460		$413.94	$449.24	$35.30	8.53%
168	470		$422.15	$458.04	$35.89	8.50%
169	480		$430.36	$466.85	$36.49	8.48%
170	490		$438.57	$475.65	$37.08	8.45%

Chesapeake Utilities
Delaware Division
Test Period Ended March 31, 2016

Exhibit RJA-4
Typical Bill Impacts

General Service - Expansion

Line No.	(a)		(c)	(d)	(e)	(f)
			Present Rates	Proposed Rates		
171	Customer Charge		$56.00	$56.00		
	Volumetric Charge					
172		20	$0.447	$0.506		
173		30	$0.278	$0.337		
174		50	$0.140	$0.199		
175	GSR Rate		$0.681	$0.681		

Line No.	MONTHLY CONSUMPTION (Ccf)	REVENUE AT PRESENT RATES	REVENUE AT PROPOSED RATES	REVENUE CHANGE AMOUNT	REVENUE CHANGE PERCENT
179	240	$263.32	$277.56	$14.24	5.41%
180	250	$271.53	$286.37	$14.84	5.46%
181	260	$279.74	$295.17	$15.43	5.52%
182	270	$287.95	$303.97	$16.02	5.56%
183	280	$296.16	$312.78	$16.62	5.61%
184	290	$304.37	$321.58	$17.21	5.65%
185	300	$312.58	$330.38	$17.80	5.70%
186	310	$320.79	$339.19	$18.40	5.74%
187	320	$329.00	$347.99	$18.99	5.77%
188	330	$337.21	$356.80	$19.59	5.81%
189	340	$345.42	$365.60	$20.18	5.84%
190	350	$353.63	$374.40	$20.77	5.87%
191	360	$361.84	$383.21	$21.37	5.90%
192	370	$370.05	$392.01	$21.96	5.93%
193	380	$378.26	$400.81	$22.55	5.96%
194	390	$386.47	$409.62	$23.15	5.99%
195	400	$394.68	$418.42	$23.74	6.01%
196	410	$402.89	$427.22	$24.33	6.04%
197	420	$411.10	$436.03	$24.93	6.06%
198	430	$419.31	$444.83	$25.52	6.09%
199	440	$427.52	$453.63	$26.11	6.11%
200	450	$435.73	$462.44	$26.71	6.13%
201	460	$443.94	$471.24	$27.30	6.15%
202	470	$452.15	$480.04	$27.89	6.17%
203	480	$460.36	$488.85	$28.49	6.19%
204	490	$468.57	$497.65	$29.08	6.21%

Chesapeake Utilities
Delaware Division
Test Period Ended March 31, 2016

Exhibit RJA-4
Typical Bill Impacts

Medium Volume Service

Line No.	(a)		(c)	(d)
			Present Rates	Proposed Rates
205	Customer Charge		$65.00	$80.00
	Volumetric Charge			
206		200	$0.227	$0.237
207		200	$0.115	$0.125
208	GSR Rate		$0.681	$0.681

Line No.	(a)	(c)	(d)	(e)	(f)
209	MONTHLY	REVENUE AT	REVENUE AT	REVENUE CHANGE	
210	CONSUMPTION	PRESENT	PROPOSED		
211	(Ccf)	RATES	RATES	AMOUNT	PERCENT
212	0.0	$65.00	$80.00	$15.00	23.08%
213	100	$155.80	$171.84	$16.04	10.29%
214	200	$246.60	$263.68	$17.08	6.93%
215	300	$326.20	$344.32	$18.12	5.55%
216	400	$405.80	$424.96	$19.16	4.72%
217	500	$485.40	$505.59	$20.19	4.16%
218	600	$565.00	$586.23	$21.23	3.76%
219	700	$644.60	$666.87	$22.27	3.46%
220	800	$724.20	$747.51	$23.31	3.22%
221	900	$803.80	$828.15	$24.35	3.03%
222	1000	$883.40	$908.79	$25.39	2.87%
223	1100	$963.00	$989.43	$26.43	2.74%
224	1200	$1,042.60	$1,070.07	$27.47	2.63%
225	1300	$1,122.20	$1,150.70	$28.50	2.54%
226	1400	$1,201.80	$1,231.34	$29.54	2.46%
227	1500	$1,281.40	$1,311.98	$30.58	2.39%
228	2000	$1,679.40	$1,715.18	$35.78	2.13%
229	2500	$2,077.40	$2,118.37	$40.97	1.97%
230	3000	$2,475.40	$2,521.56	$46.16	1.86%
231	3500	$2,873.40	$2,924.76	$51.36	1.79%
232	4000	$3,271.40	$3,327.95	$56.55	1.73%
233	5000	$4,067.40	$4,134.34	$66.94	1.65%
234	6000	$4,863.40	$4,940.73	$77.33	1.59%
235	7000	$5,659.40	$5,747.12	$87.72	1.55%
236	8000	$6,455.40	$6,553.51	$98.11	1.52%
237	9000	$7,251.40	$7,359.89	$108.49	1.50%
238	10000	$8,047.40	$8,166.28	$118.88	1.48%
239	12500	$10,037.40	$10,182.25	$144.85	1.44%
240	15000	$12,027.40	$12,198.22	$170.82	1.42%
241	17500	$14,017.40	$14,214.19	$196.79	1.40%
242	20000	$16,007.40	$16,230.16	$222.76	1.39%

Chesapeake Utilities
Delaware Division
Test Period Ended March 31, 2016

Exhibit RJA-4
Typical Bill Impacts

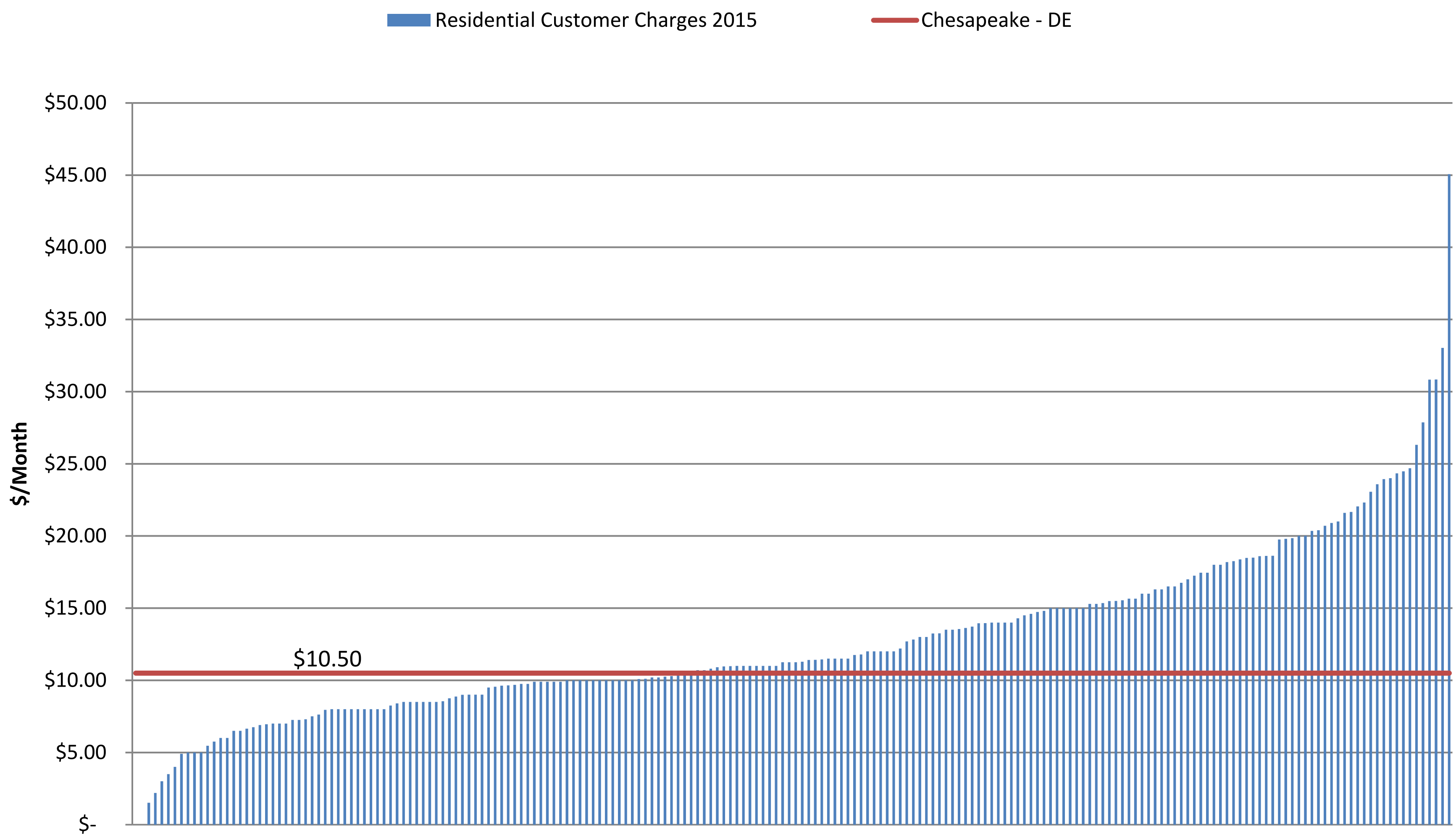
Large Volume Service

Line No.	(a)		(c)	(d)	(e)	(f)
			Present Rates	Proposed Rates		
243	Customer Charge		$125.00	$175.00		
	Volumetric Charge					
244		1,000	$0.326	$0.218		
245		1,000	$0.083	$0.088		
246	GSR Rate		$0.681	$0.681		

Line No.	MONTHLY CONSUMPTION (Ccf)	REVENUE AT PRESENT RATES	REVENUE AT PROPOSED RATES	REVENUE CHANGE AMOUNT	REVENUE CHANGE PERCENT
250	0.0	$125.00	$175.00	$50.00	40.00%
251	1,000	$1,132.00	$1,074.18	($57.82)	-5.11%
252	2,000	$1,896.00	$1,843.43	($52.57)	-2.77%
253	3,000	$2,660.00	$2,612.68	($47.32)	-1.78%
254	4,000	$3,424.00	$3,381.93	($42.07)	-1.23%
255	5,000	$4,188.00	$4,151.18	($36.82)	-0.88%
256	6,000	$4,952.00	$4,920.43	($31.57)	-0.64%
257	7,000	$5,716.00	$5,689.68	($26.32)	-0.46%
258	8,000	$6,480.00	$6,458.93	($21.07)	-0.33%
259	9,000	$7,244.00	$7,228.18	($15.82)	-0.22%
260	10,000	$8,008.00	$7,997.43	($10.57)	-0.13%
261	11,000	$8,772.00	$8,766.68	($5.32)	-0.06%
262	12,000	$9,536.00	$9,535.93	($0.07)	0.00%
263	13,000	$10,300.00	$10,305.18	$5.18	0.05%
264	14,000	$11,064.00	$11,074.43	$10.43	0.09%
265	15,000	$11,828.00	$11,843.68	$15.68	0.13%
266	16,000	$12,592.00	$12,612.93	$20.93	0.17%
267	17,000	$13,356.00	$13,382.18	$26.18	0.20%
268	18,000	$14,120.00	$14,151.43	$31.43	0.22%
269	19,000	$14,884.00	$14,920.68	$36.68	0.25%
270	20,000	$15,648.00	$15,689.93	$41.93	0.27%
271	21,000	$16,412.00	$16,459.18	$47.18	0.29%
272	22,000	$17,176.00	$17,228.43	$52.43	0.31%
273	23,000	$17,940.00	$17,997.68	$57.68	0.32%
274	24,000	$18,704.00	$18,766.93	$62.93	0.34%
275	25,000	$19,468.00	$19,536.18	$68.18	0.35%
276	26,000	$20,232.00	$20,305.43	$73.43	0.36%
277	27,000	$20,996.00	$21,074.68	$78.68	0.37%
278	28,000	$21,760.00	$21,843.93	$83.93	0.39%
279	29,000	$22,524.00	$22,613.18	$89.18	0.40%
280	30,000	$23,288.00	$23,382.43	$94.43	0.41%
281	31,000	$24,052.00	$24,151.68	$99.68	0.41%
282	32,000	$24,816.00	$24,920.93	$104.93	0.42%

Chesapeake Utilities - Delaware

Residential Monthly Customer Charges - as of September 2015



NATURAL GAS CUSTOMER CHARGE			
Company	State	Residential	Small Commercial
CONTINENTAL ENERGY - ENSTAR NATURAL GAS CO	AK	$ 14.00	$ 30.00
SEMPRA - MOBILE GAS SERVICE	AL	$ 8.50	$ 16.30
ARKANSAS OKLAHOMA GAS CORP - AR	AR	$ 10.70	$ 15.95
CENTERPOINT ARKLA AR	AR	$ 9.75	$ 13.00
SOURCEGAS LLC AR	AR	$ 10.20	$ 18.51
SOUTHWEST GAS CORP AZ	AZ	$ 10.70	$ 27.50
UNISOURCE ENERGY SERVICES	AZ	$ 10.00	$ 20.00
PACIFIC GAS & ELECTRIC CO	CA	$ -	$ 8.10
SEMPRA - SAN DIEGO GAS & ELECTRIC CO	CA	$ -	$ 10.00
SEMPRA - SOUTHERN CALIFORNIA GAS CO	CA	$ 4.90	$ 14.80
SOUTHWEST GAS CORP CA	CA	$ 5.00	$ 11.00
ATMOS ENERGY CORPORATION CO	CO	$ 11.00	$ 26.28
BLACK HILLS ENERGY - CO	CO	$ 10.08	$ 15.12
COLORADO SPRINGS, CITY OF	CO	$ 11.79	$ 23.58
SOURCEGAS LLC CO	CO	$ 10.00	$ 20.00
XCEL - PUBLIC SERVICE CO OF COLORADO	CO	$ 11.50	$ 32.08
UIL - CONNECTICUT NATURAL GAS CORP	CT	$ 16.50	$ 47.50
UIL - SOUTHERN CONNECTICUT GAS CO	CT	$ 14.00	$ 35.00
YANKEE GAS SERVICES CO	CT	$ 18.50	$ 46.00
WASHINGTON GAS LIGHT CO DC	DC	$ 9.90	$ 17.10
CHESAPEAKE UTILITY CORP DE	DE	$ 10.50	$ 26.00
DELMARVA POWER & LIGHT COMPANY	DE	$ 11.41	$ 34.37
AGL - FLORIDA CITY GAS	FL	$ 8.00	$ 9.50
CHESAPEAKE UTILITY CORP FL	FL	$ 11.00	$ 20.00
GAINESVILLE REGIONAL UTIL GAS DEPT	FL	$ 9.75	
TECO PEOPLES GAS SYSTEM INC	FL	$ 12.00	$ 25.00
AGL - ATLANTA GAS LIGHT CO	GA	$ 11.00	$ 45.00
LIBERTY UTILITIES GA	GA	$ 26.31	$ 55.60
THE GAS COMPANY	HI	$ 8.50	$ 62.00
ALLIANT - INTERSTATE P&L IA	IA	$ 12.82	
BLACK HILLS ENERGY - IA	IA	$ 18.25	$ 29.00
LIBERTY UTILITIES IA	IA	$ 7.95	$ 13.00
MIDAMERICAN ENERGY COMPANY IA	IA	$ 10.00	
AVISTA CORP - ID	ID	$ 8.00	$ 12.00
MONTANA - DAKOTA UTILITIES INTERMOUNTAN	ID	$ 6.50	$ 9.50

NATURAL GAS CUSTOMER CHARGE			
			Small
Company	State	Residential	Commercial
AGL - NICOR	IL	$ 13.55	$ 20.80
AMEREN - ILLINOIS	IL	$ 22.31	$ 39.77
INTEGRYS - NORTH SHORE GAS CO	IL	$ 24.48	$ 29.56
INTEGRYS - PEOPLES GAS LIGHT & COKE CO	IL	$ 30.83	$ 38.24
LIBERTY UTILITIES IL	IL	$ 9.90	$ 25.00
MIDAMERICAN ENERGY COMPANY IL	IL	$ 12.69	$ 93.18
MT CARMEL PUBLIC UTILITY CO	IL	$ 15.00	$ 15.00
NORTH SHORE GAS CO[1]	IL	$ 23.94	$ 24.95
PEOPLES GAS LIGHT & COKE CO[2]	IL	$ 30.84	$ 25.00
CITIZENS GAS & COKE UTILITY	IN	$ 9.00	$ 22.00
NISOURCE - NIPSCO	IN	$ 11.00	$ 30.00
VECTREN - INDIANA GAS CO INC	IN	$ 11.25	$ 17.00
VECTREN - SOUTHERN INDIANA GAS & ELECTRIC CO	IN	$ 11.00	$ 22.00
ATMOS ENERGY CORPORATION KS	KS	$ 18.19	$ 40.88
BLACK HILLS ENERGY - KS	KS	$ 17.25	$ 26.45
ONEOK - KANSAS GAS SERVICE	KS	$ 15.35	$ 28.65
ATMOS ENERGY CORPORATION - KY	KY	$ 16.00	$ 40.00
DELTA NATURAL GAS CO INC	KY	$ 20.90	$ 31.30
DUKE ENERGY KENTUCKY	KY	$ 16.00	$ 47.50
EQUITABLE RESOURCES KY	KY	$ 7.50	$ 7.50
LOUISVILLE GAS & ELECTRIC CO[3]	KY	$ 13.50	$ 40.00
NISOURCE - COLUMBIA GAS OF KENTUCKY INC	KY	$ 15.00	$ 37.50
RICHMOND NATURAL GAS & SEWAGE WKS	KY	$ 15.49	$ 15.49
ATMOS ENERGY CORPORATION LA	LA	$ 13.96	$ 23.24
ATMOS ENERGY CORPORATION TRANS LA	LA	$ 14.00	$ 14.00
CENTERPOINT ARKLA LA	LA	$ 10.00	$ 16.00
CENTERPOINT ENTEX LA	LA	$ 11.25	$ 16.00
ENTERGY NEW ORLEANS, INC	LA	$ 20.40	$ 112.58
HOLYOKE GAS & ELECTRIC DEPT, CITY OF	MA	$ 6.00	$ 10.00
LIBERTY UTILITIES MA	MA	$ 9.90	$ 22.00
NATIONAL GRID - BOSTON GAS CO	MA	$ 10.00	$ 21.00
NATIONAL GRID - COLONIAL GAS CO	MA	$ 6.00	
NATIONAL GRID - ESSEX COUNTY GAS CO	MA	$ 21.00	$ 39.00
NISOURCE - COLUMBIA GAS OF MASSACHUSETS INC	MA	$ 12.20	$ 19.80
UIL - BERKSHIRE GAS CO	MA	$ 11.42	$ 12.51
UNITIL - FITCHBURG GAS & ELECTRIC LIGHT CO	MA	$ 8.50	$ 24.00

NATURAL GAS CUSTOMER CHARGE			
			Small
Company	State	Residential	Commercial
AGL - ELKTON GAS SERVICE	MD	$ 5.75	$ 11.00
BALTIMORE GAS & ELECTRIC CO	MD	$ 13.00	$ 35.00
CHESAPEAKE UTILITY CORP MD	MD	$ 8.75	$ 17.25
EASTON UTILITIES COMMISSION	MD	$ 9.65	$ 33.25
NISOURCE - COLUMBIA GAS OF MARYLAND INC	MD	$ 13.62	$ 36.68
UGI - CENTRAL PENN GAS, INC MD	MD	$ 9.68	
WASHINGTON GAS LIGHT CO MD	MD	$ 10.20	$ 18.50
ENERGY EAST - MAINE NATURAL GAS	ME	$ 24.34	$ 34.77
GAS NATURAL - BANGOR GAS CO LLC	ME	$ 14.29	
UNITIL - NORTHERN UTILITIES INC (ME)	ME	$ 23.06	$ 54.77
CONSUMERS ENERGY CO[4]	MI	$ 11.50	$ 12.50
CONTINENTAL ENERGY - SEMCO	MI	$ 11.50	$ 11.50
DTE - CITIZENS GAS FUEL CO	MI	$ 10.50	$ 20.00
DTE - MICHIGAN CONSOLIDATED	MI	$ 10.50	$ 26.20
INTEGRYS - MICHIGAN GAS UTILITIES CO	MI	$ 12.00	$ 33.00
INTEGRYS - WISCONSIN PUBLIC SERVICE CORP MI	MI	$ 5.00	$ 7.50
XCEL - NORTHERN STATES POWER CO OF MICHIGAN	MI	$ 7.25	$ 16.00
ALLIANT - INTERSTATE P&L MN	MN	$ 5.00	
CENTERPOINT ENERGY MN	MN	$ 9.50	$ 15.00
INTEGRYS - MERC MN	MN	$ 8.50	$ 14.50
MONTANA - DAKOTA UTILITIES GREAT PLAINS MN	MN	$ 6.50	$ 20.00
XCEL - NORTHERN STATES POWER CO OF MINNESOTA	MN	$ 9.00	$ 25.00
AMEREN - UNION ELECTRIC CO	MO	$ 15.00	$ 28.83
LACLEDE GAS CO	MO	$ 20.70	$ 25.50
LIBERTY UTILITIES MO	MO	$ 20.00	$ 23.80
SOUTHERN UNION - MISSOURI GAS ENERGY	MO	$ 27.87	$ 40.74
THE EMPIRE DISTRICT GAS COMPANY	MO	$ 16.50	$ 25.00
ATMOS ENERGY CORPORATION MS	MS	$ 6.95	$ 11.27
CENTERPOINT ENTEX MS	MS	$ 11.29	$ 16.96
MONTANA - DAKOTA UTILITIES CO MT	MT	$ 6.90	$ 12.00
NORTHWESTERN ENERGY LLC MT	MT	$ 7.30	$ 19.00
GREENVILLE UTILITIES COMMISSION	NC	$ 8.00	$ 22.00
PIEDMONT NATURAL GAS CO INC NC	NC	$ 10.00	$ 22.00
SCANA - PUBLIC SERVICE CO OF NORTH CAROLINA	NC	$ 10.00	$ 17.50
MONTANA - DAKOTA UTILITIES CO ND	ND	$ 14.81	$ 20.10
MONTANA - DAKOTA UTILITIES GREAT PLAINS ND	ND	$ 3.50	$ 3.50
XCEL - NORTHERN STATES POWER CO OF NORTH DAKOTA	ND	$ 18.48	$ 30.00

NATURAL GAS CUSTOMER CHARGE			
			Small
Company	State	Residential	Commercial
BLACK HILLS ENERGY - NE	NE	$ 13.50	$ 18.50
METROPOLITAN UTILITIES DISTRICT	NE	$ 13.72	
MIDAMERICAN ENERGY COMPANY NE	NE	$ 10.00	$ 135.10
NORTHWESTERN ENERGY LLC NE	NE	$ 8.00	$ 9.00
SOURCEGAS LLC NE	NE	$ 15.00	$ 23.05
LIBERTY UTILITIES NH	NH	$ 19.85	$ 46.71
Liberty Utilities EnergyNorth	NH	$ 22.04	$ 48.24
NATIONAL GRID - ENERGY NORTH NATURAL GAS INC	NH	$ 8.00	$ 11.00
UNITIL - NORTHERN UTILITIES, INC. (NH)	NH	$ 20.01	$ 63.18
AGL - ELIZABETHTOWN GAS CO	NJ	$ 8.00	$ 16.50
NEW JERSEY NATURAL GAS CO	NJ	$ 8.25	$ 25.00
PUBLIC SERVICE ELECTRIC & GAS CO	NJ	$ 5.46	$ 10.44
SOUTH JERSEY GAS CO	NJ	$ 9.63	$ 29.16
CONTINENTAL ENERGY - NEW MEXICO GAS	NM	$ 11.50	$ 20.00
NATURAL GAS PROCESSING - ZIA NATURAL GAS CO	NM	$ 10.96	$ 300.00
NV ENERGY	NV	$ 14.00	$ 18.00
SOUTHWEST GAS CORP NV	NV	$ 10.80	$ 25.80
CENTRAL HUDSON GAS & ELECTRIC CORP[5]	NY	$ 24.00	$ 37.00
CONSOLIDATED EDISON - ORANGE & ROCKLAND UTILITY INC	NY	$ 18.63	$ 29.08
CONSOLIDATED EDISON CO OF NEW YORK	NY	$ 18.60	$ 30.45
CORNING NATURAL GAS CORP	NY	$ 19.75	$ 1,220.00
ENERGY EAST - NYSEG	NY	$ 16.30	$ 23.60
ENERGY EAST - ROCHESTER GAS & ELECTRIC	NY	$ 16.30	
NATIONAL FUEL GAS DISTRIBUTION CORP - NEW YORK	NY	$ 15.54	$ 7.10
NATIONAL GRID - LONG ISLAND	NY	$ 21.66	$ 17.60
NATIONAL GRID - NIAGARA MOHAWK	NY	$ 20.35	$ 24.22
NATIONAL GRID - NY CITY	NY	$ 45.06	$ 76.91
ST LAWRENCE GAS CO INC	NY	$ 15.00	$ 25.00
VALLEY ENERGY, INC.	NY	$ 7.62	$ 7.62
DOMINION EAST OHIO	OH	$ 23.58	$ 26.00
DUKE ENERGY OHIO	OH	$ 33.03	$ 91.64
NISOURCE - COLUMBIA GAS OF OHIO INC	OH	$ 24.69	$ 24.69
VECTREN ENERGY DELIVERY OF OHIO	OH	$ 18.37	$ 20.00
ARKANSAS OKLAHOMA GAS CORP - OK	OK	$ 15.65	$ 30.15
CENTERPOINT ARKLA OK	OK	$ 13.24	$ 43.59
ONEOK - OKLAHOMA NATURAL GAS CO	OK	$ 14.73	$ 30.28
AVISTA CORP - OR	OR	$ 8.00	$ 14.00
MONTANA - DAKOTA UTILITIES CASCADE OR	OR	$ 3.00	$ 3.00
NORTHWEST NATURAL GAS CO OR	OR	$ 8.00	$ 15.00

NATURAL GAS CUSTOMER CHARGE			
Company	State	Residential	Small Commercial
EQUITABLE RESOURCES PA	PA	$ 13.25	$ 17.00
NATIONAL FUEL GAS DISTRIBUTION CORP PA	PA	$ 12.00	
NISOURCE - COLUMBIA GAS OF PENNSYLVANIA	PA	$ 16.75	$ 21.25
PECO ENERGY CO	PA	$ 11.75	$ 28.55
PEOPLES NATURAL GAS COMPANY	PA	$ 13.95	$ 14.88
PHILADELPHIA GAS WORKS	PA	$ 12.00	$ 18.00
UGI - CENTRAL PENN GAS, INC PA	PA	$ 14.60	$ 30.40
UGI - PENN NATURAL GAS PA	PA	$ 2.19	$ 2.80
UGI - UGI UTILITIES, INC PA	PA	$ 8.55	$ 8.55
NATIONAL GRID - RI	RI	$ 13.00	$ 22.00
GREENWOOD COMMISSION OF PUBLIC WORKS	SC	$ 10.00	$ 16.25
PIEDMONT NATURAL GAS CO INC SC	SC	$ 17.45	$ 44.00
SCANA - SOUTH CAROLINA ELECTRIC & GAS CO	SC	$ 10.90	$ 21.54
MIDAMERICAN ENERGY COMPANY SD	SD	$ 8.87	$ 304.94
MONTANA - DAKOTA UTILITIES CO SD	SD	$ 8.40	$ 10.50
NORTHWESTERN ENERGY LLC SD	SD	$ 8.00	$ 10.00
AGL - CHATTANOOGA GAS CO[6]	TN	$ 14.50	$ 27.00
ATMOS ENERGY CORPORATION TN[7]	TN	$ 15.65	$ 14.15
KNOXVILLE UTILITIES BOARD	TN	$ 6.65	$ 13.00
MEMPHIS LIGHT GAS & WATER DIVISION	TN	$ 10.00	
MIDDLE TENNESSEE NATURAL GAS UTIL DIST	TN	$ 7.00	$ 16.00
PIEDMONT NATURAL GAS CO INC TN	TN	$ 17.45	$ 44.00
ATMOS ENERGY CORPORATION - Mid TX	TX	$ 18.62	$ 40.02
ATMOS ENERGY CORPORATION - West TX	TX	$ 15.50	$ 38.25
CENTERPOINT ENTEX TX	TX	$ 15.29	$ 17.24
CenterPoint Energy Resources	TX	$ 15.29	$ 17.24
CORPUS CHRISTI, CITY OF - GAS DIV	TX	$ 11.44	$ 26.30
COSERV GAS, LTD	TX	$ 7.00	$ 13.30
QUESTAR GAS COMPANY UT	UT	$ 6.75	$ 18.25
AGL - VIRGINIA NATURAL GAS	VA	$ 11.00	$ 14.10
ATMOS ENERGY CORPORATION VA	VA	$ 10.98	$ 22.00
CHARLOTTESVILLE, CITY OF	VA	$ 10.00	$ 10.00
NISOURCE - COLUMBIA GAS OF VIRGINIA INC	VA	$ 18.00	$ 22.00
COLUMBIA GAS OF VIRGINIA INC[8]	VA	$ 18.00	$ 22.00
SOUTHWESTERN VIRGINIA GAS CO	VA	$ 9.55	$ 12.75
WASHINGTON GAS LIGHT CO VA	VA	$ 11.25	$ 20.45
VERMONT GAS SYSTEMS INC	VT	$ 19.80	$ 32.82
AVISTA CORP - WA	WA	$ 9.00	$ 87.40
MONTANA - DAKOTA UTILITIES CASCADE WA	WA	$ 4.00	$ 10.00

NATURAL GAS CUSTOMER CHARGE			
Company	State	Residential	Small Commercial
NORTHWEST NATURAL GAS CO WA	WA	$ 7.00	$ 15.00
PUGET SOUND ENERGY	WA	$ 10.29	$ 33.42
ALLETE - SUPERIOR WATER LIGHT & POWER CO	WI	$ 7.25	$ 15.00
ALLIANT - WISCONSIN POWER & LIGHT CO	WI	$ 1.51	
CITY GAS CO	WI	$ 8.50	$ 12.75
INTEGRYS - WISCONSIN PUBLIC SERVICE CORP WI	WI	$ 17.00	$ 30.00
MADISON GAS & ELECTRIC CO	WI	$ 21.60	$ 24.00
WE ENERGIES	WI	$ 9.90	$ 25.50
WISCONSIN GAS CO	WI	$ 9.90	$ 25.50
XCEL - NORTHERN STATES POWER CO OF WISCONSIN	WI	$ 10.25	$ 20.00
DOMINION HOPE	WV	$ 8.99	$ 17.97
EQUITABLE RESOURCES - Peoples WV	WV	$ 8.50	$ 12.50
MOUNTAINEER GAS CO	WV	$ 10.10	$ 31.75
MONTANA - DAKOTA UTILITIES CO WY	WY	$ 12.00	$ 27.00
QUESTAR GAS COMPANY WY	WY	$ 11.00	$ 32.50
SOURCEGAS LLC WY	WY	$ 15.00	$ 70.00

Source: AGA Report, "NATURAL GAS UTILITY RATE STRUCTURE: THE CUSTOMER CHARGE COMPONENT – 2015 UPDATE" May 28, 2015 and Internet Search of Natural Gas Utility Tariffs

Notes:

[1] North Shore Gas Co. residential heating charge is $23.94 and the residential non heating charge is $15.70. Small commercial customer charge per meter class (up to 700 cf/hr) $24.95, (Over 700 and no more than 2300 cf/hr) $78.75, and (over 2300 cf/hr) $223.10.

[2] People Gas Light & Coke Co. residential heating charge is $30.84 and the residential non heating charge is $16.37.

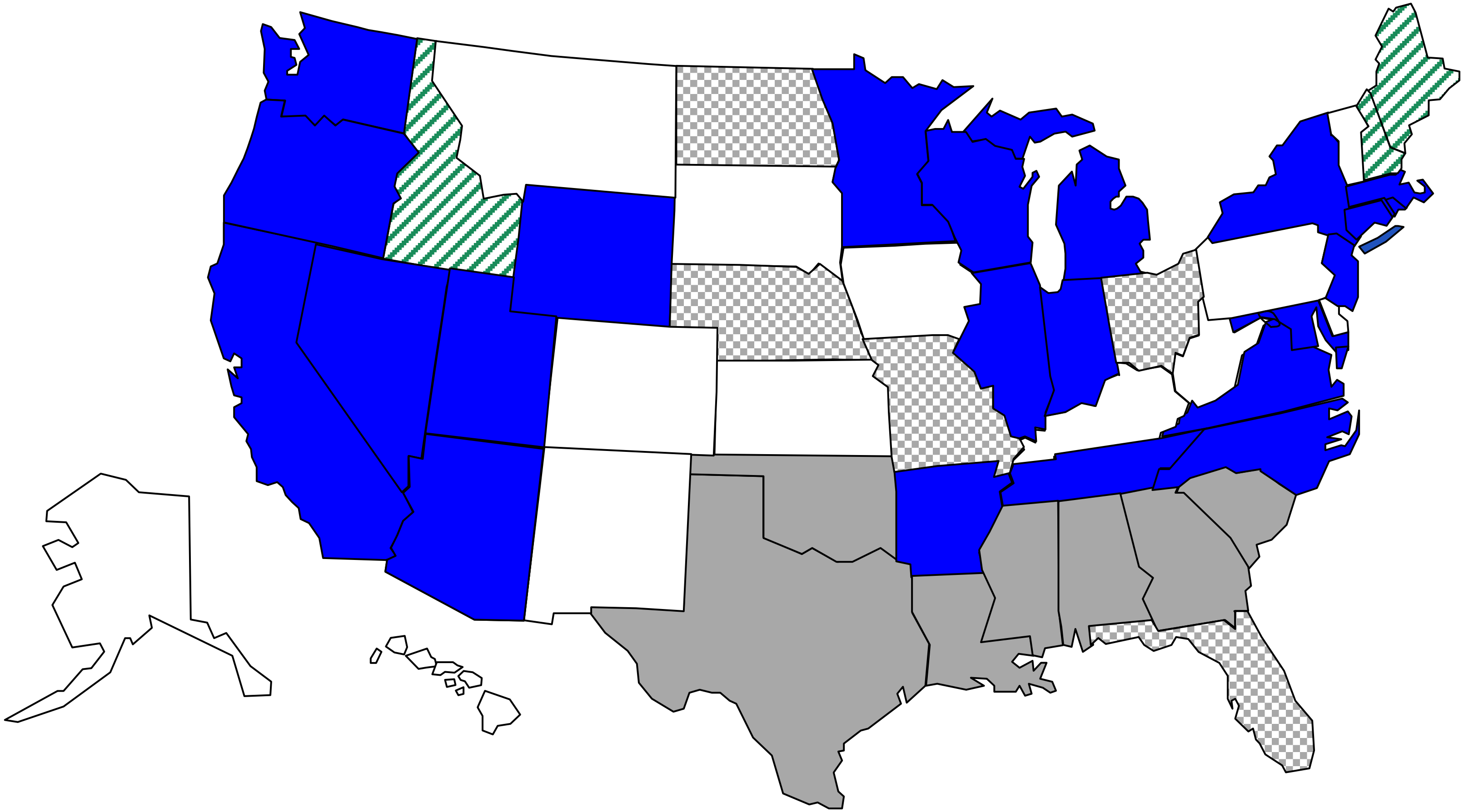
[3] Louisville Gas & Electric Co. small commercial charge meter capacity (<5000 cf/hr) $40.00 and (≥5000 cf/hr) $180.00. [4] Consumer Energy Co. small commercial charge GS-1 $12.50, GS-2 $19.50, and GS-3 $576.80.

[5] Central Hudson Gas & Electric Corp. residential charge contains three step increase moving from $24 to $25 in 2016 and then to $26 in 2017.

[6] AGL - Chattanooga Gas Co. residential customer charge is $16.00 for the months of Nov. through Apr. and $13.00 for the months of May through Sep. Average $14.50. The small commercial charge is $29.00 for the months of Nov. through Apr. and $25.00 for the months of May through Sep. Average $27.00.

[7] ATMOS Energy Corp. residential customer charge is $17.15 for the months of Oct through Apr and $14.15 for the months of May through Sep.

Chesapeake Utilities Corporation
Non-Volumetric Ratemaking Approaches – Gas Utilities



Approved Revenue Decoupling – In addition to Decoupling, IL also has SFV

Pending Revenue Decoupling

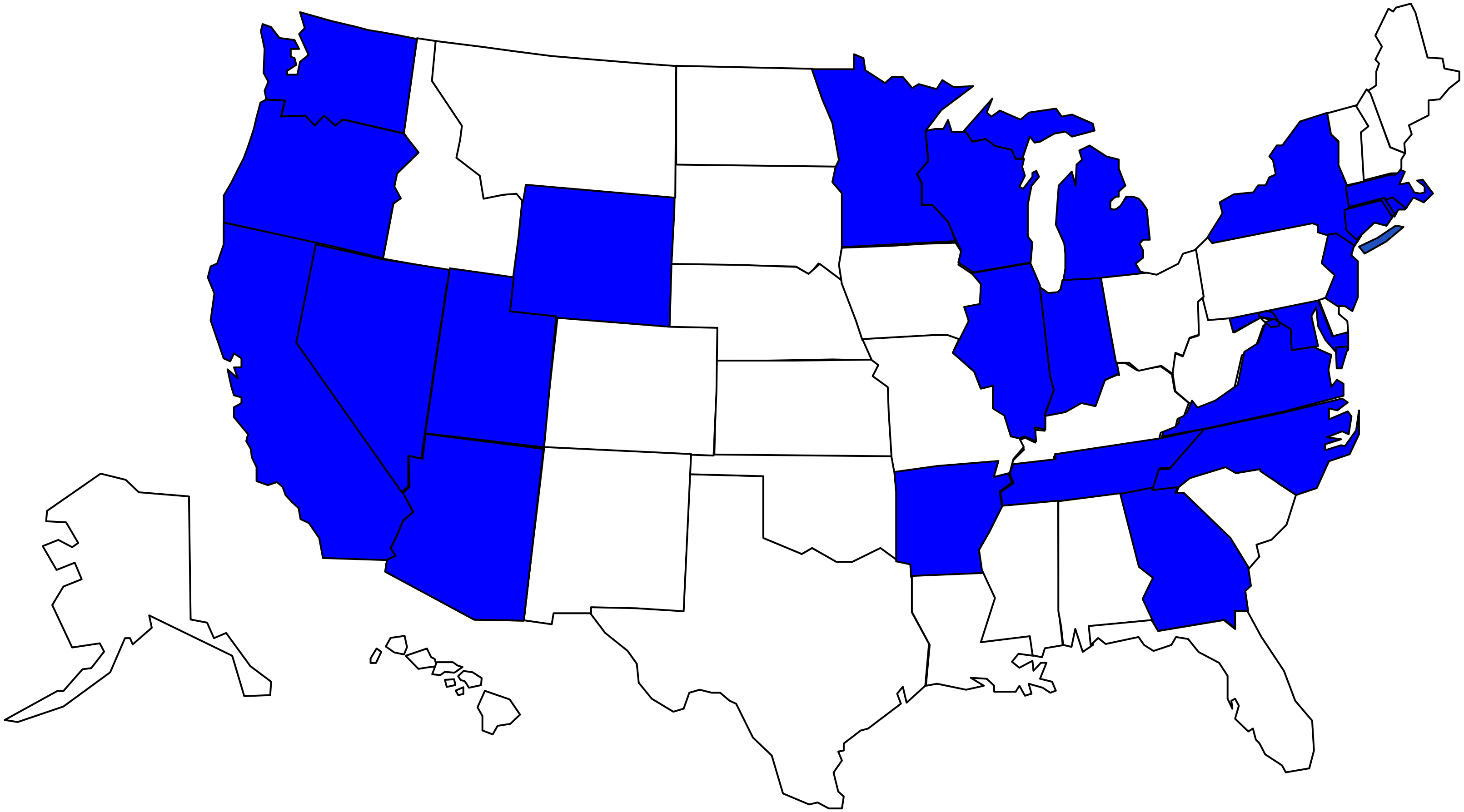
Rate Stabilization Tariff – In addition to Decoupling, TN also has Rate Stabilization

SFV Rate Design – In addition to Rate Stabilization, TX, OK, and GA also have SFV

(1) As of September 2015

Exhibit RJA-6
Schedule 2, page 1 of 1

Chesapeake Utilities Corporation
Approved Revenue Decoupling Mechanisms – Gas Utilities



(1) As of Septmeber 2015

Approved Revenue Decoupling

Approved Revenue Decoupling – Gas Utilities

Utility	State	Year Approved	Type	Applies to All Classes	Revenue/Rate Caps
Arkansas Oklahoma Gas	AR	2007	Full w/WNA	Yes	No
Arkansas Western Gas	AR	2007	Full w/WNA	No	No
CenterPoint Energy	AR	2007	Full w/WNA	No	No
Southwest Gas	AZ	2012	Full	No	Yes
UNS Gas	AZ	2012	Partial	No	Yes
Pacific Gas and Electric	CA	2002	Full	Yes	No
San Diego Gas and Electric	CA	2002	Full	Yes	No
Southern California Gas	CA	2002	Full	Yes	No
Southwest Gas	CA	2002	Full	Yes	No
Connecticut Natural Gas	CT	2014	Full	Yes	No
Liberty Utilities	GA	2011	Full	Yes	No
North Shore Gas Company	IL	2008	Full	No	No
Peoples Gas Light and Coke Company	IL	2008	Full	No	No

Approved Revenue Decoupling – Gas Utilities

Utility	State	Year Approved	Type	Applies to All Classes	Revenue/Rate Caps
Citizens Energy Group	IN	2007	Full	No	No
Vectren Indiana Gas	IN	2006	Full w/WNA	No	No
Vectren Southern Indiana G&E	IN	2006	Full w/WNA	No	No
Boston Gas and Colonial Gas	MA	2010	Full	No	Yes
Columbia Gas of Massachusetts (Bay State Gas)	MA	2009	Full	No	Yes
Fitchburg Gas and Electric	MA	2011	Full	Yes	Yes
New England Gas	MA	2010	Full	No	Yes
National Grid Massachusetts	MA	2011	Full	No	Yes
Liberty Utilities	MA	2010	Full	No	Yes
Columbia Gas of Maryland	MD	2013	Partial	No	Yes
Baltimore Gas and Electric	MD	1998	Full	No	No
Washington Gas Light	MD	2005	Full	No	Yes
Chesapeake	MD	2006	Full	No	No
Integrys Michigan Gas Utilities	MI	2010	Full w/WNA	No	Yes

Approved Revenue Decoupling – Gas Utilities

Utility	State	Year Approved	Type	Applies to All Classes	Revenue/Rate Caps
DTE Energy (Michigan Consolidated Gas)	MI	2010	Full w/WNA	No	No
Michigan Gas Utilities	MI	2015	Partial	No	Yes
CenterPoint Minnesota Gas	MN	2008	Partial	No	Yes
Minnesota Energy Resources	MN	2012	Full	No	Yes
Piedmont Natural Gas	NC	2005	Full	No	No
Public Service Co. of North Carolina	NC	2008	Full	No	No
New Jersey Natural Gas	NJ	2006	Full	No	Yes
South Jersey Gas	NJ	2006	Full	No	Yes
Southwest Gas	NV	2009	Full	No	No
Central Hudson Gas & Electric	NY	2009	Full w/WNA	No	No
Consolidated Edison of New York	NY	2007	Full w/WNA	No	No
Corning Gas	NY	2009	Full w/WNA	No	Yes
National Fuel Gas Distribution	NY	2007	Full w/WNA	No	No
National Grid Long Island (Keyspan Gas)	NY	2009	Full w/WNA	No	Yes

Approved Revenue Decoupling – Gas Utilities

Utility	State	Year Approved	Type	Applies to All Classes	Revenue/Rate Caps
National Grid New York (Brooklyn Union Gas)	NY	2009	Full w/WNA	No	Yes
National Grid Niagara Mohawk	NY	2009	Full w/WNA	No	Yes
New York State Electric & Gas Corporation	NY	2010	Full w/WNA	No	Yes
Orange and Rockland Utilities	NY	2009	Full w/WNA	No	Yes
Rochester Gas and Electric	NY	2009	Full w/WNA	No	Yes
St. Lawrence Gas	NY	2009	Full w/WNA	No	Yes
Cascade Natural Gas	OR	2006	Full	No	No
Northwest Natural Gas	OR	2002	Full w/WNA	No	No
National Grid Narragansett	RI	2012	Full w/WNA	No	No
Chattanooga Gas	TN	2010	Full w/WNA	No	Yes
Questar Gas Company	UT	2006	Full w/WNA	No	Yes
Columbia Gas of Virginia	VA	2009	Full w/WNA	No	No
Virginia Natural Gas	VA	2006	Full w/WNA	No	No
Washington Gas Light	VA	2010	Full w/WNA	No	Yes

Approved Revenue Decoupling – Gas Utilities

Utility	State	Year Approved	Type	Applies to All Classes	Revenue/Rate Caps
Avista Corp.	WA	2006	Partial	No	Yes
Cascade Natural Gas	WA	2006	Partial (Full pending)	No	No
Puget Sound Energy	WA	2013	Full	Yes	Yes
Wisconsin Public Service	WI	2008	Full	No	Yes
Questar Gas Company	WY	2009	Full w/WNA	No	No
SourceGas	WY	2011	Full w/WNA	No	No

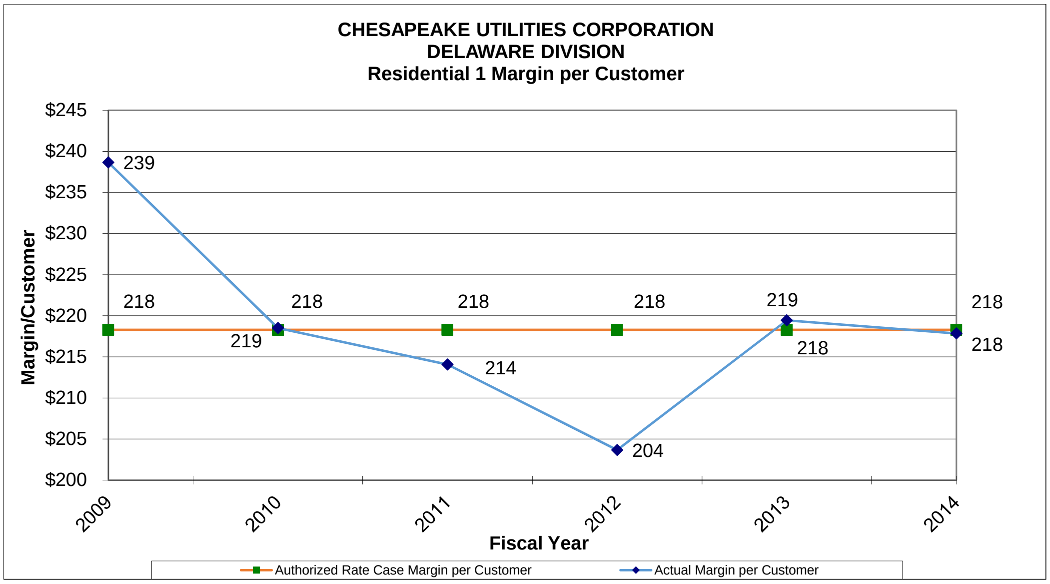
	Average Number of Customers			Actual Throughput (Ccf)		
	RS-1	RS-2	General Service	RS-1	RS-2	General Service
2009	5,953	30,142	2,564	1,578,200	20,701,490	2,475,020
2010	4,678	32,384	2,584	945,840	22,356,970	2,606,060
2011	4,486	33,519	2,594	841,490	22,219,310	2,522,080
2012	4,363	34,580	2,616	644,660	19,323,990	2,016,780
2013	4,802	35,221	2,706	929,970	23,321,100	2,790,420
2014	4,777	36,556	2,736	954,990	25,939,930	3,121,860

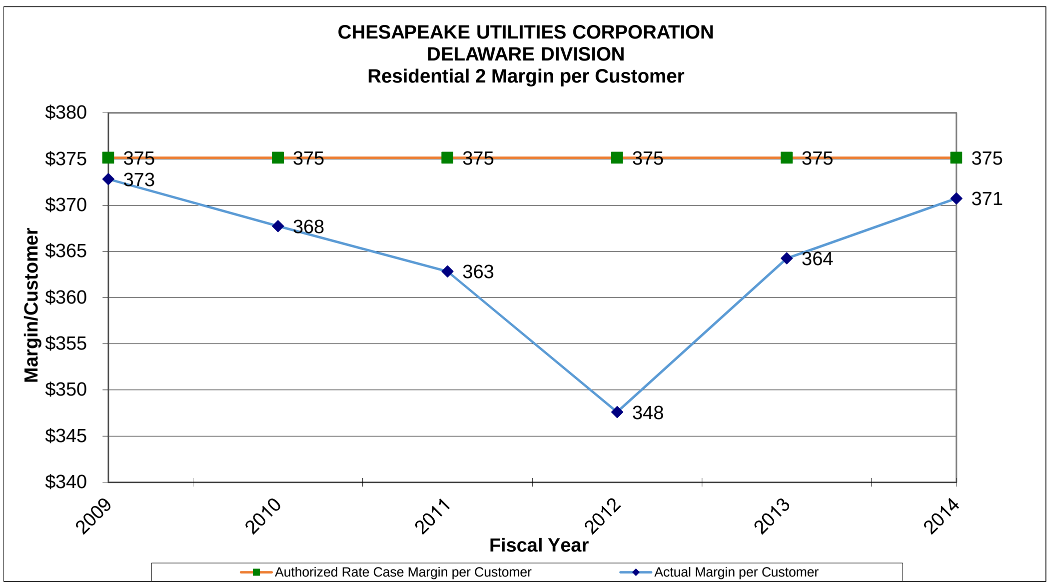
	Normalized Throughput (Ccf) (2)			Heating Degree Days			
	RS-1	RS-2	General Service	AHDD	NHDD(1)	Diff	%
2009	1,553,104	20,210,130	2,409,228	4,729	4,616	113	2.4%
2010	908,315	21,352,545	2,479,876	4,831	4,616	215	4.7%
2011	907,594	24,129,324	2,754,789	4,221	4,616	(395)	-8.6%
2012	755,356	22,716,180	2,420,830	3,936	4,616	(680)	-14.7%
2013	926,028	23,209,317	2,776,897	4,638	4,616	22	0.5%
2014	917,566	24,832,482	2,991,377	4,826	4,616	210	4.5%

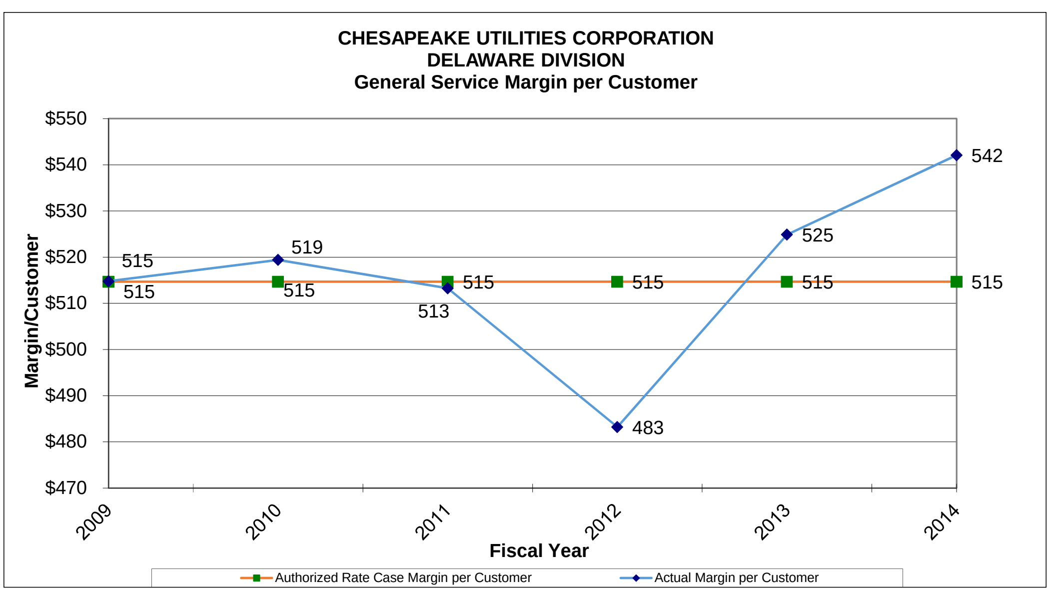
	Authorized Rate Case Use per Customer			Actual Use per Customer			Weather Normalized Use per Customer		
	RS-1	RS-2	General Service	RS-1	RS-2	General Service	RS-1	RS-2	General Service
2009	197	700	961	265	687	965	261	670	940
2010	197	700	961	202	690	1008	194	659	960
2011	197	700	961	188	663	972	202	720	1,062
2012	197	700	961	148	559	771	173	657	925
2013	197	700	961	194	662	1031	193	659	1,026
2014	197	700	961	200	710	1141	192	679	1,093

	Authorized Rate Case Margin per Customer			Actual Margin per Customer			Margin with RNA per Customer		
	RS-1	RS-2	General Service	RS-1	RS-2	General Service	RS-1	RS-2	General Service
2009	$ 218.29	$ 375.14	$ 514.69	$ 238.66	$ 372.83	$ 514.79	$ 241.59	$ 383.00	$ 526.75
2010	$ 218.29	$ 375.14	$ 514.69	$ 218.51	$ 367.74	$ 519.41	$ 216.92	$ 363.43	$ 526.81
2011	$ 218.29	$ 375.14	$ 514.69	$ 214.07	$ 362.83	$ 513.27	$ 217.79	$ 376.72	$ 516.69
2012	$ 218.29	$ 375.14	$ 514.69	$ 203.67	$ 347.61	$ 483.23	$ 211.13	$ 374.27	$ 519.12
2013	$ 218.29	$ 375.14	$ 514.69	$ 219.45	$ 364.25	$ 524.88	$ 222.01	$ 373.47	$ 534.68
2014	$ 218.29	$ 375.14	$ 514.69	$ 217.85	$ 370.74	$ 542.08	$ 218.75	$ 374.77	$ 546.15

Adjusted Twelve Months Ended	Overall ROR	Return on Equity	Approved ROR	Total Rate Base	Return Requirement	Achieved NOI	Return Excess / (Deficiency)	Revenue Excess / (Deficiency)
								1.66871
30-Jun-2015	5.52%	5.70%	8.91%	$ 65,427,754	$ 5,829,613	$ 3,614,198	$ (2,215,415)	$ (3,696,885)
31-Dec-2014	5.42%	5.57%	8.91%	$ 63,392,476	$ 5,648,270	$ 3,435,127	$ (2,213,143)	$ (3,693,093)
31-Dec-2013	8.26%	8.95%	8.91%	$ 57,847,779	$ 5,154,237	$ 4,776,925	$ (377,312)	$ (629,624)
31-Dec-2012	8.87%	9.83%	8.91%	$ 53,623,281	$ 4,777,834	$ 4,758,718	$ (19,116)	$ (31,900)
31-Dec-2011	8.73%	9.75%	8.91%	$ 53,396,661	$ 4,757,643	$ 4,661,772	$ (95,870)	$ (159,980)
31-Dec-2010	8.16%	9.05%	8.91%	$ 52,705,256	$ 4,696,038	$ 4,301,571	$ (394,467)	$ (658,252)
31-Dec-2009	7.48%	7.95%	8.91%	$ 54,008,985	$ 4,812,201	$ 4,041,476	$ (770,724)	$ (1,286,116)
							$ (6,086,048)	$ (10,155,850)


CHESAPEAKE UTILITIES CORPORATION
DELAWARE DIVISION
Residential 1 Margin per Customer
Margin/Customer
Fiscal Year
$245
$240
$235
$230
$225
$220
$215
$210
$205
$200
2009
2010
2011
2012
2013
2014
239
218
218
218
218
219
218
219
214
204
218
218
Authorized Rate Case Margin per Customer
Actual Margin per Customer


CHESAPEAKE UTILITIES CORPORATION
DELAWARE DIVISION
Residential 2 Margin per Customer
Margin/Customer
Fiscal Year
$380
$375
$370
$365
$360
$355
$350
$345
$340
2009
2010
2011
2012
2013
2014
375
375
375
375
375
375
373
368
363
348
364
371
Authorized Rate Case Margin per Customer
Actual Margin per Customer


CHESAPEAKE UTILITIES CORPORATION
DELAWARE DIVISION
General Service Margin per Customer
Margin/Customer
Fiscal Year
$550
$540
$530
$520
$510
$500
$490
$480
$470
2009
2010
2011
2012
2013
2014
515
515
519
515
515
513
515
515
515
483
525
542
Authorized Rate Case Margin per Customer
Actual Margin per Customer

Chesapeake Utilities Corporation
Delaware Division
Calculation of Quarterly Revenue Normalization Adjustment (DEMONSTRATION TEMPLATE)
Billing Months of Apr-14, May-14, Jun-14

Line No.	Revenue Normalization Adjustment	Current Quarter	1st Quarter 2014	4th Quarter 2013	3rd Quarter 2013	Annual True-Up	Total
1	Quarterly True-Up (line 8 + line 13)	$361,961					
2	Projected Firm Sales Volumes (Ccf) (line 28)	27,546,407					
3	Revenue Normalization Adjustment per Ccf (line 1/line 2) [1]	$0.013	($0.006)	$0.033	$0.016	$0.015	**$0.057**

[1] Negative = Surcharge / Positive = Credit

Starting Month	Apr-14

Line No.	Description	Estimated (Last Quarter Filing) Mar-14 RS1	RS1-E	RS2	RS2-E	GS	GS-E	Actual Mar-14 RS1	RS1-E	RS2	RS2-E	GS	GS-E	True-Up (Actual - Estimated) Mar-14 RS1	RS1-E	RS2	RS2-E	GS	GS-E	Quarter True-Up Total
4	Normalized Margin per Customer (Rate Case)	27.43	33.43	50.13	68.88	65.90	95.90	27.43	33.43	50.13	68.88	65.90	95.90							
5	Actual Margin per Customer	$26.09	$35.75	$44.30	$60.59	$65.70	$80.04	$ 25.83	$35.39	$ 43.86	$ 59.99	$ 65.05	$ 79.24							
6	Difference per Customer (line 5 - line 4)	$ (1.33)	$ 2.32	$ (5.83)	$ (8.29)	$ (0.20)	$ (15.87)	$ (1.59)	$ 1.97	$ (6.27)	$ (8.89)	$ (0.86)	$ (16.66)							
7	Number of Customers	5,020	12	36,579	89	2,826	9	5,020	12	36,579	89	2,826	9							
8	RNA Adjustment (line 6 * line 7)	($6,693)	$28	($213,353)	($738)	($579)	($143)	($7,990)	$24	($229,396)	($791)	($2,417)	($150)	($1,297)	($4)	($16,043)	($53)	($1,838)	($7)	($19,242)

Line No.	Description	Actual Apr-14 RS1	RS1-E	RS2	RS2-E	GS	GS-E	Actual May-14 RS1	RS1-E	RS2	RS2-E	GS	GS-E	Estimated Jun-14 RS1	RS1-E	RS2	RS2-E	GS	GS-E	Quarter True-Up Total
9	Normalized Margin per Customer (Rate Case)	19.55	25.55	34.63	53.38	45.64	75.64	14.76	20.76	23.30	42.05	34.50	64.50	12.44	18.44	17.45	36.20	29.67	59.67	
10	Actual Margin per Customer	$ 21.00	$32.13	$ 36.66	$ 55.92	$ 51.14	$ 66.86	$ 15.72	$24.06	$ 27.88	$ 42.89	$ 38.10	$ 59.29	$ 12.82	$22.69	$ 20.20	$ 35.81	$ 30.73	$ 56.45	
11	Difference per Customer (line 10 - line 9)	$ 1.44	$ 6.57	$ 2.03	$ 2.54	$ 5.50	$ (8.78)	$ 0.97	$ 3.30	$ 4.58	$ 0.84	$ 3.60	$ (5.20)	$ 0.38	$ 4.26	$ 2.75	$ (0.39)	$ 1.05	$ (3.22)	
12	Number of Customers	4,997	12	36,564	103	2,796	9	4,845	12	36,158	111	2,740	9	4,834	12	36,084	123	2,700	9	
13	RNA Adjustment (line 11 * line 12)	$7,212	$79	$74,136	$262	$15,383	($79)	$4,682	$40	$165,630	$93	$9,871	($47)	$1,849	$51	$99,276	($48)	$2,842	($29)	$381,203

Line No.	Description	Projected RS1	RS1-E	RS2	RS2-E	GS	GS-E	Total
	Normalized Ccf/Customer (Next 12 Months)							
14	Jul-14 Normalized Ccf/Customer	3.36	3.03	10.65	9.58	14.62	13.16	54.40
15	Aug-14 Normalized Ccf/Customer	2.98	2.69	9.25	8.33	12.25	11.02	46.52
16	Sep-14 Normalized Ccf/Customer	2.96	2.66	9.11	8.20	13.37	12.03	48.33
17	Oct-14 Normalized Ccf/Customer	3.85	3.46	16.01	14.41	21.23	19.11	78.08
18	Nov-14 Normalized Ccf/Customer	9.12	8.21	44.34	39.91	50.24	45.22	197.04
19	Dec-14 Normalized Ccf/Customer	20.77	18.70	88.43	79.59	129.30	116.37	453.17
20	Jan-15 Normalized Ccf/Customer	30.65	27.59	122.76	110.48	194.06	174.65	660.19
21	Feb-15 Normalized Ccf/Customer	37.81	34.03	138.70	124.83	231.42	208.28	775.07
22	Mar-15 Normalized Ccf/Customer	31.40	28.26	111.99	100.79	203.07	182.76	658.26
23	Apr-15 Normalized Ccf/Customer	16.80	15.12	65.24	58.72	99.95	89.95	345.77
24	May-15 Normalized Ccf/Customer	7.90	7.11	31.06	27.96	43.24	38.92	156.18
25	Jun-15 Normalized Ccf/Customer	3.60	3.24	13.42	12.08	18.70	16.83	67.86
26	Total Normalized Ccf/Customer	171	154	661	595	1,031	928	3,540.85
27	Current Customer Count (as of Jun-15)	4,834	12	36,084	123	2,700	9	43,762
28	Firm Sales Volume (Ccf) (line 26 * line 27)	827,511	1,849	23,850,626	73,170	2,784,897	8,355	27,546,407

Chesapeake Utilities Corporation
Delaware Division
Calculation of Annual Revenue Normalization Adjustment (DEMONSTRATION TEMPLATE)

Annual Revenue Normalization Adjustment to be Effective January 1, 2014

		Projected to Be Collected			**Actually Collected**			**Monthly**
Line No.		Ccf	RNA Rate	Amount	Ccf	RNA Rate	Amount	**(Over)/Under**
1	Jul	262,958	0.066347	$ 17,447	421,550	0.0663	$ 27,949	$ 10,502
2	Augst	224,875	0.066347	$ 14,920	411,900	0.0663	$ 27,309	$ 12,389
3	Sep	233,618	0.066347	$ 15,500	424,410	0.0663	$ 28,138	$ 12,638
4	3rd Quarter 2012	721,451	0.066347	$ 47,866	1,257,860	0.0663	$ 83,396	$ 35,530
5								
6	Oct	377,416	0.121459	$ 45,840	648,740	0.1215	$ 78,822	$ 32,981
7	Nov	952,474	0.121459	$ 115,686	2,201,120	0.1215	$ 267,436	$ 151,750
8	Dec	2,190,609	0.121459	$ 266,069	3,339,210	0.1215	$ 405,714	$ 139,645
9	4th Quarter 2012	3,520,498	0.121459	$ 427,595	6,189,070	0.1215	$ 751,972	$ 324,377
10								
11	Jan	3,191,381	-0.00817	$ (26,061)	4,647,470	-0.0082	$ (38,109)	$ (12,048)
12	Feb	3,746,674	-0.00817	$ (30,595)	5,412,640	-0.0082	$ (44,384)	$ (13,788)
13	Mar	3,182,017	-0.00817	$ (25,984)	4,630,820	-0.0082	$ (37,973)	$ (11,988)
14	1st Quarter 2013	10,120,072	-0.00817	$ (82,641)	14,690,930	-0.0082	$ (120,466)	$ (37,825)
15								
16	Apr	1,671,434	0.036935	$ 61,734	2,976,540	0.0369	$ 109,834	$ 48,100
17	May	754,956	0.036935	$ 27,884	1,143,660	0.0369	$ 42,201	$ 14,317
18	Jun	328,046	0.036935	$ 12,116	602,780	0.0369	$ 22,243	$ 10,126
19	2nd Quarter 2013	2,754,436	0.036935	$ 101,734	4,722,980	0.0369	$ 174,278	$ 72,544
20								

21	Annual (Over)/Under	$ 394,625
22	Projected 12 Months of Firm Sales Volume (Ccf) - Starting January	26,829,293
23	Annual Revenue Normalization Adjustment	$ 0.0147
24		

		RS1	RS1-E	RS2	RS2-E	GS	GS-E	Total
25		RS1	RS1-E	RS2	RS2-E	GS	GS-E	Total
26	Weather Normalized Use Per Customer	171.19	154.07	660.98	594.88	1,031.44	928.30	
27	Current Customer Count (as of October 2013)	4,776	12	35,146	90	2,639	4	
28	12 Months of Firm Sales Volume (Ccf)	817,582	1,849	23,230,631	53,539	2,721,979	3,713	26,829,293

RS1, RS2, and GS - Combined

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
	Customer Count	Target Margin	Actual Margin	Shortfall (Surplus)	% of Margin	Actual Throughput (Ccf)	Expected Throughput (Ccf)	RNA per Ccf (Next 12 Months)	Margin with RNA
1st Quarter 2009	38,958	$ 5,943,488	$ 5,159,335	$ 784,153	15%	14,235,200	13,449,350		$ 5,159,335
2nd Quarter 2009	38,563	$ 2,811,283	$ 3,122,528	(311,244)	-10%	3,955,910	3,885,036	0.033	$ 3,252,238
3rd Quarter 2009	38,210	$ 1,874,898	$ 2,235,517	(360,618)	-16%	1,291,400	1,020,967	0.020	$ 2,261,216
4th Quarter 2009	38,902	$ 3,332,768	$ 3,460,918	(128,150)	-4%	5,272,200	5,088,734	0.038	$ 3,660,163
1st Quarter 2010	39,828	$ 6,215,517	$ 5,341,295	874,222	16%	15,272,940	13,920,297	(0.005)	$ 5,046,741
2nd Quarter 2010	39,419	$ 2,924,785	$ 3,020,858	(96,074)	-3%	3,246,060	4,117,893	0.030	$ 3,070,496
3rd Quarter 2010	39,265	$ 1,946,721	$ 2,273,102	(326,381)	-14%	1,251,490	1,079,547	0.021	$ 2,280,991
4th Quarter 2010	40,073	$ 3,439,795	$ 3,638,104	(198,309)	-5%	6,138,380	5,436,605	0.032	$ 3,747,362
1st Quarter 2011	40,977	$ 6,411,790	$ 5,443,084	968,707	18%	15,354,940	14,385,036	(0.008)	$ 5,535,726
2nd Quarter 2011	40,516	$ 3,011,560	$ 3,241,176	(229,616)	-7%	4,203,190	4,254,070	0.030	$ 3,426,005
3rd Quarter 2011	40,050	$ 1,987,633	$ 2,293,023	(305,390)	-13%	1,242,270	1,113,937	0.013	$ 2,326,828
4th Quarter 2011	40,851	$ 3,520,780	$ 3,475,958	44,822	1%	4,782,480	5,578,797	0.023	$ 3,655,984
1st Quarter 2012	41,828	$ 6,578,764	$ 4,912,593	1,666,172	34%	11,402,170	14,761,353	0.002	$ 4,927,005
2nd Quarter 2012	41,345	$ 3,085,560	$ 3,095,185	(9,625)	0%	3,140,630	4,377,202	0.065	$ 3,297,844
3rd Quarter 2012	41,076	$ 2,041,852	$ 2,348,564	(306,712)	-13%	1,257,710	1,145,819	0.066	$ 2,431,432
4th Quarter 2012	41,988	$ 3,600,078	$ 3,816,847	(216,770)	-6%	6,184,920	5,770,349	0.121	$ 4,565,222
1st Quarter 2013	42,940	$ 6,718,412	$ 5,500,752	1,217,660	22%	14,680,730	15,040,415	(0.008)	$ 5,423,467
2nd Quarter 2013	42,614	$ 3,168,248	$ 3,520,544	(352,297)	-10%	4,715,540	4,456,461	0.037	$ 3,708,507
3rd Quarter 2013	42,170	$ 2,092,709	$ 2,404,646	(311,938)	-13%	1,294,630	1,172,294	0.016	$ 2,428,873
4th Quarter 2013	43,195	$ 3,706,606	$ 3,877,683	(171,077)	-4%	6,350,590	5,876,183	0.033	$ 4,106,455
1st Quarter 2014	44,285	$ 6,931,009	$ 5,994,923	936,087	16%	17,388,470	15,493,717	(0.006)	$ 5,897,041
2nd Quarter 2014	43,906	$ 3,264,018	$ 3,650,748	(386,730)	-11%	4,963,130	4,598,178	0.027	$ 3,788,793
3rd Quarter 2014	43,474	$ 2,155,772	$ 2,465,949	(310,178)	-13%	1,306,730	1,208,224	0.007	$ 2,476,131
4th Quarter 2014	44,607	$ 3,847,243	$ 3,964,632	(117,389)	-3%	6,358,450	6,059,645	0.017	$ 4,077,081
1st Quarter 2015							16,133,083		
2nd Quarter 2015							4,673,874		
3rd Quarter 2015							1,236,992		
4th Quarter 2015							6,266,688		

Annual Summary	Annual True-Up	Annual RNA per Ccf	Targeted Margin	Actual Margin	Margin with RNA
2009	(370,514)	(0.016)	13,962,437	13,978,297	14,332,951.77
2010	381,227	0.016	14,526,817	14,273,360	14,145,589.90
2011	(12,780)	(0.001)	14,931,762	14,453,241	14,944,542.42
2012	84,751	0.003	15,306,254	14,173,189	15,221,502.88
2013	18,672	0.001	15,685,975	15,303,625	15,667,302.69
2014	(41,005)	(0.001)	16,198,042	16,076,252	16,239,047.00

BEFORE THE

PUBLIC SERVICE COMMISSION

OF DELAWARE

CASE NO. __________

CHESAPEAKE UTILITIES CORPORATION

Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Concerning Cost of Capital

Chesapeake Utilities Corporation
Direct Testimony of Paul R. Moul
Table of Contents

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
CE	Comparable Earnings
DCF	Discounted Cash Flow
g	Growth rate
IGF	Internally Generated Funds
IRR	Internal Rate of Return
LDC	local distribution companies
Lev	Leverage modification
LIBOR	London Interbank Offered Rate
LT	Long Term
M&M	Modigliani & Miller
MPL	Minimum Pension Liability
NAIC	National Association of Insurance Commissioners
OCI	Other Comprehensive Income
P-E	Price earnings
PSC	Public Service Commission of Delaware
r	represents the expected rate of return on common equity
RDM	Revenue Decoupling Mechanism
Rf	Risk-free rate of return
Rm	Return on the market
RP	Risk Premium
s	Represents the new common shares expected to be issued by a firm
SBBI	Stocks, Bonds, Bills and Inflation

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
s x v	Represents external growth
S&P	Standard & Poor's
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value
RNM	Revenue Normailization Mechanism

DIRECT TESTIMONY OF PAUL R. MOUL

INTRODUCTION AND SUMMARY OF RECOMMENDATION

Q. Please state your name, occupation and business address.

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

Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate rate of return that the Public Service Commission of Delaware ("PSC" or the "Commission") should recognize in the determination of the revenues that Chesapeake Utilities Corporation ("Chesapeake" or the "Company") should be authorized as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in Attachments PRM-1 through PRM-15 which accompany my direct testimony.

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

A. My conclusion is that the Company's cost of common equity is 11.00%. With this return, I have presented on page 1 of Attachment PRM-1 the weighted average cost of capital, which is 8.55% for Chesapeake. The resulting overall cost of capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should, if adopted by the Commission, establish a compensatory level of return for the use of capital and provide the Company with the ability to attract capital on reasonable terms.

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

A. In 2014, the Company's three divisions and its wholly-owned Florida subsidiary provide natural gas service to approximately 141,000 customers in central and southern Delaware, Maryland's Eastern Shore, and in Florida. The Company's Florida subsidiary provides electric delivery service to approximately 31,000 customers. In its Delaware division, the Company serves approximately 45,000 customers. Throughput to these customers was represented by approximately 34% to residential sales customers and 66% to commercial and industrial sales and transportation customers.

The Company's flowing gas is provided by transportation arrangements with Eastern Shore Natural Gas Company ("Eastern Shore"), another wholly-owned subsidiary. Eastern Shore also serves other utilities and industrial customers in Pennsylvania, Delaware and the Eastern Shore of Maryland. In addition, the Company's propane distribution and wholesale marketing segment provides distribution service to approximately 53,300 customers in central and southern Delaware, the Eastern Shore of Maryland, southeastern Pennsylvania, central Florida, and the Eastern Shore of Virginia. It also markets propane to wholesale customers including large independent oil and petrochemical companies, resellers and propane distribution companies in the southeastern United States.

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

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity for a natural gas utility, such as Chesapeake. In this regard, I relied on four (4) well-recognized measures of the cost of equity: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach. The results of a variety of approaches indicate that the Company's cost of common equity is 11.00%.

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

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

Q. What approach have you used in measuring the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from my proxy group of

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

nine natural gas companies. The proxy group consists of natural gas companies that: (i) are engaged in the natural gas distribution business, (ii) have publicly-traded common stock, (iii) are contained in The Value Line Investment Survey, and (iv) are not currently the target of a merger or acquisition. From the natural gas utilities covered by the basic service of Value Line, I excluded three companies. The eliminations were: AGL Resources due to the announced acquisition of it by Southern Company, NiSource Inc. due to its electric operations and recent separation of the former natural gas pipeline/storage operations, and UGI Corp. due to its highly diversified businesses. I should note that subsequent to the selection of the members of the Gas Group, Duke Energy Corp. struck a $4.9 billion deal to acquire Piedmont Natural Gas Co. The offer represented a premium of 40.0% to the stock price of Piedmont on October 23, 2015. However, this event does not have an impact on my cost of equity analysis because it post-dated the market data that I used in my analysis that ended on August 31, 2015. The companies in the proxy group are identified on page 2 of Attachment PRM-3. I will refer to these companies as the "Gas Group" throughout my testimony.

Q. How have you performed your cost of equity analysis with the market data for the Gas Group?

A. I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not separately measured the cost of equity for the individual companies within the Gas Group, because the determination of the cost of equity for an individual company has become increasingly problematic. By employing group average data, rather than individual companies' analysis, I have helped to minimize the effect of extraneous influences on the market data for an individual company.

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, any single method can provide an incomplete measure of the cost of equity depending upon extraneous factors that may influence market sentiment. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches, as shown on page 2 of Attachment PRM-1.

Gas Group	Excluding Flotation Costs	Including Flotation Costs [1]
DCF	9.97%	10.12%
Risk Premium	11.25%	11.40%
CAPM	11.89%	12.04%
Comparable Earnings	12.80%	12.80%
Average	11.48%	11.59%
Median	11.57%	11.72%
Mid-point	11.39%	11.46%

Focusing upon the market model approaches to estimating the cost of equity (i.e., DCF, RP and CAPM), the average equity return is 11.04% (9.97% + 11.25% +

[2] Flotation costs are defined as the out-of-pocket costs associated with the issuance of common stock. Those costs typically consist of the underwriters' discount and company issuance expenses.

11.89% = 33.11% ÷ 3), excluding flotation costs. From the results of these models, I recommend that the Commission set the Company's rate of return on common equity at 11.00%. I also believe my recommended cost of equity is appropriate because it makes no provision for the prospect that the rate of return may not be achieved due to unforeseen events that could occur during the rate effective period.

NATURAL GAS RISK FACTORS

Q. What factors currently affect the business risk of the natural gas utilities?

A. Gas utilities face risks arising from competition, economic regulation, the business cycle, and customer usage patterns. Today, they operate in a more complex environment with time frames for decision-making considerably shortened. Their business profile is influenced by market-oriented pricing for the commodity distributed to customers and open access for the transportation of natural gas for customers.

Natural gas utilities have focused increased attention on safety and reliability issues and on conservation and energy efficiency. In order to address these issues and to comply with new and pending pipeline safety regulations, natural gas companies are now allocating more of their resources to addressing aging infrastructure issues, which have led to increased external capital requirements.

Q. Does the Company face competition in its natural gas business?

A. Yes. Natural gas faces significant competition from alternative energy sources. The Company faces direct competition from electricity, fuel oil, and propane in its service territory. Propane and fuel oil have an advantage because they are not inhibited by regulatory constraints when conducting their marketing activities. This situation is unlike that of Chesapeake where specific thresholds must be satisfied for system expansions, and where promotional activities are constrained.

Q. How does the Company's throughput to industrial and transportation customers affect its risk profile?

A. The Company's risk profile is influenced by natural gas sold/delivered to industrial and transportation customers. The throughput to the Company's top ten customers represented 565,544 mcfs, or approximately 7% of throughput. Success in this aspect of the Company's market is subject to the business cycle, the price of alternative energy sources, and pressures from the competitors. Moreover, external factors can also influence the Company's throughput to these customers which face competitive pressure on its operations from facilities located outside the Company's service territory.

Q. Please indicate how its construction program affects the Company's risk profile.

A. The Company is faced with the requirement to undertake investments to maintain and upgrade existing facilities in its service territory. To maintain safe and reliable service to existing customers, the Company must invest to upgrade its infrastructure. The rehabilitation of the Company's infrastructure represents a non-revenue producing use of capital. The Company's Delaware Division had 10.801 miles of its distribution mains constructed of unprotected steel pipe as of year-end 2014. The Company projects its construction expenditures in the Delaware Division will be:

Year	Capital Expenditures
2015	14,632,739
2016	18,044,467
2017	16,015,181
Total	$48,692,387

Over the next three years, these capital expenditures will represent approximately 56% ($48,692,387 ÷ $87,595,060) of the net utility plant in service at December 31, 2014.

Q. Does your cost of equity analysis and recommendation take into account the Revenue Normalization Mechanism ("RNM") that the Company is proposing in this case?

A. Yes. The Company proposes to include in its tariff the RNM that is intended to "decouple" the recovery of the revenues for a given customer class from usage of the customers in that class. My cost of equity analysis that provides an 11.00% rate of return on common equity takes into account the Company's proposal.

Q. Do the LDCs included in your Gas Group already have tariff mechanisms similar to the RNM?

A. The LDCs included in my Gas Group already have tariff mechanisms similar to decoupling, and therefore my analysis already reflects the impact of decoupling on investor expectations through the use of market-determined models. All but one of the companies in my Gas Group has some form of revenue decoupling mechanism ("RDM") that deals with abnormal temperature situations, as does the Company's proposed RNM. The sole exception is Laclede, which does not have an RDM in Missouri but does have a weather mitigated rate design that recovers its fixed costs more evenly during the heating season. This rate is designed to accomplish more assured recovery of fixed costs in spite of variations in sales, which is the intent of decoupling of revenues from variations in sales due to weather. As a group, the market prices of these companies' common equity reflect the expectations of investors that the companies' revenues are stabilized to some extent by decoupling or other mechanisms. Therefore my analysis reflects the impacts of RNM on investor expectations through the use of market-determined models. As such, the market prices of these companies' common stocks reflect the expectations of investors related to a regulatory mechanism that adjusts revenues for conservation, abnormal weather, and other items. The trend in the industry is to stabilize the recovery of fixed costs, which are unaffected by usage. Indeed, there has been a proliferation of tracking mechanisms in the LDC business. Since my Gas Group that I use to measure the cost of equity has the risk attributes related to the RDM "baked in" to their stock prices, absent the benefit of the RDM would increase the cost of equity as determined by the models that are applied with the Gas Group data.

Q. How do investors assess the risk to an LDC for variations in customer usage under conditions of normal weather, which the RNM is designed to accommodate, among other factors?

A. Investors in a gas utility can only formulate reasonable expectations based upon normal weather, although achieved results may vary significantly from those expectations from year to year due to variations in weather. That is to say, a rational investor in a gas utility can only anticipate, and base his or her analyses on normal temperature conditions. The financial theory upon which the cost of equity is based recognizes that investors value their investments on a long-term basis covering a number of years, not just one year. For example, the DCF formula explicitly assumes a growth rate "approaching infinity." Additionally, as I will discuss later, analysts' forecasts of utilities' earnings and dividend growth, which investors take into account in making investment decisions, typically are provided on a five-year basis. Weather, by definition, is normal over the long-term or multi-year period, although it may vary significantly from year to year. Moreover, one of the standard models of the cost of equity (i.e., CAPM) suggests that there is no measurable effect on the cost of equity because weather represents a company-specific risk, which does not receive compensation in the CAPM. Therefore, the theories and models underlying my cost of capital analysis obviate the need for any adjustments based upon short-term phenomena such as weather variations which have no long-term effect. Accordingly, over the long term, the investor required cost of capital or discount rate assumed for an investment in a gas utility would be the same either with or without a RNM.

Q. How should the Commission respond to the issues facing the natural gas utilities and in particular Chesapeake?

A. As previously noted, a fair rate of return for the Company represents a key to a financial profile that will provide the Company with the ability to raise the capital necessary to meet its capital needs on an ongoing basis. In the situation where additional capital is required, as shown by the construction expenditures indicated above, the regulatory process must establish a return on equity that provides a reasonable opportunity for the Company to actually achieve its cost of capital. The Commission should recognize and take into account the competitive environment in the natural gas business in determining the cost of capital for the Company and provide a reasonable opportunity for the Company to actually achieve its cost of capital.

FUNDAMENTAL RISK ANALYSIS

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

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors that bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. For this purpose, I compared Chesapeake to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and to the Gas Group.

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

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

Q. What companies comprise the gas group?

A. My Gas Group obtained from the Value Line publication consists of the following companies: Atmos Energy Corp., Chesapeake Utilities Corp., Laclede Group, New Jersey Resources Corp., Northwest Natural Gas, Piedmont Natural Gas Co., South Jersey Industries, Inc., Southwest Gas Corp., and WGL Holdings, Inc. As noted previously, Piedmont Natural Gas was retained in the Gas Group because the market evidence that I used predates the announcement that Duke Energy would acquire the company.

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

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

Q. How do the bond ratings compare for Chesapeake, the Gas Group, and the S&P Public Utilities?

A. There is no public rating on the debt of Chesapeake. The Company's long-term debt carries a designation of "1" from the National Association of Insurance Commissioners ("NAIC"), which is equivalent to all of the A ratings (i.e., AAA, AA, A and Aaa, Aa, A) by Standard & Poor's Corporation ("S&P") and Moody's Investors Service ("Moody's") -- both national recognized credit rating agencies. It is important, therefore, that the Company experience an opportunity to achieve an adequate rate of return so that its credit quality conforms to the standards for the A credit quality. Presently, the average corporate credit rating ("CCR") for the Gas Group is A- from S&P and the Long Term ("LT") issuer rating is A2 from Moody's. The CCR designation by S&P and LT issuer rating by Moody's focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. For the S&P Public Utilities, the average composite rating is BBB+ by S&P and A3 by Moody's. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. How do the financial data compare for Chesapeake, the Gas Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Attachments PRM-2, PRM-3, and PRM-4. The data cover the five-year period 2010-2014. The important categories of relative risk may be summarized as follows:

<u>Size.</u> In terms of capitalization, Chesapeake is smaller than the average size of the Gas Group, which itself is a group of relatively small size companies. The average size of the S&P Public Utilities is much larger than the Gas Group, and the Gas Group is larger than Chesapeake. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity. This is the case for Chesapeake compared to the Gas Group, and the Gas Group compared to the S&P Public Utilities.

<u>Market Ratios.</u> Market-based financial ratios provide a partial indication of

the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return on equity for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.

Chesapeake's five-year average price-earnings multiple was somewhat lower than that of the average of the Gas Group. The five-year average price-earnings multiple for the Gas Group was fairly similar to that of the S&P Public Utilities. The five-year average dividend yield for Chesapeake was lower than the average of the Gas Group. The five-year average dividend yield for the S&P Public Utilities was higher. The five-year average market-to-book ratio was somewhat similar for Chesapeake and the Gas Group, but higher than the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 68.2% for Chesapeake, 57.0% for the Gas Group, and 45.3% for the S&P Public Utilities.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.034 (0.4% ÷ 11.8%) for Chesapeake, 0.066 (0.7% ÷ 10.6%) for the Gas Group, and 0.102 (1.0% ÷ 9.8%) for the S&P Public Utilities.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income taxes). The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin. The five-year average operating ratios were 86.3% for Chesapeake, 87.8% for the Gas Group, and 81.3% for the S&P Public Utilities.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average interest coverage (excluding Allowance for Funds Used During Construction ("AFUDC")") was 6.60 times for Chesapeake, 4.86 times for the Gas Group, and 3.19 times for the S&P Public Utilities.

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

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 96.8% for Chesapeake, 86.8% for the Gas Group, and 87.5% for the S&P Public Utilities.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[3] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of .65 for Chesapeake, .78 as the average for the Gas Group (see page 2 of Attachment PRM-3), and .77 as the average for the S&P Public Utilities (see page 3 of Attachment PRM-4).

Q. Please summarize your risk evaluation of the Company and the Gas Group.

A. The risk of Chesapeake parallels that of the Gas Group in certain respects with regard to historical financial performance. However, the Company's small size adds to its risk. As such, the cost of equity derived from the Gas Group would tend

[3] The procedure used to calculate the beta coefficient published by Value Line is described on page 3 of Schedule 15. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

to provide a conservative measure for the Company's cost of equity.

CAPITAL STRUCTURE RATIOS

Q. Please explain the selection of capital structure ratios for Chesapeake.

A. It is appropriate that Chesapeake's capital structure ratios be employed for rate of return purposes. Furthermore, consistency requires that the embedded cost rate of the Company's senior securities also be employed. This procedure is consistent with the ratesetting procedures used by the Commission in prior rate cases for Chesapeake.

Q. Does Attachment PRM-5 provide the Company's capitalization and capital structure ratios?

A. Yes. Attachment PRM-5 presents the Company's capitalization and related capital structure ratios based upon investor-provided capital. The June 30, 2015 capitalization corresponds with the end of the historical period and March 31, 2016 is pro forma for the test year in this case. Attachment PRM-5 contains a ratesetting adjustment to remove the accumulated Other Comprehensive Income ("OCI") from the Company's common equity account. I have also excluded the debt and capital lease obligations of subsidiary companies that are not associated with utility operations of Chesapeake. It also shows the pro forma adjustments used to develop the March 31, 2016 capitalization. Those adjustments relate to principal repayments on debt, the issuance of new long-term debt and common stock, as well as a forecast of year-end retained earnings.

Q. Please explain the justification for removing the accumulated OCI?

A. The accumulated OCI must be eliminated from the capital structure for ratesetting purposes. OCI arises from a variety of sources, including: minimum pension liability ("MPL"), foreign currency hedges, unrealized gains and losses on securities available for sale, interest rate swaps, and other cash flow hedges. The accumulated OCI for the Company has its roots in the MPL and commodity contracts cash flow hedges. None of the accounting entries that affect accumulated OCI have anything to do with financing the rate base of the Company (i.e., they do not generate or consume any cash). A MPL entry must be recorded on the balance sheet when the present value of the pension benefit earned by employees exceeds the market value of trust fund assets. As such, MPL arises from changes in stock market values and interest rates, which impacts the value of the trust fund assets, as well as the present value of the pension benefit obligation. SFAS 87 requires that the MPL be recognized as a pension expense over future periods, as long as the MPL continues to exist. If the stock market improves and when interest rates rise from recent low levels, the MPL will reverse and not impact future pension expense. Hence, the accumulated OCI must be excluded from the common equity.

Q. What financing arrangements are currently in place for Chesapeake?

A. On October 8, 2015, the Company established a Private Shelf Agreement with Prudential Investment Management for the issuance of up to $150 million of senior promissory notes. This agreement extends for three-years and has been approved by the Commission. On this date, the Company also entered into a revolving Credit Agreement with a group of five banks that provide a five-year credit facility of $150 million, having both a long-term and short-term pricing option. The Company also has the ability to issue additional common equity pursuant to an SEC Form S-4 registration statement filed on December 12, 2014 for the sale of up to 790,769 common shares.

Q. What pro forma financings have you reflected on Attachment PRM-5?

A. I have reflected a $130 million issue of senior notes and $33.5 million of additional common equity in the pro forma capital structure. It is expected that the debt issue will occur in two tranches in 2016. The first tranche of $70 million will occur in the first quarter of 2016 and the second tranche of $60 million will occur later in 2016. These debt issues will be used to repay a portion of short-term debt that has been incurred to finance utility plant additions. As noted above, Chesapeake Utilities already has in place a commitment with Prudential Investment Management that will fund most of the long-term debt needs associated with those projects. As to the common equity financing, Chesapeake Utilities plans to issue $70 million of new common equity to investors. The issuance costs associated with that financing is expected to be approximately $3 million. This will provide Chesapeake Utilities with approximately $67 million of net proceeds. One-half of that amount, or $33.5 million, has been reflected in the pro forma capital structure, which provides the common equity component necessary to permanently finance its large capital expenditure program. Amounts to be drawn under the new revolving credit agreement are not shown here because they will not be borrowed until 2017.

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

A. I will adopt the Company's test year-end capital structure ratios of 39.61% long-term debt and 60.39% common equity.

COST OF SENIOR CAPITAL

Q. What cost rate have you assigned to the debt portion of Chesapeake's capital structure?

A. Consistency with the capital structure ratios for the Company requires that the embedded cost rate of Chesapeake's senior securities must also be employed. This procedure is consistent with the ratesetting procedures used by the Commission for the Company. The determination of the cost of debt is essentially an arithmetic exercise. This is due to the fact that the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Attachment PRM-6, the actual embedded cost of long-term debt was 5.12% on June 30, 2015. The embedded cost of long-term debt is expected to be 4.82% at March 31, 2016, as shown on page 3 of Attachment PRM-6. For the new issue of long-term debt, the Company expects that the coupon rate will be 4.50%, the maturity will occur in 15-years, and the issuance costs will be $220,000. The details leading to the development of the individual effective cost rates for each series of long-term debt are shown on page 3 of Attachment PRM-6. The effective cost rate is the internal rate of return ("IRR") that equates the present value of all future interest and principal payments with the net proceeds of the bond.

The 4.82% debt cost rate is related to the amount of long-term debt shown on Attachment PRM-5, which provides the basis for the 39.61% long-term debt ratio.

COST OF EQUITY – GENERAL APPROACH

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

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

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As I describe below, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and arrived at a cost of equity of at least 11.00% for the Company.

DISCOUNTED CASH FLOW

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

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model and assumes future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: P = D/(k-g), where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: k= D/P + g. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model.[4] My DCF results are provided on page 2 of Attachment PRM-1 for the Gas Group. The DCF return is 9.97%, excluding flotation costs and 10.12%, including flotation costs.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

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

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

A. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended August 2015, the monthly dividend yields are shown on Attachment PRM-7 and reflect an adjustment to the month-end prices to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the twelve months ended August 2015, the average dividend yield was 3.26% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three-month periods were 3.30% and 3.36%, respectively. I have used, for the purpose of the DCF model, the six-month average dividend yield of 3.30% for the Gas Group. The use of this dividend yield will reflect current capital costs, while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investor anticipated cash flows for the Gas Group. I have adjusted the six-month average dividend yield in three different, but generally accepted, manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Attachment PRM-7. This adjustment adds nine basis points to the six-month average historical yield, thus producing the 3.39% adjusted dividend yield for the Gas Group.

Q. Please explain the underlying factors that influence investor's growth expectations.

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

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share.

Thereafter, a firm enters a “transition” stage where fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the “transition” phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or “steady-state” stage is reached when a firm’s earnings growth, payout ratio, and return on equity stabilizes at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third “steady-state” growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time.

Q. Did you assume a non-constant growth rate in your analysis?

A. No. I acknowledge that growth can also be expressed in multiple stages, but there is no need to do so in this case. As my subsequent analysis will reveal, my growth rate determination provides a constant growth rate that is sustainable given the fundamentals currently affecting the industry. For example, infrastructure rehabilitation adds to the growth of rate base that will provide the foundation for future growth that is consistent with the constant growth rate.

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

A. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner. In my opinion, all relevant growth rate indicators using a variety of techniques must be evaluated when formulating a judgment of investor-expected growth.

Q. What company-specific data have you considered in your growth rate analysis?

A. As presented on Attachments PRM-8 and PRM-9, I have considered both historical and projected growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. While analysts will review all measures of growth as I have done, it is earnings per share growth that influences directly the expectations of investors for utility stocks.[5] Forecasts of earnings growth are required within the context of the DCF because the model is a forward-looking concept, and with a constant price-earnings multiple and payout ratio, all other measures of growth will mirror earnings growth. So with the assumptions underlying the DCF, all forward-looking projections should be similar with a constant price-earnings multiple, earned return, and payout ratio.

As to the issue of historical data, investors cannot purchase past earnings of a utility, rather they are only entitled to future earnings. In addition, assigning significant weight to historical performance results in double counting of the historical data. While history cannot be ignored, it is already factored into the

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

analysts' forecasts of earnings growth. In developing a forecast of future earnings growth, an analyst would first apprise himself/herself of the historical performance of a company. Hence, there is no need to count historical growth rates a second time, because historical performance is already reflected in analysts' forecasts which reflect an assessment of how the future will diverge from historical performance.

Attachment PRM-8 shows the historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. The historical growth rates were taken from the Value Line publication that provides these data. As shown on Attachment PRM-8, the historical growth of earnings per share was in the range of 4.17% to 5.72% for the Gas Group.

Q. What is presented in Attachment PRM-9?

A. Attachment PRM-9 provides projected earnings per share growth rates taken from analysts' forecasts compiled by IBES/First Call, Zacks, Morningstar, SNL, and Value Line. IBES/First Call, Zacks, Morningstar, and SNL represent reliable authorities of projected growth upon which investors rely. The IBES/First Call, Zacks, and SNL growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Zacks, Morningstar, and SNL estimates are obtained from the Internet and are widely available to investors. First Call probably is quoted most frequently in the financial press when reporting on earnings forecasts. The Value Line forecasts also are widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries. The IBES/First Call, Zacks, and

Morningstar, and SNL forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on Attachment PRM-9 for the Gas Group.

Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the traditional DCF model?

A. Yes. In fact, it illustrates that the infinite form of the DCF model contains an unrealistic assumption. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investor expected return. The growth in the price per share will equal the growth in earnings per share absent any change in price-earnings ("P-E") multiple -- a necessary assumption of the DCF. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, conforms with the type of analysis that influences the actual total return expectation of investors. Moreover, academic research focuses on five-year growth rates as they influence stock prices. Indeed, if investors really required forecasts which extended beyond five years in order to properly value common stocks, then I am sure that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of investors. The absence of such a publication is proof that investors do not require infinite forecasts in order to purchase and sell stocks in the marketplace.

Q. What does Attachment PRM-9 show as the projected growth rates?

A. As to the five-year forecast growth rates, Attachment PRM-9 indicates that the projected earnings per share growth rates for the Gas Group are 5.10% by IBES/First Call, 5.41% by Zacks, 5.20% by Morningstar, 5.49% by SNL, and 6.61% by Value Line. The Value Line projections indicate that earnings per share for the Gas Group will grow prospectively at a more rapid rate (i.e., 6.61%) than the dividends per share (i.e., 4.67%), which translates into a declining dividend payout ratio for the future. As noted earlier, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

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

A. A variety of factors should be examined to reach a conclusion on the DCF growth rate. However, certain growth rate variables should be emphasized when reaching a conclusion on an appropriate growth rate. From the various alternative measures of growth identified above, earnings per share should receive greatest emphasis. Earnings per share growth are the primary determinant of investors' expectations regarding their total returns in the stock market. This is because the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). Moreover, earnings per share (derived from net income) are the source of dividend payments and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is a forecast of earnings per share growth.[6] Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, Morningstar, and Value Line, represent a reasonable assessment of investor expectations.

The forecasts of earnings per share growth, as shown on Attachment PRM-9, provide a range of average growth rates of 5.10% to 6.61%. Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 5.75% is a reasonable estimate of investor expected growth within the array of earnings per share growth rates shown by the analysts' forecasts. This improving economic growth argues for a higher DCF growth rate.

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

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

A. Only if the capital structure ratios are measured with the market value of debt and equity. In the case of the Gas Group, those average capital structure ratios are 33.29% long-term debt, 0.11% preferred stock, and 66.60% common equity, as shown on Attachment PRM-10. If book values are used to compute the capital structure ratios, then an adjustment is required.

Q. Please explain why.

A. If regulators use the results of the DCF (which are based on the market price of the stock of the companies analyzed) to compute the weighted average cost of capital with a book value capital structure used for ratesetting purposes, those results will not reflect the higher level of financial risk associated with the book value capital structure. Where, as here, a stock's market price diverges from a utility's book value, the potential exists for a financial risk difference, because the capitalization of a utility measured at its market value contains more equity, less debt and therefore less risk than the capitalization measured at its book value.

This shortcoming of the DCF has persuaded the Pennsylvania Public Utility Commission to adjust the cost of equity upward to make the return consistent with the book value capital structure. Provisions for this risk difference were made by the Pennsylvania Public Utility Commission in the following cases:

Date	Company	Docket Number	Basis Points
January 10, 2002	Pennsylvania-American Water Co.	Docket No. R-00016339	60 basis points
August 1, 2002	Philadelphia Suburban Water Co.	Docket No. R-00016750	80 basis points
January 29, 2004	Pennsylvania-American Water Co.	Docket No. R-00038304 (affirmed by the Commonwealth Court on November 8, 2004)	60 basis points
August 5, 2004	Aqua Pennsylvania, Inc.	Docket No. R-00038805	60 basis points
December 22, 2004	PPL Electric Utilities Corp.	Docket No. R-00049255	45 basis points
February 8, 2007	PPL Gas Utilities Corp.	Docket No. R-00061398	70 basis points

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

Q. Please continue with your discussion of the calculation of the leverage adjustment.

A. The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different than indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market capitalization of a firm. If the ratesetting process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the ratesetting process uses a different set of ratios calculated from the book value capitalization, then further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the equity. This adjustment is developed through precise mathematical calculations, using well recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. The calculations presented in the lower panel of data shown on Attachment PRM-10, under the heading "M&M," provides a return of 7.91% when applicable to a capital structure with 100% common equity.

Q. Are there specific factors that influence market-to-book ratios that determine whether the leverage adjustment should be made?

A. No. The leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations concerning market prices relative to book are not on point. The leverage adjustment deals with the issue of financial risk and does not transform the DCF result to a book value return through a market-to-book adjustment. Again, the leverage adjustment that I propose is based on the fundamental financial precept that the cost of equity is equal to the rate of return for an unleveraged firm (i.e., where the overall rate of return equates to the cost of equity with a capital structure that contains 100% equity) plus the additional return required for introducing debt and/or preferred stock leverage into the capital structure.

Further, as noted previously, the relatively high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on equity that differs from their cost of equity. Stock prices above book value are common for utility stocks, and indeed the stock prices of non-regulated companies exceed book values by even greater margins. In this regard, according to the Barron's issue of September 14, 2015, the major market indices' market-to-book ratios are well above unity. The Dow Jones Utility index traded at a multiple of 1.67 times book value, which is below the market multiple of other indices. For example, the S&P Industrial index was at 3.52 times book value, and the Dow Jones Industrial index was at 3.01 times book value. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of their cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they indeed exist.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true that when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

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

A. No, it is not. The adjustment that I label as a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g), in the context of a return that applies to the capital structure used in ratemaking, which is computed with book value weights rather than market value weights, in order to arrive at the utility's total cost of equity. I specify a separate factor, which I call the leverage adjustment, but there is no need to do so other than providing identification for this factor. If I expressed my return solely in the context of the book value weights that we use to calculate the weighted average cost of capital, and ignore the familiar D/P + g expression entirely, then there would be no separate element to reflect the financial leverage change from market value to book value capitalization. As shown in the bottom panel of data on Attachment PRM-10, the equity return applicable to the book value common equity ratio is equal to 7.91%, which is the return for the Gas Group applicable to its equity with no debt in its capital structure (i.e., the cost of capital is equal to the cost of equity with a 100% equity ratio) plus 2.05% compensation for having a 45.44% debt ratio, plus 0.01% for having a 0.16% preferred stock ratio. The sum of the parts is 9.97% (7.91% + 2.05% + 0.01%) and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I summed the 3.39% dividend yield, the 5.75% growth rate, and the 0.83% for the leverage adjustment in order to arrive at the same 9.97% (3.39% + 5.75% + 0.83%) return. I know of no means to mathematically solve for the 0.83% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.83% adjustment is merely a convenient way to compare the 9.97% return computed directly with the Modigliani & Miller formulas to the 9.14% return generated by the DCF model based on a market value capital structure. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

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

A. As explained previously, I have utilized a six-month average dividend yield ("D_1/P_0") adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate ("g") previously developed. The DCF also includes the leverage modification ("lev.") required when the book value equity ratio is used in determining the weighted average cost of capital in the ratesetting process rather than the market value equity ratio related to the price of stock. The cost of equity must also include an adjustment to cover flotation costs ("flot."), as shown on Attachment PRM-11. The resulting DCF cost rate is:

	D_1/P_0	+	*g*	+	*lev.*	=	*k*	x	*flot.*	=	*K*
Gas Group	3.39%	+	5.75%	+	0.83%	=	9.97%	x	1.015	=	10.12%

As indicated by the DCF result shown above, the flotation cost adjustment adds 0.15% (10.12% - 9.97%) to the rate of return on common equity for the Gas Group.

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

RISK PREMIUM ANALYSIS

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

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on page 2 of Attachment PRM-1. That result is 11.25%, excluding flotation costs, and 11.40%, including flotation costs. As with other models used to determine the cost of equity, the Risk Premium approach has its limitations, including potential imprecision in the assessment of the future cost of corporate debt and the measurement of the risk-adjusted common equity premium.

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

A. In my opinion, a 4.75% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

Q. What historical data is shown by the Moody's data?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on page 1 of Attachment PRM-12. For the twelve months ended August 2015, the average monthly yield on Moody's index of A-rated public utility bonds was 4.02%. For the six and three-month periods ended August 2014, the yields were 4.12% and 4.35%, respectively. During the twelve-months ended

August 2015, the range of the yields on A-rated public utility bonds was 3.58% to 4.40%. Page 2 of Attachment PRM-12 shows the long-run spread in yields between A-rated public utility bonds and long-term Treasury bonds. As shown on page 3 of Attachment PRM-12, the yields on A-rated public utility bonds have exceeded those on Treasury bonds by 1.16% on a twelve-month average basis, 1.25% on a six-month average basis, and 1.33% on a the three-month average basis. From these averages, 1.00% represents a reasonable spread for the yield on A-rated public utility bonds over Treasury bonds.

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

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe below. The Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on September 1, 2015, and a yield spread of 1.00%, derived from historical data.

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

A. Shown below is my calculation of the prospective yield on A-rated public utility bonds using the building blocks discussed above, i.e., the Blue Chip forecast of

Treasury bond yields and the public utility bond yield spread. For comparative purposes, I also have shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2015	Third	4.1%	5.1%	3.0%	1.00%	4.00%
2015	Fourth	4.2%	5.2%	3.1%	1.00%	4.10%
2016	First	4.4%	5.4%	3.3%	1.00%	4.30%
2016	Second	4.6%	5.5%	3.5%	1.00%	4.50%
2016	Third	4.7%	5.7%	3.7%	1.00%	4.70%
2016	Fourth	4.9%	5.8%	3.8%	1.00%	4.80%

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

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its June 1, 2015 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2017-2021	5.9%	6.7%	4.8%
2022-2026	6.1%	6.9%	5.0%

The longer term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near term forecasts. By focusing more on the near term forecasts, a 4.75% yield on A-rated public utility bonds represents a conservative benchmark for measuring the cost of equity in this case.

Q. What equity risk premium have you determined for public utilities?

A. To develop an appropriate equity risk premium, I analyzed the results from Stocks, Bonds, Bills and Inflation ("SBBI") 2015 Classic Yearbook published by Ibbotson Associates that is part of Morningstar. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on page 1 of Attachment PRM-13.

Common Equity Risk Premiums

Low Interest Rates	7.36%
Average Across All Interest Rates	5.69%
High Interest Rates	3.98%

Based on my analysis of the historical data, the equity risk premium was 7.36% when the marginal cost of long-term government bonds was low (i.e., 3.00%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.28% on average during periods of high interest rates) the spread narrowed to 3.98%. Over the entire spectrum of interest rates, the equity risk premium was 5.69% when the average government bond yield was 5.12%. With the forecast indicating an upward movement of interest rates that I described above from historically low levels, I have utilized a 6.50% equity risk premium. This equity risk premium is between the 7.36%

premium related to periods of low interest rates and the 5.69% premium related to average interest rates across all levels.

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

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i"), the equity risk premium (i.e., "RP"), and the flotation cost ("flot.") adjustment. The Risk Premium approach provides a cost of equity of:

	i	**+**	***RP***	**=**	***k***	**+**	***flot.***	**=**	***K***
Gas Group	4.75%	+	6.50%	=	11.25%	+	0.15%	=	11.40%

<u>CAPITAL ASSET PRICING MODEL</u>

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

A. The CAPM uses the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Attachment PRM-1, the result of the CAPM is 11.89%, excluding flotation costs, and 12.04%, including flotation costs. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 2 of Attachment PRM-3, the average beta is 0.78 for the Gas Group.

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

A. The betas must be reflective of the financial risk associated with the ratesetting capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line (market value) betas have been unleveraged and releveraged for the book value common equity ratios using the Hamada formula,[7] as follows:

$$\beta l = \beta u\ [1 + (1 - t)\ D/E + P/E]$$

where ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.59 for the Gas Group if it employed no leverage and was 100% equity financed. Those calculations are shown on Attachment PRM-10 under the section labeled "Hamada" who is credited with developing those formulas. With the unleveraged

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

beta as a base, I calculated the leveraged beta of 0.91 for the book value capital structure of the Gas Group. The book value leveraged beta that I will employ in the CAPM cost of equity is 0.91 for the Gas Group.

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

A. As shown on page 1 of Attachment PRM-14, I provided the historical yields on Treasury notes and bonds. For the twelve months ended August 2015, the average yield on 30-year Treasury bonds was 2.87%. For the six- and three-months ended August 2015, the yields on 30-year Treasury bonds were 2.87% and 3.01%, respectively. During the twelve-months ended August 2015, the range of the yields on 30-year Treasury bonds was 2.46% to 3.26%. The low yields that existed during recent periods can be traced to the financial crisis and its aftermath commonly referred to as the Great Recession. The resulting decline in the yields on Treasury obligations was attributed to a number of factors, including: the sovereign debt crisis in the euro zone, concern over a possible double dip recession, the potential for deflation, and the Federal Reserve's large balance sheet that was expanded through the purchase of Treasury obligations and mortgage-backed securities (also known as QEI, QEII, and QEIII), and the reinvestment of the proceeds from maturing obligations and the lengthening of the maturity of the Fed's bond portfolio through the sale of short-term Treasuries and the purchase of long-term Treasury obligations (also known as "operation twist"). Essentially, low interest rates were the product of the policy of the FOMC in its attempt to deal with stagnant job growth, which is part of its dual mandate. The FOMC has ended its bond purchasing program.

As shown on page 2 of Attachment PRM-14, forecasts published by Blue Chip on September 1, 2015 indicate that the yields on long-term Treasury bonds are expected to be in the range of 3.0% to 3.8% during the next six quarters. The longer term forecasts described previously show that the yields on 30-year Treasury bonds will average 4.8% from 2017 through 2021 and 5.0% from 2022 to 2026. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a 3.75% risk-free rate of return for CAPM purposes, which considers not only the Blue Chip forecasts, but also the recent trend in the yields on long-term Treasury bonds.

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

A. As shown in the lower panel of data presented on page 2 of Attachment PRM-14, the market premium is derived from historical data and the Value Line and S&P 500 returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on page 1 of Attachment PRM-13. On that schedule, the market return was 12.21% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 3.00% when interest rates were low. As I describe above, interest rates are forecast to trend upward in the future. To recognize that trend, I have given weight to the average returns and yields that existed across all interest rate levels. As such, I carried over to page 2 of Attachment PRM-14 the average large common stock returns of 12.14% (12.21% + 12.07% = 24.28% ÷ 2) and the average yield on long-term government bonds of 4.06% (3.00% + 5.12% = 8.12% ÷ 2). These financial returns rest between those experienced during periods of low interest rates and those experienced across all levels of interest rates. The resulting market premium is 8.08% (12.14% - 4.06%) based on historical data, as shown on page 2 of Attachment PRM-14. For the forecast returns, I calculated a 12.97% total market return from the Value Line data and a DCF return of 9.32% for the S&P 500. With the average forecast return of 11.15% (12.97% + 9.32% = 22.29% ÷ 2), I calculated a market premium of 7.40% (11.15% - 3.75%) using forecast data. The market premium applicable to the CAPM derived from these sources equals 7.74% (7.40% + 8.08% = 15.48% ÷ 2).

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

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. As the size of a firm decreases, its risk and required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms.[8] Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled “Equity and the Small-Stock Effect,” it was demonstrated that the CAPM could understate the cost of equity significantly according to a company’s size. Indeed, it was demonstrated in the

[8] See Fundamentals of Financial Management, Fifth Edition, at 623.

SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) were in excess of those shown by the simple CAPM. In this regard, the Gas Group has a market-based average equity capitalization of $2,319 million. The mid-cap adjustment of 1.10%, as revealed on page 3 of Attachment PRM-14, would be warranted at a minimum.

Q. What CAPM result have you determined?

A. Using the 3.75% risk-free rate of return, the leverage adjusted beta of 0.91 for the Gas Group, the 7.74% market premium, the 1.10% size adjustment, and the 0.15% flotation cost adjustment, the following result is indicated.

	Rf	**+**	***ß***	***x (***	***Rm-Rf***	***) +***	***size***	**=**	***k***	**+**	***flot.***	**=**	***K***
Gas Group	3.75%	+	0.91	x (	7.74%	) +	1.10%	=	11.89%	+	0.15%	=	12.04%

COMPARABLE EARNINGS APPROACH

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

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

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

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

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

Q. How have you implemented the Comparable Earnings Approach?

A. In order to implement the Comparable Earnings approach, non-regulated companies were selected from The Value Line Investment Survey for Windows that have six categories of comparability designed to reflect the risk of the Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The definition for these parameters is provided on page 3 of Attachment PRM-15. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on page 1 of Attachment PRM-15.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Attachment PRM-15, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities.

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

A. I have used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 12.3% using only the returns that were less than 20%, as shown on page 2 of Attachment PRM-15. The average forecasted rate of return as published by Value Line is 13.3% also using values less than 20%, as provided on page 2 of Attachment PRM-15. Using the average of these data my Comparable Earnings result is 12.80%, as shown on page 2 of Attachment PRM-1.

CONCLUSION ON COST OF EQUITY

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

A. Based upon the application of a variety of methods and models described previously, it is my opinion that the rate of return on common equity is 11.00%. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method. In conclusion, the Company is entitled to an 11.00% rate of return on common equity so that it can compete in the capital markets and be compensated for its risk profile.

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

A. Yes, it does.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

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

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

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

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

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past forty-one years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty-seven (37) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on Environmental Quality. My testimony has been offered in over 300 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

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

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

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

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

DATED: DECEMBER 16 , 2015

STATE OF NEW JERSEY)
)
COUNTY OF CAMDEN)

AFFIDAVIT OF PAUL R. MOUL

PAUL R. MOUL, being first duly sworn according to law, on oath deposes and says that he is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of Paul R. Moul"; that, if asked the questions which appear in the text of the direct testimony, he would give the answers that are therein set forth; and that he adopts this testimony as his sworn direct testimony in these proceedings.

Paul R. Moul

Paul R. Moul

Then personally appeared this 16th day of December 2015 the above-named Paul R. Moul and acknowledged the foregoing Testimony to be his free act and deed. Before me,

Ruby Marie Tucker

Notary Public
My Commission Expires:

RUBY MARIE TUCKER
ID # 2165661
NOTARY PUBLIC
STATE OF NEW JERSEY
My Commission Expires May 12, 2019

CHESAPEAKE UTILIITES CORPORATION

Attachments to Accompany the

Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning
Cost of Capital
And
Fair Rate of Return

Chesapeake Utilities Corporation
Index of Schedules

Chesapeake Utilities Corporation
Summary Cost of Capital
ProForma at March 31, 2016

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Debt	39.61%	4.82%	1.91%
Equity	60.39%	11.00%	6.64%
Total	100.00%		8.55%

Indicated levels of fixed charge coverage assuming that the Company could actually achieve its overall cost of capital:

Pre-tax coverage of interest expense based upon a 35.00% income tax rate
(12.13% ÷ 1.91%) 6.35 x

Post-tax coverage of interest expense
(8.55% ÷ 1.91%) 4.48 x

Chesapeake Utilities Corporation
Cost of Equity
as of August 31, 2015

Discounted Cash Flow (DCF)					D_1/P_0 [1]	+	g [2]	+	*lev.* [3]	=	*k*	x	*flot.* [4]	=	*K*
Gas Group					3.39%	+	5.75%	+	0.83%	=	9.97%	x	1.015	=	10.12%
Risk Premium (RP)							*I* [5]	+	*RP* [6]	=	*k*	+	flot.	=	*K*
Gas Group							4.75%	+	6.50%	=	11.25%	+	0.15%	=	11.40%
Capital Asset Pricing Model (CAPM)	*Rf* [7]	+	*ß* [8]	x (			*Rm-Rf* [9]	) +	*size* [10]	=	*k*	+	flot.	=	*K*
Gas Group	3.75%	+	0.91	x (			7.74%	) +	1.10%	=	11.89%	+	0.15%	=	12.04%
Comparable Earnings (CE) [11]											*Historical*		*Forecast*		*Average*
Comparable Earnings Group											12.3%		13.3%		12.80%

References:
(1) Schedule 07
(2) Schedule 09
(3) Schedule 10
(4) Schedule 11
(5) A-rated public utility bond yield comprised of a 3.75% risk-free rate of return (Schedule 14 page 2) and a yield spread of 1.00% (Schedule 12 page 3)
(6) Schedule 13 page 1
(7) Schedule 14 page 2
(8) Schedule 10
(9) Schedule 14 page 2
(10) Schedule 14 page 3
(11) Schedule 15 page 2

Chesapeake Utilities Corporation
Capitalization and Financial Statistics
2010-2014, Inclusive

	2014	2013	2012	2011	2010	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 473.6	$ 410.3	$ 371.8	$ 363.8	$ 328.5	
Short-Term Debt	$ 88.2	$ 105.7	$ 61.2	$ 34.7	$ 64.0	
Total Capital	$ 561.8	$ 515.9	$ 433.0	$ 398.5	$ 392.4	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	18 x	16 x	15 x	14 x	13 x	15 x
Market/Book Ratio	226.1%	192.3%	171.1%	164.6%	152.3%	181.3%
Dividend Yield	2.4%	2.8%	3.2%	3.4%	3.7%	3.1%
Dividend Payout Ratio	43.4%	45.0%	47.8%	47.2%	47.5%	46.2%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	35.4%	31.4%	29.6%	32.6%	30.1%	31.8%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity (1)	64.6%	68.6%	70.4%	67.4%	69.9%	68.2%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	45.5%	45.5%	39.6%	38.4%	41.5%	42.1%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity (1)	54.5%	54.5%	60.4%	61.6%	58.5%	57.9%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity (1)	12.3%	12.1%	11.4%	11.6%	11.8%	11.8%
Operating Ratio (2)	86.1%	85.7%	85.0%	87.1%	87.7%	86.3%
Coverage incl. AFUDC (3)						
Pre-tax: All Interest Charges	7.29 x	7.56 x	6.44 x	6.07 x	5.70 x	6.61 x
Post-tax: All Interest Charges	4.78 x	4.92 x	4.26 x	4.07 x	3.85 x	4.38 x
Overall Coverage: All Int. & Pfd. Div.	4.78 x	4.92 x	4.26 x	4.07 x	3.85 x	4.38 x
Coverage excl. AFUDC (4)						
Pre-tax: All Interest Charges	7.29 x	7.54 x	6.42 x	6.07 x	5.70 x	6.60 x
Post-tax: All Interest Charges	4.78 x	4.90 x	4.25 x	4.07 x	3.85 x	4.37 x
Overall Coverage: All Int. & Pfd. Div.	4.78 x	4.90 x	4.25 x	4.07 x	3.85 x	4.37 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	0.2%	0.4%	0.4%	0.0%	0.0%	0.2%
Effective Income Tax Rate	39.9%	40.2%	40.1%	39.4%	39.4%	39.8%
Internal Cash Generation/Construction (5)	89.9%	68.6%	83.8%	126.1%	115.4%	96.8%
Gross Cash Flow/ Avg. Total Debt (6)	41.3%	39.3%	44.8%	44.9%	38.8%	41.8%
Gross Cash Flow Interest Coverage (7)	11.54 x	10.47 x	9.12 x	8.75 x	7.89 x	9.55 x
Common Dividend Coverage (8)	7.29 x	6.10 x	5.89 x	6.08 x	5.76 x	6.22 x

See Page 2 for Notes.

Chesapeake Utilities Corporation
Capitalization and Financial Statistics
2010-2014, Inclusive

Notes:

(1) Excluding Accumulated Other Comprehensive Income (“OCI”) from the equity account..

(2) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.

(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFUDC) as a percentage of average total debt.

(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.

(7) Common dividend coverage is the relationship of internally generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Audited Financial Statements by Deloitte Touche Tohmatsu

Gas Group
Capitalization and Financial Statistics [1]
2010-2014, Inclusive

	2014	2013	2012	2011	2010	Average
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 2,483.7	$ 2,124.7	$ 1,832.4	$ 1,738.8	$ 1,675.8	
Short-Term Debt	$ 240.8	$ 247.6	$ 232.7	$ 142.2	$ 146.4	
Total Capital	$ 2,724.5	$ 2,372.3	$ 2,065.1	$ 1,881.0	$ 1,822.2	
Market-Based Financial Ratios						
Price-Earnings Multiple	19 x	19 x	17 x	16 x	15 x	17 x
Market/Book Ratio	196.1%	183.7%	182.7%	184.2%	173.9%	184.1%
Dividend Yield	3.2%	3.5%	3.6%	3.6%	3.8%	3.5%
Dividend Payout Ratio	64.2%	68.8%	61.0%	59.3%	57.1%	62.1%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	45.7%	43.7%	41.6%	41.1%	41.9%	42.8%
Preferred Stock	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%
Common Equity [2]	54.1%	56.1%	58.3%	58.7%	58.0%	57.0%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	51.9%	51.0%	48.4%	46.4%	48.2%	49.2%
Preferred Stock	0.1%	0.1%	0.1%	0.2%	0.2%	0.1%
Common Equity [2]	48.0%	48.9%	51.4%	53.5%	51.6%	50.7%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	10.2%	9.8%	10.7%	11.0%	11.5%	10.6%
Operating Ratio [3]	87.2%	87.8%	86.7%	88.4%	88.8%	87.8%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	4.95 x	4.73 x	5.01 x	4.95 x	5.03 x	4.93 x
Post-tax: All Interest Charges	3.67 x	3.60 x	3.77 x	3.61 x	3.55 x	3.64 x
Overall Coverage: All Int. & Pfd. Div.	3.66 x	3.58 x	3.75 x	3.60 x	3.54 x	3.63 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	4.89 x	4.61 x	4.90 x	4.90 x	4.99 x	4.86 x
Post-tax: All Interest Charges	3.61 x	3.48 x	3.67 x	3.57 x	3.51 x	3.57 x
Overall Coverage: All Int. & Pfd. Div.	3.60 x	3.46 x	3.65 x	3.55 x	3.50 x	3.55 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	2.3%	4.5%	3.7%	1.7%	1.4%	2.7%
Effective Income Tax Rate	32.2%	27.9%	31.1%	34.7%	36.8%	32.5%
Internal Cash Generation/Construction [5]	82.8%	62.9%	69.4%	97.9%	121.0%	86.8%
Gross Cash Flow/ Avg. Total Debt [6]	26.2%	24.1%	28.7%	30.1%	30.4%	27.9%
Gross Cash Flow Interest Coverage [7]	7.75 x	7.00 x	7.16 x	6.88 x	7.05 x	7.17 x
Common Dividend Coverage [8]	4.66 x	4.08 x	4.27 x	4.41 x	4.73 x	4.43 x

See Page 2 for Notes.

Gas Group
Capitalization and Financial Statistics
2010-2014, Inclusive

Notes:

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

Basis of Selection:
The Gas Group includes companies that are contained in The Value Line Investment Survey within the industry group “Natural Gas Utility,” they are not currently the target of a publicly-announced merger or acquisition, and after eliminating NiSource due to its electric operations and recent separation of the former natural gas pipeline/storage operations and UGI Corp. due to its highly diversified businesses.

		Corporate Credit Ratings		Stock	S&P Stock	Value Line
Ticker	Company	Moody's	S&P	Traded	Ranking	Beta
ATO	Atmos Energy Corp.	A2	A-	NYSE	A-	0.85
CPK	Chesapeake Utilities Corp.			NYSE	A	0.65
LG	Laclede Group	A3	A-	NYSE	B+	0.70
NJR	New Jersey Resources Corp.	Aa2	A	NYSE	B+	0.85
NWN	Northwest Natural Gas Co.	A3	A+	NYSE	A-	0.70
PNY	Piedmont Natural Gas Co.	A2	A	NYSE	A	0.80
SJI	South Jersey Industries, Inc.	A2	BBB+	NYSE	A-	0.85
SWX	Southwest Gas Corporation	A3	BBB+	NYSE	B+	0.85
WGL	WGL Holdings, Inc.	A1	A+	NYSE	B+	0.80
	Average	A2	A-		B+	0.78

Note: Ratings are those of utility subsidiaries

Source of Information: Utility COMPUSTAT
Moody’s Investors Service
Standard & Poor’s Corporation

Standard & Poor's Public Utilities
Capitalization and Financial Statistics [1]
2010-2014, Inclusive

	2014	2013	2012	2011	2010	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 23,785.1	$ 22,496.2	$ 21,620.0	$ 18,840.8	$ 17,587.3	
Short-Term Debt	$ 887.5	$ 703.8	$ 648.9	$ 531.4	$ 435.4	
Total Capital	$ 24,672.6	$ 23,200.0	$ 22,268.9	$ 19,372.2	$ 18,022.7	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	21 x	21 x	18 x	15 x	15 x	18 x
Market/Book Ratio	201.5%	175.8%	164.0%	155.2%	142.8%	167.9%
Dividend Yield	3.6%	3.9%	4.1%	4.4%	4.8%	4.2%
Dividend Payout Ratio	74.3%	81.1%	72.9%	64.7%	72.0%	73.0%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	52.8%	52.7%	52.9%	52.9%	53.4%	52.9%
Preferred Stock	2.7%	1.9%	1.6%	1.3%	1.3%	1.8%
Common Equity [2]	44.4%	45.4%	45.5%	45.8%	45.3%	45.3%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	54.7%	54.3%	54.5%	54.5%	54.7%	54.5%
Preferred Stock	2.6%	1.9%	1.6%	1.3%	1.3%	1.7%
Common Equity [2]	42.7%	43.9%	44.0%	44.3%	44.0%	43.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	9.9%	8.4%	9.2%	10.5%	10.8%	9.8%
Operating Ratio [3]	81.0%	81.3%	81.3%	81.4%	81.6%	81.3%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.57 x	3.24 x	2.94 x	3.35 x	3.34 x	3.29 x
Post-tax: All Interest Charges	2.70 x	2.46 x	2.35 x	2.59 x	2.52 x	2.52 x
Overall Coverage: All Int. & Pfd. Div.	2.67 x	2.43 x	2.32 x	2.57 x	2.50 x	2.50 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	3.47 x	3.15 x	2.85 x	3.25 x	3.25 x	3.19 x
Post-tax: All Interest Charges	2.60 x	2.36 x	2.25 x	2.49 x	2.43 x	2.43 x
Overall Coverage: All Int. & Pfd. Div.	2.57 x	2.34 x	2.22 x	2.47 x	2.41 x	2.40 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	7.6%	7.6%	7.1%	5.7%	6.7%	6.9%
Effective Income Tax Rate	30.2%	35.2%	31.8%	33.5%	34.3%	33.0%
Internal Cash Generation/Construction [5]	85.0%	80.3%	75.0%	89.4%	108.0%	87.5%
Gross Cash Flow/ Avg. Total Debt [6]	23.3%	22.7%	21.9%	23.2%	23.9%	23.0%
Gross Cash Flow Interest Coverage [7]	5.70 x	5.47 x	5.37 x	5.12 x	5.09 x	5.35 x
Common Dividend Coverage [8]	7.00 x	6.38 x	4.31 x	4.58 x	4.88 x	5.43 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2010-2014, Inclusive

Notes:

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

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities

Company Identities

	Ticker	Credit Rating (1) Moody's	S&P	Common Stock Traded	S&P Stock Ranking	Value Line Beta
AGL Resources Inc.	GAS	A2	BBB+	NYSE	A	0.75
Ameren Corporation	AEE	Baa1	BBB+	NYSE	B	0.80
American Electric Power	AEP	Baa1	BBB	NYSE	B	0.70
CMS Energy	CMS	A3	BBB	NYSE	B	0.70
CenterPoint Energy	CNP	A3	A-	NYSE	B	0.80
Consolidated Edison	ED	A2	A-	NYSE	B+	0.60
DTE Energy Co.	DTE	A2	BBB+	NYSE	B+	0.80
Dominion Resources	D	A2	A-	NYSE	B+	0.70
Duke Energy	DUK	A1	BBB+	NYSE	B	0.65
Edison Int'l	EIX	A2	BBB+	NYSE	B	0.80
Entergy Corp.	ETR	Baa1	BBB	NYSE	A	0.70
EQT Corp.	EQT	Baa3	BBB	NYSE	B+	1.15
Exelon Corp.	EXC	A2	BBB	NYSE	B+	0.75
FirstEnergy Corp.	FE	Baa2	BBB-	NYSE	B+	0.75
Integrys Energy Group	TEG	A1	A-	NYSE	B	1.00
NextEra Energy Inc.	NEE	A1	A-	NYSE	A	0.70
NiSource Inc.	NI	Baa1	BBB-	NYSE	B	0.85
Northeast Utilities	NU	Baa1	A-	NYSE	B	0.75
NRG Energy Inc.	NRG	Ba3	BB-	NYSE	B	1.05
ONEOK, Inc.	OKE	Baa3	BB+	NYSE	A-	1.05
PEPCO Holdings, Inc.	POM	Baa1	BBB+	NYSE	B	0.75
PG&E Corp.	PCG	A3	BBB	NYSE	B	0.60
PPL Corp.	PPL	Baa1	BBB	NYSE	B+	0.65
Pinnacle West Capital	PNW	A3	A-	NYSE	B	0.75
Public Serv. Enterprise Inc.	PEG	A2	BBB+	NYSE	B+	0.75
SCANA Corp.	SCG	Baa2	BBB+	NYSE	A-	0.70
Sempra Energy	SRE	A1	A	NYSE	B+	0.75
Southern Co.	SO	A3	A	NYSE	A-	0.55
TECO Energy	TE	A2	BBB+	NYSE	B	0.95
Wisconsin Energy Corp.	WEC	A1	A-	NYSE	A	0.65
Xcel Energy Inc	XEL	A2	A-	NYSE	B+	0.65
Average for S&P Utilities		A3	BBB+		B+	0.77

Note: (1) Ratings are those of utility subsidiaries

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

Chesapeake Utilities Corporation
Capitalization and Related Capital Structure Ratios
Actual at June 30, 2015, Estimated at March 31, 2016, and ProForma at March 31, 2016

	Actual at June 30, 2015			Estimated at March 31, 2016			ProForma at March 31, 2016		
	Amount Outstanding	Ratios Excl. S-T Debt	Ratios Incl. S-T Debt	Amount Outstanding	Ratios Excl. S-T Debt	Ratios Incl. S-T Debt	Amount Outstanding	Ratios Excl. S-T Debt	Ratios Incl. S-T Debt
Long-Term Debt	$ 151,681,818	29.84%	25.15%	$ 215,454,545 (2)	35.79%	29.58%	$ 275,454,545 (2)	39.61%	37.82%
Common Equity									
Common stock	7,418,752			7,418,752			7,418,752		
Premium on Capital Stock	187,903,057			191,008,057			224,508,057 (3)		
Retained earnings(1)	161,332,819			188,107,059			188,107,059		
Deferred compensation obl.	1,843,207			1,843,207			1,843,207		
Treasury stock	(1,843,207)			(1,843,207)			(1,843,207)		
Total Common Equity	356,654,628	70.16%	59.14%	386,533,868	64.21%	53.07%	420,033,868	60.39%	57.67%
Total Permanent Capital	508,336,446	100.00%	84.29%	601,988,413	100.00%	82.65%	695,488,413	100.00%	95.49%
Short-Term Debt	94,712,542		15.71%	126,307,553		17.34%	32,807,553		4.50%
Total Capital	$ 603,048,988		100.00%	$ 728,295,966		99.99%	$ 728,295,966		99.99%

Notes:
(1)Excluding Accumulated Other Comprehensive Income
(2)Reflects changes in debt principal amounts of:

Chesapeake Senior Note 5	$ (2,727,273)	
Chesapeake Senior Note 6	$ (2,000,000)	
Chesapeake Senior Note 7	$ (1,500,000)	
Chesapeake Senior Note 12	$ 70,000,000	$ 60,000,000
(3)Reflects Additional Equity		$ 33,500,000

Source of Information: Company provided data

Chesapeake Utilities Corporation
Calculation of the Embedded Cost of Long-Term Debt
Actual at June 30, 2015

Series	Principal Amount Outstanding (1)	Percent to Total	Effective Cost Rate (2)	Weighted Cost Rate
Chesapeake Senior Note 5	$ 8,181,818	5.39%	6.71%	0.36%
Chesapeake Senior Note 6	12,000,000	7.91%	5.56%	0.44%
Chesapeake Senior Note 7	25,500,000	16.81%	5.95%	1.00%
Chesapeake Senior Note 8	29,000,000	19.12%	6.38%	1.22%
Chesapeake Senior Note 9	7,000,000	4.62%	6.68%	0.31%
Chesapeake Senior Note 10	20,000,000	13.19%	3.77%	0.50%
Chesapeake Senior Note 11	50,000,000	32.96%	3.93%	1.29%
Total	$ 151,681,818	100.00%		5.12%

Note:
(1) Long-term debt, net of current maturities.
(2) As calculated on page 4 of this schedule.

Source of Information: Company provided data

Chesapeake Utilities Corporation
Calculation of the Embedded Cost of Long-Term Debt
Estimated at March 31, 2016

Series	Principal Amount Outstanding [1]	Percent to Total	Effective Cost Rate [2]	Weighted Cost Rate
Chesapeake Senior Note 5	$ 5,454,545	2.53%	6.71%	0.17%
Chesapeake Senior Note 6	10,000,000	4.64%	5.56%	0.26%
Chesapeake Senior Note 7	24,000,000	11.14%	5.95%	0.66%
Chesapeake Senior Note 8	29,000,000	13.46%	6.38%	0.86%
Chesapeake Senior Note 9	7,000,000	3.25%	6.68%	0.22%
Chesapeake Senior Note 10	20,000,000	9.28%	3.77%	0.35%
Chesapeake Senior Note 11	50,000,000	23.21%	3.93%	0.91%
Chesapeake Senior Note 12	70,000,000	32.49%	4.52%	1.47%
Total	$ 215,454,545	100.00%		4.90%

Note:
[1] Long-term debt, net of current maturities.
[2] As calculated on page 4 of this schedule.

Source of Information: Company provided data

Chesapeake Utilities Corporation
Calculation of the Embedded Cost of Long-Term Debt
ProForma at March 31, 2016

Series	Principal Amount Outstanding [1]	Percent to Total	Effective Cost Rate [2]	Weighted Cost Rate
Chesapeake Senior Note 5	$ 5,454,545	1.98%	6.71%	0.13%
Chesapeake Senior Note 6	10,000,000	3.63%	5.56%	0.20%
Chesapeake Senior Note 7	24,000,000	8.71%	5.95%	0.52%
Chesapeake Senior Note 8	29,000,000	10.53%	6.38%	0.67%
Chesapeake Senior Note 9	7,000,000	2.54%	6.68%	0.17%
Chesapeake Senior Note 10	20,000,000	7.26%	3.77%	0.27%
Chesapeake Senior Note 11	50,000,000	18.15%	3.93%	0.71%
Chesapeake Senior Note 12	130,000,000	47.20%	4.52%	2.13%
Total	$ 275,454,545	100.00%		4.82%

Note:
[1] Long-term debt, net of current maturities.
[2] As calculated on page 4 of this schedule.

Source of Information: Company provided data

Chesapeake Utilities Corporation
Calculation of the Effective Cost of Long-Term Debt by Series

Series	Coupon Rate	Date of Issue	Date of Maturity	Principal Amount Issued	Discount and Expense	Net Proceeds	Net Proceeds Ratio	Effective Cost Rate [1]
Chesapeake Senior Note 5	6.64%	10/31/02	10/31/17	$30,000,000	$141,831	$ 29,858,169	99.53%	6.71%
Chesapeake Senior Note 6	5.50%	10/12/06	10/12/20	$20,000,000	$79,566	$ 19,920,434	99.60%	5.56%
Chesapeake Senior Note 7	5.93%	10/31/08	10/31/23	$30,000,000	$39,518	$ 29,960,482	99.87%	5.95%
Chesapeake Senior Note 8	5.68%	06/24/11	06/30/26	$29,000,000	$1,496,322	$ 27,503,678	94.84%	6.38%
Chesapeake Senior Note 9	6.43%	05/02/13	05/02/28	$7,000,000	$121,631	$ 6,878,369	98.26%	6.68%
Chesapeake Senior Note 10	3.73%	12/16/13	12/16/28	20,000,000	$68,794	$ 19,931,206	99.66%	3.77%
Chesapeake Senior Note 11	3.88%	05/15/14	05/15/29	$50,000,000	$192,790	$ 49,807,210	99.61%	3.93%
Chesapeake Senior Note 12	4.50% [2]	12/31/15	12/31/30	$130,000,000	$220,000	$ 129,780,000	99.83%	4.52%

Notes: [1] The effective cost for each issue is the internal rate of return ("irr") using as inputs the term of the issue, the coupon rate, the annual sinking fund payments, and the net proceeds.
[2] Estimated

Source of Information: Company provided data

Monthly Dividend Yields for
Gas Group
for the Twelve Months Ending August 2015

Company	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	12-Month Average	6-Month Average	3-Month Average
Atmos Energy Corp (ATO)	3.11%	2.96%	2.91%	2.81%	2.76%	2.94%	2.83%	2.91%	2.89%	3.05%	2.84%	2.85%			
Chesapeake Utilities Corp (CPK)	2.60%	2.24%	2.42%	2.18%	2.22%	2.30%	2.14%	2.41%	2.20%	2.14%	2.24%	2.35%			
Laclede Group Inc (LG)	3.80%	3.64%	3.66%	3.47%	3.44%	3.58%	3.60%	3.56%	3.47%	3.54%	3.42%	3.50%			
New Jersey Resources Corporation (NJR)	3.57%	3.09%	3.13%	2.95%	2.83%	2.89%	2.90%	2.96%	3.01%	3.27%	3.13%	3.21%			
Northwest Natural Gas (NWN)	4.39%	3.96%	4.01%	3.75%	3.73%	3.95%	3.90%	3.98%	4.18%	4.44%	4.30%	4.25%			
Piedmont Natural Gas Co (PNY)	3.82%	3.38%	3.44%	3.25%	3.32%	3.56%	3.58%	3.54%	3.56%	3.74%	3.49%	3.44%			
South Jersey Industries Inc (SJI)	3.55%	3.45%	3.55%	3.42%	3.47%	3.57%	3.71%	3.83%	3.84%	4.07%	4.17%	4.21%			
Southwest Gas Corp (SWX)	3.02%	2.53%	2.52%	2.37%	2.39%	2.55%	2.52%	2.96%	2.98%	3.06%	2.89%	2.94%			
WGL Holdings Inc (WGL)	4.22%	3.75%	3.62%	3.25%	3.12%	3.31%	3.14%	3.37%	3.23%	3.43%	3.32%	3.43%			
Average	**3.56%**	**3.22%**	**3.25%**	**3.05%**	**3.03%**	**3.18%**	**3.15%**	**3.28%**	**3.26%**	**3.42%**	**3.31%**	**3.35%**	**3.26%**	**3.30%**	**3.36%**

Note: Monthly dividend yields are calculated by dividing the annualized quarterly dividend by the month-end closing stock price adjusted by the fraction of the ex-dividend.

Source of Information: http://performance.morningstar.com/stock/performance-return
http://www.snl.com/interactivex/dividends

Forward-looking Dividend Yield		D_0/P_0		D_1/P_0
	1/2 Growth	D_0/P_0	(.5g)	D_1/P_0
		3.30%	1.028750	3.39%
	Discrete	D_0/P_0	Adj.	D_1/P_0
		3.30%	1.035686	3.41%
	Quarterly	D_0/P_0	Adj.	D_1/P_0
		0.8238%	1.014075	3.38%
	Average			3.39%
	Growth rate			5.75%
	K			9.14%

$$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$$

$$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$$

$$K = \left[\left(1 + \frac{D_0(1+g)^{.25}}{P_0}\right)^4 - 1\right] + g$$

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

Gas Group	Earnings per Share		Dividends per Share		Book Value per Share		Cash Flow per Share	
	Value Line		Value Line		Value Line		Value Line	
	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year
Atmos Energy Corp.	5.00%	5.00%	2.00%	1.50%	4.50%	6.00%	4.00%	5.00%
Chesapeake Utilities Corp.	10.50%	8.50%	4.50%	3.00%	8.50%	8.50%	12.50%	7.00%
Laclede Group	-2.00%	4.00%	3.00%	2.50%	7.50%	7.00%	-2.00%	3.00%
New Jersey Resources Corp.	5.50%	6.50%	8.50%	6.50%	4.50%	8.00%	4.50%	5.00%
Northwest Natural Gas	-4.00%	2.50%	3.50%	3.50%	3.00%	3.50%	-1.00%	3.00%
Piedmont Natural Gas Co.	3.50%	5.00%	3.50%	4.00%	4.00%	5.00%	3.50%	5.00%
South Jersey Industries, Inc.	6.50%	8.00%	10.00%	8.50%	8.00%	8.50%	7.50%	8.00%
Southwest Gas Corp.	11.00%	8.50%	8.00%	5.00%	5.00%	5.00%	6.00%	4.50%
WGL Holdings, Inc.	1.50%	3.50%	3.00%	2.50%	3.00%	4.00%	1.50%	2.50%
Average	4.17%	5.72%	5.11%	4.11%	5.33%	6.17%	4.06%	4.78%

Source of Information: Value Line Investment Survey, September 4, 2015

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

					Value Line				
Gas Group	I/B/E/S First Call	Zacks	Morningstar	SNL	Earnings Per Share	Dividends Per Share	Book Value Per Share	Cash Flow Per Share	Percent Retained to Common Equity
Atmos Energy Corp.	7.00%	7.00%	6.60%	6.80%	7.00%	5.00%	4.50%	4.50%	5.50%
Chesapeake Utilities Corp.	3.00%	NA	3.00%	NA	8.50%	5.50%	9.00%	7.50%	7.00%
Laclede Group, Inc.	4.42%	4.90%	-	4.70%	10.00%	4.50%	7.50%	8.50%	4.00%
New Jersey Resources Corp.	6.00%	6.00%	MNF (1)	6.00%	4.00%	3.50%	7.50%	4.50%	6.50%
Northwest Natural Gas	4.00%	4.00%	4.00%	4.00%	7.00%	2.50%	3.50%	4.50%	3.50%
Piedmont Natural Gas Co.	5.00%	5.00%	7.60%	6.00%	3.00%	3.00%	4.50%	2.00%	3.00%
South Jersey Industries, Inc.	6.00%	NA	6.00%	NA	7.50%	7.00%	6.50%	7.50%	5.50%
Southwest Gas Corporation	4.00%	5.00%	2.40%	4.00%	7.00%	8.00%	4.50%	5.50%	6.00%
WGL Holdings, Inc.	6.50%	6.00%	6.80%	6.90%	5.50%	3.00%	3.50%	4.00%	5.00%
Average	5.10%	5.41%	5.20%	5.49%	6.61%	4.67%	5.67%	5.39%	5.11%

Note: (1) Excluding negative growth rate of -14.20% by Morningstar

Source of Information : Yahoo Finance, September 2, 2015
Zacks, September 2, 2015
Morningstar, September 2, 2015
SNL, September 2, 2015
Value Line Investment Survey, September 4, 2015

Gas Group
Financial Risk Adjustment

		ATMOS Energy (NYSE:ATO)	Chesapeake Utilities (NYSE:CPK)	Laclede Group (NYSE:LG)	New Jersey Resources (NYSE:NJR)	Northwest Natural Gas (NYSE:NWN)	Piedmont Natural Gas (NYSE:PNY)	South Jersey Industries (NYSE:SJI)	Southwest Gas (SWX)	WGL Holdings (NYSE:WGL)	Average
Fiscal Year		09/30/14	12/31/14	09/30/14	09/30/14	12/31/14	10/31/14	12/31/14	12/31/14	09/30/14	
Capitalization at Fair Values											
	Debt(D)	2,769,541	180,700	1,937,300	586,909	756,808	1,617,453	1,058,500	1,795,928	809,300	1,279,160
	Preferred(P)	0	0	0	0	0	0	0	0	28,173	3,130
	Equity(E)	4,788,512	724,475	2,003,729	1,982,284	1,361,472	2,984,963	2,013,487	2,875,598	2,133,654	2,318,686
	Total	7,558,053	905,175	3,941,029	2,569,193	2,118,280	4,602,416	3,071,987	4,671,526	2,971,127	3,600,976
Capital Structure Ratios											
	Debt(D)	36.64%	19.96%	49.16%	22.84%	35.73%	35.14%	34.46%	38.44%	27.24%	33.29%
	Preferred(P)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.95%	0.11%
	Equity(E)	63.36%	80.04%	50.84%	77.16%	64.27%	64.86%	65.54%	61.56%	71.81%	66.60%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Common Stock											
	Issued	100,388.092	14,588.711	43,183.818	42,178.156	27,284.000	78,531.000	34,167.430	46,523.184	50,656.553	
	Treasury	0.000	0.000	0.000	2,932.775	0.000	0.000	0.000	0.000	0.000	
	Outstanding	100,388.092	14,588.711	43,183.818	39,245.381	27,284.000	78,531.000	34,167.430	46,523.184	50,656.553	
	Market Price	$ 47.70	$ 49.66	$ 46.40	$ 50.51	$ 49.90	$ 38.01	$ 58.93	$ 61.81	$ 42.12	
Capitalization at Carrying Amounts											
	Debt(D)	2,460,000	161,500	1,851,000	557,845	661,700	1,425,000	1,009,400	1,663,950	679,200	1,163,288
	Preferred(P)	0	0	0	0	0	0	0	0	28,173	3,130
	Equity(E)	3,086,232	300,322	1,508,400	966,166	767,321	1,308,602	932,432	1,488,523	1,246,576	1,289,397
	Total	5,546,232	461,822	3,359,400	1,524,011	1,429,021	2,733,602	1,941,832	3,152,473	1,953,949	2,455,816
Capital Structure Ratios											
	Debt(D)	44.35%	34.97%	55.10%	36.60%	46.30%	52.13%	51.98%	52.78%	34.76%	45.44%
	Preferred(P)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.44%	0.16%
	Equity(E)	55.65%	65.03%	44.90%	63.40%	53.70%	47.87%	48.02%	47.22%	63.80%	54.40%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Betas	Value Line	0.85	0.65	0.70	0.85	0.70	0.80	0.85	0.85	0.80	0.78

Hamada	Bl	=	Bu	[1+	(1 - t)	D/E	+	P/E	]
	0.78	=	Bu	[1+	(1-0.35)	0.4998	+	0.0017	]
	0.78	=	Bu	[1+	0.65	0.4998	+	0.0017	]
	0.78	=	Bu	1.3266					
	0.59	=	Bu						

Hamada	Bl	=	0.59	[1+	(1 - t)	D/E	+	P/E	]
	Bl	=	0.59	[1+	0.65	0.8353	+	0.0029	]
	Bl	=	0.59	1.5458					
	Bl	=	0.91						

M&M	ku	=	ke	-	(((	ku	-	i	)	1-t	)	D	/	E	-	(ku	- d	)	P	/	E
	7.91%	=	9.14%	-	(((	7.91%	-	4.12%	)	0.65	)	33.29%	/	66.60%	-	7.91%	- 5.68%	)	0.11%	/	66.60%
	7.91%	=	9.14%	-	(((	3.79%			)	0.65	)	0.4998			-	2.23%		)	0.0017		
	7.91%	=	9.14%	-	((	2.46%					)	0.4998			-	2.23%		)	0.0017		
	7.91%	=	9.14%	-		1.23%									-	0.00%					

M&M	ke	=	ku	+	(((	ku	-	i	)	1-t	)	D	/	E	+	(ku	- d	)	P	/	E
	9.97%	=	7.91%	+	(((	7.91%	-	4.12%	)	0.65	)	45.44%	/	54.40%	+	7.91%	- 5.68%	)	0.16%	/	54.40%
	9.97%	=	7.91%	+	(((	3.79%			)	0.65	)	0.8353			+	2.23%		)	0.0029		
	9.97%	=	7.91%	+	((	2.46%					)	0.8353			+	2.23%		)	0.0029		
	9.97%	=	7.91%	+		2.05%									+	0.01%					

Analysis of Public Offerings of Gas Distribution Company Common Stock

Company	Date of Offering	No. of shares offered	Dollar amount of offering	Price to public	Underwriters' discount and commission	Gross Proceeds per share	Estimated company issuance expenses	Net proceeds per share	Percent of offering price: Underwriters' discount and commission	Percent of offering price: Estimated company issuance expenses	Percent of offering price: Total Issuance and selling expense
Piedmont Natural Gas Company, Inc.	01/29/13	4,000,000	$ 128,000,000	$32.00	1.120	$30.880	$0.088	$30.792	3.5%	0.3%	3.8%
Atmos Energy Corporation	12/07/06	5,500,000	$ 173,250,000	$31.50	1.103	$30.398	$0.073	$30.325	3.5%	0.2%	3.7%
AGL Resources Inc.	11/19/04	9,600,000	$ 297,696,000	$31.01	0.930	$30.080	$0.042	$30.038	3.0%	0.1%	3.1%
Atmos Energy Corporation	10/21/04	14,000,000	$ 346,500,000	$24.75	0.990	$23.760	$0.029	$23.731	4.0%	0.1%	4.1%
Atmos Energy Corporation	07/19/04	8,650,000	$ 214,087,500	$24.75	0.990	$23.760	$0.046	$23.714	4.0%	0.2%	4.2%
The Laclede Group, Inc.	05/25/04	1,500,000	$ 40,200,000	$26.80	0.871	$25.929	$0.067	$25.862	3.3%	0.3%	3.6%
Northwest Natural Gas Company	03/30/04	1,200,000	$ 37,200,000	$31.00	1.010	$29.990	$0.146	$29.844	3.3%	0.5%	3.8%
Piedmont Natural Gas Company, Inc.	01/23/04	4,250,000	$ 180,625,000	$42.50	1.490	$41.010	$0.082	$40.928	3.5%	0.2%	3.7%
Atmos Energy Corporation	06/18/03	4,000,000	$ 101,240,000	$25.31	1.012	$24.298	$0.095	$24.203	4.0%	0.4%	4.4%
AGL Resources Inc.	02/11/03	5,600,000	$ 123,200,000	$22.00	0.770	$21.230	$0.045	$21.185	3.5%	0.2%	3.7%
WGL Holdings, Inc	06/26/01	1,790,000	$ 47,846,700	$26.73	0.895	$25.835	$0.031	$25.804	3.3%	0.1%	3.4%
Atmos Energy Corporation	11/07/00	6,000,000	$ 133,500,000	$22.25	1.110	$21.140	$0.058	$21.082	5.0%	0.3%	5.3%
Average									3.7%	0.2%	3.9%

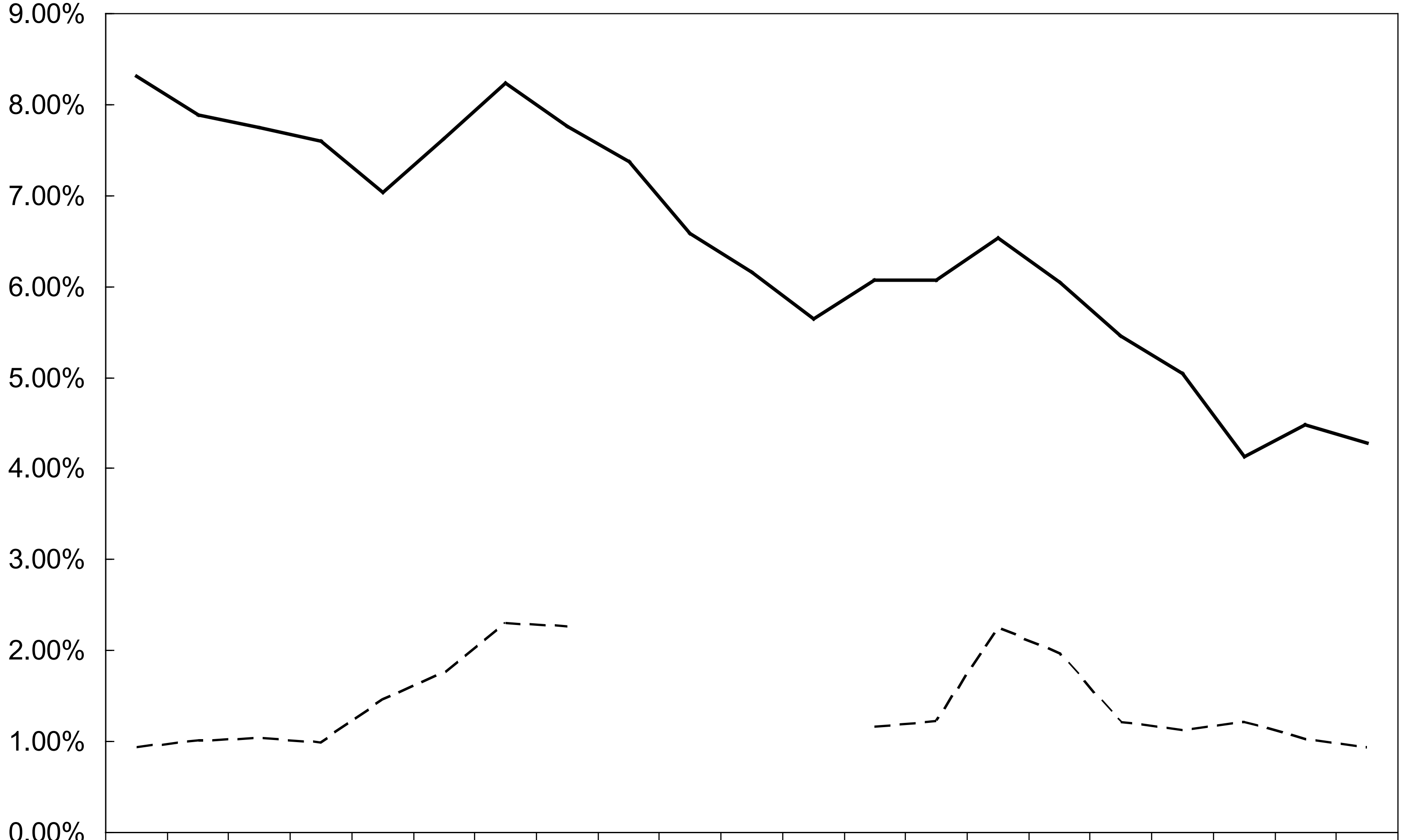
Source of Information: SNL Financial and SEC filings

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2010-2014
and the Twelve Months Ended August 2015

Years	Aa Rated	A Rated	Baa Rated	Average
2010	5.24%	5.46%	5.96%	5.55%
2011	4.78%	5.04%	5.57%	5.13%
2012	3.83%	4.13%	4.86%	4.27%
2013	4.24%	4.48%	4.98%	4.57%
2014	4.19%	4.28%	4.80%	4.42%
Five-Year Average	4.46%	4.68%	5.23%	4.79%
Months				
Sep-14	4.18%	4.24%	4.79%	4.40%
Oct-14	3.98%	4.06%	4.67%	4.24%
Nov-14	4.03%	4.09%	4.75%	4.29%
Dec-14	3.90%	3.95%	4.70%	4.18%
Jan-15	3.52%	3.58%	4.39%	3.83%
Feb-15	3.62%	3.67%	4.44%	3.91%
Mar-15	3.67%	3.74%	4.51%	3.97%
Apr-15	3.63%	3.75%	4.51%	3.96%
May-15	4.05%	4.17%	4.91%	4.38%
Jun-15	4.29%	4.39%	5.13%	4.60%
Jul-15	4.27%	4.40%	5.22%	4.63%
Aug-15	4.13%	4.25%	5.23%	4.54%
Twelve-Month Average	3.94%	4.02%	4.77%	4.24%
Six-Month Average	4.01%	4.12%	4.92%	4.35%
Three-Month Average	4.23%	4.35%	5.19%	4.59%

Source: Mergent Bond Record

Yields on
A-rated Public Utility Bonds and
Spreads over 30-Year Treasuries



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
A-rated Public Utility	8.31%	7.89%	7.75%	7.60%	7.04%	7.62%	8.24%	7.76%	7.37%	6.58%	6.16%	5.65%	6.07%	6.07%	6.53%	6.04%	5.46%	5.04%	4.13%	4.48%	4.28%
Spread vs. 30-year	0.94%	1.01%	1.04%	0.99%	1.46%	1.75%	2.30%	2.27%					1.16%	1.23%	2.25%	1.96%	1.21%	1.13%	1.21%	1.03%	0.94%

A rated Public Utility Bonds over 30-Year Treasuries

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-99	6.97%	5.16%	1.81%
Feb-99	7.09%	5.37%	1.72%
Mar-99	7.26%	5.58%	1.68%
Apr-99	7.22%	5.55%	1.67%
May-99	7.47%	5.81%	1.66%
Jun-99	7.74%	6.04%	1.70%
Jul-99	7.71%	5.98%	1.73%
Aug-99	7.91%	6.07%	1.84%
Sep-99	7.93%	6.07%	1.86%
Oct-99	8.06%	6.26%	1.80%
Nov-99	7.94%	6.15%	1.79%
Dec-99	8.14%	6.35%	1.79%
Jan-00	8.35%	6.63%	1.72%
Feb-00	8.25%	6.23%	2.02%
Mar-00	8.28%	6.05%	2.23%
Apr-00	8.29%	5.85%	2.44%
May-00	8.70%	6.15%	2.55%
Jun-00	8.36%	5.93%	2.43%
Jul-00	8.25%	5.85%	2.40%
Aug-00	8.13%	5.72%	2.41%
Sep-00	8.23%	5.83%	2.40%
Oct-00	8.14%	5.80%	2.34%
Nov-00	8.11%	5.78%	2.33%
Dec-00	7.84%	5.49%	2.35%
Jan-01	7.80%	5.54%	2.26%
Feb-01	7.74%	5.45%	2.29%
Mar-01	7.68%	5.34%	2.34%
Apr-01	7.94%	5.65%	2.29%
May-01	7.99%	5.78%	2.21%
Jun-01	7.85%	5.67%	2.18%
Jul-01	7.78%	5.61%	2.17%
Aug-01	7.59%	5.48%	2.11%
Sep-01	7.75%	5.48%	2.27%
Oct-01	7.63%	5.32%	2.31%
Nov-01	7.57%	5.12%	2.45%
Dec-01	7.83%	5.48%	2.35%
Jan-02	7.66%	5.45%	2.21%
Feb-02	7.54%	5.40%	2.14%
Mar-02	7.76%		
Apr-02	7.57%		
May-02	7.52%		
Jun-02	7.42%		
Jul-02	7.31%		
Aug-02	7.17%		
Sep-02	7.08%		
Oct-02	7.23%		
Nov-02	7.14%		
Dec-02	7.07%		

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-03	7.07%		
Feb-03	6.93%		
Mar-03	6.79%		
Apr-03	6.64%		
May-03	6.36%		
Jun-03	6.21%		
Jul-03	6.57%		
Aug-03	6.78%		
Sep-03	6.56%		
Oct-03	6.43%		
Nov-03	6.37%		
Dec-03	6.27%		
Jan-04	6.15%		
Feb-04	6.15%		
Mar-04	5.97%		
Apr-04	6.35%		
May-04	6.62%		
Jun-04	6.46%		
Jul-04	6.27%		
Aug-04	6.14%		
Sep-04	5.98%		
Oct-04	5.94%		
Nov-04	5.97%		
Dec-04	5.92%		
Jan-05	5.78%		
Feb-05	5.61%		
Mar-05	5.83%		
Apr-05	5.64%		
May-05	5.53%		
Jun-05	5.40%		
Jul-05	5.51%		
Aug-05	5.50%		
Sep-05	5.52%		
Oct-05	5.79%		
Nov-05	5.88%		
Dec-05	5.80%		
Jan-06	5.75%		
Feb-06	5.82%	4.54%	1.28%
Mar-06	5.98%	4.73%	1.25%
Apr-06	6.29%	5.06%	1.23%
May-06	6.42%	5.20%	1.22%
Jun-06	6.40%	5.15%	1.25%
Jul-06	6.37%	5.13%	1.24%
Aug-06	6.20%	5.00%	1.20%
Sep-06	6.00%	4.85%	1.15%
Oct-06	5.98%	4.85%	1.13%
Nov-06	5.80%	4.69%	1.11%
Dec-06	5.81%	4.68%	1.13%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-07	5.96%	4.85%	1.11%
Feb-07	5.90%	4.82%	1.08%
Mar-07	5.85%	4.72%	1.13%
Apr-07	5.97%	4.87%	1.10%
May-07	5.99%	4.90%	1.09%
Jun-07	6.30%	5.20%	1.10%
Jul-07	6.25%	5.11%	1.14%
Aug-07	6.24%	4.93%	1.31%
Sep-07	6.18%	4.79%	1.39%
Oct-07	6.11%	4.77%	1.34%
Nov-07	5.97%	4.52%	1.45%
Dec-07	6.16%	4.53%	1.63%
Jan-08	6.02%	4.33%	1.69%
Feb-08	6.21%	4.52%	1.69%
Mar-08	6.21%	4.39%	1.82%
Apr-08	6.29%	4.44%	1.85%
May-08	6.28%	4.60%	1.68%
Jun-08	6.38%	4.69%	1.69%
Jul-08	6.40%	4.57%	1.83%
Aug-08	6.37%	4.50%	1.87%
Sep-08	6.49%	4.27%	2.22%
Oct-08	7.56%	4.17%	3.39%
Nov-08	7.60%	4.00%	3.60%
Dec-08	6.52%	2.87%	3.65%
Jan-09	6.39%	3.13%	3.26%
Feb-09	6.30%	3.59%	2.71%
Mar-09	6.42%	3.64%	2.78%
Apr-09	6.48%	3.76%	2.72%
May-09	6.49%	4.23%	2.26%
Jun-09	6.20%	4.52%	1.68%
Jul-09	5.97%	4.41%	1.56%
Aug-09	5.71%	4.37%	1.34%
Sep-09	5.53%	4.19%	1.34%
Oct-09	5.55%	4.19%	1.36%
Nov-09	5.64%	4.31%	1.33%
Dec-09	5.79%	4.49%	1.30%
Jan-10	5.77%	4.60%	1.17%
Feb-10	5.87%	4.62%	1.25%
Mar-10	5.84%	4.64%	1.20%
Apr-10	5.81%	4.69%	1.12%
May-10	5.50%	4.29%	1.21%
Jun-10	5.46%	4.13%	1.33%
Jul-10	5.26%	3.99%	1.27%
Aug-10	5.01%	3.80%	1.21%
Sep-10	5.01%	3.77%	1.24%
Oct-10	5.10%	3.87%	1.23%
Nov-10	5.37%	4.19%	1.18%
Dec-10	5.56%	4.42%	1.14%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-11	5.57%	4.52%	1.05%
Feb-11	5.68%	4.65%	1.03%
Mar-11	5.56%	4.51%	1.05%
Apr-11	5.55%	4.50%	1.05%
May-11	5.32%	4.29%	1.03%
Jun-11	5.26%	4.23%	1.03%
Jul-11	5.27%	4.27%	1.00%
Aug-11	4.69%	3.65%	1.04%
Sep-11	4.48%	3.18%	1.30%
Oct-11	4.52%	3.13%	1.39%
Nov-11	4.25%	3.02%	1.23%
Dec-11	4.33%	2.98%	1.35%
Jan-12	4.34%	3.03%	1.31%
Feb-12	4.36%	3.11%	1.25%
Mar-12	4.48%	3.28%	1.20%
Apr-12	4.40%	3.18%	1.22%
May-12	4.20%	2.93%	1.27%
Jun-12	4.08%	2.70%	1.38%
Jul-12	3.93%	2.59%	1.34%
Aug-12	4.00%	2.77%	1.23%
Sep-12	4.02%	2.88%	1.14%
Oct-12	3.91%	2.90%	1.01%
Nov-12	3.84%	2.80%	1.04%
Dec-12	4.00%	2.88%	1.12%
Jan-13	4.15%	3.08%	1.07%
Feb-13	4.18%	3.17%	1.01%
Mar-13	4.20%	3.16%	1.04%
Apr-13	4.00%	2.93%	1.07%
May-13	4.17%	3.11%	1.06%
Jun-13	4.53%	3.40%	1.13%
Jul-13	4.68%	3.61%	1.07%
Aug-13	4.73%	3.76%	0.97%
Sep-13	4.80%	3.79%	1.01%
Oct-13	4.70%	3.68%	1.02%
Nov-13	4.77%	3.80%	0.97%
Dec-13	4.81%	3.89%	0.92%
Jan-14	4.63%	3.77%	0.86%
Feb-14	4.53%	3.66%	0.87%
Mar-14	4.51%	3.62%	0.89%
Apr-14	4.41%	3.52%	0.89%
May-14	4.26%	3.39%	0.87%
Jun-14	4.29%	3.42%	0.87%
Jul-14	4.23%	3.33%	0.90%
Aug-14	4.13%	3.20%	0.93%
Sep-14	4.24%	3.26%	0.98%
Oct-14	4.06%	3.04%	1.02%
Nov-14	4.09%	3.04%	1.05%
Dec-14	3.95%	2.83%	1.12%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-15	3.58%	2.46%	1.12%
Feb-15	3.67%	2.57%	1.10%
Mar-15	3.74%	2.63%	1.11%
Apr-15	3.75%	2.59%	1.16%
May-15	4.17%	2.96%	1.21%
Jun-15	4.39%	3.11%	1.28%
Jul-15	4.40%	3.07%	1.33%
Aug-15	4.25%	2.86%	1.39%
Average:			
12-months			1.16%
6-months			1.25%
3-months			1.33%

Common Equity Risk Premiums
Years 1926-2014

	Large Common Stocks	Long-Term Corp. Bonds	Equity Risk Premium	Long-Term Govt. Bonds Yields
Low Interest Rates	12.21%	4.85%	7.36%	3.00%
Average Across All Interest Rates	12.07%	6.38%	5.69%	5.12%
High Interest Rates	11.93%	7.95%	3.98%	7.28%

Source of Information: Stocks, Bonds, Bills, and Inflation (SBBI) 2015 Classic Yearbook

Basic Series
Annual Total Returns (except yields)

Year	Large Common Stocks	Long-Term Corp. Bonds	Long-Term Govt. Bonds Yields
1940	-9.78%	3.39%	1.94%
1945	36.44%	4.08%	1.99%
1941	-11.59%	2.73%	2.04%
1949	18.79%	3.31%	2.09%
1946	-8.07%	1.72%	2.12%
1950	31.71%	2.12%	2.24%
1939	-0.41%	3.97%	2.26%
1948	5.50%	4.14%	2.37%
2014	13.69%	17.28%	2.40%
2012	16.00%	10.68%	2.41%
1947	5.71%	-2.34%	2.43%
1942	20.34%	2.60%	2.46%
1944	19.75%	4.73%	2.46%
1943	25.90%	2.83%	2.48%
2011	2.11%	17.95%	2.48%
1938	31.12%	6.13%	2.52%
1936	33.92%	6.74%	2.55%
1951	24.02%	-2.69%	2.69%
1954	52.62%	5.39%	2.72%
1937	-35.03%	2.75%	2.73%
1953	-0.99%	3.41%	2.74%
1935	47.67%	9.61%	2.76%
1952	18.37%	3.52%	2.79%
1934	-1.44%	13.84%	2.93%
1955	31.56%	0.48%	2.95%
2008	-37.00%	8.78%	3.03%
1932	-8.19%	10.82%	3.15%
1927	37.49%	7.44%	3.17%
1957	-10.78%	8.71%	3.23%
1930	-24.90%	7.98%	3.30%
1933	53.99%	10.38%	3.36%
1928	43.61%	2.84%	3.40%
1929	-8.42%	3.27%	3.40%
1956	6.56%	-6.81%	3.45%
1926	11.62%	7.37%	3.54%
2013	32.39%	-7.07%	3.67%
1960	0.47%	9.07%	3.80%
1958	43.36%	-2.22%	3.82%
1962	-8.73%	7.95%	3.95%
1931	-43.34%	-1.85%	4.07%
2010	15.06%	12.44%	4.14%
1961	26.89%	4.82%	4.15%
1963	22.80%	2.19%	4.17%
1964	16.48%	4.77%	4.23%
1959	11.96%	-0.97%	4.47%
1965	12.45%	-0.46%	4.50%
2007	5.49%	2.60%	4.50%
1966	-10.06%	0.20%	4.55%
2009	26.46%	3.02%	4.58%
2005	4.91%	5.87%	4.61%
2002	-22.10%	16.33%	4.84%
2004	10.88%	8.72%	4.84%
2006	15.79%	3.24%	4.91%
2003	28.68%	5.27%	5.11%
1998	28.58%	10.76%	5.42%
1967	23.98%	-4.95%	5.56%
2000	-9.10%	12.87%	5.58%
2001	-11.89%	10.65%	5.75%
1971	14.30%	11.01%	5.97%
1968	11.06%	2.57%	5.98%
1972	18.99%	7.26%	5.99%
1997	33.36%	12.95%	6.02%
1995	37.58%	27.20%	6.03%
1970	3.86%	18.37%	6.48%
1993	10.08%	13.19%	6.54%
1996	22.96%	1.40%	6.73%
1999	21.04%	-7.45%	6.82%
1969	-8.50%	-8.09%	6.87%
1976	23.93%	18.65%	7.21%
1973	-14.69%	1.14%	7.26%
1992	7.62%	9.39%	7.26%
1991	30.47%	19.89%	7.30%
1974	-26.47%	-3.06%	7.60%
1986	18.67%	19.85%	7.89%
1994	1.32%	-5.76%	7.99%
1977	-7.16%	1.71%	8.03%
1975	37.23%	14.64%	8.05%
1989	31.69%	16.23%	8.16%
1990	-3.10%	6.78%	8.44%
1978	6.57%	-0.07%	8.98%
1988	16.61%	10.70%	9.19%
1987	5.25%	-0.27%	9.20%
1985	31.73%	30.09%	9.56%
1979	18.61%	-4.18%	10.12%
1982	21.55%	42.56%	10.95%
1984	6.27%	16.86%	11.70%
1983	22.56%	6.26%	11.97%
1980	32.50%	-2.76%	11.99%
1981	-4.92%	-1.24%	13.34%

Yields for Treasury Constant Maturities
Yearly for 2010-2014
and the Twelve Months Ended August 2015

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year	30-Year
2010	0.32%	0.70%	1.11%	1.93%	2.62%	3.21%	4.03%	4.25%
2011	0.18%	0.45%	0.75%	1.52%	2.16%	2.79%	3.62%	3.91%
2012	0.18%	0.28%	0.38%	0.76%	1.22%	1.80%	2.54%	2.92%
2013	0.13%	0.31%	0.54%	1.17%	1.74%	2.35%	3.12%	3.45%
2014	0.12%	0.46%	0.90%	1.64%	2.14%	2.54%	3.07%	3.34%
Five-Year Average	0.19%	0.44%	0.74%	1.40%	1.98%	2.54%	3.28%	3.57%
Months								
Sep-14	0.11%	0.57%	1.05%	1.77%	2.22%	2.53%	3.01%	3.26%
Oct-14	0.10%	0.45%	0.88%	1.55%	1.98%	2.30%	2.77%	3.04%
Nov-14	0.13%	0.53%	0.96%	1.62%	2.03%	2.33%	2.76%	3.04%
Dec-14	0.21%	0.64%	1.06%	1.64%	1.98%	2.21%	2.55%	2.83%
Jan-15	0.20%	0.55%	0.90%	1.37%	1.67%	1.88%	2.20%	2.46%
Feb-15	0.22%	0.62%	0.99%	1.47%	1.79%	1.98%	2.34%	2.57%
Mar-15	0.25%	0.64%	1.02%	1.52%	1.84%	2.04%	2.41%	2.63%
Apr-15	0.23%	0.54%	0.87%	1.35%	1.69%	1.94%	2.33%	2.59%
May-15	0.24%	0.61%	0.98%	1.54%	1.93%	2.20%	2.69%	2.96%
Jun-15	0.28%	0.69%	1.07%	1.68%	2.10%	2.36%	2.85%	3.11%
Jul-15	0.30%	0.67%	1.03%	1.63%	2.04%	2.32%	2.77%	3.07%
Aug-15	0.38%	0.70%	1.03%	1.54%	1.91%	2.17%	2.55%	2.86%
Twelve-Month Average	0.22%	0.60%	0.99%	1.56%	1.93%	2.19%	2.60%	2.87%
Six-Month Average	0.28%	0.64%	1.00%	1.54%	1.92%	2.17%	2.60%	2.87%
Three-Month Average	0.32%	0.69%	1.04%	1.62%	2.02%	2.28%	2.72%	3.01%

Source: Federal Reserve statistical release H.15

Measures of the Risk-Free Rate & Corporate Bond Yields

The forecast of Treasury and Corporate yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated September 1, 2015

		Treasury					Corporate	
Year	Quarter	1-Year Bill	2-Year Note	5-Year Note	10-Year Note	30-Year Bond	Aaa Bond	Baa Bond
2015	Third	0.4%	0.7%	1.6%	2.3%	3.0%	4.1%	5.1%
2015	Fourth	0.6%	1.0%	1.8%	2.5%	3.1%	4.2%	5.2%
2016	First	0.9%	1.3%	2.1%	2.6%	3.3%	4.4%	5.4%
2016	Second	1.2%	1.6%	2.3%	2.8%	3.5%	4.6%	5.5%
2016	Third	1.5%	1.9%	2.5%	3.0%	3.7%	4.7%	5.7%
2016	Fourth	1.8%	2.1%	2.7%	3.2%	3.8%	4.9%	5.8%

Measures of the Market Premium

Value Line Return					
As of:	Dividend Yield		Median Appreciation Potential		Median Total Return
11-Sep-15	2.3%	+	10.67%	=	12.97%

DCF Result for the S&P 500 Composite					
D/P	(1+.5g)	+	g	=	k
2.17%	(1.0354)	+	7.07%	=	9.32%

where:	Price (P)	at	31-Aug-15	=	1972.18
	Dividend (D)	for	2nd Qtr. '15	=	10.70
	Dividend (D)		annualized	=	42.80
	Growth (g)	by	First Call	=	7.07%

Summary			
Value Line			12.97%
S&P 500			9.32%
Average			11.15%
Risk-free Rate of Return (Rf)			3.75%
Forecast Market Premium			7.40%
Historical Market Premium	(Rm)	(Rf)	
1926-2014 Arith. mean	12.14%	4.06%	8.08%
Average - Forecast/Historical			7.74%

This phenomenon can also be viewed graphically, as depicted in the Graph 7-2. The security market line is based on the pure CAPM without adjusting for the size premium. Based on the risk (or beta) of a security, the expected return should fluctuate along the security market line. However, the expected returns for the smaller deciles of the NYSE/AMEX/NASDAQ lie above the line, indicating that these deciles have had returns in excess of those appropriate for their systematic risk.

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

Decile	Beta*	Arithmetic Mean Return (%)	Actual Return in Excess of Riskless Rate** (%)	CAPM Return in Excess of Riskless Rate† (%)	Size Premium (Return in Excess of CAPM) (%)
1	0.91	11.15	6.08	6.40	-0.32
2	1.04	12.96	7.89	7.24	0.65
3	1.10	13.71	8.64	7.70	0.94
4	1.13	14.01	8.93	7.88	1.05
5	1.16	14.84	9.76	8.11	1.65
6	1.19	15.01	9.94	8.31	1.63
7	1.24	15.53	10.46	8.69	1.77
8	1.30	16.35	11.27	9.10	2.18
9	1.35	17.13	12.06	9.42	2.64
10	1.40	20.62	15.54	9.82	5.72
Mid-Cap, 3-5	1.12	14.00	8.93	7.83	1.10
Low-Cap, 6-8	1.23	15.44	10.36	8.59	1.77
Micro-Cap, 9-10	1.36	18.26	13.18	9.49	3.69

Data from 1926–2014.

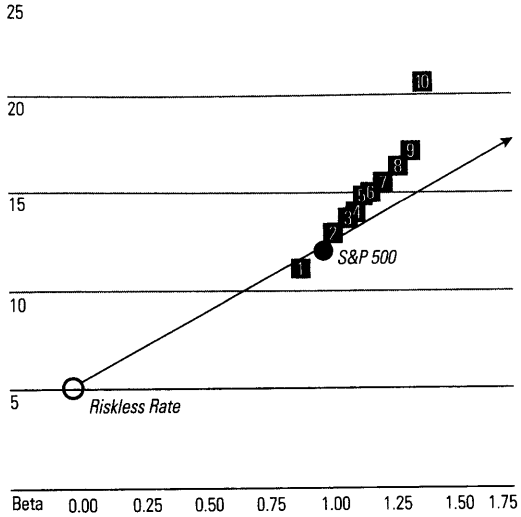
*Betas are estimated from monthly returns in excess of the 30-day U.S. Treasury bill total return, January 1926–December 2014.

**Historical riskless rate measured by the 89-year arithmetic mean income return component of 20-year government bonds (5.07%).

†Calculated in the context of the CAPM by multiplying the equity risk premium by beta. The equity risk premium is estimated by the arithmetic mean total return of the S&P 500 (12.07%) minus the arithmetic mean income return component of 20-year government bonds (5.07%) from 1926–2014.

Source: Morningstar and CRSP. Calculated (or Derived) based on data from CRSP US Stock Database and CRSP US Indices Database ©2015 Center for Research in Security Prices (CRSP®), The University of Chicago Booth School of Business. Used with permission.

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



Data from 1926–2014.

Serial Correlation in Small-Cap Stock Returns

In four of the last 10 years, large-capitalization stocks (deciles 1-2 of NYSE/AMEX/NASDAQ) have outperformed small-capitalization stocks (deciles 9-10). This has led some market observers to speculate that there is no size premium. But statistical evidence suggests that periods of underperformance should be expected. For instance, large-cap stocks have outperformed small-cap stocks in nearly half of the years since 1926. It should be noted, however, that large-cap stocks' average historical outperformance has been less than the average historical outperformance of small-cap stocks.

History tells us that small companies are riskier than large companies. Table 7-1 [see page 100] shows the standard deviation (a measure of risk) for each decile of the NYSE/AMEX/NASDAQ. As one moves from larger to smaller deciles, the standard deviation of return grows. Investors are compensated for taking on this additional risk by the higher returns provided by small companies. It is important to note, however, that the risk/return profile is over the long term. If small companies did not provide higher long-term returns, investors would be more inclined to invest in the less-risky stocks of large companies.

Comparable Earnings Approach
Using Non-Utility Companies with
Timeliness of 2, 3 & 4; Safety Rank of 1, 2 & 3; Financial Strength of B++, A & A+;
Price Stability of 85 to 100; Betas of .65 to .85; and Technical Rank of 3, 4 & 5

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
Airgas Inc.	CHEMSPEC	3	1	A	90	0.85	3
Alleghany Corp.	INSPRPTY	3	1	A	100	0.75	3
Bard (C.R.)	MEDICINV	2	1	A+	90	0.80	4
Berkley (W.R.)	INSPRPTY	3	1	A	100	0.75	3
Bio-Techne Corp.	BIOTECH	4	1	A+	90	0.80	4
Brown-Forman 'B'	BEVERAGE	2	1	A+	95	0.85	3
Clorox Co.	HOUSEPRD	3	2	B++	100	0.65	4
Copart Inc.	RETAUTO	3	2	A	85	0.85	3
DaVita HealthCare	MEDSERV	3	2	B++	85	0.85	3
Dollar Tree Inc.	RETAIL	2	2	A	85	0.65	3
Dr Pepper Snapple	BEVERAGE	2	2	A	95	0.65	4
Ecolab Inc.	CHEMSPEC	2	1	A	95	0.85	3
Erie Indemnity	INSPRPTY	4	2	B++	95	0.75	3
Gallagher (Arthur J.)	FINSERV	3	1	A	95	0.85	3
Gen'l Mills	FOODPROC	3	1	A+	100	0.65	3
Hanover Insurance	INSPRPTY	3	2	B++	90	0.85	4
Hormel Foods	FOODPROC	2	1	A	95	0.75	3
Kellogg	FOODPROC	4	1	A	100	0.65	5
Kroger Co.	GROCERY	2	2	A	90	0.75	4
Laboratory Corp.	MEDSERV	3	1	A	90	0.80	3
Lancaster Colony	HOUSEPRD	3	1	A+	90	0.80	3
Lilly (Eli)	DRUG	4	1	A+	95	0.80	3
Markel Corp.	INSPRPTY	2	1	A	100	0.70	4
Marsh & McLennan	FINSERV	2	2	A	95	0.85	3
McCormick & Co.	FOODPROC	3	1	A+	100	0.75	3
Motorola Solutions	TELEQUIP	3	1	A	90	0.85	5
Paychex Inc.	ITSERV	3	1	A	95	0.85	3
Philip Morris Int'l	TOBACCO	4	2	B++	95	0.80	5
Progressive (Ohio)	INSPRPTY	3	2	B++	95	0.85	4
RLI Corp.	INSPRPTY	3	2	B++	85	0.85	4
Republic Services	ENVIRONM	3	2	B++	95	0.80	4
Synopsys Inc.	SOFTWARE	2	1	A	90	0.85	3
Sysco Corp.	GROCERY	4	1	A+	100	0.75	3
Verisk Analytics	INFOSER	3	2	B++	95	0.70	3
Waste Management	ENVIRONM	3	1	A	95	0.85	4
Watsco Inc.	BUILDSUP	2	2	A	85	0.85	3
West Pharmac. Svcs.	MEDICNON	3	2	B++	85	0.85	3
Average		3	1	A	93	0.79	3
Gas Group	Average	3	2	A	97	0.78	4

Source of Information: Value Line Investment Survey for Windows, August 2014

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2010-2014 and
Projected 3-5 Year Returns

Company	2010	2011	2012	2013	2014	Average	Projected 2018-20
Airgas Inc.	14.4%	17.9%	22.2%	19.1%	17.1%	18.1%	22.5%
Alleghany Corp.	4.6%	4.9%	11.0%	7.1%	5.8%	6.7%	6.5%
Bard (C.R.)	32.8%	31.9%	29.4%	22.7%	36.1%	30.6%	22.0%
Berkley (W.R.)	11.4%	7.7%	8.8%	9.7%	10.6%	9.6%	10.0%
Bio-Techne Corp.	21.9%	19.2%	16.7%	15.3%	14.0%	17.4%	10.5%
Brown-Forman 'B'	25.4%	24.8%	35.4%	32.4%	35.9%	30.8%	29.0%
Clorox Co.	NMF	-	NMF	NMF	NMF	-	NMF
Copart Inc.	13.9%	30.0%	32.5%	23.6%	19.9%	24.0%	15.5%
DaVita HealthCare	22.8%	22.5%	16.3%	18.4%	15.2%	19.0%	17.0%
Dollar Tree Inc.	27.2%	36.3%	34.9%	51.0%	33.6%	36.6%	22.0%
Dr Pepper Snapple	23.7%	26.8%	26.9%	26.5%	30.6%	26.9%	19.0%
Ecolab Inc.	24.9%	10.5%	14.7%	14.7%	17.4%	16.4%	15.5%
Erie Indemnity	17.8%	21.4%	24.9%	22.2%	24.0%	22.1%	29.0%
Gallagher (Arthur J.)	14.8%	11.9%	11.8%	12.9%	9.4%	12.2%	11.5%
Gen'l Mills	29.1%	26.0%	26.6%	26.8%	27.9%	27.3%	32.5%
Hanover Insurance	6.2%	1.3%	1.8%	8.8%	8.2%	5.3%	9.5%
Hormel Foods	17.0%	17.8%	17.7%	15.9%	16.7%	17.0%	17.5%
Kellogg	57.8%	69.9%	53.6%	38.9%	50.1%	54.1%	37.0%
Kroger Co.	21.1%	30.0%	33.8%	27.8%	32.6%	29.1%	23.0%
Laboratory Corp.	23.7%	25.9%	24.4%	25.6%	20.4%	24.0%	16.0%
Lancaster Colony	23.7%	20.6%	17.0%	21.8%	19.1%	20.4%	18.5%
Lilly (Eli)	42.2%	36.3%	25.6%	25.5%	19.4%	29.8%	26.0%
Markel Corp.	7.7%	3.7%	6.5%	3.5%	3.6%	5.0%	5.5%
Marsh & McLennan	8.6%	16.2%	17.8%	16.9%	20.2%	15.9%	20.5%
McCormick & Co.	24.4%	23.1%	24.0%	21.5%	24.4%	23.5%	22.5%
Motorola Solutions	11.1%	17.0%	29.2%	35.0%	23.2%	23.1%	NMF
Paychex Inc.	34.0%	34.4%	34.2%	32.1%	35.3%	34.0%	44.5%
Philip Morris Int'l	NMF	NMF	NMF	NMF	NMF	-	NMF
Progressive (Ohio)	16.6%	16.5%	11.7%	14.8%	16.5%	15.2%	18.0%
RLI Corp.	13.9%	14.7%	10.9%	13.5%	13.6%	13.3%	12.0%
Republic Services	8.4%	9.7%	8.6%	9.0%	9.0%	8.9%	10.0%
Synopsys Inc.	9.1%	10.2%	12.6%	13.7%	13.1%	11.7%	15.0%
Sysco Corp.	30.9%	24.5%	23.9%	19.1%	17.7%	23.2%	23.5%
Verisk Analytics	-	-	NMF	NMF	NMF	-	19.0%
Waste Management	16.2%	16.6%	15.2%	17.7%	19.7%	17.1%	24.0%
Watsco Inc.	10.6%	11.3%	13.8%	15.2%	17.1%	13.6%	19.0%
West Pharmac. Svcs.	11.6%	12.5%	13.3%	12.4%	13.3%	12.6%	15.5%
Average						20.4%	19.4%
Median						18.6%	18.8%
Average (excluding companies with values >20%)						12.3%	13.3%

Comparable Earnings Approach

Screening Parameters

Timeliness Rank

The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.