

July 21, 2020

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: *Panhandle Eastern Pipe Line Company, LP, et al.*
Prepared Rebuttal Testimony
Docket Nos. RP19-1523-000, et al.

Dear Ms. Bose:

Pursuant to the Presiding Administrative Law Judge's Order Adopting Procedural Schedule issued October 16, 2019, as amended June 17, 2020, Panhandle Eastern Pipe Line Company, LP ("Panhandle") hereby submits for filing the following rebuttal testimony and exhibits:

- 1) Exhibit No. PE-0228 – Prepared Rebuttal Testimony of A. E. Bulkley
 - i) Exhibit No. PE-0229 – supporting documents and materials.

Pursuant to the procedural schedule in this proceeding, Panhandle is filing its prepared rebuttal testimony on Return on Equity (ROE) related matters. Panhandle is serving all parties on the Commission's service lists with copies of the filed rebuttal testimony and exhibits. Panhandle also is serving the Presiding Administrative Law Judge and her law clerk with electronic copies of the filed rebuttal testimony and exhibits.

Respectfully submitted,

PANHANDLE EASTERN PIPE LINE COMPANY, LP

/s/ Michael T. Langston
Michael T. Langston
Vice President, Chief Regulatory Officer

Attachments

Panhandle Eastern Pipe Line Company, LP

Index of Prepared Rebuttal Testimony and Exhibits

<u>Witness</u>	<u>Exhibit No.</u>	<u>Description</u>	<u>Confidentiality Designation</u>
A. E. Bulkley	PE-0228	Prepared Rebuttal Testimony	Public
	PE-0229	Schedule 1: Summary of ROE Model Results	Public
		Schedule 2: Discounted Cash Flow ("DCF") Results	Public
		Schedule 3: Capital Asset Pricing Model	Public
		Schedule 4: EPS Growth Rates	Public
		Schedule 5: Value Line Reports	Public
		Schedule 6: Standard & Poor's ("S&P") Earnings and Estimates Report	Public
		Schedule 7: Dominion Press Release and 2019 SEC Form 10-K	Public
		Schedule 8: EPS Growth Rate History	Public
		Schedule 9: S&P Report on U.S. Midstream Industry	Public
		Schedule 10: Moody's Report on Midstream Energy	Public
		Schedule 11: Discovery Responses Provided by Opposing Witnesses	Public
		Schedule 12: S&P 500 Price Data	Public
		Schedule 13: Market Price Changes	Public
		Schedule 14: Michigan Public Service Commission Order	Public
		Schedule 15: Adjustment of PMDG CAPM	Public
		Schedule 16: Chicago Board Options Exchange Volatility Index	Public
		Schedule 17: TC Pipelines L.P. S&P Credit Rating	Public

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Panhandle Eastern Pipe Line Company, LP) Docket Nos. RP19-1523-000, et al.
)
)

**PREPARED REBUTTAL TESTIMONY
OF ANN E. BULKLEY ON BEHALF OF
PANHANDLE EASTERN PIPE LINE COMPANY, LP**

July 21, 2020

**Summary of
Prepared Rebuttal Testimony of
Ann E. Bulkley**

Panhandle Witness Ann E. Bulkley's Prepared Rebuttal Testimony responds to the Prepared Direct and Answering Testimony (Exhibit No. S-0106) and Supplemental Testimony (Exhibit No. S-0159) of John Johnson, filed on behalf of the Federal Energy Regulatory Commission ("FERC" or "Commission"), the Prepared Answering Testimony (Exhibit No. MPC-0015) of Bonnie Janssen on behalf of the Michigan Public Service Commission ("MPSC"), and the Prepared Answering Testimony (Exhibit No. MPC-0021), and Supplemental Testimony (Exhibit No. MPC-0034) of Kirk D. Megginson on behalf of the MPSC and the Prepared Direct and Answering Testimony (Exhibit No. PMG-0001) and Supplemental Testimony (Exhibit No. PMG-0018) of Elizabeth Crowe on behalf of the Panhandle Municipal Defense Group ("PMDG") (collectively, the "Opposing Witnesses"). Specifically, she is responding to their cost of equity¹ recommendations, and the analyses used to support their recommendations.

¹ Throughout Panhandle Witness Bulkley's testimony, she interchangeably use the terms "Return on Equity (ROE)" and "Cost of Equity."

Ms. Bulkley discusses the methodologies relied upon by the Opposing Witnesses in their respective Direct and Answering Testimonies and their Supplemental Testimonies that was filed to address the Return on Equity (“ROE”) methodology that the Commission recently issued in its *Policy Statement on Determining Return on Equity for Natural Gas and Oil Pipelines*, Docket No. PL19-4-000, 171 FERC ¶ 61,155 (2020) (“Pipeline ROE Policy Statement”) that requires the use of an equal weighting of the two-stage Discounted Cash Flow (“DCF”) model and the Capital Asset Pricing Model (“CAPM”) to develop the ROE. Ms. Bulkley explains how the analyses filed in the Opposing Witnesses’ Direct and Answering Testimonies were not consistent with the methodology determined by the Commission in the Pipeline ROE Policy Statement and should not be considered in setting the ROE for Panhandle. Furthermore, Witness Bulkley’s Prepared Rebuttal Testimony demonstrates that the Supplemental Testimonies filed by the Opposing Witnesses also do not meet the Commission’s guidelines that were either established or affirmed by the Pipeline ROE Policy Statement.

As discussed in Ms. Bulkley’s Prepared Rebuttal Testimony, the ROE estimation methodologies developed in the Opposing Witnesses’ Direct and Answer Testimonies are not consistent with the methodology that was determined by the Commission in the Pipeline ROE Policy Statement, therefore the results from the analyses presented in their Direct and Answer Testimonies should not be used to establish an ROE for Panhandle. Likewise, Ms. Bulkley sets out in her Prepared

Rebuttal Testimony how the methodologies used by the Opposing Witnesses' in their Supplemental Testimonies are not consistent with the Commission's Pipeline ROE Policy Statement. In addition to such inconsistencies with the Commission's methodology, there are two primary areas of disagreement between Ms. Bulkley and the Opposing Witnesses, which are (i) the development of the proxy group and (ii) the Earnings Per Share ("EPS") growth rates relied on in the DCF model. Witness Bulkley's Prepared Rebuttal Testimony discusses why certain proxy companies that are included by the Opposing Witnesses are not risk comparable to Panhandle and that reliance on the DCF results for these companies understates the cost of equity for Panhandle.

Witness Bulkley's Prepared Rebuttal Testimony also addresses the data that has been relied upon by the Opposing Witnesses and concludes that such data has been greatly influenced by market conditions that have been affected by the pandemic and therefore should not be considered in developing the ROE for Panhandle. Ms. Bulkley's testimony demonstrates that growth rates were first affected by the pandemic in February 2020 and that the effects of the current conditions are still present in the growth rate data as of the end of May. Therefore, Ms. Bulkley updated the results for several proxy groups using data through the end of the test period in this proceeding, January 31, 2020, which is prior to the pandemic and the supply and demand shocks to the country's pipeline segment and the market overall.

Panhandle Witness Bulkley also presents evidence and provides a recommendation regarding a range of reasonable returns on equity to set the ROE for Panhandle, to be used for ratemaking purposes. Based on the models that are consistent with the approach outlined by the Commission in the Pipeline ROE Policy Statement, using several proxy groups and considering Panhandle's business risks as compared to the average proxy group company, Ms. Bulkley concludes that the recommended ROE of 14.67 percent that she presented in her Prepared Direct Testimony (Exhibit No. PE-0036) is appropriate for Panhandle.

TABLE OF CONTENTS

I.	INTRODUCTION	1
A.	Summary of Testimony	2
II.	PROXY GROUP SELECTION.....	9
A.	Dominion	13
B.	National Fuel Gas	18
C.	Tallgrass Energy Partners.....	22
D.	TC Pipelines.....	23
E.	Common Proxy Group Companies.....	32
III.	COST OF EQUITY ESTIMATION APPROACHES.....	34
A.	DCF Analyses	39
B.	Recent Market Conditions	40
C.	Growth Rates	46
IV.	CAPM ANALYSES	55
V.	RISK ANALYSIS.....	71
VI.	SUMMARY AND CONCLUSIONS	77

TABLE OF ACRONYMS

CAPM	Capital Asset Pricing Model
Commission	Federal Energy Regulatory Commission
Concentric	Concentric Energy Advisors, Inc.
DCF	Discounted Cash Flow
Dominion	Dominion Energy, Inc.
Enable	Enable Midstream Partners LP
EPS	Earnings Per Share
EQM	EQM Midstream Partners, LP
FERC	Federal Energy Regulatory Commission
KMI	Kinder Morgan, Inc.
MLP	Master Limited Partnership
Moody's	Moody's Investors Service
MPSC	Michigan Public Service Commission
MRP	Market Risk Premium
NFG	National Fuel Gas Company
Northern	Northern Natural Gas Company
Panhandle	Panhandle Eastern Pipe Line Company, LP
PMDG	Panhandle Municipal Defense Group
ROE	Return on Equity
S&P	Standard and Poor's
Tallgrass	Tallgrass Energy, LP
TC Energy	TC Energy Corporation
TC PipeLines	TC PipeLines, LP
Trial Staff	Commission Trial Staff
Williams	Williams Companies, Inc.

TABLE OF EXHIBITS

Exhibit No.	Description	Confidentiality Designation
PE-0229	Schedule 1: Summary of ROE Model Results	Public
PE-0229	Schedule 2: Discounted Cash Flow (“DCF”) Results	Public
PE-0229	Schedule 3: Capital Asset Pricing Model	Public
PE-0229	Schedule 4: EPS Growth Rates	Public
PE-0229	Schedule 5: Value Line Reports	Public
PE-0229	Schedule 6: Standard and Poor’s (“S&P”) Earnings and Estimates	Public
PE-0229	Schedule 7: Dominion Press Release and 2019 SEC Form 10-K	Public
PE-0229	Schedule 8: EPS Growth Rate History	Public
PE-0229	Schedule 9: S&P Report on U.S. Midstream Energy	Public
PE-0229	Schedule 10: Moody’s Report on Midstream Energy	Public
PE-0229	Schedule 11: Discovery Responses Provided by Opposing Witnesses	Public
PE-0229	Schedule 12: S&P 500 Price Data	Public
PE-0229	Schedule 13: Market Price Changes	Public
PE-0229	Schedule 14: Michigan Public Service Commission Order	Public
PE-0229	Schedule 15: Adjustment of PMDG CAPM	Public
PE-0229	Schedule 16: Chicago Board Options Exchange Volatility Index	Public
PE-0229	Schedule 17: TC Pipelines L.P. S&P Credit Rating	Public

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Panhandle Eastern Pipe Line Company, LP) Docket Nos. RP19-1523-000, et al.

**PREPARED REBUTTAL TESTIMONY
OF
ANN E. BULKLEY**

I. INTRODUCTION

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

A. My name is Ann E. Bulkley. I am employed by Concentric Energy Advisors, Inc. (“Concentric”) as a Senior Vice President. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. On whose behalf are you submitting this Testimony?

A. I am submitting this Testimony on behalf of Panhandle Eastern Pipe Line Company, LP (“Panhandle”).

Q. Are you the same Ann E. Bulkley who previously filed testimony on behalf of Panhandle in this proceeding?

A. Yes, I am. I filed Prepared Direct Testimony and supporting exhibits as Exhibit Nos. PE-0036 through PE-0039 on August 30, 2019 in Docket No. RP19-1523-

000 and Prepared Answering Testimony and supporting exhibits as Exhibit Nos.
PE-0082 through PE-0084 on October 7, 2019 in Docket No. RP19-78-000 et al.

A. Summary of Testimony

Q. What is the purpose of your Prepared Rebuttal Testimony?

A. I have been asked by Panhandle to evaluate the Prepared Direct and Answering
Testimony (Exhibit No. S-0106) and Supplemental Testimony (Exhibit No. S-
0159) of John Johnson, filed on behalf of the Federal Energy Regulatory
Commission (“FERC” or “Commission”), the Prepared Answering Testimony
(Exhibit No. MPC-0015) of Bonnie Janssen on behalf of the Michigan Public
Service Commission (“MPSC”), and the Prepared Answering Testimony (Exhibit
No. MPC-0021) and Supplemental Testimony (Exhibit No. MPC-0034) of Kirk D.
Megginson on behalf of the MPSC and the Prepared Direct and Answering
Testimony (Exhibit No. PMG-0001) and Supplemental Testimony (Exhibit No.
PMG-0018) of Elizabeth Crowe on behalf of the Panhandle Municipal Defense
Group (“PMDG”) (collectively, the “Opposing Witnesses”). Specifically, I am

1 responding to their cost of equity² recommendations, and the analyses used to
2 support their recommendations. My Prepared Rebuttal Testimony also presents
3 evidence and provides a recommendation regarding a range of reasonable returns
4 on equity to help set the Return on Equity (“ROE”) for Panhandle, to be used for
5 ratemaking purposes.

6 **Q. Have you provided any exhibits with your testimony?**

7 A. Yes. I have included the following exhibits:

<u>Exhibit No.</u>	<u>Exhibit Description</u>
Exhibit No. PE-0228	Prepared Rebuttal Testimony of Ann E. Bulkley
Exhibit No. PE-0229	
Schedule 1	Summary of ROE Model Results
Schedule 2	Discounted Cash Flow (“DCF”) Results
Schedule 3	Capital Asset Pricing Model
Schedule 4	EPS Growth Rates
Schedule 5	Value Line Reports
Schedule 6	Standard & Poor’s (“S&P”) Earnings and Estimates

² Throughout my testimony, I interchangeably use the terms “ROE” and “Cost of Equity.”

1	Schedule 7	Dominion Press Release and 2019 SEC Form 10-K
2	Schedule 8	EPS Growth Rate History
3	Schedule 9	S&P Report on U.S. Midstream Industry
4	Schedule 10	Moody's Report on Midstream Energy
5	Schedule 11	Discovery Responses Provided by Opposing Witnesses
6	Schedule 12	S&P 500 Price Data
7	Schedule 13	Market Price Changes
8	Schedule 14	Michigan Public Service Commission Order
9	Schedule 15	Adjustment of PMDG CAPM
10	Schedule 16	Chicago Board Options Exchange Volatility Index
11	Schedule 17	TC PipeLines L.P. S&P Credit Rating

12 **Q. Were these exhibits prepared by you or under your direction?**

13 A. Yes, they were.

14 **Q. Please summarize your Prepared Rebuttal Testimony.**

15 A. For the reasons discussed in the remainder of my rebuttal testimony, my primary
16 observations and conclusions with respect to the testimony of the Opposing
17 Witnesses relate to the following:

- 18 • Despite the FERC's recent review of multiple ROE estimation models and
19 the consideration of those models in determining a reasonable range of
20 ROEs in recent orders, and the ability to update their analyses to address

1 the Commission's recently issued *Policy Statement on Determining Return*
2 *on Equity for Natural Gas and Oil Pipelines*, Docket No. PL19-4-000, 171
3 FERC ¶ 61,155 (2020) ("Pipeline ROE Policy Statement"), the Opposing
4 Witnesses have not relied on methodologies that are consistent with the
5 Commission's stated methodology in the development of their ROE
6 recommendations.

- 7 • Since the filing of my Prepared Direct Testimony and the Prepared Direct
8 and Answering Testimony of the Opposing Witnesses in Docket No. RP19-
9 1523-000, the FERC issued its Pipeline ROE Policy Statement that
10 requires, among other things, the use of an equal weighting of the two-stage
11 DCF model and the Capital Asset Pricing Model ("CAPM") to develop the
12 ROE. The recommendations presented by each of the Opposing Witnesses
13 in this proceeding in their Prepared Direct and Answering Testimonies
14 relied exclusively on the results of their DCF model results, which is not
15 consistent with the FERC's decision in the Pipeline ROE Policy Statement.
16 In their Supplemental Testimonies, the Opposing Witnesses also have not
17 provided updated analyses that are consistent with the Commission's
18 methodology.
- 19 • In his Direct and Answering Testimony, Commission Trial Staff ("Trial
20 Staff") Witness Johnson prepared both a DCF and CAPM analysis,

1 however his recommendation was based entirely on the result of his DCF
2 model, which is inconsistent with the FERC's decision in the Pipeline ROE
3 Policy Statement. In his Supplemental Testimony, Trial Staff Witness
4 Johnson rescreened his proxy group and relied on a proxy group for the
5 DCF of four companies, one of which is not risk-comparable to Panhandle
6 and should be eliminated from the group. As Trial Staff Witness Johnson
7 acknowledges, the Commission has maintained that the proxy group must
8 be at least four companies. Furthermore, Trial Staff Witness Johnson uses
9 different proxy groups in the calculation of the DCF and CAPM
10 methodologies and then equally weighs the results of those models. The
11 Commission's Pipeline ROE Policy Statement does not provide for the use
12 of differing proxy groups for each ROE estimation methodology.

- 13 • In their Direct and Answering Testimonies, MPSC Witness Megginson and
14 PMDG Witness Crowe did not develop an analysis of the ROE using the
15 CAPM. Therefore, the recommendations offered by these witnesses in their
16 Direct and Answering Testimonies are not consistent with the
17 methodologies that the FERC is requiring and should not be relied on in
18 this proceeding.
- 19 • In his Supplemental Testimony, MPSC Witness Megginson did not
20 rescreen the members of his proposed proxy group. Mr. Megginson did not

1 update his DCF approach in his Supplemental Testimony, relying on data
2 as of March 20, 2020 for that model. MPSC Witness Megginson developed
3 a CAPM model using market return data from Trial Staff Witness
4 Johnson's Direct and Answering testimony. Witness Megginson's CAPM
5 analysis cannot be relied upon however because the analysis was developed
6 using an inconsistent set of assumptions. Mr. Megginson uses market
7 return data as of March 2020 and a risk-free rate and Betas through June 1,
8 2020. This inconsistency renders MPSC Witness Megginson's CAPM
9 unusable.

- 10 • Likewise, PMDG Witness Crowe did not rescreen the members of her
11 proposed proxy group in her Supplemental Testimony. PMDG Witness
12 Crowe updates her DCF analysis through May 31, 2020 and develops a
13 CAPM using data through June 10, 2020. Witness Crowe's CAPM analysis
14 is flawed in that it relies on an outlier test in the CAPM that was
15 specifically considered and rejected by the Commission in its Pipeline ROE
16 Policy Statement. Therefore, the results of PMDG Witness Crowe's
17 CAPM are invalid.

- 18 • In addition, the Opposing Witnesses have relied on growth rate data in their
19 DCF analyses that have been influenced by significant short-term market
20 conditions that should not be considered appropriate to establish a forward-

1 looking cost of equity. As a result, the DCF results developed by the
2 Opposing Witnesses reflect extraordinary market conditions that cannot be
3 expected to continue over the period that rates would be in effect,
4 understating the cost of equity for Panhandle.

- 5 • The Opposing Witnesses have relied on certain proxy companies that are
6 not risk comparable to Panhandle. Reliance on the DCF results for these
7 companies understates the cost of equity for Panhandle.
- 8 • Updating the results for several proxy groups results in a range of median
9 results from 12.43 percent to 15.04 percent. The upper bound for these
10 proxy groups results in a range of returns from 18.40 percent to 19.31
11 percent.
- 12 • Based on the model results using this combined proxy group and
13 considering Panhandle's business risks as compared to the average proxy
14 group company, it is reasonable to consider an ROE above the median
15 result. Taking these factors into consideration, the 14.67 percent ROE that
16 I recommended in my Prepared Direct Testimony is appropriate for
17 Panhandle.

1 **II. PROXY GROUP SELECTION**

2 **Q. Please summarize the differences between the proxy group that you relied on**
3 **and the proxy groups that have been proposed by the Opposing Witnesses in**
4 **this docket.**

5 A. As summarized in Figure 1 below there are several differences between the proxy
6 group that I have relied on and the groups proposed by the Opposing Witnesses in
7 this docket.

1

Figure 1: Comparison of Proxy Companies

Proxy Company	Ticker	Bulkley	MPSC	Trial Staff	Trial Staff Supplemental	PMD G1	PMD G2
Enbridge, Inc.	ENB	X	X	X	X		
Enable Midstream Partners LP	ENBL	X					X
EQM Midstream Partners, LP	EQM	X					X
Kinder Morgan, Inc.	KMI	X	X	X	X ³	X	X
TC PipeLines, LP	TCP	X			X ⁴		
TC Energy Corporation	TRP	X	X	X	X	X	X
Williams Companies, Inc.	WMB	X	X	X	X	X	X
Dominion Energy, Inc.	D		X			X	X
National Fuel Gas Company	NFG		X	X	X	X	X
Tallgrass Energy Partners, LP	TGE						X

2

³ Trial Staff Witness Johnson used Kinder Morgan, Inc. only in his CAPM in his Supplemental Testimony. Exhibit No. S-0159.

⁴ Trial Staff Witness Johnson used TC PipeLines, LP only in his CAPM in his Supplemental Testimony. Exhibit No. S-0159.

1 **Q. How does the Commission determine the proxy group for a pipeline**
2 **company?**

3 A. In the Pipeline ROE Policy Statement, the Commission reaffirmed the overall
4 screening criteria that it has relied on since its issuance of *Composition of Proxy*
5 *Groups for Determining Gas and Oil Pipeline Return on Equity*, 123 FERC ¶
6 61,048 (2008) (“2008 Policy Statement”) for establishing the proxy group.
7 Specifically, the Commission relies on the three criteria: 1) the company’s stock
8 must be publicly traded; 2) the company must be recognized as a natural gas or oil
9 pipeline company and its stock must be recognized and tracked by an investment
10 information service such as Value Line; and 3) pipeline operations must constitute
11 a high proportion of the company’s business. Pipeline ROE Policy Statement, 171
12 FERC ¶ 61,155 at P 58. Regarding the third criterion, the Commission has
13 indicated that this standard has historically required that the pipeline operations
14 account for at least 50 percent of the company’s assets or operating income over
15 the most recent three-year period. Furthermore, the Commission affirms that its
16 preference has been for a proxy group of at least four and preferably five
17 companies, recognizing that adding more members to the group is only preferable
18 if the additional companies are representative proxy companies. *Id.* at P 59.
19 Finally, the Commission recognizes that the options for proxy group companies

1 have been reduced as mergers and transformations occur in the industry and
2 therefore, the Commission has relaxed their 50 percent criterion to reach five
3 companies in the group. 2008 Policy Statement at P 16.

4 **Q. Does the Pipeline ROE Policy Statement adjust the Commission's historical**
5 **views on the proxy group?**

6 A. Yes. In the Pipeline ROE Policy Statement, the Commission acknowledges that it
7 is reasonable to include Canadian companies in the proxy group, recognizing that
8 at the present time, the risk factors for Canadian pipeline companies are similar to
9 the risk factors faced by U.S. pipeline companies. Therefore, the Commission
10 concluded that Canadian pipeline companies are risk-appropriate proxy
11 companies. Pipeline ROE Policy Statement, 171 FERC ¶ 61,155 at P 58.

12 **Q. What companies have the Opposing Witnesses included in their proxy groups**
13 **that you disagree with?**

14 A. I do not agree with the inclusion of Dominion Energy, Inc. ("Dominion"),
15 National Fuel Gas Company ("NFG"), or Tallgrass Energy Partners, LP
16 ("Tallgrass"). Dominion has been included in the proxy group by MPSC Witness
17 Janssen and PMDG Witness Crowe. NFG has been included in the proxy groups
18 of each of the Opposing Witnesses and Tallgrass is only included in the second
19 proxy group considered by PMDG Witness Crowe. However, the only proxy

1 group for which PMDG Witness Crowe prepares a CAPM analysis is her first
2 proxy group. Therefore, it appears that she does not rely on the results of her
3 second proxy group in making her final recommendation on her proposed ROE for
4 Panhandle. See Exhibit No. PMG-0019 at page 1.

5 **A. Dominion Energy, Inc.**

6 **Q. Please explain why Dominion should not be included in the proxy group.**

7 A. MPSC Witness Janssen includes Dominion in her proposed proxy group but
8 elects not to rely on net income or operating income data, which have been
9 consistently used by the Commission in the determination of ROE, because the
10 2019 SEC filings were not available prior to the preparation of her analysis.
11 Therefore, MPSC Witness Janssen applies her own criterion not found anywhere
12 in the Commission's 2008 Policy Statement or the Pipeline ROE Policy Statement
13 -- the number of miles of pipeline owned by the company. Witness Janssen
14 concludes that Dominion should be included in the proxy group because the
15 company owns Commission regulated interstate natural gas transmission pipelines
16 and other energy assets. Exhibit No. MPC-0015 at page 17. While it is relevant
17 that Dominion owns pipeline assets, MPSC Witness Ms. Janssen makes no
18 attempt to determine how the ownership of those assets through operating

1 subsidiaries makes the publicly-traded parent company (Dominion) risk-
2 comparable to Panhandle.

3 As noted in the 2008 Policy Statement and more recently in the Pipeline
4 ROE Policy Statement, the Commission has historically determined that pipeline
5 operations represent a significant portion of the company's operations if "the
6 pipeline business accounted for, on average, at least 50% of a company's assets or
7 operating income over the most recent three-year period." 171 FERC ¶ 61,155 at P
8 58. Furthermore, the Commission has required, among other things, that proxy
9 companies be recognized as a natural gas pipeline company by an investment
10 information service, such as Value Line.

11 MPSC Witness Janssen's analysis does not provide any basis for
12 determining the comparability of the Dominion corporate entity with Panhandle.
13 For example, Value Line currently classifies Dominion as an electric utility.
14 Exhibit No. PE-0229, Schedule 5. Furthermore, MPSC Witness Janssen does not
15 provide any analysis to support the contention that the pipeline operations owned
16 by Dominion make the parent company a risk-appropriate proxy company for
17 Panhandle. MPSC Witness Janssen's analysis of Dominion does not comport
18 with Commission precedent. For these reasons, Dominion should not be included
19 in the proxy group.

1 **Q. Do you believe that the analysis that was developed by PMDG Witness Crowe**
2 **demonstrates that Dominion is a risk-appropriate proxy company for**
3 **Panhandle?**

4 A. No, I do not. PMDG Witness Crowe testifies that she relied on the Commission's
5 2008 Policy Statement in the development of her proxy group that included
6 Dominion. Exhibit No. PMG-0001 at 48. However, PMDG Witness Crowe has
7 not applied the screening criteria that the Commission has historically relied on to
8 ensure that Dominion is sufficiently comparable to Panhandle to be included in the
9 proxy group. While PMDG Witness Crowe acknowledges the Commission's
10 long-standing precedent of using the percentage of operating income or net
11 income that is derived from natural gas transmission operations to determine the
12 comparability of a potential proxy company to the subject company PMDG
13 Witness Crowe has not applied that criteria correctly. As shown in Exhibit No.
14 PMG-0010 at page 2, PMDG Witness Crowe's calculation of the percentage of
15 operating income derived from natural gas operations fails to eliminate corporate
16 adjustments from the total net income, overstating the income derived from
17 Dominion's transmission and storage operations. Witness Crowe inaccurately
18 claims in Exhibit No. PMG-0010 at page 2 that Dominion derives 69 percent of its
19 2019 net income from natural gas transmission and storage operations by

1 including negative adjustments for corporate or other operations in the total net
2 income. Trial Staff Witness Johnson and I agree that it is appropriate to exclude
3 negative adjustments/eliminations or corporate adjustments from the total net
4 income to determine how much each business segment contributes to the proxy
5 company's operations. *See* Exhibit No. S-0108 at page 20, footnotes 1 and 2.

6 **Q. What operations are included in Dominion's "corporate and other" reporting**
7 **segment?**

8 A. As noted in Dominion's 2019 SEC Form 10-K, Exhibit No. PE-0229, Schedule 7,
9 the Corporate and Other segment includes the company's corporate, service
10 companies and other functions, including merger and integration costs associated
11 with the acquisition of SCANA Corporation, litigation costs acquired in that
12 acquisition, and the retirement of assets that are no longer part of the business
13 operations. It is reasonable and appropriate to exclude these negative adjustments
14 from the ongoing business operations to determine what percentage natural gas
15 transmission and storage contributes to the forward-looking business operations of
16 Dominion.

1 **Q. When corporate and other costs are eliminated from the calculation, does**
2 **Dominion meet the Commission's criterion for natural gas transmission**
3 **operations to be included in the proxy group?**

4 A. No, it does not. As shown in Figure 2 below, when negative corporate
5 adjustments are eliminated from 2019 total net income, the gas transmission and
6 storage business segment represents approximately 24 percent of Dominion's total
7 net income, which is well below the 50 percent threshold. Therefore, when the
8 Commission's long-standing criterion is applied, Dominion is not risk comparable
9 to Panhandle and should be excluded from the proxy group. Furthermore, as
10 shown in Exhibit No. PE-0229, Schedule 7, over the last several years Dominion
11 has taken a series of steps to refocus its operations on "state-regulated, sustainably
12 focused utilities". These steps include recent mergers with Questar Corporation
13 and SCANA Corporation and the divestiture of Dominion's interest in the Blue
14 Racer Midstream natural gas system and Dominion's merchant generation assets.

15 **Q. Does Dominion meet the Commission's relaxed thresholds to establish a**
16 **reasonably sized proxy group?**

17 A. No. While it has been the case that certain screening criteria have been adjusted to
18 develop an appropriately-sized proxy group, I cannot recall any proxy group
19 where the Commission approved the use of a company in a natural gas pipeline

proxy group that derived less than 25 percent of its operating income from natural gas operations.

Figure 2: Dominion 2019 Net Income from Gas Transmission Operations (\$million)⁵

Dominion Energy Virginia	Gas Transmission and Storage	Gas Distribution	Dominion Energy South Carolina	Contracted Generation	Corporate & Other	Total Excluding Corporate & Other	Percent Gas Transmission and Storage
\$1,786	\$934	\$488	\$430	\$276	(\$2,556)	\$3,914	23.9%

B. National Fuel Gas Company

Q. Does NFG meet the income or asset screens established by the Commission for inclusion in a pipeline proxy group?

A. No, NFG does not meet the Commission's long-standing criterion that 50 percent of the total operating income of the potential proxy company should be derived from interstate natural gas pipeline operations or 50 percent of the assets should be

⁵ Exhibit No. PE-0229, Schedule 7.

1 invested in interstate natural gas pipeline operations. Therefore, NFG is not risk
2 comparable to Panhandle and should be excluded from the proxy group.

3 The fact that NFG's operating income derived from and assets invested in
4 pipeline assets is below the Commission's 50 percent threshold is not disputed by
5 the Opposing Witnesses in this proceeding. Trial Staff Witness Johnson
6 acknowledges that NFG does not meet the minimum threshold for natural gas
7 pipeline assets or operating income, indicating that in 2019 the assets devoted to
8 interstate pipeline operations were only 29.01 percent and the operating income
9 derived from pipeline operations was 24.40 percent. Exhibit No. S-0108 at page
10 26. MPSC Witness Janssen also reviewed 2019 data and calculates percentages of
11 assets and operating income for NFG that are 29 percent and 24 percent
12 respectively, which is consistent with Trial Staff Witness Johnson's calculation for
13 2019. Exhibit No. MPC-0015 at 17. PMDG Witness Crowe acknowledges that
14 the combined operating income of NFG's natural gas distribution (utility) and
15 interstate pipeline operations was only 44 percent. *See* Exhibit No. PE-0229,
16 Schedule 11 at page 5.

1 **Q. On what basis do the Opposing Witnesses contend that it is appropriate to**
2 **include NFG in the proxy group?**

3 A. Trial Staff Witness Johnson and PMDG Witness Crowe both cite to the Kern
4 River order where the Commission included NFG because the combination of the
5 interstate natural gas and utility operations met the 50 percent screening criterion.
6 Exhibit No. S-0106 at pages 35-36; Exhibit No. PMG-0001 at pages 41-42, citing
7 to *Kern River Gas Transmission Co.*, Opinion No. 486-B, 126 FERC ¶ 61,034
8 (2009).

9 **Q. Do you agree with including NFG in the proxy group on this basis?**

10 A. No, I do not. As a preliminary matter, the purpose of establishing a proxy group
11 is to identify companies that are comparable to the subject company in certain
12 fundamental business and financial respects, not to identify companies that are
13 comprised of operations that are more and less risky than the subject company.
14 That is, the fact that the distribution, exploration and production, and marketing
15 and trading functions are all either more or less risky than the subject company
16 means that they are *not* comparable to the subject company's risks in certain
17 fundamental business and financial respects regardless of whether or not they
18 offset each other. Further, it is not clear that the less risky distribution segment
19 offsets the riskier exploration and production, and marketing and trading

1 functions. As shown in Trial Staff Witness Johnson's Exhibit No. S-0108 at page
2 26, comparing the most recent three years of earnings, on average exploration and
3 production contributed to 41.93 percent of NFG's total and the utility segment
4 contributed on average 16.29 percent. Over the four-year period, the earnings of
5 the exploration and production segment went from a high of 156.34 percent of
6 total earnings to 36.86 percent, while the range of earnings from the utility
7 segment was -17.59 percent to 20.07 percent. This history demonstrates that the
8 risk of the LDC operations does not offset the risk of the exploration and
9 production segment. Given NFG's relatively low proportion of pipeline assets in
10 its overall operations, and Trial Staff's recent exclusion of NFG in another natural
11 gas pipeline case, I believe it is appropriate to continue to exclude NFG from the
12 proxy group.

13 **Q. Has NFG been excluded from other Staff proxy groups?**

14 A. Yes. In recent testimony filed by Trial Staff Witness Edward Alvarez III on July
15 25, 2019 in Enable Mississippi River Transmission, LLC's section 4 rate case in
16 Docket No. RP18-923-004, NFG was excluded from Trial Staff's proxy group.
17 [Docket No. RP18-923-004 Exhibit No. S-0029 at pages 19-20] In that case Trial
18 Staff Witness Alvarez III indicated that NFG did not meet the 50 percent standard
19 of natural gas pipeline operations. In addition approximately 25 percent of NFG's

1 assets were devoted to exploration and production, which are riskier in the assets
2 spectrum.

3 **C. Tallgrass Energy Partners, LP**

4 **Q. Did all of the Opposing Witnesses include Tallgrass in their proxy group?**

5 A. No. PMDG Witness Crowe was the only witness that included Tallgrass in a proxy
6 group. It is important to note that Witness Crowe only included Tallgrass in her
7 second proxy group, in her Direct and Answering Testimony referred to as
8 PMDG2 in Figure 1 above. Although PMDG Witness Crowe developed two
9 different proxy groups (PMDG1 and PMDG2), she only prepared a CAPM using
10 PMDG1, therefore it appears that she is relying entirely on her PMDG1 proxy
11 group for her ROE recommendation. In her Supplemental Testimony, Witness
12 Crowe testified that Tallgrass was no longer publicly traded as of April 20, 2020
13 and therefore removed the company from her PMDG2 proxy group. Exhibit No.
14 PMG-0020 at page 1.

15 **Q. Have the Opposing Witnesses excluded other companies that you included in**
16 **your proxy group?**

17 A. Yes. Opposing Witnesses excluded Enable Midstream Partners LP. (“Enable”),
18 EQM Midstream Partners, LP (“EQM”) and TC PipeLines, LP (“TC Pipelines”)

1 from their proxy groups. I included each of these companies in the proxy group
2 developed in my Prepared Direct Testimony. Exhibit No. PE-0036 at 15. At that
3 time, Enable and EQM had positive short-term growth rates and met the criteria
4 outlined in that testimony. Based on information through January 31, 2020, the
5 short-term growth rates for Enable and EQM were negative and therefore I have
6 excluded these companies from the proxy group used in my Prepared Rebuttal
7 Testimony. As noted by Trial Staff Witness Johnson, the Commission has
8 eliminated companies with negative short-term growth rates since the two-stage
9 DCF model assumes 33 years of growth at the short-term growth rate. *See*
10 *Williston Basin Interstate Pipeline Company*, 104 FERC ¶ 61,031 at P 29 (2003).

11 **D. TC Pipelines, LP**

12 **Q. Why do the Opposing Witnesses argue that TC Pipelines should be**
13 **eliminated from the proxy group?**

14 A. In his Direct and Answering Testimony, Trial Staff Witness Johnson argues that
15 TC Pipelines should be eliminated because there was a negative growth rate for
16 TC Pipelines as of February 28, 2020. Exhibit No. S-0106 at page 19 and Exhibit
17 No. S-0107 at page 12. In his Supplemental Testimony, Trial Staff Witness
18 Johnson continues to exclude TC Pipelines from his DCF based on the growth rate

1 but includes this Master Limited Partnership (“MLP”) in his CAPM analysis.
2 Exhibit No. S-0159 at page 21. PMDG Witness Crowe excludes TC Pipelines
3 because TC Pipelines cut its distribution two years ago and that in March 2020 the
4 growth rate for TC Pipelines was negative. Exhibit No. PMG-0001 at 45. MPSC
5 Witness Janssen excludes TC Pipelines because it did not have a “grade” from
6 Value Line and it is owned by TC Energy Corporation (“TC Energy”). Exhibit No.
7 MPC-0015 at 10.

8 **Q. What is your response to the reasons offered by the Opposing Witnesses?**

9 A. From the outset, it is clear that TC Pipelines is comparable to the risk profile of
10 Panhandle from the fact that Trial Staff Witness Johnson uses this MLP in the
11 proxy group for his CAPM analysis. Exhibit No. S-0159 at 21. Trial Staff Witness
12 Johnson and PMDG Witness Crowe both reference negative growth rates as a
13 reason for excluding TC Pipelines from the proxy group. Trial Staff Witness
14 Johnson relies on growth rates as of the end of February 2020 in his Direct and
15 Answering Testimony and through the end of May in his Supplemental
16 Testimony. PMDG Witness Crowe relies on March 2020 growth rates in her
17 Direct and Answering Testimony and May 2020 in her Supplemental Testimony.
18 While PMDG Witness Crowe relies on the negative growth rate as a screening
19 criterion for TC Pipelines, later in her Direct and Answering Testimony she states

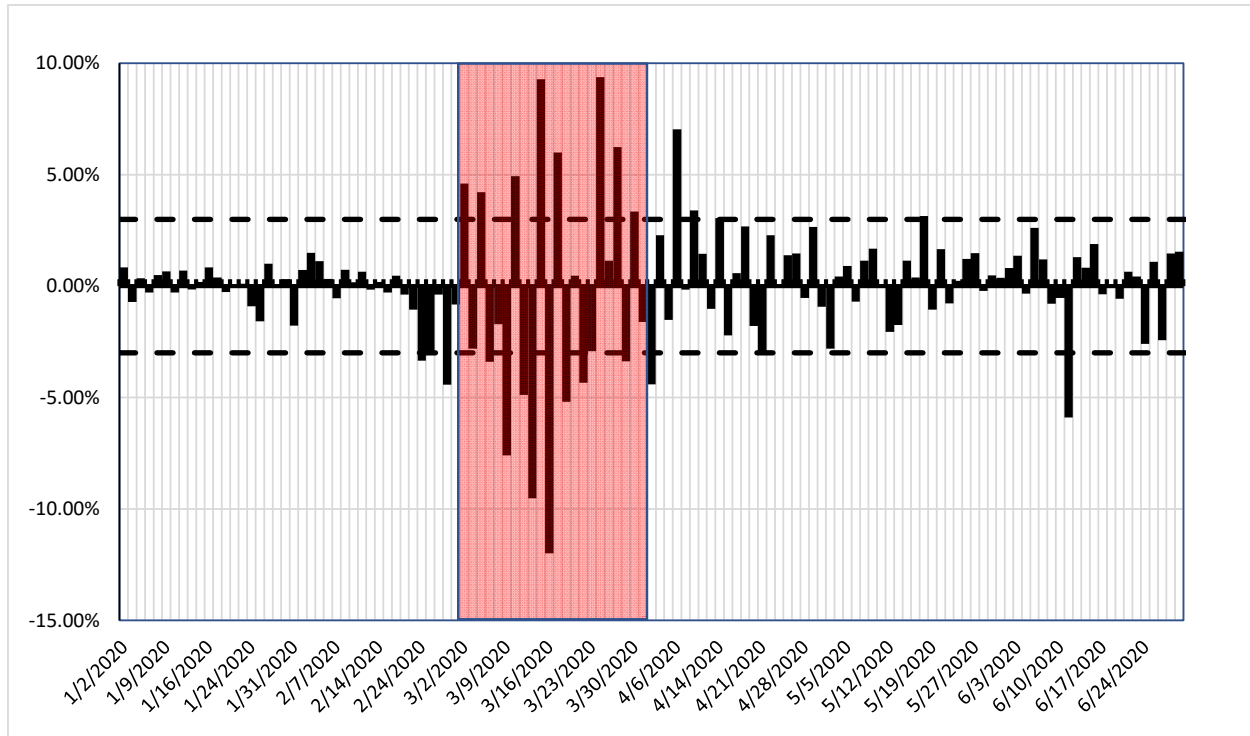
1 that she does not believe that negative short-term growth rates should necessarily
2 disqualify other potential proxy companies from inclusion in the proxy group, nor
3 does she think that it would improperly skew the results of the DCF model.
4 Exhibit No. PMG-0001 at page 43. Therefore, it is unclear how she has applied
5 this screening criterion.

6 In addition, PMDG Witness Crowe's testimony also is confusing regarding
7 the appropriate data that should have been relied upon given recent market events.
8 PMDG Witness Crowe states in her Direct and Answering Testimony that she has
9 not relied on March 2020 price data because of market conditions; referencing the
10 effect of the decline in oil prices, the effect of COVID-19 worldwide, the Federal
11 Reserve's decision to cut interest rates, and related concerns. *Id.* at page 48. While
12 I agree that the March 2020 data has been affected by market conditions, as shown
13 in Figure 3 below, the effects of recent market conditions began before March
14 2020. Stock prices reached an all-time high on February 19, 2020, followed by a
15 substantial, unprecedented decline that began just following this peak, declining
16 approximately 13 percent by the end of February and 34 percent through March
17 23, 2020 with individual daily declines of up to almost 12 percent and rebounds of
18 up to 9.5 percent. Exhibit No. PE-0229, Schedule 12. This level of volatility is
19 comparable to the period of the financial market collapse of 2008/2009. Exhibit

1 No. PE-0229, Schedule 16. Therefore, it is reasonable to conclude that growth rate
2 data that PMDG Witness Crowe relied on as of the end of February 2020 was also
3 affected by recent market conditions and should not be included in the ROE
4 estimation models. Furthermore, in PMDG Witness Crowe's Supplemental
5 Testimony, she relies on data through May 31, 2020, which includes the time
6 periods and effects that she sought to avoid in her Direct and Answering
7 Testimony.

1

Figure 3: S&P 500 Stock Price change⁶



2

⁶ S&P Global Market Intelligence. © 2020 S&P Global Market Intelligence (and its affiliates, as applicable) (individually and collectively, "S&P"). All rights reserved. For intended recipient only. No further distribution or reproduction permitted without S&P's prior written permission. A reference to or any observation concerning a particular investment, security or credit rating in the S&P information is not a recommendation to buy, sell, or hold such investment or security or make any other investment decisions. S&P and its third party licensors: (1) do not guarantee the accuracy, completeness, timeliness or availability of any information and are not responsible for any errors or omissions or for the results obtained from the use of such content; and (2) give no express or implied warranties of any kind. In no event shall S&P or its third party licensors be liable for any damages, including, without limitation, direct and indirect damages in connection with any use of the S&P information. See Exhibit No. PE-0229, Schedule 12.

1 Based on these dramatic changes in market conditions, caused by rapid
2 decline in oil prices, worldwide effects of COVID-19 and the Federal Reserve's
3 response to these market changes, it is appropriate to exclude data after January
4 31, 2020 (the end of the test period in this proceeding) from the analytical period
5 that is used to set the forward-looking cost of equity.

6 **Q. Would TC Pipelines be included in the proxy group based on data as of**
7 **January 31, 2020?**

8 A. Yes. As shown in Exhibit No. PE-0229, Schedule 4, as of January 31, 2020,
9 which is prior to any effects of these short-term market conditions, the EPS growth
10 rate for TC Pipelines was positive, and therefore should be included in the proxy
11 group.

12 **Q. Do you agree with PMDG Witness Crowe that a distribution cut is a valid**
13 **reason to exclude TC Pipelines from the proxy group?**

14 A. No, I do not. First, it is important to note that in its recent Pipeline ROE Policy
15 Statement, the Commission did not include dividend cuts as a basis to exclude
16 companies from the proxy group. Pipeline ROE Policy Statement, 171 FERC ¶
17 61,155 at P 58. While it may be reasonable to exclude companies from the proxy
18 group for a recent cut in the dividend, PMDG Witness Crowe excluded TC
19 Pipelines from her proxy group because it cut its distribution two years ago. Since

1 that time, TC Pipelines has maintained its dividend. Therefore, it is unreasonable
2 for PMDG Witness Crowe to take the position that a change in dividends that was
3 made two years ago “is an indication of the level of uncertainty surrounding future
4 prospects of MLP-owned pipelines in the United States”. Exhibit No. PMG-0001
5 at page 45. TC Pipelines maintaining its dividend for the past two years is
6 sufficient history to demonstrate the stability of this company and to support its
7 inclusion in the proxy group. While Trial Staff Witness Johnson also agrees that it
8 is important to consider dividend or distribution cuts, the criterion applied by Mr.
9 Johnson, which is based on FERC Opinion No. 510, is only that the cut cannot be
10 within the six-month analytical period. *See* Exhibit No. S-0106 at 16. *See also*
11 *Portland Natural Gas Transmission System*, Opinion No. 510, 134 FERC ¶ 61,129
12 at PP 183, 186-187 (2011), and *Coakley v. Bangor-Hydro-Electric Co.*, Opinion
13 No. 531, 147 FERC ¶ 61,234 at P 112 (2017). Clearly, Ms. Crowe’s two-year
14 criterion is excessive and should not be applied to determine comparable proxy
15 companies.

16 **Q. Do you agree with MPSC Witness Janssen’s reasons for excluding TC**
17 **Pipelines from the proxy group?**

18 A. No, I do not. MPSC Witness Janssen is the only witness in this proceeding who
19 required, as a proxy group screening criterion, that a company have a “grade”

1 from Value Line or that excluded a company because it was an operating
2 subsidiary of another company. In a discovery response [Exhibit No. PE-0229,
3 Schedule 11 at page 3] [PEPL-MPSC-2.11] Witness Janssen clarified a “grade” to
4 mean the following:

5 In my testimony if I stated that there was no grade for Value Line, that
6 would be that Value Line was not providing research on that stock and
7 thus no grade.

8 The additional information provided by MPSC Witness Janssen does not
9 clarify her point because, as shown in Exhibit No. PE-0229, Schedule 5, TC
10 Pipelines has been operating for more than five years and is covered by Value
11 Line. These are criteria established by the Commission in the Pipeline ROE
12 Policy Statement and in the 2008 Policy Statement. It is important to note that the
13 Commission’s recent Pipeline ROE Policy Statement does not indicate any
14 requirements that there be a “grade” reported by Value Line.

15 Furthermore, while MPSC witness Janssen testifies that TC Pipelines was
16 excluded from the proxy group because its operations were owned by TC Energy,
17 she also noted that she was not aware of any FERC orders or opinions that have
18 excluded a pipeline company from the proxy group because the company is a
19 stand-alone operating subsidiary of another company. [Exhibit No. PE-0229,
20 Schedule 11 at page 3] [PEPL-MPSC-2.11] No other witness in this proceeding

1 has eliminated a company from the proxy group on this basis. TC Pipelines is a
2 risk-comparable company to Panhandle that has observable market data available
3 that can be used to determine investors' expectation for the ROE for a natural gas
4 pipeline operation. Therefore, the fact that the TC Pipelines is owned by another
5 entity is not a reasonable basis for excluding it from the proxy group.

6 Furthermore, in the Pipeline ROE Policy Statement, the Commission determined
7 that Canadian companies like TC Pipelines can be included in the proxy group.

8 **Q. Is TC Pipelines comparable to Panhandle?**

9 A. Yes. As discussed in my Prepared Direct Testimony, TC Pipelines is a publicly
10 traded natural gas transmission MLP that invests 100 percent of its assets in
11 natural gas pipelines and from which 100 percent of the operating income is
12 derived. TC Pipelines is rated BBB by S&P, which is an acceptable rating based
13 on the Commission's established criteria. Exhibit No. PE-0229, Schedule 17 . The
14 pipelines owned by TC Pipelines have financial and operating risks that are
15 common to all natural gas pipelines including Panhandle. Therefore, it is
16 reasonable and appropriate to include TC Pipelines in the proxy group for
17 Panhandle.

E. Common Proxy Group Companies

Q. Are there any companies that are consistent across all of the witnesses in this docket?

A. Yes. There are three companies that are consistent across all of the witnesses in this docket; Kinder Morgan, Inc. (“Kinder Morgan”),⁷ TC Energy, and Williams Companies, Inc. (“Williams”). In addition, Trial Staff, MPSC and Panhandle are in agreement that it is appropriate to include Enbridge Inc. in the proxy group. This would result in a Common Proxy Group of four companies.

Q. Has the Commission allowed the use of a four-company proxy group in prior cases?

A. Yes. As noted in the Pipeline ROE Policy Statement, the Commission recently affirmed its position that “a proxy group should consist of at least four, and preferably at least five members” if representative members can be found. Pipeline ROE Policy Statement, 171 FERC ¶ 61,155 at P 59; *see also*, *SFPP, LP*, 134

⁷ Trial Staff relies on Kinder Morgan in their Direct and Answering Testimony and in the CAPM in the Supplemental Testimony.

1 FERC ¶ 61,121 at P 203 (2011). Furthermore in *Southern California Edison Co.*,
2 Opinion No. 445, 92 FERC ¶ 61,070 (2000) and in *Consumers Energy Company*,
3 Opinion No. 429, 85 FERC ¶ 61,100 (1998), the Commission relied on a proxy
4 group of four companies.

5 **Q. How should the Commission's views on the size of the proxy group be**
6 **interpreted based on these decisions?**

7 A. The Commission has stated that a proxy group can have no less than four
8 companies. The overarching goal should be that the companies are truly
9 comparable. Therefore, it is less important to add companies to the group beyond
10 the four-company minimum if that means that the results are less risk-comparable
11 to the proxy company. Pipeline ROE Policy Statement, 171 FERC ¶ 61,155 at P
12 59. The four companies that I am considering in this Common Proxy Group are
13 comparable to Panhandle and result in a reasonable proxy group.

1 **III. COST OF EQUITY ESTIMATION APPROACHES**

2 **Q. What analytical techniques have the Opposing Witnesses employed in their**
3 **determination of the cost of equity for Panhandle?**

4 A. In their Direct and Answering Testimonies, all of the Opposing Witnesses relied
5 exclusively on the results of the DCF model. As shown in Figure 4 below, while
6 Trial Staff Witness Johnson provided a CAPM analysis, he did not rely on the
7 results of that model in making his final recommendation. In addition, it is
8 important to note that MPSC Witness Megginson acknowledged that the
9 Commission relied on equal weighting of the DCF and CAPM methodologies in
10 Opinion No. 569, and recognized that while Opinion No. 569 was an electric
11 transmission docket, the Commission “left the door open” to applying the same
12 methodology to natural gas and oil pipeline ROEs. Exhibit No. MPC-0021 at page
13 7; *Ass’n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator,*
14 *Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 (2019). Despite this recognition, Mr.
15 Megginson did not provide a CAPM analysis. *Id.* at pages 6, 7 and 9.
16 Furthermore, he did not rely on the traditional DCF model that has been
17 considered by the Commission. MPSC Witness Megginson relied on his own
18 modified version of the DCF for his final recommended ROE that arbitrarily
19 reduced the growth rates for all companies in the group by 50 percent due to
20 “current market volatility and its impact to long-term growth expectations”. *Id.* at

1 page 21. MPSC Witness Megginson does not develop any other ROE estimation
2 methodologies to corroborate his DCF analyses or to substantiate his decision to
3 reduce the long-term growth rate by 50 percent. Finally, PMDG Witness Crowe
4 developed two DCF analyses using different proxy groups, relying entirely on the
5 PMDG1 proxy group shown in Figure 1 above to support her ROE
6 recommendation. Exhibit No. PMG-0001 at page 6. PMDG Witness Crowe also
7 does not develop estimates of the ROE using any methodologies other than the
8 DCF model.

Figure 4: Summary of ROE methodologies relied on by Opposing Witnesses in Direct and Answering Testimony

ROE Estimation Model	Trial Staff Witness Johnson	MPSC Witness Megginson⁸	PMDG Witness Crowe⁹
Traditional DCF	11.14%	11.24%	9.79%
Modified/Second DCF	None	10.54%	10.56%
CAPM	12.04%	None	None
Recommendation	11.14%	10.54%	9.79%

Q. How did the Opposing Witnesses change their analyses in their Supplemental Testimonies?

A. In Supplemental Testimony, each of the Opposing Witnesses relied on both a DCF and CAPM analysis to establish their recommended ROEs. Trial Staff rescreened the proxy group and updated the DCF and CAPM analyses using the average of six months of data through May 2020. In his Supplemental Testimony, MPSC

⁸ Exhibit No. MPC-0023.

⁹ Exhibit No. PMG-0010 at page 1.

1 Witness Megginson relied on the same proxy group that he used in his Prepared
2 Answering Testimony and the same DCF analysis using data through March 20,
3 2020. Exhibit No. MPC-0034 at page 4. In his Supplemental Testimony, MPSC
4 Witness Megginson developed a CAPM analysis using the market return
5 calculation from Trial Staff Witness Johnson's Direct and Answering Testimony
6 and made other assumptions using data from May and June 2020. PMDG Witness
7 Crowe updated the DCF results for the proxy groups developed in her Prepared
8 Direct and Answering Testimony through May 31, 2020 and developed a CAPM
9 result using assumptions through June 10, 2020. Figure 5 below summarizes the
10 results of the analyses presented by the Opposing Witnesses in their Supplemental
11 Testimonies.

Figure 5: Updated Results and Recommendations of Opposing Witnesses

ROE Estimation Model	Trial Staff Witness Johnson	MPSC Witness Megginson¹⁰	PMDG Witness Crowe¹¹
Traditional DCF	11.88%	11.24%	10.29%
Modified/Second DCF	None	10.54%	10.29%
CAPM	12.13%	11.80%	9.90%
Recommendation	12.01%	11.17%	10.10%
Analytical period (six months ending)	DCF & CAPM: May 2020	DCF: March 2020 CAPM: Combination of March 2020 and June 2020	DCF: May 2020 CAPM: June 10, 2020

Q. What is your conclusion regarding the recommendations of the Opposing Witnesses in this proceeding?

A. In their Direct and Answering Testimonies, the Opposing Witnesses relied exclusively on the results of their DCF models. In their Supplemental Testimonies, while each of the Opposing Witnesses have presented the results of both DCF and

¹⁰ Exhibit No. MPC-0023.

¹¹ Exhibit No. PMG-0010 at page 1.

1 CAPM analyses that were used to develop their updated recommendations, none
2 of the analyses of the Opposing Witnesses are consistent with the Commission's
3 recent decision in the Pipeline ROE Policy Statement and rely on various and
4 differing time periods for growth rates and other factors.

5 **A. DCF Analyses**

6 **Q. Do you agree with how the Opposing Witnesses developed the assumptions**
7 **used in the DCF model?**

8 A. Not entirely. Earlier in my rebuttal testimony I note the differences between the
9 Opposing Witnesses and myself on the appropriate proxy companies to use in the
10 analysis. I also disagree with certain assumptions used by the Opposing Witnesses
11 in their analyses. Most importantly, I disagree with the following:

12 a) The use of market data after January 31, 2020. The test period in this
13 proceeding ends as of January 31, 2020, which is a reasonable period to use
14 to establish the ROE. Furthermore, since that time there have been dramatic
15 change in market conditions that have affected the short-term growth rates of
16 the companies that are most comparable to Panhandle. Since the current
17 extra-ordinary market conditions are not expected to persist for the next three
18 to five years, the dramatic change in growth rates that resulted from these
19 market conditions should not be considered in the development of a cost of

equity that is intended to reflect the forward-looking period for which the rates in this case are being determined.

b) MPSC Witness Megginson's arbitrary determination to reduce the growth rates in his DCF analysis for corporations by 50 percent.

c) PMDG Witness Crowe's use of negative 5-year EPS growth rates in her DCF analysis.

d) Trial Staff's use of two different proxy groups to develop the DCF and CAPM.

B. Recent Market Conditions

Q. Do the Opposing Witnesses in this proceeding recognize that recent events create anomalous market conditions that should not affect the results of the analysis?

A. While certain of the Opposing Witnesses state that it is important to exclude the effect of recent market conditions from the analysis, they still relied on data from February and March 2020 that was affected by short-term market events in their Direct and Answering testimonies. In the analyses presented in Supplemental Testimonies, the Opposing Witnesses have relied on data from more current time periods, which has the effect of a greater portion of the market data being affected by COVID-19. For example, in her Direct and Answering Testimony, PMDG Witness Crowe testifies that she did not rely on March data because it is important

1 not to give a partial month full weight in the analysis and also testifies that there
2 were market implications from COVID-19, decline in oil prices and the action of
3 the Federal Reserve that should be considered in establishing the appropriate
4 analytical time period. Exhibit No. PMG-0001 at page 48. Despite those stated
5 concerns, PMDG Witness Crowe does in fact rely on market data from February
6 2020 and growth rates from March 2020. Exhibit No. PMG-0010 at page 1. In her
7 Supplemental Testimony, PMDG Witness Crowe does not address her concerns
8 about the use of recent market data and the effects of the pandemic on that data
9 and instead updates her dividend yield calculations to rely on the six months
10 ending May 31, 2020. Exhibit No. PMG-0018 at page 6. As shown in Figure 3
11 above, market data since January 2020 has been extremely volatile, and that
12 volatility has continued into June. By updating through May 2020, Witness
13 Crowe's dividend yield calculation reflects four months of data that has been
14 affected by significant market volatility resulting from the COVID-19 crisis.

15 **Q. Does Trial Staff Witness Johnson discuss the effect of market conditions on**
16 **his DCF analysis?**

17 A. No. Trial Staff Witness Johnson testifies that expected and future economic and
18 capital market conditions are reflected in current stock prices and therefore are
19 incorporated in the DCF results. Exhibit No. S-0106 at page 11.

1 **Q. Do you agree with Trial Staff Witness Johnson on how current market**
2 **conditions are reflected in the DCF model?**

3 A. No, I do not. As noted previously, February and March 2020 market data was
4 affected significantly by the current pandemic, resulting in significant volatility in
5 stock prices. On February 12, 2020, the Dow Jones Industrial Average reached
6 record high levels followed by the NASDAQ Composite and the S&P 500 Index
7 on February 19, 2020. In the following week, from February 24 to 28, 2020, the
8 stock market reported its largest one week decline since the 2008 financial crisis
9 relating to the COVID-19 pandemic. As of the end of February 2020, the Dow
10 Jones Industrial average had lost 9.13 percent in one week, the S&P 500 declined
11 8.42 percent and the NASDAQ declined 7.09 percent. Exhibit No. PE-0229,
12 Schedule 13. Throughout March 2020 volatility continued and trading was
13 suspended due to the need to stop the downward trading spirals created by trading
14 algorithms. Over the period from February 24, 2020 through March 23, 2020, the
15 Dow Jones Industrial average had lost 33.51 percent, the S&P 500 declined 30.64
16 percent and the NASDAQ declined 25.60 percent. Exhibit No. PE-0229, Schedule
17 13. As shown in Figure 3, significant price volatility has continued since February
18 2020. While I recognize that the Commission historically has had a preference for
19 relying on more current market data, the change in the volatility of the S&P 500
20 index as shown in Figure 3 demonstrates that the most recent market conditions

1 are not representative of the longer term historical market conditions.

2 Furthermore, the purpose of the ROE analyses presented in this proceeding is to
3 determine the investor-required, forward looking cost of equity. Relying on data
4 from this atypical market period should not be considered reflective of investor-
5 expectations on a forward-looking basis. To the extent that it were to be expected
6 on a going forward basis, the volatility that has been experienced since January
7 2020 should suggest a much higher cost of equity. The greater the volatility in the
8 value of equity, the more risk to equity investors and therefore, it would be
9 reasonable to expect that the cost of equity would be higher in volatile market
10 conditions. Rather, in the testimonies provided by the Opposing Witnesses in this
11 proceeding, which rely on the data from this volatile period, their
12 recommendations suggest returns that are demonstrative of a lower overall cost of
13 equity. This is counterintuitive. Trial Staff Witness Johnson updating his analyses
14 in his Supplemental Testimony to include data through May 2020 places much too
15 great of an emphasis on the growth rates that have been reported in current market
16 conditions that cannot be expected to continue throughout the forward-looking
17 period that rates will be in effect for Panhandle.

1 **Q. Do any of the Opposing Witnesses recognize that market conditions have**
2 **been affected by short term events?**

3 A. In his Prepared Direct and Answering Testimony, Trial Staff Witness Johnson
4 relies on data as of the end of the test period, which is January 31, 2020, to
5 determine the percentage of natural gas transmission operations for the potential
6 proxy companies, but relies on market price and growth rate data as of the end of
7 February 2020 [Exhibit No. S-0107 at pages 4 and 16] to develop his ROE
8 estimation models. Despite recognizing the Commission's preference for data that
9 more accurately reflects investor needs, Trial Staff Witness Johnson does not
10 address the effect of current market conditions on the market data used in his
11 analysis. Exhibit No. S-0106 at page 40. Trial Staff Witness Johnson updates his
12 analyses in his Supplemental Testimony to include data through May 2020, which
13 places greater emphasis on current market conditions that cannot be expected to
14 continue throughout the forward-looking period that rates will be in effect for
15 Panhandle.

16 In his Answering Testimony, MPSC Witness Megginson notes that current
17 market conditions cannot be ignored and recognizes that the projected five-year
18 growth rate forecasts had changed for some of the proxy companies in a two-week
19 period. Exhibit No. MPC-0021 at page 8 and Exhibit No. MPC-0023 at page 4.
20 Based on the events of a two-week period, MPSC Witness Megginson testifies

1 that it is appropriate to reduce the long-term GDP growth rate for the companies in
2 his proxy group by 50 percent. Exhibit No. MPC-0021 at page 9.

3 In her Prepared Direct and Answering Testimony, PMDG Witness Crowe
4 testifies as to the changes to the market as a result of the “decline of oil prices,
5 worldwide coronavirus impacts, the Federal Reserve’s decision to cut interest
6 rates” and states that the use of data from the end of February should be
7 conservative approach because a updating financials might substantially reduce
8 the results of the models. Exhibit No. PMG-0001 at page 48. In her Supplemental
9 Testimony, PMDG Witness Crowe completely ignores her previous testimony
10 expressing concern regarding current extraordinary market conditions and relies
11 on a six-month average dividend yield calculation ending May 31, 2020.

12 **Q. Is there Commission precedent supporting the use of data from different time**
13 **periods to develop the ROE estimation models?**

14 A. No. I am unaware of any instance where the Commission has relied upon
15 differing time periods for the ROE estimation models that it has considered. It is
16 reasonable to expect that the data used in the ROE estimation models reflect the
17 same market conditions. Further, based on the updated methodology in the
18 Pipeline ROE Policy Statement it is of additional importance to rely on data for
19 the same proxy group and time-period because the results of the DCF and CAPM

1 are averaged together to develop the range of reasonableness. [Docket No. PL19-
2 4-000, 171 FERC ¶ 61,155]

3 **C. Growth Rates**

4 **Q. How have the growth rates used in the DCF been affected by market**
5 **conditions?**

6 A. It is apparent that the 5-year projected growth rates for some of the proxy
7 companies were significantly affected from the end of January to the end of
8 February and beyond this period. As shown in PMDG Witness Crowe's
9 workpaper, Kinder Morgan's IBES growth rate estimate for the next three to five
10 years for Kinder Morgan, Inc. significantly has declined from the 8.05 percent
11 growth rate estimate for this company that existed from October 1, 2019 through
12 the end of January 2020. Exhibit No. PMG-0010 Workpaper. Kinder Morgan's
13 growth rate changed to 0.23 percent by the end of February (or as of March 2,
14 2020 when PMDG Witness Crowe downloaded this information for her
15 testimony). Therefore, this data as of the end of February was affected by recent
16 market conditions. MPSC Witness Megginson's testimony sets out that this five-
17 year projected growth rate estimate was negative by March 18, 2020,
18 demonstrating that the March data continued to be influenced by recent events.
19 Exhibit No. MPC-0021 at page 9. This substantial change in the growth rate for
20 Kinder Morgan is inconsistent with the projections for the company's overall

1 performance, as discussed by Value Line in the November 2019 report relied on
2 by Ms. Crowe and the more recent February 2020 report [Exhibit PE-0229,
3 Schedule 5]:

4 The company remains on track for solid operational performance in the
5 years ahead. It should benefit from the Elba Liquefaction units, which
6 have been placed into service. Management has stated that four are
7 already in service and that ten are expected by midyear, should current
8 schedules hold. Meantime, the company ought to benefit from \$3.6
9 billion in additional projects that should be in service in the years ahead.
10 Still commodity prices may remain depressed, which could hamper top-
11 line expansion, though it should be noted that the company achieves
12 profits based on the amount of fuel transported. Overall, we think that
13 earnings will reach \$1.15 per share in 2020, \$1.30 per share in 2021,
14 and \$1.80 per share by the 2023-2025 period.

15 **Q. Are there other examples of short-term growth rates that appear to be**
16 **affected by current market conditions?**

17 A. Yes. As shown in Exhibit No. PE-0229, Schedule 4, the “next five years” annual
18 EPS growth rate reported by IBES for TC Pipelines was 9.30 percent as of the end
19 of January 2020.¹² In February 2020, one month later, this same “next five years”
20 annual EPS growth rate for TC Pipelines was negative 0.60 percent (-0.60%).
21 Value Line’s description of TC Pipelines, published in its February 2020 report

¹² IBES growth rates as reported by Yahoo!Finance.

1 describes the company as having a long-term customer base and stable cash
2 distributions.

3 The company owns interests in six natural gas interstate pipeline
4 systems, through which it transports approximately 9.1 billion cubic feet
5 of natural gas per day from producing regions and import facilities to
6 market hubs and consuming markets, primarily in the western and
7 midwestern United States. It serves large utilities, local distribution
8 companies, and natural gas marketers and producing companies. Also,
9 the company invests in long-term critical energy infrastructure that
10 provides reliable delivery of energy to customers in the United States;
11 develops or acquires assets that provide stable cash distributions and
12 opportunities for new capital additions...Value Line Report on TC
13 Pipelines LP, February 28, 2020. *See* Exhibit No. PE-0229, Schedule 5.

14 **Q. What are your conclusions with respect to growth rates after January 2020?**

15 A. Recent market conditions, which included a warmer than normal winter followed
16 by the pandemic resulted in short-term supply/demand imbalance in the natural
17 gas markets that has been reflected in the five-year growth rates since January
18 2020. As shown in Figure 6 below, the expected earnings growth rates for the
19 proxy group companies have been positive over an extended period of time and
20 only turned negative in February and March 2020. Similar to stock prices, since
21 January 2020, the earnings growth rates have been affected by short-term market
22 conditions, the result of which has been dramatic changes in many of the growth
23 rates for several proxy companies, from strong positive growth to negative growth
24 rates in a one month period. This short-term market shock should not be expected

to continue for the time that Panhandle's rates will be in effect and therefore
should not be included in the analysis of the appropriate cost of equity.

Figure 6: Projected EPS Growth Rates for Proxy Companies¹³

Company	Ticker	Sep-18	Dec-18	Mar-19	Jun-19	Sep-19	Dec-19	Mar-20	Apr-20	May-20
Dominion Resources, Inc.	D	6.35%	6.68%	5.53%	4.60%	4.59%	4.41%	4.88%	4.88%	4.88%
Enable Midstream Partners LP	ENBL	6.50%	8.10%	7.20%	3.85%	5.40%	-4.50%	-4.00%	-27.50%	-27.50%
Enbridge Inc.	ENB	5.49%	5.49%	4.86%	5.49%	5.49%	5.49%	5.49%	5.49%	5.49%
Energy Transfer Partners LP	ET	60.20%	16.39%	21.48%	14.80%	16.50%	16.50%	-1.94%	-3.04%	-3.04%
Enterprise Products Partners L.P.	EPD	5.30%	9.39%	8.31%	9.58%	12.12%	7.59%	-1.27%	-6.75%	-6.75%
EQT Midstream Partners, LP	EQM	8.50%	8.50%	3.71%	2.95%	2.48%	-2.12%	-3.70%	-7.59%	-7.59%
Kinder Morgan, Inc.	KMI	12.00%	12.00%	12.00%	5.30%	6.50%	8.04%	-5.75%	-5.18%	-5.18%
National Fuel Gas Company	NFG	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%
TC Energy Corp	TRP	5.81%	5.81%	5.81%	5.81%	5.81%	5.81%	5.81%	5.81%	5.81%
TC PipeLines, LP	TCP	5.70%	9.30%	9.30%	9.30%	9.30%	9.30%	-0.60%	-0.70%	-0.70%
Williams Companies, Inc.	WMB	10.00%	8.00%	8.96%	10.80%	8.78%	11.15%	6.92%	1.98%	1.98%

Q. Have rating agencies commented on the effects of recent market conditions on the industry?

A. Yes. In March 2020, S&P issued a report outlining the supply and demand shocks that have recently affected the industry. In particular, S&P noted that the combination of the oil price war and COVID-19 have created a perfect storm for

¹³ Source: Thomson Reuters' First Call, provided by Yahoo! Finance. Exhibit No. PE-0229, Schedule 8.

1 the industry.¹⁴ Moody's Investor Services ("Moody's") also noted the risk to
2 midstream companies of both a supply and demand shock, however indicated that
3 interstate gas pipelines that operate with regulated, fee-based contracts may have
4 less price and volume risk.¹⁵

5 Despite these concerns, S&P ratings affirmed their Rating on Kinder
6 Morgan at BBB with a stable outlook, noting that the company has largely
7 contracted cash flows and that S&P expects that the company has sufficient
8 leverage. This rating occurred after the EPS growth rate projections for Kinder
9 Morgan declined from 8.05 percent in December 2019 and January 2020 to
10 negative 5.75 percent (-5.75%) in March 2020.

11 **Q. What are your conclusions based on the trend in growth rates and these**
12 **rating agency analyses?**

13 A. It is likely that the negative projected EPS growth rate that have been reported
14 beginning in February and March 2020 and continuing through May 2020 are a

¹⁴ S&P Global Ratings, "Supply and Demand Shocks are Throwing the U.S. Midstream Industry Off Balance", March 24, 2020. Exhibit No. PE-0229, Schedule 9.

¹⁵ Moody's Investor service, Midstream Energy-Global, "Outlook turns negative as E&P sector's volumetric declines weigh on EBITDA", June 10, 2020. *See* Exhibit No. PE-0229, Schedule 10.

1 response to current market shocks rather than sustainable long-term fundamental
2 market shifts that should be expected to continue into the future. Therefore, it is
3 not reasonable to rely on the data that has been affected by these conditions. The
4 data as of the end of the test period (January 31, 2020) has not been affected by
5 these extraordinary conditions.

6 **Q. Do you agree with MPSC Witness Megginson that the long-term growth rate**
7 **should be adjusted in response to current market information?**

8 A. No, I do not. First, MSPC Witness Megginson is relying on the 5-year projected
9 EPS growth rates as of March 2020, which reflects current market conditions. In
10 addition, MSPC Witness Megginson is reducing the *long-term* growth rate by 50
11 percent, to address these same short-term market conditions. The long-term GDP
12 growth rate used by the Commission in the Two-Stage DCF model is intended to
13 reflect a growth rate that is sustainable in perpetuity. MPSC Witness Megginson's
14 position that investors' expectations about the perpetual growth rate for the proxy
15 companies has been fundamentally altered by short-term market conditions is
16 unsupported and unreasonable.

17 **Q. Has the Commission supported reducing the long-term growth rate to**
18 **account for short-term market conditions?**

19 A. No, it has not. In the Pipeline ROE Policy Statement, that was issued in May
20 2020, the Commission declined to adopt any changes to the DCF model and

1 affirmed the continued use of the long-term GDP growth rate for corporations and
2 50 percent of the GDP growth rate for MLPs, consistent with the 2008 Policy
3 Statement. Pipeline ROE Policy Statement, 171 FERC ¶ 61,155 at P 29.

4 Therefore, it appears that the Commission has considered each of the assumptions
5 in the DCF model, in the current market conditions, and has determined that there
6 are no adjustments required, including the MPSC Witness Megginson's use of 50
7 percent of the long-term growth rate.

8 **Q. Is MPSC Witness Megginson's approach consistent with the approach relied**
9 **on by the Michigan Public Service Commission?**

10 A. No, it is not. The Michigan Public Service Commission has held that market
11 volatility increases the risk on the utilities that it regulates. In a recent case,
12 Exhibit No. PE-0229, Schedule 14, the Michigan Public Service Commission
13 explicitly acknowledged the effect of market volatility on regulated utilities'
14 ability to access capital, stating:

15 It is also important to consider how extreme market reactions to singular
16 events, as have occurred in the recent past, may impact how easily
17 capital will be able to be accessed during the future test period should
18 an unforeseen market shock occur.

19 Therefore, MPSC Witness Megginson's approach for addressing periods of
20 market uncertainty are not consistent with the approach that the Michigan
21 Commission has relied on recently.

1 **Q. Do you agree with MPSC Witness Megginson's DCF analysis that does not**
2 **reduce the long-term growth rate by 50 percent?**

3 A. No, I do not. There are several reasons why Witness Megginson's DCF analysis is
4 not correct. First, as discussed previously, I do not agree that Dominion or NFG is
5 risk comparable to Panhandle, and therefore do not agree with MPSC Witness
6 Megginson's inclusion of these companies in the proxy group. In addition, while
7 MPSC Witness Megginson's data indicates that Kinder Morgan had a negative
8 growth rate at the time that he prepared his analyses, rather than excluding this
9 company from the DCF, he included this company with a 5-year projected growth
10 rate of 0 percent. As discussed in my Direct Testimony, the proxy group should be
11 screened to exclude companies that have negative 5-year growth rates. This is
12 consistent with the Commission's longstanding precedent. Exhibit No. S-0106 at
13 page 18; *see also Williston Basin Interstate Pipeline Company*, 104 FERC ¶
14 61,031 at P 29 (2003) and Opinion No. 569, 169 FERC ¶ 61,129 at P 155.
15 Therefore, including Kinder Morgan in the proxy group at a growth rate of 0
16 percent renders the DCF results presented by MPSC Witness Megginson invalid.

17 **Q. What is your concern with the growth rates relied on by PMDG Witness**
18 **Crowe in her DCF analysis?**

19 A. In her Prepared Direct and Answering Testimony PMDG Witness Crowe develops
20 two proxy groups and DCF analyses, one with five companies (PMDG1) and the

1 second with eight companies (PMDG2). In addition, in her Supplemental
2 Testimony, PMDG Witness Crowe relies on growth rates that are affected by
3 current extraordinary market conditions. For example, as shown in Exhibit No.
4 PMG-0020 at page 1, the growth rate she uses for Kinder Morgan is 0.45 percent.
5 As discussed previously, in January 2020, the growth rate for Kinder Morgan was
6 8.05 percent. Therefore, the results of this analysis should not be relied upon as a
7 forward-looking estimate of the required return on equity for Panhandle.

8
9 Considering her second proxy group (PMDG2), PMDG Witness Crowe
10 reduces the number of companies in the proxy group to seven companies in
11 recognition that Tallgrass is no longer publicly traded. The DCF analysis that she
12 performs using her the second proxy group relies on negative 5-year EPS growth
13 rates. As discussed above in my response to MPSC Witness Megginson's
14 testimony, the Commission has consistently removed companies with negative
15 growth rates from the analysis. Therefore, the results of PMDG Witness Crowe's
16 analysis using her second proxy group (PMDG2) cannot be relied on in
17 determining the appropriate ROE.

1 **IV. CAPM ANALYSES**

2 **Q. Do you agree with how the Opposing Witnesses developed the assumptions**
3 **used in the CAPM model?**

4 A. Not entirely. In addition to the analytical periods used by the Opposing
5 Witnesses, which have been discussed in Section III above, I disagree with the
6 following:

- 7 1) Trial Staff's use of a different proxy group in the CAPM than what it used in the
8 DCF
- 9 2) The outlier test relied on by PMDG Witness Crowe
- 10 3) MPSC Witness Megginson's use of assumptions from differing time periods.

11 **Q. Please explain why you disagree with the proxy group that Trial Staff relied**
12 **on in the development of the CAPM.**

13 A. In his Supplemental Testimony, Trial Staff Witness Johnson relies on different
14 proxy groups to develop the DCF results and the CAPM results. In the Pipeline
15 ROE Policy Statement, the Commission provides criteria for establishing a
16 comparable group and a methodology for developing the range of returns that
17 should be considered for pipelines, including the use of the DCF and CAPM
18 methodologies. The Pipeline ROE Policy Statement does not provide for the use
19 of different comparable groups to develop the return estimates. Furthermore, there
20 is no Commission precedent of which I am aware where the Commission has

1 adopted this approach. The development of an analysis using a proxy group results
2 in a risk profile that is somewhat related to the risks of the proxy group in
3 aggregate. Using different proxy groups for different methodologies would result
4 in ROE estimates that are based on groups with different risk profiles. Because of
5 the risk differences, it is not appropriate to simply average the results derived from
6 the DCF and CAPM methodologies for groups that have different risk profiles.
7 Therefore, it is not reasonable to rely on the combination of Trial Staff's DCF and
8 CAPM results in the determination of the appropriate ROE for Panhandle.

9 **Q. Please discuss your concerns with PMDG Witness Crowe's CAPM analysis.**

10 A. As discussed in Section II above, Ms. Crowe's primary proxy group (PMDG1)
11 includes both Dominion and NFG, both of which do not meet the Commission's
12 previously relied upon screening criteria for comparable companies. As shown in
13 Figure 7 below, reviewing the Betas for these companies as compared to the Betas
14 for the proxy group companies that have been considered by other witnesses in
15 this proceeding and the Value Line natural gas distribution companies segment
16 demonstrates that the risk profile of Dominion and NFG is more comparable to a
17 natural gas utility than a pipeline company.

1

Figure 7: Comparison of Pipeline and LDC Betas

	Ticker	Natural Gas Pipeline¹⁶
Enbridge, Inc.	ENB	0.95
Kinder Morgan, Inc.	KMI	1.30
TC PipeLines, LP	TCP	1.20
TC Energy Corporation	TRP	1.10
Williams Companies, Inc.	WMB	1.60
Mean Beta		1.23

2

	Ticker	Value Line Natural Gas Distribution Companies¹⁷
Atmos Energy Corporation	ATO	0.80
Chesapeake Utilities Corporation	CPK	0.75
New Jersey Resources Corporation	NJR	0.90
NiSource Inc.	NI	0.85
Northwest Natural Gas Company	NWN	0.80

¹⁶ Exhibit No. PMG-0019 and Exhibit No. S-0160.

¹⁷ Exhibit No. PE-0229, Schedule 5.

ONE Gas, Inc.	OGS	0.80
South Jersey Industries, Inc.	SJI	0.95
Southwest Gas Corporation	SWX	0.90
Spire, Inc.	SR	0.80
UGI Corporation	UGI	0.95
Mean excluding D and NFG		0.85
Dominion Energy, Inc.	D	0.80
National Fuel Gas Company	NFG	0.70
Mean of D and NFG		0.85

1 **Q. Are there other aspects of PMDG Witness Crowe’s CAPM analysis that you**
2 **disagree with?**

3 A. Yes. Ms. Crowe relies on an outlier test that excludes results that are more than
4 150 percent of the median result of the CAPM. Exhibit No. PMG-0018 at page 5.
5 In the Pipeline ROE Policy Statement the Commission noted that it did not believe
6 that a rigid outlier test, such as what was Ms. Crowe has applied, is appropriate
7 because the Commission relies on the median result in setting ROEs for pipelines
8 in contrast with the ROEs set for Regional Transmission Operators (“RTO”s) that
9 rely explicitly on the low and high observations. Furthermore, the Commission
10 noted that removing observations as a result of outliers could further reduce the
11 number of observations below the four to five member proxy companies preferred

1 by the Commission. Pipeline ROE Policy Statement, 171 FERC ¶ 61,155 at PP
2 87-88.

3 **Q. Do you agree with PMDG Witness Crowe that there are outliers in the results**
4 **that should be addressed by exclusion of certain observations?**

5 A. In this circumstance, I do not. Reviewing the results of Ms. Crowe's CAPM, it is
6 apparent that the low end of the range is set by NFG and Dominion, which, as
7 discussed previously, should not be included in the proxy group. Recognizing that
8 excluding these companies would not result in a proxy group that meets the
9 Commission's four company lower limit, the median result without these
10 companies would be 12.88 percent. [Exhibit No. PE-0229, Schedule 15 at page 1]
11 Applying the Commission's updated outlier test; 200 percent of the median result,
12 as described in Order 569-A (which was issued the same day as the Pipeline ROE
13 Policy Statement) would result in a high-end outlier test of 21.34 percent. [Exhibit
14 No. PE-0229, Schedule 15 at page 2] Using PMDG Witness Crowe's proxy group
15 excluding NFG and Dominion would result in a high-end outlier test of 25.76
16 percent. [Exhibit No. PE-0229, Schedule 15 at page 2] Based on the
17 Commission's updated outlier test, no observations should be removed from the
18 CAPM analysis in this proceeding.

1 **Q. What are your conclusions about PMDG Witness Crowe's final**
2 **recommended ROE?**

3 A. Ms. Crowe's recommendation is based on a proxy group that includes companies
4 that are not comparable to Panhandle. The inclusion of Dominion and NFG in the
5 proxy group results in a group that does not fully reflect the risks of pipeline
6 ownership. In addition, despite her original concerns about the effect of market
7 conditions on the ROE for Panhandle, Ms. Crowe has ignored the volatility
8 created in the market due to COVID-19 and has relied on data over the entire
9 period of the pandemic in her updated analyses. Finally, Ms. Crowe relies on
10 invalid outlier tests that are based on outdated Commission thoughts with respect
11 to the identification of outliers. The Commission has been clear that such tests are
12 not necessary for pipeline ROE determinations. However, If Ms. Crowe had
13 applied the outlier test in the same manner as the Commission determined
14 appropriate for electric transmission cases in Order No. 569-A (which was issued
15 the same day as the Pipeline ROE Policy Statement) she would have correctly
16 determined that there were no outliers in her analysis. For all these reasons, the
17 results of Ms. Crowe's DCF and CAPM analyses are flawed, inconsistent with the
18 Commission's recent determinations on establishing an appropriate ROE for
19 pipeline companies and therefore should not be relied upon.

1 **Q. Do you agree with MSPC Witness Megginson's CAPM analysis?**

2 A. No, I do not. MPSC Witness Megginson's CAPM analysis is internally
3 inconsistent, relying on a market return from one period and a risk-free rate and
4 beta from another time-period. Therefore, the results of this analysis cannot be
5 relied on as an estimate of the cost of equity for Panhandle. MPSC Witness
6 Megginson notes that he did not develop his own market return based on the S&P
7 500. Rather, in his Supplemental Testimony, MPSC Witness Megginson relied on
8 the market return calculated by Trial Staff Witness Johnson in his Prepared Direct
9 and Answering Testimony, which included data through March 4, 2020. Exhibit
10 No. MPC-0034 at page 7; *see also* Exhibit No. PE-0229, Schedule 11, page 1.
11 [PEPL-Staff -6.35] The remaining assumptions used in Witness Megginson's
12 model were based on the six month average bond yield as of June 1, 2020 and
13 Value Line betas as reported May 15-29, 2020.

14 **Q. How does MPSC Witness Megginson use the results of his ROE estimation**
15 **models to develop a recommended ROE?**

16 A. As shown on Exhibit No. MPC-0035 at page 1, Witness Megginson averages the
17 results of his DCF model, assuming a 50 percent GDP growth rate, based on data
18 as of March 2020 with the results of his CAPM analysis that uses data from March
19 2020 and June 2020 to develop his recommended return of 11.17 percent.

1 **Q. What is your conclusion with respect to MPSC Witness Megginson's updated**
2 **analyses?**

3 A. I do not believe it is appropriate to rely on the results of MPSC Witness
4 Megginson's DCF or CAPM analyses. As discussed previously, it is not
5 appropriate to rely on the data beyond January 2020 due to the unusual
6 circumstances for pipeline companies resulting from the decline in oil prices and
7 the pandemic. Furthermore, the reduction in the long-term GDP growth rate by 50
8 percent is not supported by the Commission. In fact, in the Pipeline ROE Policy
9 Statement, the Commission affirmed that it was making no changes to the growth
10 rates used in the DCF analysis, despite proposals made in that docket. Finally, I
11 do not agree that it is appropriate to develop an ROE estimate using assumptions
12 from varying time periods, as Witness Megginson did in developing his CAPM
13 results. I conclude that Mr. Megginson has not developed an ROE
14 recommendation that is consistent with the Commission's determination in the
15 Pipeline ROE Policy Statement. Therefore, it would not be appropriate to rely
16 upon his recommendation in setting the ROE for Panhandle.

1 **Q. Have you prepared updated analyses that are consistent with the**
2 **methodology outlined in the Commission's Pipeline Policy Statement?**

3 A. Yes, I have updated my analyses to be consistent with the methodology
4 established by the Commission in the Pipeline ROE Policy Statement, using the
5 average results of the Two-Stage DCF model and the CAPM analysis.

6 **Q. What time-period did you use for your analysis?**

7 A. I relied on data as of January 31, 2020, which corresponds to the end of the test
8 period in this proceeding and excludes the effects of the COVID-19 pandemic on
9 the market data.

10 **Q. What companies have you included in your updated analyses?**

11 A. I have developed ROE results using three proxy groups: 1) the proxy group that I
12 filed in my Direct Testimony, excluding those companies that no longer meet the
13 screening criteria; 2) a Common Proxy Group that includes companies that are
14 agreed upon by most of the witnesses in this proceeding; and 3) a proxy group that
15 includes all of the proxy companies relied upon by any witness in this proceeding.

16 **Q. Did you make any changes to the methodology you used to develop the Two-**
17 **stage DCF model?**

18 A. No, I did not. The Two Stage DCF analysis that was presented in my Direct
19 Testimony is consistent with the methodology outlined in the Commission's
20 Pipeline ROE Policy Statement.

1 **Q. Did you make any adjustments to the CAPM that you developed in your**
2 **Direct Testimony?**

3 A. Yes, I did. I adjusted the market return calculation used in my CAPM analysis. In
4 order to be consistent with the Pipeline ROE Policy statement, I calculated the
5 expected market return based on a one-stage DCF model of all dividend paying
6 companies in the S&P 500, excluding companies with negative growth rates or
7 growth rates that exceed 20 percent. Pipeline ROE Policy Statement, 171 FERC ¶
8 61,155 at P 39.

9 **Q. Did you consider any other estimates of the market risk premium?**

10 A. Yes. I also included an estimate of the Market Risk Premium (“MRP”) using data
11 published by S&P. Specifically, I used the dividend yield and growth rate for the
12 S&P 500 as published in S&P’s Earnings and Estimates report, provided in
13 Exhibit No. PE-0229, Schedule 6 to develop the return on the market using a
14 single stage DCF model. I then calculated the MRP as the difference between the
15 market return and the risk-free rate.

16 **Q. Did you make any changes to the risk-free rate used in your Direct**
17 **Testimony?**

18 A. No. The Pipeline ROE Policy Statement relied on the six-month average yield on
19 the 30-year Treasury bond, which is consistent with the approach that I relied on
20 in my Direct Testimony. I updated this data for the six months ended January 31,

2020, which is consistent with the test period in this proceeding, which as shown in Figure 3 is a period of more stable price data for the market overall.

Q. What Beta coefficients did you use in your CAPM?

A. I relied on Value Line adjusted Beta coefficients, consistent with the Commission's precedent.

Q. Did you include a size premium?

A. Yes. I calculated a size premium using the Duff and Phelps data that calculates a size adjustment based on a regression of the monthly returns on the stock index in excess of the yield on the 30-year Treasury over a historical period, as relied on in the Pipeline ROE Policy Statement, 171 FERC ¶ 61,155 at P 44.

Q. How did your proxy group change from the proxy group you relied on in your Direct Testimony?

A. I exclude Enable Midstream Partners LP and EQM Midstream Partners, LP because, as discussed previously, these companies no longer met the screening criteria that I applied in my Direct Testimony. My revised proxy group is summarized in Figure 8, below.

Figure 8: Bulkley Revised Proxy Group

Company	Ticker
Enbridge, Inc.	ENB
Kinder Morgan, Inc.	KMI
TC PipeLines, LP	TCP
TC Energy Corporation	TRP
Williams Companies, Inc.	WMB

Q. Please summarize the results of your analysis for your revised proxy group.

A. The detailed results of my DCF and CAPM analyses are provided in Exhibit No. PE-0229, Schedules 2 and 3. As summarized in Figure 9 below, the median results are 14.47 percent using the Value Line data to calculate the market return and 15.04 percent using the data published in S&P's Earnings and Estimates report. The high end of the range is 18.40 percent and 19.31 percent based on those two sources respectively.

Figure 9: Summary of Bulkley Revised Proxy Group DCF and CAPM analyses

Methodology	Lower Bound	Median	Upper Bound
DCF	11.31%	13.38%	14.70%
CAPM- VL Market Return	12.16%	15.56%	22.10%
CAPM- S&P Market Return	13.12%	16.70%	23.92%
Average ROE Estimate (VL Mkt Return)	11.73%	14.47%	18.40%

Average ROE Estimate (S&P Mkt Return)	12.21%	15.04%	19.31%
---------------------------------------	--------	--------	--------

Q. What companies did you include in the Common Proxy Group?

A. As discussed previously, I included those companies that were in the proxy groups of every witnesses in this proceeding. In addition, I included Enbridge Inc. which was included in the proxy group for Trial Staff, MPSC and my original proxy group.

Figure 10: Common Proxy Group

Company	Ticker
Enbridge, Inc.	ENB
Kinder Morgan, Inc.	KMI
TC Energy Corporation	TRP
Williams Companies, Inc.	WMB

Q. What are the model results for the Common Proxy Group?

A. As shown in Figure 11 below, and Exhibit No. PE-0229, Schedules 2 and 3, the median results for the Common Proxy Group are 13.41 percent using the Value Line market return and 13.99 percent using the S&P market return. The upper bound is 18.40 percent to 19.31 percent.

Figure 11: Updated DCF Results- Common Proxy Group¹⁸

Methodology	Lower Bound	Median	Upper Bound
DCF	11.31%	12.62%	14.70%
CAPM- VL Market Return	12.16%	14.20%	22.10%
CAPM- S&P Market Return	13.12%	15.35%	23.92%
Average ROE Estimate (VL Mkt Return)	11.73%	13.41%	18.40%
Average ROE Estimate (S&P Mkt Return)	12.21%	13.99%	19.31%

Q. What companies did you include in the Combined Proxy Group?

A. As shown in Figure 12, I included all of the companies that were included in each of the proxy groups proposed by the Opposing Witnesses. In addition, I included companies in my proxy group that were not included in the proxy groups of the Opposing Witnesses.

¹⁸ Relies on six months of market data ending January 31, 2020.

Figure 12: Combined Proxy Group

Company	Ticker
Dominion Energy, Inc.	D
Enterprise Products Partners L.P.	EPD
Enbridge Inc.	ENB
Kinder Morgan, Inc.	KMI
National Fuel Gas Company	NFG
TC PipeLines, LP	TCP
TC Energy Corporation	TRP
Williams Companies, Inc.	WMB

Q. What are the results using the Combined Proxy Group?

A. As shown in Figure 13 below, and Exhibit No. PE-0229, Schedules 2 and 3, the median results for the Common Proxy Group are 12.43 percent using the Value Line market return and 12.88 percent using the S&P market return. The upper bound is 18.40 percent to 19.31 percent.

Figure 13: Updated DCF Results- Combined Proxy Group¹⁹

Methodology	Lower Bound	Median	Upper Bound
DCF	9.24%	11.86%	14.70%
CAPM- VL Market Return	7.56%	13.00%	22.10%
CAPM- S&P Market Return	8.09%	13.91%	23.92%
Average ROE Estimate (VL Mkt Return)	8.40%	12.43%	18.40%
Average ROE Estimate (S&P Mkt Return)	8.66%	12.88%	19.31%

Q. What is your conclusion regarding the range of results?

A. Based on the analyses summarized in Figures 9, 11 and 13, the median results for the proxy groups that I considered range from 12.43 percent to 15.04 percent. The high end of the range is between 18.40 percent and 19.31 percent. The return that was recommended in my Direct Testimony is just slightly below the top end of the range of median results and well below the range established by the high-end estimate. Therefore, I conclude that my recommended ROE is a conservative estimate of the investor-required return on equity for Panhandle.

¹⁹ *Id.*

1 **V. RISK ANALYSIS**

2 **Q. Did the Opposing Witnesses consider how the overall risks of his proxy**
3 **companies compare to the risks faced by Panhandle?**

4 A. Trial Staff Witness Johnson determined that Panhandle has average business and
5 financial risk based on the fact that Panhandle's issuer credit ratings are
6 investment grade, and S&P Global Ratings ranked Panhandle as average risk.
7 Exhibit No. S-0106 at page 48. PMDG Witness Crowe takes the position
8 Panhandle's proposed equity ratio of 63 percent demonstrates that Panhandle is
9 not highly leveraged. In addition, she contends that because a portion of
10 Panhandle's long-term is a note payable to an affiliate it is lower risk than debt
11 held with unaffiliated third parties. Exhibit No. PMG-0001 at page 49. MPSC
12 Witness Megginson also states that credit ratings are a "suitable gauge of a
13 company's risk profile". Exhibit No. MPC-0021 at page 20.

14 **Q. Do you agree that credit ratings address all business and financial risk?**

15 A. No, I do not. However, as shown in Figure 14 below, Panhandle's S&P issuer
16 rating of BBB- is lower than the majority of proxy companies that have been
17 considered by any of the Opposing Witnesses in their proxy groups and
18 Panhandle's Moody's issuer rating of Baa3 is at the lower end of the range of the
19 proposed proxy companies.

Figure 14: Summary of Credit Ratings for Proposed Proxy Companies

Company	S&P Rating	Moody's Rating
Dominion Energy, Inc.	BBB+	Baa2
Enterprise Products Partners L.P.	BBB+	NA
Enbridge Inc.	BBB	Baa2
Kinder Morgan, Inc.	BBB	Baa2
National Fuel Gas Company	BBB-	Baa3
TC PipeLines, LP	BBB	Baa2
TC Energy Corporation	BBB+	Baa2
Williams Companies, Inc.	BBB	Baa3
Panhandle Eastern Pipe Line	BBB-	Baa3

In addition, while credit ratings of BBB- and Baa3 are investment grade ratings, they are both only one credit rating notch from being rated below investment grade. Credit ratings are intended to measure the likelihood that a company will meet its debt-payment obligations, and debt investors require a return commensurate with the risk that the company will fail to meet that obligation. However, equity investors bear the residual risk associated with ownership, and have a claim on cash flows only after debt holders are paid. As such, debt and equity securities are exposed to different risks, and therefore require different

1 returns. Virtually all equity can be eroded prior to any losses to debt holders due
2 to their respective seniority. Equity financing carries no repayment obligation and
3 is therefore much riskier than a debt investor's position. As such, for the
4 determination of the cost of equity, an analysis of the relative risk of Panhandle
5 must be from the perspective of equity investors. Therefore, relying entirely on
6 credit ratings as a measure of the risk to equity is an inadequate analysis.

7 **Q. Has the Commission considered credit ratings relevant in determining the**
8 **relative risk of a pipeline company?**

9 A. Yes. In Opinion 486-B, the Commission stated:

10 [T]he Commission also takes into account the credit ratings of
11 companies on the assumption that such ratings, although not focused
12 exclusively on equity risk, are nevertheless used by equity investors in
13 developing their risk perceptions. Common sense dictates that a
14 company with a high credit rating will be perceived as a lower risk by
15 equity investors than a company with a low credit rating. *Kern River*
16 *Gas Transmission Co.*, 126 FERC ¶ 61,034 at P 137 (2009).

17 **Q. Do you agree with PMDG Witness Crowe that financing through an affiliate**
18 **results in less risk than financing through a third party?**

19 A. No, I do not. The fixed obligation of long-term debt is consistent whether or not
20 the debt is held by an affiliate or an independent third party. Furthermore, the
21 cash flow implications from a debt to equity ratio is not dependent on the holder of
22 the debt instrument. Finally, the risk to equity and as a result the return
23 requirement, which is the issue that is ultimately the subject of Ms. Crowe's

1 testimony on this point, is unchanged whether the long-term debt is held by an
2 affiliated entity or an independent third party. Therefore, I do not agree that
3 having debt held by an affiliate lowers the overall risk for Panhandle from an
4 equity investor perspective.

5 **Q. How do you respond to the PMDG Witness Crowe's position that**
6 **Panhandle's proposed equity ratio demonstrates that Panhandle is not highly**
7 **leveraged?**

8 A. It is important to note that while PMDG Witness Crowe contends that the
9 proposed equity ratio demonstrates lower risk, she also is proposing other
10 adjustments to Panhandle's rate proposal that would reduce Panhandle's equity
11 capitalization from the proposed 63.3 percent to 51.1 percent. Exhibit No. PMG-
12 0001 at page 33. Therefore, it is important to note that her overall proposal means
13 higher risk to Panhandle.

14 **Q. How do the overall risks of the natural gas pipeline proxy companies compare**
15 **with the risks faced by Panhandle?**

16 A. The proxy companies I have selected are the most reasonable companies to use to
17 reflect Panhandle's business operations and associated risks. As shown on Exhibit
18 No. PE-0037, Schedules 2 and 3, all of the natural gas pipeline proxy companies I
19 include in my proxy group are significantly more diversified than Panhandle both
20 in terms of geographic markets and lines of business. Each of the proxy group

1 companies has a portfolio of assets that source gas from more than one producing
2 region and that reach multiple market areas, which serves to reduce overall risk.
3 However, most of the pipeline assets owned by the proxy group companies face
4 various degrees of competition.

5 In contrast, Panhandle is a smaller natural gas transmission pipeline serving
6 a region that has a number of competing pipelines. Moreover, as discussed in my
7 description of Panhandle in my Prepared Direct Testimony, the increased
8 competition has resulted in a decline in the average miles of haul on the Panhandle
9 system since Panhandle's last rate case. Exhibit No. PE-0036 at 11. The
10 competition could prevent Panhandle from being able to retain or attract firm,
11 long-haul maximum rate contract customers going forward and, thus, results in a
12 significant additional risk relative to the proxy group. As such, Panhandle is
13 subject to unique risks which, while significant to Panhandle, are not nearly as
14 significant for any of the proxy group members. Finally, Panhandle's credit
15 ratings are below all of the companies in my proxy group, and all but one of the
16 companies in the combined proxy group, which includes all of the companies
17 proposed by the witnesses in this proceeding. Therefore, Panhandle's overall risks
18 are somewhat higher than the average proxy group company, and the median
19 results may be a somewhat conservative measure of Panhandle's cost of equity.

1 **Q. How should Panhandle's above average risk be reflected in the ROE**
2 **recommendation?**

3 A. Based on the risk factors discussed above, Panhandle satisfies the Commission's
4 threshold for placement at a level above the median.

5 **Q. Has Trial Staff recommended an ROE for a pipeline company that deviates**
6 **from the median result?**

7 A. Yes, in the Northern Natural Gas Company ("Northern") NGA section 4 rate case
8 in Docket No. RP19-1353-000, Trial Staff concluded that Northern's overall risk
9 profile was below the average of the proxy group and concluded that as a result
10 the ROE should be set at the median of the lower half of the range to reflect below
11 average risk for this company. Relying on a similar approach, setting the ROE for
12 Panhandle at the midpoint of the upper half of the range, to reflect its overall
13 higher risk profile than the proxy group, would result in an ROE of between 15.76
14 percent using the Combined Proxy Group and 16.81 percent using my proxy
15 group. Using the Common Proxy Group the midpoint of the upper half of the
16 range would be 16.28 percent.²⁰

²⁰ Results are the average of the midpoint results for the ROE estimates using the VL Market Return and the S&P Market Return in the CAPM.

1 **VI. SUMMARY AND CONCLUSIONS**

2 **Q. Would you please summarize your conclusions and the results of your cost of**
3 **capital study?**

4 A. The Opposing Witnesses' recommendations are not consistent with the
5 methodologies outlined in the Commission's Pipeline ROE Policy Statement and
6 therefore should not be relied upon to set the ROE for Panhandle. Opposing
7 Witnesses' recommendations improperly consider data that has been affected by
8 the current pandemic and is not reflective of the forward-looking market
9 conditions over the time period when the rates that are set in this proceeding will
10 be in effect. In addition, certain results of the Opposing Witnesses are based on
11 proxy groups that are not risk-comparable to Panhandle. As for the CAPM,
12 Opposing Witnesses' methodology and assumptions used in such analyses in their
13 Supplemental Testimonies do not reflect the methodologies outlined in the
14 Commission's Pipeline ROE Policy Statement. Finally, none of the Opposing
15 Witnesses have addressed the relative risk of Panhandle and the proxy group
16 companies in determining the appropriate ROE for Panhandle. Therefore, these
17 recommendations should not be used to inform the Commission's views on the
18 investor-required ROE for Panhandle. While I believe that the risk profile of
19 Panhandle relative to the proxy group would support an ROE commensurate with

1 an above average risk utility, the proposed ROE of 14.67 percent is conservative
2 when compared with the results for the proxy group.

3 **Q. Does this conclude your Prepared Rebuttal Testimony in this proceeding?**

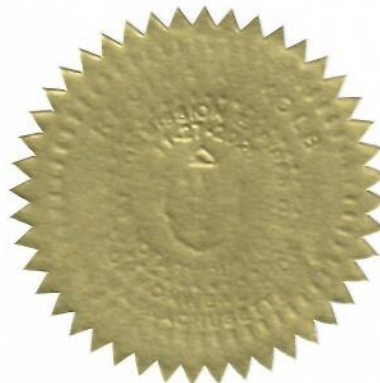
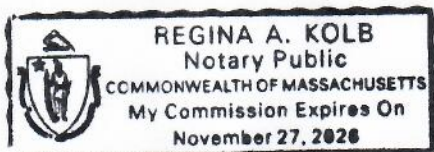
4 **A. Yes, it does**

Panhandle Eastern Pipe Line Company, LP) Docket Nos. RP19-1523-000, et al.

Ann E Bulkeny

Ben C. Lich
Notary Public

My Commission Expires:
November 27, 2026



Summary of Bulkley ROE Model Results

Model	Lower Bound	Median	Upper Bound
Discounted Cash Flow	11.31%	13.38%	14.70%
Capital Asset Pricing Model - VL Market Return	12.16%	15.56%	22.10%
Capital Asset Pricing Model - S&P Market Return	13.12%	16.70%	23.92%
Average ROE Estimate (VL Mkt Return)	11.73%	14.47%	18.40%
Average ROE Estimate (S&P Mkt Return)	12.21%	15.04%	19.31%

Summary of Common ROE Model Results

Model	Lower Bound	Median	Upper Bound
Discounted Cash Flow	11.31%	12.62%	14.70%
Capital Asset Pricing Model - VL Market Return	12.16%	14.20%	22.10%
Capital Asset Pricing Model - S&P Market Return	13.12%	15.35%	23.92%
Average ROE Estimate (VL Mkt Return)	11.73%	13.41%	18.40%
Average ROE Estimate (S&P Mkt Return)	12.21%	13.99%	19.31%

Summary of Combined ROE Model Results

Model	Lower Bound	Median	Upper Bound
Discounted Cash Flow	9.24%	11.86%	14.70%
Capital Asset Pricing Model - VL Market Return	7.56%	13.00%	22.10%
Capital Asset Pricing Model - S&P Market Return	8.09%	13.91%	23.92%
Average ROE Estimate (VL Mkt Return)	8.40%	12.43%	18.40%
Average ROE Estimate (S&P Mkt Return)	8.66%	12.88%	19.31%

Panhandle Eastern Pipe Line Company, LP - Bulkley Proxy Group

FERC DCF Policy Statement Approach Results

Line No.	Ticker		[1]	[2]	[3]	[4]	[5]	[6]
			Dividend Yield	Expected Dividend Yield Times (1 + 0.50g)	Analysts Projected EPS Growth Rate (g)	GDP Growth Rate	Weighted Average Growth Rate	Investor Required Return
1	Enbridge Inc.	ENB	8.09%	8.30%	5.49%	4.28%	5.09%	13.38%
2	Kinder Morgan, Inc.	KMI	4.90%	5.07%	8.05%	4.28%	6.79%	11.86%
3	TC PipeLines, LP	TCP	6.53%	6.75%	9.30%	2.14%	6.91%	13.67%
4	TC Energy Corp	TRP	5.85%	6.01%	5.81%	4.28%	5.30%	11.31%
5	Williams Companies, Inc.	WMB	6.52%	6.77%	9.75%	4.28%	7.93%	14.70%
6	Zone of Reasonableness Low							11.31%
7	Median of Lower Half							11.86%
8	Median							13.38%
9	Median of Upper Half							13.67%
10	Zone of Reasonableness High							14.70%

Notes:

[1] See Schedule 2 DCF p.4
[2] Equals [1]*(1+[5]*0.5)
[3] See Schedule 2 DCF p.8
[4] See Schedule 2 DCF p.9
[5] Equals [3]*2/3 + [4]*1/3
[6] Equals [2] + [5]

Panhandle Eastern Pipe Line Company, LP - Common Proxy Group

FERC DCF Policy Statement Approach Results

Line No.	Ticker	[1]	[2]	[3]	[4]	[5]	[6]
		Dividend Yield	Expected Dividend Yield Times (1 + 0.50g)	Analysts Projected EPS Growth Rate (g)	GDP Growth Rate	Weighted Average Growth Rate	Investor Required Return
1	Enbridge Inc.	ENB	8.09%	8.30%	5.49%	4.28%	13.38%
2	Kinder Morgan, Inc.	KMI	4.90%	5.07%	8.05%	4.28%	11.86%
3	TC Energy Corp	TRP	5.85%	6.01%	5.81%	4.28%	11.31%
4	Williams Companies, Inc.	WMB	6.52%	6.77%	9.75%	4.28%	14.70%
5	Zone of Reasonableness Low						11.31%
6	Median of Lower Half						11.58%
7	Median						12.62%
8	Median of Upper Half						14.04%
9	Zone of Reasonableness High						14.70%

Notes:

[1] See Schedule 2 DCF p.4
[2] Equals [1]*(1+[5]*0.5)
[3] See Schedule 2 DCF p.8
[4] See Schedule 2 DCF p.9
[5] Equals [3]*2/3 + [4]*1/3
[6] Equals [2] + [5]

Panhandle Eastern Pipe Line Company, LP - Combined Proxy Group

FERC DCF Policy Statement Approach Results

Line No.	Ticker	Analysts					
		[1] Dividend Yield	[2] Expected Dividend Yield Times (1 + 0.50g)	[3] Projected EPS Growth Rate (g)	[4] GDP Growth Rate	[5] Weighted Average Growth Rate	[6] Investor Required Return
1	Dominion Energy, Inc.	D	4.70%	4.80%	4.51%	4.28%	9.24%
2	Enbridge Inc.	ENB	8.09%	8.30%	5.49%	4.28%	13.38%
3	Kinder Morgan, Inc.	KMI	4.90%	5.07%	8.05%	4.28%	11.86%
4	National Fuel Gas Company	NFG	3.78%	3.92%	8.50%	4.28%	11.01%
5	TC PipeLines, LP	TCP	6.53%	6.75%	9.30%	2.14%	13.67%
6	TC Energy Corp	TRP	5.85%	6.01%	5.81%	4.28%	11.31%
7	Williams Companies	WMB	6.52%	6.77%	9.75%	4.28%	14.70%
8	Zone of Reasonableness Low						9.24%
9	Median of Lower Half						11.16%
10	Median						11.86%
11	Median of Upper Half						13.52%
12	Zone of Reasonableness High						14.70%

Notes:

[1] See Schedule 2 DCF p.4
[2] Equals [1]*(1+[5]*0.5)
[3] See Schedule 2 DCF p.8
[4] See Schedule 2 DCF p.9
[5] Equals [3]*2/3 + [4]*1/3
[6] Equals [2] + [5]

Panhandle Eastern Pipe Line Company, LP - Combined Proxy Group

**U.S. Natural Gas Pipeline & Storage Proxy Companies
Dividend Yields
January 2019 - June 2019**

Line No.		<u>Ticker</u>	<u>Yield</u>
1	Dominion Energy, Inc.	D	4.70%
2	Enbridge Inc.	ENB	8.09%
3	Kinder Morgan, Inc.	KMI	4.90%
4	National Fuel Gas Company	NFG	3.78%
5	TC PipeLines, LP	TCP	6.53%
6	TC Energy Corp	TRP	5.85%
7	Williams Companies, Inc.	WMB	6.52%
8	Average		5.77%
9	Median		5.85%
10	Max		8.09%
11	Min		3.78%

Source: Bloomberg, as of January 30, 2020

Panhandle Eastern Pipe Line Company, LP - Combined Proxy Group

Line No.

		High Price	Low Price	Average Price	Indicated Annualized Dividend	Dividend Yield
	Enbridge Inc.					
1	Jan-20	41.26	39.43	40.34	2.95	7.32%
2	Dec-19	39.86	37.50	38.68	2.95	7.63%
3	Nov-19	38.77	36.48	37.63	2.95	7.85%
4	Oct-19	36.83	33.79	35.31	2.95	8.36%
5	Sep-19	36.12	33.09	34.60	2.95	8.53%
6	Aug-19	34.45	32.23	33.34	2.95	8.85%
7	Average					8.09%

		High Price	Low Price	Average Price	Indicated Annu	Dividend Yield
	Dominion Energy, Inc.					
8	Jan-20	85.12	74.55	79.84	3.76	4.71%
9	Dec-19	82.64	67.84	75.24	3.76	5.00%
10	Nov-19	89.06	57.79	73.43	3.76	5.12%
11	Oct-19	90.89	76.39	83.64	3.76	4.50%
12	Sep-19	86.69	81.26	83.98	3.67	4.37%
13	Aug-19	82.95	79.77	81.36	3.67	4.51%
14	Average					4.70%

		High Price	Low Price	Average Price	Indicated Annualized Dividend	Dividend Yield
	Kinder Morgan, Inc.					
15	Jan-20	21.88	20.76	21.32	1.00	4.69%
16	Dec-19	21.36	19.13	20.25	1.00	4.94%
17	Nov-19	20.73	19.50	20.12	1.00	4.97%
18	Oct-19	20.74	19.63	20.19	1.00	4.95%
19	Sep-19	20.99	19.90	20.45	1.00	4.89%
20	Aug-19	20.91	19.50	20.21	1.00	4.95%
21	Average					4.90%

					Indicated Annualized Dividend	Dividend Yield
	National Fuel Gas Company	High Price	Low Price	Average Price		
22	Jan-20	46.67	41.34	44.01	1.74	3.95%
23	Dec-19	47.7	44.365	46.03	1.74	3.78%
24	Nov-19	47.05	44.01	45.53	1.74	3.82%
25	Oct-19	47.01	42.98	45.00	1.74	3.87%
26	Sep-19	50.46	46.03	48.25	1.74	3.61%
27	Aug-19	49.17	45.47	47.32	1.74	3.68%
28	Average					3.78%

					Indicated Annualized Dividend	Dividend Yield	
	TC PipeLines, LP	High Price	Low Price	Average Price			
29		Jan-20	44.65	39.83	42.24	2.60	6.16%
30		Dec-19	43.93	37.05	40.49	2.60	6.42%
31		Nov-19	40.73	37.77	39.25	2.60	6.62%
32		Oct-19	40.75	38.19	39.47	2.60	6.59%
33		Sep-19	42.11	37.62	39.87	2.60	6.52%
34		Aug-19	39.99	35.87	37.93	2.60	6.85%
	Average						6.53%

					Indicated Annualized Dividend	Dividend Yield
	TC Energy Corp	High Price	Low Price	Average Price		
30	Jan-20	55.70	52.25	53.98	3.00	5.56%
31	Dec-19	53.95	49.97	51.96	3.00	5.77%
32	Nov-19	51.75	48.81	50.28	3.00	5.97%
33	Oct-19	52.25	49.99	51.12	3.00	5.87%
34	Sep-19	52.69	49.58	51.14	3.00	5.87%
35	Aug-19	51.27	47.22	49.25	3.00	6.09%
	Average					5.85%

		High Price	Low Price	Average Price	Indicated Annualized Dividend	Dividend Yield
	Williams Companies, Inc.					

31	Jan-20	24.17	20.58	22.38	1.52	6.79%
32	Dec-19	24.06	22.03	23.04	1.52	6.60%
33	Nov-19	23.55	21.90	22.73	1.52	6.69%
34	Oct-19	24.32	22.10	23.21	1.52	6.55%
35	Sep-19	25.29	23.22	24.26	1.52	6.27%
36	Aug-19	26.28	22.76	24.52	1.52	6.20%
Average						<u>6.52%</u>

Source: Bloomberg, as of January 31, 2020

Panhandle Eastern Pipe Line Company, LP - Combined Proxy Group

**U.S. Natural Gas Pipeline & Storage Proxy Companies
Growth Rate Forecasts**

Line No.	Company	Ticker	Yahoo EPS	Yahoo EPS
			Growth Estimates as of January 2020	Growth Estimates as of May 2020
1	Dominion Energy, Inc.	D	4.51%	4.88%
2	Enbridge Inc.	ENB	5.49%	5.49%
3	Kinder Morgan, Inc.	KMI	8.05%	-5.18%
4	National Fuel Gas Company	NFG	8.50%	8.50%
5	TC PipeLines, LP	TCP	9.30%	-0.70%
6	TC Energy Corp	TRP	5.81%	5.81%
7	Williams Companies, Inc.	WMB	9.75%	1.98%

Source: Thomson Reuters' First Call, provided by Yahoo! Finance

Panhandle Eastern Pipe Line Company, LP

**Long-Term
U.S. Gross Domestic Product (GDP)
Growth Forecasts**

Line No.	Source	[A]	[B]	[C]
		Beginning Year	Ending Year	Annual GDP Growth
1	BCFF [1]	2021	2030	4.24%
2	EIA [2]	2023	2050	4.24%
3	SSA [3]	2023	2075	4.35%
4	Average			4.28%

Notes:

[1] Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2019, at 14. Nominal GDP = (Real GDP) * (GDP Chained Price Index)

[2] Energy Information Administration Annual Energy Outlook 2020 with projections to 2050 (January 2020), Table A20. Macroeconomic Indicators. Nominal GDP=(Real GDP)*(GDP Chain Type Price Index). https://www.eia.gov/outlooks/aeo/tables_ref.php

[3] Social Security Administration: The 2019 OASDI Trustees Report, Table VI.G4.—OASDI and HI Annual and Summarized Income, Cost, and Balance as a Percentage of GDP, Calendar Years 2018-95 https://www.ssa.gov/oact/tr/2019/VI_G2_OASDHI_GDP.html

Panhandle Eastern Pipe Line Company, LP - Bulkley Proxy Group

Capital Asset Pricing Model

$$K = R_f + \beta (R_m - R_f)$$

							[1]
Risk Free Rate							2.22%
Market Return [2]							12.43%
Risk Premium [3]							10.21%
							Current 30-day average of 30-year U.S. Treasury bond yield
Line No.			Value Line Beta	Unadjusted CAPM	6-Month Avg Market Cap (\$ Mil)	Size Premium (%)	
1	Enbridge Inc.	ENB	1.00	12.43%	74,418.2	-0.27%	12.16%
2	Kinder Morgan, Inc.	KMI	1.35	16.00%	46,250.2	-0.27%	15.73%
3	TC PipeLines, LP	TCP	1.20	14.47%	2,843.5	1.08%	15.56%
4	TC Energy Corp	TRP	1.05	12.94%	47,937.6	-0.27%	12.67%
5	Williams Companies, Inc.	WMB	1.90	21.62%	28,243.0	0.48%	22.10%
6	Zone of Reasonableness Low						12.16%
7	Median of Lower Half						12.67%
8	Median						15.56%
9	Median of Upper Half						15.73%
10	Zone of Reasonableness High						22.10%

Notes:

[1] Source: Bloomberg Professional

[2] See Schedule 3 CAPM p19-32

[3] Equals [2] - [1]

Panhandle Eastern Pipe Line Company, LP - Bulkley Proxy Group

Capital Asset Pricing Model

$$K = R_f + \beta (R_m - R_f)$$

							[1]
Risk Free Rate							2.22%
Market Return [2]							13.38%
Risk Premium [3]							11.17%
							Current 30-day average of 30-year U.S. Treasury bond yield
Line No.			Value Line Beta	Unadjusted CAPM	6-Month Avg Market Cap (\$ Mil)	Size Premium (%)	
1	Enbridge Inc.	ENB	1.00	13.38%	74,418.2	-0.27%	13.12%
2	Kinder Morgan, Inc.	KMI	1.35	17.29%	46,250.2	-0.27%	17.03%
3	TC PipeLines, LP	TCP	1.20	15.62%	2,843.5	1.08%	16.70%
4	TC Energy Corp	TRP	1.05	13.94%	47,937.6	-0.27%	13.68%
5	Williams Companies, Inc.	WMB	1.90	23.44%	28,243.0	0.48%	23.92%
6	Zone of Reasonableness Low						13.12%
7	Median of Lower Half						13.68%
8	Median						16.70%
9	Median of Upper Half						17.03%
10	Zone of Reasonableness High						23.92%

Notes:

[1] Source: Bloomberg Professional

[2] See Schedule 3 CAPM p33

[3] Equals [2] - [1]

Panhandle Eastern Pipe Line Company, LP - Common Proxy Group

Capital Asset Pricing Model

$$K = R_f + \beta (R_m - R_f)$$

							[1]
Risk Free Rate							2.22%
Market Return [2]							12.43%
Risk Premium [3]							10.21%
							Current 30-day average of 30-year U.S. Treasury bond yield
Line No.			Value Line Beta	Unadjusted CAPM	6-Month Avg Market Cap (\$ Mil)	Size Premium (%)	
1	Enbridge Inc.	ENB	1.00	12.43%	74,418.2	-0.27%	12.16%
2	Kinder Morgan, Inc.	KMI	1.35	16.00%	46,250.2	-0.27%	15.73%
3	TC Energy Corp	TRP	1.05	12.94%	47,937.6	-0.27%	12.67%
4	Williams Companies, Inc.	WMB	1.90	21.62%	28,243.0	0.48%	22.10%
5	Zone of Reasonableness Low						12.16%
6	Median of Lower Half						12.67%
7	Median						14.20%
8	Median of Upper Half						15.73%
9	Zone of Reasonableness High						22.10%

Notes:

[1] Source: Bloomberg Professional

[2] See Schedule 3 CAPM p19-32

[3] Equals [2] - [1]

Panhandle Eastern Pipe Line Company, LP - Common Proxy Group

Capital Asset Pricing Model

$$K = R_f + \beta (R_m - R_f)$$

							[1]
Risk Free Rate							2.22%
Market Return [2]							13.38%
Risk Premium [3]							11.17%
							Current 30-day average of 30-year U.S. Treasury bond yield
Line No.			Value Line Beta	Unadjusted CAPM	6-Month Avg Market Cap (\$ Mil)	Size Premium (%)	
1	Enbridge Inc.	ENB	1.00	13.38%	74,418.2	-0.27%	13.12%
2	Kinder Morgan, Inc.	KMI	1.35	17.29%	46,250.2	-0.27%	17.03%
3	TC Energy Corp	TRP	1.05	13.94%	47,937.6	-0.27%	13.68%
4	Williams Companies, Inc.	WMB	1.90	23.44%	28,243.0	0.48%	23.92%
5	Zone of Reasonableness Low						13.12%
6	Median of Lower Half						13.40%
7	Median						15.35%
8	Median of Upper Half						17.03%
9	Zone of Reasonableness High						23.92%

Notes:

[1] Source: Bloomberg Professional

[2] See Schedule 3 CAPM p33

[3] Equals [2] - [1]

Panhandle Eastern Pipe Line Company, LP - Combined Proxy Group

Capital Asset Pricing Model

$$K = R_f + \beta (R_m - R_f)$$

							[1]
Risk Free Rate							2.22%
Market Return [2]							12.43%
Risk Premium [3]							10.21%
							Current 30-day average of 30-year U.S. Treasury bond yield
Line No.			Value Line Beta	Unadjusted CAPM	6-Month Avg Market Cap (\$ Mil)	Size Premium (%)	
1	Dominion Energy, Inc.	D	0.55	7.83%	65,607.4	-0.27%	7.56%
2	Enbridge Inc.	ENB	1.00	12.43%	74,418.2	-0.27%	12.16%
3	Kinder Morgan, Inc.	KMI	1.35	16.00%	46,250.2	-0.27%	15.73%
4	National Fuel Gas Company	NFG	0.95	11.92%	3,972.2	1.08%	13.00%
5	TC PipeLines, LP	TCP	1.20	14.47%	2,843.5	1.08%	15.56%
6	TC Energy Corp	TRP	1.05	12.94%	47,937.6	-0.27%	12.67%
7	Williams Companies, Inc.	WMB	1.90	21.62%	28,243.0	0.48%	22.10%
8	Zone of Reasonableness Low						7.56%
9	Median of Lower Half						12.42%
10	Median						13.00%
11	Median of Upper Half						15.64%
12	Zone of Reasonableness High						22.10%

Notes:

[1] Source: Bloomberg Professional

[2] See Schedule 3 CAPM p19-32

[3] Equals [2] - [1]

Panhandle Eastern Pipe Line Company, LP - Combined Proxy Group

Capital Asset Pricing Model

$$K = R_f + \beta (R_m - R_f)$$

							[1]
Risk Free Rate							2.22%
Market Return [2]							13.38%
Risk Premium [3]							11.17%
							Current 30-day average of 30-year U.S. Treasury bond yield
Line No.			Value Line Beta	Unadjusted CAPM	6-Month Avg Market Cap (\$ Mil)	Size Premium (%)	
1	Dominion Energy, Inc.	D	0.55	8.36%	65,607.4	-0.27%	8.09%
2	Enbridge Inc.	ENB	1.00	13.38%	74,418.2	-0.27%	13.12%
3	Kinder Morgan, Inc.	KMI	1.35	17.29%	46,250.2	-0.27%	17.03%
4	National Fuel Gas Company	NFG	0.95	12.83%	3,972.2	1.08%	13.91%
5	TC PipeLines, LP	TCP	1.20	15.62%	2,843.5	1.08%	16.70%
6	TC Energy Corp	TRP	1.05	13.94%	47,937.6	-0.27%	13.68%
7	Williams Companies, Inc.	WMB	1.90	23.44%	28,243.0	0.48%	23.92%
8	Zone of Reasonableness Low						8.09%
9	Median of Lower Half						13.40%
10	Median						13.91%
11	Median of Upper Half						16.86%
12	Zone of Reasonableness High						23.92%

Notes:

[1] Source: Bloomberg Professional

[2] See Schedule 3 CAPM p33

[3] Equals [2] - [1]

Panhandle 1

	D			ENB			KMI		
	Low	High	Avg Low & High	Low	High	Avg Low & High	Low	High	Avg Low & High
Jan-20	67,721	71,692	69,706	80,228	83,507	81,867	47,406	49,286	48,346
Dec-19	65,782	68,658	67,220	76,565	80,491	78,528	43,374	48,017	45,696
Nov-19	65,535	68,695	67,115	74,338	78,387	76,362	44,416	46,568	45,492
Oct-19	63,966	66,537	65,251	69,096	74,155	71,626	45,254	46,453	45,854
Sep-19	61,355	65,106	63,231	67,738	72,960	70,349	45,548	47,359	46,453
Aug-19	59,748	62,495	61,122	65,996	69,558	67,777	44,303	47,019	45,661
AVG			65,607			74,418			46,250

D US Equity		ENB US Equity		KMI US Equity	
Daily Price		Daily Price		Daily Price	
CUR_MKT_CAP		CUR_MKT_CAP		CUR_MKT_CAP	
1/30/2020	71,692	1/30/2020	83,507	1/30/2020	48,516
1/29/2020	70,788	1/29/2020	83,244	1/29/2020	47,995
1/28/2020	70,067	1/28/2020	83,163	1/28/2020	48,606
1/27/2020	69,072	1/27/2020	82,636	1/27/2020	48,221
1/24/2020	69,636	1/24/2020	83,082	1/24/2020	48,833
1/23/2020	69,694	1/23/2020	82,980	1/23/2020	49,286
1/22/2020	69,379	1/22/2020	82,657	1/22/2020	47,474
1/21/2020	69,661	1/21/2020	82,454	1/21/2020	47,406
1/17/2020	69,677	1/17/2020	82,009	1/17/2020	48,380
1/16/2020	69,230	1/16/2020	81,948	1/16/2020	48,402
1/15/2020	68,799	1/15/2020	81,361	1/15/2020	48,493
1/14/2020	67,937	1/14/2020	81,422	1/14/2020	48,606
1/13/2020	68,019	1/13/2020	81,503	1/13/2020	48,810
1/10/2020	68,036	1/10/2020	80,835	1/10/2020	48,719
1/9/2020	67,912	1/9/2020	80,633	1/9/2020	48,810
1/8/2020	67,721	1/8/2020	80,774	1/8/2020	47,927
1/7/2020	68,152	1/7/2020	80,430	1/7/2020	48,312
1/6/2020	68,301	1/6/2020	80,977	1/6/2020	48,198
1/3/2020	67,779	1/3/2020	80,228	1/3/2020	48,017
1/2/2020	67,945	1/2/2020	80,370	1/2/2020	47,655
12/31/2019	68,658	12/31/2019	80,491	12/31/2019	47,949
12/30/2019	68,044	12/30/2019	80,046	12/30/2019	47,632
12/27/2019	67,978	12/27/2019	80,127	12/27/2019	47,745
12/26/2019	67,530	12/26/2019	80,289	12/26/2019	48,017
12/24/2019	67,447	12/24/2019	80,066	12/24/2019	47,859
12/23/2019	67,505	12/23/2019	80,086	12/23/2019	48,017
12/20/2019	67,757	12/20/2019	79,783	12/20/2019	47,496
12/19/2019	67,329	12/19/2019	79,155	12/19/2019	47,202

D US Equity Daily Price CUR_MKT_CAP		ENB US Equity Daily Price CUR_MKT_CAP		KMI US Equity Daily Price CUR_MKT_CAP	
12/18/2019	67,041	12/18/2019	79,074	12/18/2019	46,930
12/17/2019	67,131	12/17/2019	77,981	12/17/2019	46,454
12/16/2019	67,197	12/16/2019	78,184	12/16/2019	46,613
12/13/2019	66,572	12/13/2019	77,536	12/13/2019	45,752
12/12/2019	66,415	12/12/2019	77,435	12/12/2019	45,639
12/11/2019	66,588	12/11/2019	78,224	12/11/2019	45,752
12/10/2019	65,922	12/10/2019	78,346	12/10/2019	45,571
12/9/2019	65,782	12/9/2019	78,528	12/9/2019	45,163
12/6/2019	66,671	12/6/2019	77,941	12/6/2019	44,733
12/5/2019	66,827	12/5/2019	77,860	12/5/2019	44,575
12/4/2019	67,699	12/4/2019	77,435	12/4/2019	43,714
12/3/2019	67,444	12/3/2019	76,848	12/3/2019	43,374
12/2/2019	67,494	12/2/2019	76,565	12/2/2019	43,940
11/29/2019	68,407	11/29/2019	76,909	11/29/2019	44,416
11/27/2019	68,383	11/27/2019	76,808	11/27/2019	44,688
11/26/2019	68,695	11/26/2019	76,342	11/26/2019	44,620
11/25/2019	68,506	11/25/2019	76,464	11/25/2019	45,209
11/22/2019	68,514	11/22/2019	75,715	11/22/2019	45,209
11/21/2019	68,333	11/21/2019	76,423	11/21/2019	45,662
11/20/2019	68,234	11/20/2019	76,322	11/20/2019	45,435
11/19/2019	67,839	11/19/2019	76,140	11/19/2019	45,322
11/18/2019	67,971	11/18/2019	77,031	11/18/2019	45,616
11/15/2019	67,584	11/15/2019	77,273	11/15/2019	46,296
11/14/2019	67,131	11/14/2019	76,342	11/14/2019	45,798
11/13/2019	66,539	11/13/2019	78,387	11/13/2019	46,092
11/12/2019	65,617	11/12/2019	77,435	11/12/2019	45,458
11/11/2019	65,535	11/11/2019	76,423	11/11/2019	45,163
11/8/2019	66,078	11/8/2019	75,836	11/8/2019	45,367
11/7/2019	66,103	11/7/2019	74,338	11/7/2019	45,390
11/6/2019	66,621	11/6/2019	74,703	11/6/2019	45,775
11/5/2019	66,959	11/5/2019	74,723	11/5/2019	46,477
11/4/2019	68,358	11/4/2019	74,642	11/4/2019	46,568
11/1/2019	66,898	11/1/2019	74,622	11/1/2019	46,432
10/31/2019	66,320	10/31/2019	73,691	10/31/2019	45,254
10/30/2019	65,725	10/30/2019	73,730	10/30/2019	45,299
10/29/2019	65,669	10/29/2019	73,730	10/29/2019	45,684
10/28/2019	65,339	10/28/2019	74,155	10/28/2019	45,707
10/25/2019	65,789	10/25/2019	73,832	10/25/2019	46,251
10/24/2019	66,456	10/24/2019	74,054	10/24/2019	46,296
10/23/2019	66,456	10/23/2019	73,993	10/23/2019	46,205
10/22/2019	66,537	10/22/2019	73,407	10/22/2019	46,024
10/21/2019	66,215	10/21/2019	73,285	10/21/2019	45,662
10/18/2019	66,006	10/18/2019	73,083	10/18/2019	45,321

D US Equity Daily Price CUR_MKT_CAP		ENB US Equity Daily Price CUR_MKT_CAP		KMI US Equity Daily Price CUR_MKT_CAP	
10/17/2019	66,183	10/17/2019	72,334	10/17/2019	45,435
10/16/2019	65,717	10/16/2019	72,212	10/16/2019	45,321
10/15/2019	65,380	10/15/2019	72,233	10/15/2019	45,684
10/14/2019	65,267	10/14/2019	72,091	10/14/2019	45,593
10/11/2019	65,797	10/11/2019	72,678	10/11/2019	45,797
10/10/2019	65,701	10/10/2019	72,172	10/10/2019	45,819
10/9/2019	65,347	10/9/2019	71,180	10/9/2019	45,684
10/8/2019	64,849	10/8/2019	70,391	10/8/2019	45,299
10/7/2019	65,219	10/7/2019	70,431	10/7/2019	45,955
10/4/2019	65,637	10/4/2019	70,431	10/4/2019	46,453
10/3/2019	63,966	10/3/2019	69,541	10/3/2019	46,136
10/2/2019	64,247	10/2/2019	69,096	10/2/2019	45,661
10/1/2019	65,251	10/1/2019	71,120	10/1/2019	45,933
9/30/2019	65,106	9/30/2019	70,998	9/30/2019	46,657
9/27/2019	65,066	9/27/2019	72,960	9/27/2019	46,793
9/26/2019	64,882	9/26/2019	72,312	9/26/2019	46,453
9/25/2019	64,584	9/25/2019	71,462	9/25/2019	46,431
9/24/2019	64,946	9/24/2019	71,584	9/24/2019	46,566
9/23/2019	64,954	9/23/2019	71,138	9/23/2019	47,042
9/20/2019	64,946	9/20/2019	71,523	9/20/2019	47,359
9/19/2019	65,010	9/19/2019	71,239	9/19/2019	46,838
9/18/2019	64,319	9/18/2019	71,219	9/18/2019	46,793
9/17/2019	63,492	9/17/2019	71,341	9/17/2019	46,951
9/16/2019	63,058	9/16/2019	71,159	9/16/2019	46,793
9/13/2019	63,082	9/13/2019	70,632	9/13/2019	46,340
9/12/2019	63,098	9/12/2019	70,228	9/12/2019	46,227
9/11/2019	63,010	9/11/2019	70,369	9/11/2019	46,295
9/10/2019	61,869	9/10/2019	70,268	9/10/2019	45,797
9/9/2019	61,596	9/9/2019	69,620	9/9/2019	46,204
9/6/2019	61,355	9/6/2019	69,499	9/6/2019	46,204
9/5/2019	62,206	9/5/2019	68,953	9/5/2019	46,431
9/4/2019	63,588	9/4/2019	68,123	9/4/2019	46,023
9/3/2019	63,307	9/3/2019	67,738	9/3/2019	45,548
8/30/2019	62,367	8/30/2019	67,718	8/30/2019	45,887
8/29/2019	62,471	8/29/2019	67,433	8/29/2019	46,182
8/28/2019	61,772	8/28/2019	66,806	8/28/2019	45,865
8/27/2019	61,981	8/27/2019	66,583	8/27/2019	45,367
8/26/2019	61,716	8/26/2019	66,563	8/26/2019	45,095
8/23/2019	61,009	8/23/2019	65,996	8/23/2019	44,303
8/22/2019	61,475	8/22/2019	67,575	8/22/2019	45,729
8/21/2019	61,853	8/21/2019	68,506	8/21/2019	46,159
8/20/2019	61,788	8/20/2019	67,454	8/20/2019	45,593
8/19/2019	62,495	8/19/2019	68,223	8/19/2019	46,204

D US Equity		ENB US Equity		KMI US Equity	
Daily Price		Daily Price		Daily Price	
CUR_MKT_CAP		CUR_MKT_CAP		CUR_MKT_CAP	
8/16/2019	61,748	8/16/2019	68,040	8/16/2019	45,570
8/15/2019	61,901	8/15/2019	66,948	8/15/2019	45,004
8/14/2019	60,519	8/14/2019	66,300	8/14/2019	44,823
8/13/2019	60,559	8/13/2019	69,558	8/13/2019	46,431
8/12/2019	59,748	8/12/2019	68,202	8/12/2019	46,046
8/9/2019	60,125	8/9/2019	68,425	8/9/2019	46,114
8/8/2019	60,519	8/8/2019	68,688	8/8/2019	46,114
8/7/2019	59,796	8/7/2019	67,838	8/7/2019	45,208
8/6/2019	60,431	8/6/2019	66,300	8/6/2019	45,344
8/5/2019	59,989	8/5/2019	66,644	8/5/2019	44,914
8/2/2019	61,073	8/2/2019	67,798	8/2/2019	45,752
8/1/2019	60,985	8/1/2019	68,081	8/1/2019	47,019
7/31/2019	59,608	7/31/2019	67,575	7/31/2019	46,680

Eastern Pipe Line Company, LP - Combined Proxy Group

Market Capitalization Data

		NFG			TRP			TCP			WMB		
High	Low	High	Avg Low & High	Low	High	Avg Low & High	Low	High	Avg Low & High	Low	High	Avg Low & High	Low
	3,635	3,947	3,791	48,962	51,859	50,411	2,921	3,173	3,047	25,647	29,138	27,392	
	3,847	4,094	3,971	46,860	50,308	48,584	2,660	3,110	2,885	26,823	29,016	27,920	
	3,886	4,027	3,957	46,421	48,065	47,243	2,737	2,864	2,801	26,604	28,277	27,441	
	3,738	3,970	3,854	47,028	48,393	47,711	2,737	2,874	2,806	27,041	28,870	27,956	
	4,040	4,316	4,178	46,443	48,757	47,600	2,696	2,911	2,804	28,543	30,301	29,422	
	3,934	4,232	4,083	44,359	47,796	46,077	2,609	2,829	2,719	27,731	30,924	29,328	
			3,972			47,938			2,844			28,243	

NFG US Equity		TRP US Equity		TCP US Equity		WMB US Equity	
Daily Price		Daily Price		Daily Price		Daily Price	
CUR_MKT_CAP		CUR_MKT_CAP		CUR_MKT_CAP		CUR_MKT_CAP	
1/30/2020	3,635	1/30/2020	51,560	1/30/2020	2,946	1/30/2020	25,780
1/29/2020	3,664	1/29/2020	51,719	1/29/2020	2,968	1/29/2020	25,647
1/28/2020	3,704	1/28/2020	51,859	1/28/2020	2,977	1/28/2020	26,229
1/27/2020	3,689	1/27/2020	51,261	1/27/2020	2,980	1/27/2020	26,192
1/24/2020	3,749	1/24/2020	51,401	1/24/2020	2,997	1/24/2020	26,895
1/23/2020	3,826	1/23/2020	51,233	1/23/2020	3,047	1/23/2020	27,198
1/22/2020	3,807	1/22/2020	50,644	1/22/2020	3,091	1/22/2020	27,441
1/21/2020	3,872	1/21/2020	50,971	1/21/2020	3,098	1/21/2020	27,889
1/17/2020	3,927	1/17/2020	50,710	1/17/2020	3,130	1/17/2020	28,919
1/16/2020	3,916	1/16/2020	50,242	1/16/2020	3,156	1/16/2020	29,138
1/15/2020	3,909	1/15/2020	49,897	1/15/2020	3,173	1/15/2020	28,859
1/14/2020	3,871	1/14/2020	49,299	1/14/2020	3,133	1/14/2020	28,895
1/13/2020	3,871	1/13/2020	49,252	1/13/2020	3,061	1/13/2020	28,823
1/10/2020	3,879	1/10/2020	48,962	1/10/2020	2,973	1/10/2020	28,483
1/9/2020	3,880	1/9/2020	49,411	1/9/2020	3,006	1/9/2020	28,689
1/8/2020	3,886	1/8/2020	49,467	1/8/2020	3,003	1/8/2020	28,520
1/7/2020	3,930	1/7/2020	49,345	1/7/2020	2,978	1/7/2020	28,968
1/6/2020	3,947	1/6/2020	49,775	1/6/2020	2,973	1/6/2020	28,968
1/3/2020	3,904	1/3/2020	49,439	1/3/2020	2,921	1/3/2020	28,592
1/2/2020	3,872	1/2/2020	49,243	1/2/2020	2,945	1/2/2020	28,471
12/31/2019	4,018	12/31/2019	49,813	12/31/2019	3,016	12/31/2019	28,750
12/30/2019	3,967	12/30/2019	49,215	12/30/2019	2,980	12/30/2019	28,120
12/27/2019	4,046	12/27/2019	50,252	12/27/2019	3,026	12/27/2019	28,592
12/26/2019	4,054	12/26/2019	50,308	12/26/2019	3,110	12/26/2019	28,859
12/24/2019	4,032	12/24/2019	49,532	12/24/2019	3,045	12/24/2019	28,895
12/23/2019	4,094	12/23/2019	49,738	12/23/2019	2,964	12/23/2019	29,016
12/20/2019	4,087	12/20/2019	49,532	12/20/2019	2,872	12/20/2019	28,847
12/19/2019	4,083	12/19/2019	49,121	12/19/2019	2,908	12/19/2019	28,483

NFG US Equity Daily Price CUR_MKT_CAP		TRP US Equity Daily Price CUR_MKT_CAP		TCP US Equity Daily Price CUR_MKT_CAP		WMB US Equity Daily Price CUR_MKT_CAP	
12/18/2019	4,083	12/18/2019	49,093	12/18/2019	2,940	12/18/2019	27,974
12/17/2019	4,016	12/17/2019	48,635	12/17/2019	2,917	12/17/2019	27,804
12/16/2019	4,028	12/16/2019	48,271	12/16/2019	2,861	12/16/2019	27,659
12/13/2019	4,003	12/13/2019	47,589	12/13/2019	2,797	12/13/2019	27,526
12/12/2019	3,980	12/12/2019	48,009	12/12/2019	2,797	12/12/2019	27,453
12/11/2019	3,964	12/11/2019	48,280	12/11/2019	2,791	12/11/2019	28,107
12/10/2019	3,956	12/10/2019	48,075	12/10/2019	2,789	12/10/2019	27,804
12/9/2019	3,892	12/9/2019	47,710	12/9/2019	2,766	12/9/2019	27,756
12/6/2019	3,896	12/6/2019	47,421	12/6/2019	2,691	12/6/2019	27,138
12/5/2019	3,879	12/5/2019	47,402	12/5/2019	2,660	12/5/2019	26,895
12/4/2019	3,892	12/4/2019	47,019	12/4/2019	2,679	12/4/2019	26,823
12/3/2019	3,847	12/3/2019	46,860	12/3/2019	2,700	12/3/2019	26,907
12/2/2019	3,879	12/2/2019	47,159	12/2/2019	2,679	12/2/2019	27,332
11/29/2019	3,886	11/29/2019	47,589	11/29/2019	2,780	11/29/2019	27,538
11/27/2019	3,948	11/27/2019	47,692	11/27/2019	2,737	11/27/2019	27,526
11/26/2019	3,905	11/26/2019	47,495	11/26/2019	2,742	11/26/2019	27,720
11/25/2019	3,948	11/25/2019	47,626	11/25/2019	2,810	11/25/2019	27,986
11/22/2019	3,911	11/22/2019	47,393	11/22/2019	2,829	11/22/2019	27,998
11/21/2019	3,892	11/21/2019	47,841	11/21/2019	2,834	11/21/2019	27,623
11/20/2019	3,917	11/20/2019	47,692	11/20/2019	2,771	11/20/2019	27,126
11/19/2019	3,933	11/19/2019	47,878	11/19/2019	2,812	11/19/2019	26,835
11/18/2019	3,965	11/18/2019	48,065	11/18/2019	2,827	11/18/2019	27,029
11/15/2019	3,967	11/15/2019	48,019	11/15/2019	2,864	11/15/2019	27,101
11/14/2019	3,894	11/14/2019	47,617	11/14/2019	2,835	11/14/2019	26,604
11/13/2019	3,983	11/13/2019	47,645	11/13/2019	2,816	11/13/2019	26,714
11/12/2019	3,973	11/12/2019	47,841	11/12/2019	2,804	11/12/2019	26,714
11/11/2019	3,952	11/11/2019	47,122	11/11/2019	2,822	11/11/2019	26,762
11/8/2019	4,027	11/8/2019	47,009	11/8/2019	2,815	11/8/2019	26,774
11/7/2019	4,017	11/7/2019	46,421	11/7/2019	2,857	11/7/2019	26,823
11/6/2019	3,977	11/6/2019	47,047	11/6/2019	2,831	11/6/2019	26,956
11/5/2019	3,984	11/5/2019	46,439	11/5/2019	2,841	11/5/2019	27,817
11/4/2019	3,996	11/4/2019	47,243	11/4/2019	2,793	11/4/2019	28,277
11/1/2019	3,924	11/1/2019	47,766	11/1/2019	2,827	11/1/2019	27,744
10/31/2019	3,911	10/31/2019	47,028	10/31/2019	2,825	10/31/2019	27,041
10/30/2019	3,913	10/30/2019	47,040	10/30/2019	2,806	10/30/2019	27,743
10/29/2019	3,970	10/29/2019	47,078	10/29/2019	2,780	10/29/2019	28,143
10/28/2019	3,928	10/28/2019	47,432	10/28/2019	2,787	10/28/2019	27,840
10/25/2019	3,939	10/25/2019	47,647	10/25/2019	2,756	10/25/2019	28,167
10/24/2019	3,929	10/24/2019	47,945	10/24/2019	2,792	10/24/2019	28,143
10/23/2019	3,946	10/23/2019	48,141	10/23/2019	2,775	10/23/2019	28,434
10/22/2019	3,910	10/22/2019	48,039	10/22/2019	2,737	10/22/2019	28,131
10/21/2019	3,863	10/21/2019	48,393	10/21/2019	2,781	10/21/2019	27,925
10/18/2019	3,848	10/18/2019	48,001	10/18/2019	2,760	10/18/2019	27,767

NFG US Equity		TRP US Equity		TCP US Equity		WMB US Equity	
Daily Price		Daily Price		Daily Price		Daily Price	
CUR_MKT_CAP		CUR_MKT_CAP		CUR_MKT_CAP		CUR_MKT_CAP	
10/17/2019	3,869	10/17/2019	48,011	10/17/2019	2,767	10/17/2019	27,634
10/16/2019	3,876	10/16/2019	47,749	10/16/2019	2,786	10/16/2019	27,646
10/15/2019	3,870	10/15/2019	47,563	10/15/2019	2,801	10/15/2019	28,058
10/14/2019	3,864	10/14/2019	47,544	10/14/2019	2,771	10/14/2019	28,022
10/11/2019	3,877	10/11/2019	47,731	10/11/2019	2,759	10/11/2019	27,986
10/10/2019	3,754	10/10/2019	47,824	10/10/2019	2,807	10/10/2019	27,561
10/9/2019	3,749	10/9/2019	47,936	10/9/2019	2,827	10/9/2019	27,537
10/8/2019	3,738	10/8/2019	47,367	10/8/2019	2,804	10/8/2019	27,767
10/7/2019	3,806	10/7/2019	48,039	10/7/2019	2,833	10/7/2019	28,458
10/4/2019	3,885	10/4/2019	47,955	10/4/2019	2,836	10/4/2019	28,664
10/3/2019	3,894	10/3/2019	47,432	10/3/2019	2,860	10/3/2019	28,555
10/2/2019	3,895	10/2/2019	47,330	10/2/2019	2,843	10/2/2019	28,325
10/1/2019	3,935	10/1/2019	48,011	10/1/2019	2,874	10/1/2019	28,870
9/30/2019	4,050	9/30/2019	48,309	9/30/2019	2,900	9/30/2019	29,161
9/27/2019	4,062	9/27/2019	48,225	9/27/2019	2,879	9/27/2019	29,331
9/26/2019	4,086	9/26/2019	48,757	9/26/2019	2,896	9/26/2019	29,246
9/25/2019	4,145	9/25/2019	48,393	9/25/2019	2,854	9/25/2019	29,573
9/24/2019	4,132	9/24/2019	48,393	9/24/2019	2,852	9/24/2019	29,440
9/23/2019	4,129	9/23/2019	48,514	9/23/2019	2,867	9/23/2019	29,828
9/20/2019	4,081	9/20/2019	48,225	9/20/2019	2,886	9/20/2019	29,949
9/19/2019	4,154	9/19/2019	47,498	9/19/2019	2,907	9/19/2019	30,070
9/18/2019	4,191	9/18/2019	47,292	9/18/2019	2,909	9/18/2019	30,107
9/17/2019	4,184	9/17/2019	47,106	9/17/2019	2,911	9/17/2019	30,301
9/16/2019	4,242	9/16/2019	46,630	9/16/2019	2,911	9/16/2019	30,288
9/13/2019	4,206	9/13/2019	46,443	9/13/2019	2,875	9/13/2019	29,937
9/12/2019	4,207	9/12/2019	46,537	9/12/2019	2,740	9/12/2019	29,440
9/11/2019	4,316	9/11/2019	46,723	9/11/2019	2,754	9/11/2019	30,252
9/10/2019	4,253	9/10/2019	47,581	9/10/2019	2,730	9/10/2019	30,119
9/9/2019	4,161	9/9/2019	47,740	9/9/2019	2,696	9/9/2019	29,913
9/6/2019	4,057	9/6/2019	47,628	9/6/2019	2,749	9/6/2019	29,234
9/5/2019	4,097	9/5/2019	47,889	9/5/2019	2,790	9/5/2019	29,173
9/4/2019	4,055	9/4/2019	48,449	9/4/2019	2,791	9/4/2019	28,725
9/3/2019	4,040	9/3/2019	48,412	9/3/2019	2,801	9/3/2019	28,543
8/30/2019	4,034	8/30/2019	47,796	8/30/2019	2,792	8/30/2019	28,604
8/29/2019	4,023	8/29/2019	47,136	8/29/2019	2,797	8/29/2019	28,737
8/28/2019	3,950	8/28/2019	46,560	8/28/2019	2,741	8/28/2019	28,276
8/27/2019	3,949	8/27/2019	45,771	8/27/2019	2,685	8/27/2019	27,780
8/26/2019	4,006	8/26/2019	45,343	8/26/2019	2,661	8/26/2019	27,792
8/23/2019	3,934	8/23/2019	44,963	8/23/2019	2,637	8/23/2019	27,731
8/22/2019	4,052	8/22/2019	45,223	8/22/2019	2,685	8/22/2019	28,604
8/21/2019	4,103	8/21/2019	45,381	8/21/2019	2,670	8/21/2019	28,943
8/20/2019	4,052	8/20/2019	44,693	8/20/2019	2,675	8/20/2019	28,519
8/19/2019	4,097	8/19/2019	45,130	8/19/2019	2,693	8/19/2019	28,555

	NFG US Equity Daily Price CUR_MKT_CAP
8/16/2019	4,060
8/15/2019	4,021
8/14/2019	4,012
8/13/2019	4,084
8/12/2019	4,069
8/9/2019	4,097
8/8/2019	4,232
8/7/2019	4,194
8/6/2019	4,131
8/5/2019	4,119
8/2/2019	4,217
8/1/2019	4,045
7/31/2019	4,120

	TRP US Equity Daily Price CUR_MKT_CAP
8/16/2019	44,953
8/15/2019	44,359
8/14/2019	44,359
8/13/2019	45,956
8/12/2019	44,823
8/9/2019	44,675
8/8/2019	44,675
8/7/2019	44,396
8/6/2019	44,665
8/5/2019	44,424
8/2/2019	45,130
8/1/2019	45,576
7/31/2019	45,474

	TCP US Equity Daily Price CUR_MKT_CAP
8/16/2019	2,643
8/15/2019	2,645
8/14/2019	2,636
8/13/2019	2,659
8/12/2019	2,609
8/9/2019	2,636
8/8/2019	2,724
8/7/2019	2,706
8/6/2019	2,736
8/5/2019	2,753
8/2/2019	2,795
8/1/2019	2,829
7/31/2019	2,887

	WMB US Equity Daily Price CUR_MKT_CAP
8/16/2019	28,216
8/15/2019	27,780
8/14/2019	28,010
8/13/2019	28,955
8/12/2019	28,725
8/9/2019	29,076
8/8/2019	29,125
8/7/2019	28,628
8/6/2019	28,519
8/5/2019	28,822
8/2/2019	30,313
8/1/2019	30,924
7/31/2019	29,858

Panhandle Eastern Pipe Line Company, LP

Size Premium Calculation

	[1]	[2]
	Market Capitalization of Largest Company (\$M)	Size Premium
Breakdown of Deci		
1-Largest	\$ 1,061,355.01	-0.27%
2	\$ 30,542.94	0.48%
3	\$ 13,100.23	0.69%
4	\$ 6,614.96	0.77%
5	\$ 4,311.25	1.08%
6	\$ 2,685.87	1.37%
7	\$ 1,668.28	1.47%
8	\$ 993.85	1.61%
9	\$ 515.60	2.26%
10-Smallest	\$ 229.75	4.99%

Notes:

[1] Duff & Phelps Cost of Capital Navigator - Size Premium: Annual Data as of 12/31/2019

[2] Duff & Phelps Cost of Capital Navigator - Size Premium: Annual Data as of 12/31/2019

Pandhandle Eastern Pipe Line Company, LP

Price Data

H15T30Y Index			
	Low	High	Avg Low & High
Jan-20	1.99	2.38	2.19
Dec-19	2.17	2.39	2.28
Nov-19	2.18	2.43	2.31
Oct-19	2.01	2.34	2.18
Sep-19	1.95	2.37	2.16
Aug-19	1.94	2.44	2.19
AVG			2.22

H15T30Y Index
Date PX_LAST

1/31/2020	1.99
1/30/2020	2.04
1/29/2020	2.05
1/28/2020	2.1
1/27/2020	2.05
1/24/2020	2.14
1/23/2020	2.18
1/22/2020	2.22
1/21/2020	2.23
1/17/2020	2.29
1/16/2020	2.26
1/15/2020	2.23
1/14/2020	2.27
1/13/2020	2.3
1/10/2020	2.28
1/9/2020	2.38
1/8/2020	2.35
1/7/2020	2.31
1/6/2020	2.28
1/3/2020	2.26
1/2/2020	2.33
12/31/2019	2.39
12/30/2019	2.34
12/27/2019	2.32
12/26/2019	2.33
12/24/2019	2.33
12/23/2019	2.35
12/20/2019	2.34
12/19/2019	2.35
12/18/2019	2.35
12/17/2019	2.31
12/16/2019	2.3
12/13/2019	2.26
12/12/2019	2.32
12/11/2019	2.23
12/10/2019	2.26
12/9/2019	2.27
12/6/2019	2.29
12/5/2019	2.24
12/4/2019	2.22

H15T30Y Index

Date	PX_LAST
12/3/2019	2.17
12/2/2019	2.28
11/29/2019	2.21
11/27/2019	2.19
11/26/2019	2.18
11/25/2019	2.21
11/22/2019	2.22
11/21/2019	2.24
11/20/2019	2.2
11/19/2019	2.26
11/18/2019	2.3
11/15/2019	2.31
11/14/2019	2.31
11/13/2019	2.36
11/12/2019	2.39
11/8/2019	2.43
11/7/2019	2.4
11/6/2019	2.3
11/5/2019	2.34
11/4/2019	2.27
11/1/2019	2.21
10/31/2019	2.17
10/30/2019	2.26
10/29/2019	2.33
10/28/2019	2.34
10/25/2019	2.29
10/24/2019	2.26
10/23/2019	2.25
10/22/2019	2.26
10/21/2019	2.28
10/18/2019	2.25
10/17/2019	2.24
10/16/2019	2.23
10/15/2019	2.23
10/11/2019	2.22
10/10/2019	2.16
10/9/2019	2.08
10/8/2019	2.04
10/7/2019	2.05
10/4/2019	2.01
10/3/2019	2.04
10/2/2019	2.09
10/1/2019	2.11
9/30/2019	2.12
9/27/2019	2.13
9/26/2019	2.15
9/25/2019	2.18
9/24/2019	2.09
9/23/2019	2.16
9/20/2019	2.17
9/19/2019	2.22
9/18/2019	2.25
9/17/2019	2.27
9/16/2019	2.31
9/13/2019	2.37
9/12/2019	2.22
9/11/2019	2.22
9/10/2019	2.19
9/9/2019	2.11
9/6/2019	2.02
9/5/2019	2.06
9/4/2019	1.97
9/3/2019	1.95
8/30/2019	1.96

H15T30Y Index	
Date	PX_LAST
8/29/2019	1.97
8/28/2019	1.94
8/27/2019	1.97
8/26/2019	2.04
8/23/2019	2.02
8/22/2019	2.11
8/21/2019	2.07
8/20/2019	2.04
8/19/2019	2.08
8/16/2019	2.01
8/15/2019	1.98
8/14/2019	2.03
8/13/2019	2.15
8/12/2019	2.14
8/9/2019	2.26
8/8/2019	2.25
8/7/2019	2.22
8/6/2019	2.25
8/5/2019	2.3
8/2/2019	2.39
8/1/2019	2.44

Pandhandle Eastern Pipe Line Company, LP

Market Return Calculation

Market Return Calculation	
Dividend-Paying, 0 - 20 Percent Growth Range	

Market Dividend Yield	2.26%
Market Long-Term Growth	10.06%
Required Return	12.43%

Dividend-
Paying, 0 - 20
Percent
Growth
Range

									Range	Cap. Weighted	Cap. Weighted
					Current Dividend Yield	Value Line Earnings Growth		% of Total Market Cap.	Div. Yield	Long-Term Growth	
	Name	Ticker	Shares Outst'g	Price			Market Cap.				
LYB UN Equity	LyondellBasell Industries NV	LYB	333.4	77.86	5.39	5.50	25959.38	0.12%	0.01%	0.01%	
AXP UN Equity	American Express Co	AXP	818.3	129.87	1.32	10.00	106268.85	0.50%	0.01%	0.05%	
VZ UN Equity	Verizon Communications Inc	VZ	4,136.0	59.44	4.14	4.00	245843.84	1.16%	0.05%	0.05%	
AVGO UN Equity	Broadcom Inc	AVGO	397.8	305.16	4.26	33.50	121390.21				
BA UN Equity	Boeing Co/The	BA	563.2	318.27	2.58	12.00	179234.39	0.85%	0.02%	0.10%	
CAT UN Equity	Caterpillar Inc	CAT	552.7	131.35	3.14	12.00	72591.63	0.34%	0.01%	0.04%	
JPM UN Equity	JPMorgan Chase & Co	JPM	3,136.5	132.36	2.72	6.00	415145.15	1.96%	0.05%	0.12%	
CVX UN Equity	Chevron Corp	CVX	1,890.9	107.14	4.82	16.50	202588.03	0.96%	0.05%	0.16%	
KO UN Equity	Coca-Cola Co/The	KO	4,284.5	58.40	2.74	6.50	250214.27	1.18%	0.03%	0.08%	
ABBV UN Equity	AbbVie Inc	ABBV	1,478.8	81.02	5.83	10.50	119814.08	0.57%	0.03%	0.06%	
DIS UN Equity	Walt Disney Co/The	DIS	1,805.3	138.31	1.27	7.50	249685.37	1.18%	0.01%	0.09%	
FLT UN Equity	FleetCor Technologies Inc	FLT	86.8	315.23	n/a	12.50	27355.97				
EXR UN Equity	Extra Space Storage Inc	EXR	129.5	110.68	3.25	4.00	14334.28	0.07%	0.00%	0.00%	
XOM UN Equity	Exxon Mobil Corp	XOM	4,231.1	62.12	5.60	11.00	262836.30	1.24%	0.07%	0.14%	
PSX UN Equity	Phillips 66	PSX	444.4	91.37	3.94	10.00	40600.99	0.19%	0.01%	0.02%	
GE UN Equity	General Electric Co	GE	8,733.5	12.45	0.32	2.00	108732.69	0.51%	0.00%	0.01%	
HPQ UN Equity	HP Inc	HPQ	1,453.2	21.32	3.31	8.00	30981.95	0.15%	0.00%	0.01%	
HD UN Equity	Home Depot Inc/The	HD	1,090.8	228.10	2.38	9.00	248818.55	1.17%	0.03%	0.11%	
IBM UN Equity	International Business Machines Corp	IBM	885.6	143.73	4.51	1.00	127292.61	0.60%	0.03%	0.01%	
CXO UN Equity	Concho Resources Inc	CXO	201.0	75.78	0.66	21.00	15233.98				
JNJ UN Equity	Johnson & Johnson	JNJ	2,631.9	148.87	2.55	12.00	391806.78	1.85%	0.05%	0.22%	
MCD UN Equity	McDonald's Corp	MCD	753.1	213.97	2.34	8.50	161139.31	0.76%	0.02%	0.06%	
MRK UN Equity	Merck & Co Inc	MRK	2,546.0	85.44	2.86	9.00	217528.87	1.03%	0.03%	0.09%	

	Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	Value Line Earnings Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
MMM UN Equity	3M Co	MMM	575.1	158.66	3.63	6.00	91237.59	0.43%	0.02%	0.03%
AWK UN Equity	American Water Works Co Inc	AWK	180.8	136.20	1.47	9.50	24621.69	0.12%	0.00%	0.01%
BAC UN Equity	Bank of America Corp	BAC	8,836.1	32.83	2.19	10.50	290090.77	1.37%	0.03%	0.14%
BKR UN Equity	Baker Hughes Co	BKR	649.9	21.66	3.32		0.00			
PFE UN Equity	Pfizer Inc	PFE	5,534.1	37.24	4.08	10.00	206090.70	0.97%	0.04%	0.10%
PG UN Equity	Procter & Gamble Co/The	PG	2,469.5	124.62	2.39	9.00	307743.23	1.45%	0.03%	0.13%
T UN Equity	AT&T Inc	T	7,255.0	37.62	5.53	5.50	272933.10	1.29%	0.07%	0.07%
NBL UW Equity	Noble Energy Inc	NBL	478.3	19.77	2.43	0.00	9455.95			
TRV UN Equity	Travelers Cos Inc/The	TRV	255.5	131.62	2.49	9.00	33628.91	0.16%	0.00%	0.01%
UTX UN Equity	United Technologies Corp	UTX	863.3	150.20	1.96	9.00	129663.00	0.61%	0.01%	0.06%
ADI UW Equity	Analog Devices Inc	ADI	369.0	109.75	1.97	9.00	40492.70	0.19%	0.00%	0.02%
WMT UN Equity	Walmart Inc	WMT	2,837.2	114.49	1.85	7.50	324828.17	1.53%	0.03%	0.11%
CSCO UW Equity	Cisco Systems Inc	CSCO	4,242.3	45.97	3.05	7.50	195016.83	0.92%	0.03%	0.07%
INTC UW Equity	Intel Corp	INTC	4,277.0	63.93	2.06	10.50	273428.61	1.29%	0.03%	0.14%
GM UN Equity	General Motors Co	GM	1,428.8	33.39	4.55	2.00	47707.10	0.23%	0.01%	0.00%
MSFT UW Equity	Microsoft Corp	MSFT	7,606.0	170.23	1.20	14.00	1294777.38	6.11%	0.07%	0.86%
DG UN Equity	Dollar General Corp	DG	254.6	153.41	0.83	12.00	39058.19	0.18%	0.00%	0.02%
CI UN Equity	Cigna Corp	CI	373.4	192.38	0.02	14.50	71839.50	0.34%	0.00%	0.05%
KMI UN Equity	Kinder Morgan Inc/DE	KMI	2,265.0	20.87	4.79	35.50	47269.82			
C UN Equity	Citigroup Inc	C	2,114.1	74.41	2.74	10.00	157310.18	0.74%	0.02%	0.07%
AIG UN Equity	American International Group Inc	AIG	870.0	50.26	2.55		0.00			
HON UN Equity	Honeywell International Inc	HON	714.5	173.22	2.08	8.50	123771.41	0.58%	0.01%	0.05%
MO UN Equity	Altria Group Inc	MO	1,858.0	47.53	7.07	8.50	88309.88	0.42%	0.03%	0.04%
HCA UN Equity	HCA Healthcare Inc	HCA	339.2	138.80	1.24	12.50	47077.91	0.22%	0.00%	0.03%
UAA UN Equity	Under Armour Inc	UAA	188.2	20.18	n/a	18.00	3797.92			
IP UN Equity	International Paper Co	IP	392.1	40.72	5.03	9.00	15966.96	0.08%	0.00%	0.01%
HPE UN Equity	Hewlett Packard Enterprise Co	HPE	1,292.9	13.93	3.45	6.50	18010.46	0.09%	0.00%	0.01%
ABT UN Equity	Abbott Laboratories	ABT	1,768.5	87.14	1.65	10.00	154103.26	0.73%	0.01%	0.07%
AFL UN Equity	Aflac Inc	AFL	734.0	51.57	2.09	8.00	37853.31	0.18%	0.00%	0.01%
APD UN Equity	Air Products & Chemicals Inc	APD	220.7	238.71	2.25	12.00	52678.05	0.25%	0.01%	0.03%
RCL UN Equity	Royal Caribbean Cruises Ltd	RCL	209.6	117.08	2.66	12.50	24543.60	0.12%	0.00%	0.01%
AEP UN Equity	American Electric Power Co Inc	AEP	494.0	104.22	2.69	4.00	51479.68	0.24%	0.01%	0.01%
HES UN Equity	Hess Corp	HES	304.7	56.57	1.77		0.00			
AON UN Equity	Aon PLC	AON	232.1	220.25	0.80	11.00	51109.45	0.24%	0.00%	0.03%
APA UN Equity	Apache Corp	APA	376.0	27.44	3.64		0.00			
ADM UN Equity	Archer-Daniels-Midland Co	ADM	556.7	44.76	3.22	9.50	24917.27	0.12%	0.00%	0.01%
ADP UW Equity	Automatic Data Processing Inc	ADP	431.8	171.39	2.12	13.50	73998.32	0.35%	0.01%	0.05%
VRSK UW Equity	Verisk Analytics Inc	VRSK	163.9	162.47	0.62	9.50	26623.96	0.13%	0.00%	0.01%
AZO UN Equity	AutoZone Inc	AZO	23.6	1,057.96	n/a	13.50	24960.45			
AVY UN Equity	Avery Dennison Corp	AVY	83.5	131.24	1.77	11.00	10958.93	0.05%	0.00%	0.01%

	Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	Value Line Earnings Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
MSCI UN Equity	MSCI Inc	MSCI	84.7	285.80	0.95	18.50	24209.26	0.11%	0.00%	0.02%
BLL UN Equity	Ball Corp	BLL	327.1	72.18	0.83	25.00	23612.24			
BK UN Equity	Bank of New York Mellon Corp/The	BK	900.7	44.78	2.77	7.00	40332.58	0.19%	0.01%	0.01%
BAX UN Equity	Baxter International Inc	BAX	510.6	89.22	0.99	10.50	45551.81	0.22%	0.00%	0.02%
BDX UN Equity	Becton Dickinson and Co	BDX	271.0	275.18	1.15	9.50	74577.08	0.35%	0.00%	0.03%
BRK/B UN Equity	Berkshire Hathaway Inc	BRK/B	1,383.4	224.43	n/a	6.00	310479.83			
BBY UN Equity	Best Buy Co Inc	BBY	258.8	84.69	2.36	10.50	21915.82	0.10%	0.00%	0.01%
HRB UN Equity	H&R Block Inc	HRB	195.2	23.20	4.48	7.00	4529.71	0.02%	0.00%	0.00%
BSX UN Equity	Boston Scientific Corp	BSX	1,393.8	41.87	n/a	16.00	58359.41			
BMJ UN Equity	Bristol-Myers Squibb Co	BMJ	2,341.0	62.95	2.86	9.00	147365.89	0.70%	0.02%	0.06%
FBHS UN Equity	Fortune Brands Home & Security Inc	FBHS	139.2	68.71	1.40	8.50	9561.07	0.05%	0.00%	0.00%
BF/B UN Equity	Brown-Forman Corp	BF/B	308.8	67.64	1.03	14.50	20887.71	0.10%	0.00%	0.01%
COG UN Equity	Cabot Oil & Gas Corp	COG	407.9	14.09	2.84	46.50	5747.66			
CPB UN Equity	Campbell Soup Co	CPB	301.7	48.39	2.89	2.00	14597.09	0.07%	0.00%	0.00%
KSU UN Equity	Kansas City Southern	KSU	96.2	168.69	0.95	12.00	16219.71	0.08%	0.00%	0.01%
HLT UN Equity	Hilton Worldwide Holdings Inc	HLT	282.2	107.80	0.56		0.00			
CCL UN Equity	Carnival Corp	CCL	527.1	43.53	4.59	10.00	22942.70	0.11%	0.00%	0.01%
QRVO UN Equity	Qorvo Inc	QRVO	115.7	105.86	n/a		0.00			
CTL UN Equity	CenturyLink Inc	CTL	1,090.2	13.66	7.32	1.00	14892.53	0.07%	0.01%	0.00%
UDR UN Equity	UDR Inc	UDR	293.1	47.91	2.86	5.50	14040.17	0.07%	0.00%	0.00%
CLX UN Equity	Clorox Co/The	CLX	125.5	157.31	2.70	3.50	19742.88	0.09%	0.00%	0.00%
PAYC UN Equity	Paycom Software Inc	PAYC	58.4	318.16	n/a	26.00	18580.23			
CMS UN Equity	CMS Energy Corp	CMS	283.8	68.51	2.38	7.00	19446.02	0.09%	0.00%	0.01%
NWL UN Equity	Newell Brands Inc	NWL	423.4	19.53	4.71	4.00	8269.00	0.04%	0.00%	0.00%
CL UN Equity	Colgate-Palmolive Co	CL	857.0	73.78	2.33	5.50	63232.71	0.30%	0.01%	0.02%
CMA UN Equity	Comerica Inc	CMA	144.2	61.16	4.45	9.50	8816.46	0.04%	0.00%	0.00%
IPGP UN Equity	IPG Photonics Corp	IPGP	53.1	127.67	n/a	9.50	6775.45			
CAG UN Equity	Conagra Brands Inc	CAG	486.8	32.92	2.58	5.50	16025.92	0.08%	0.00%	0.00%
ED UN Equity	Consolidated Edison Inc	ED	332.4	94.00	3.26	3.00	31248.42	0.15%	0.00%	0.00%
SLG UN Equity	SL Green Realty Corp	SLG	80.3	92.04	3.85	5.50	7386.95	0.03%	0.00%	0.00%
GLW UN Equity	Corning Inc	GLW	762.0	26.69	3.00	15.00	20337.78	0.10%	0.00%	0.01%
CMI UN Equity	Cummins Inc	CMI	153.2	159.97	3.28	8.00	24508.04	0.12%	0.00%	0.01%
DHR UN Equity	Danaher Corp	DHR	695.5	160.87	0.42	14.00	111885.09	0.53%	0.00%	0.07%
TGT UN Equity	Target Corp	TGT	506.7	110.74	2.38	9.50	56116.06	0.26%	0.01%	0.03%
DE UN Equity	Deere & Co	DE	314.8	158.58	1.92	13.50	49922.25	0.24%	0.00%	0.03%
D UN Equity	Dominion Energy Inc	D	829.0	85.75	4.38	6.50	71086.75	0.34%	0.01%	0.02%
DOV UN Equity	Dover Corp	DOV	145.3	113.85	1.72	12.50	16538.53	0.08%	0.00%	0.01%
LNT UN Equity	Alliant Energy Corp	LNT	244.1	59.36	2.56	6.50	14488.00	0.07%	0.00%	0.00%
DUK UN Equity	Duke Energy Corp	DUK	729.0	97.63	3.87	6.00	71175.49	0.34%	0.01%	0.02%
REG UN Equity	Regency Centers Corp	REG	167.6	62.04	3.77	16.00	10395.67	0.05%	0.00%	0.01%

	Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	Value Line Earnings Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
ETN UN Equity	Eaton Corp PLC	ETN	413.4	94.47	3.01	7.00	39053.90	0.18%	0.01%	0.01%
ECL UN Equity	Ecolab Inc	ECL	288.2	196.11	0.96	10.00	56527.53	0.27%	0.00%	0.03%
PKI UN Equity	PerkinElmer Inc	PKI	111.1	92.48	0.30	11.00	10274.62	0.05%	0.00%	0.01%
EMR UN Equity	Emerson Electric Co	EMR	609.2	71.63	2.79	11.50	43633.70	0.21%	0.01%	0.02%
EOG UN Equity	EOG Resources Inc	EOG	581.8	72.91	1.58	31.50	42416.41			
ETR UN Equity	Entergy Corp	ETR	199.1	131.52	2.83	2.00	26185.90	0.12%	0.00%	0.00%
EFX UN Equity	Equifax Inc	EFX	121.1	149.90	1.04	8.50	18150.34	0.09%	0.00%	0.01%
IQV UN Equity	IQVIA Holdings Inc	IQV	194.0	155.25	n/a	12.50	30124.40			
IT UN Equity	Gartner Inc	IT	89.5	160.78	n/a	13.50	14382.25			
FDX UN Equity	FedEx Corp	FDX	261.1	144.64	1.80	7.50	37768.25	0.18%	0.00%	0.01%
M UN Equity	Macy's Inc	M	309.0	15.95	9.47	2.00	4927.99	0.02%	0.00%	0.00%
FMC UN Equity	FMC Corp	FMC	129.6	95.59	1.84	15.00	12389.90	0.06%	0.00%	0.01%
F UN Equity	Ford Motor Co	F	3,894.0	8.82	6.80	3.00	34345.48	0.16%	0.01%	0.00%
NEE UN Equity	NextEra Energy Inc	NEE	488.8	268.20	1.86	10.50	131089.72	0.62%	0.01%	0.06%
BEN UN Equity	Franklin Resources Inc	BEN	496.9	25.30	4.27	10.00	12571.52	0.06%	0.00%	0.01%
FCX UN Equity	Freeport-McMoRan Inc	FCX	1,450.9	11.10	1.80	22.50	16105.15			
GPS UN Equity	Gap Inc/The	GPS	373.3	17.41	5.57	3.00	6499.14	0.03%	0.00%	0.00%
GD UN Equity	General Dynamics Corp	GD	289.3	175.44	2.33	6.00	50755.84	0.24%	0.01%	0.01%
GIS UN Equity	General Mills Inc	GIS	604.8	52.22	3.75	4.50	31583.54	0.15%	0.01%	0.01%
GPC UN Equity	Genuine Parts Co	GPC	145.3	93.57	3.26	8.00	13595.07	0.06%	0.00%	0.01%
ATO UN Equity	Atmos Energy Corp	ATO	122.3	117.03	1.97	7.50	14307.97	0.07%	0.00%	0.01%
GWW UN Equity	WW Grainger Inc	GWW	53.9	302.67	1.90	8.50	16303.62	0.08%	0.00%	0.01%
HAL UN Equity	Halliburton Co	HAL	877.8	21.81	3.30	19.50	19144.91	0.09%	0.00%	0.02%
HOG UN Equity	Harley-Davidson Inc	HOG	154.3	33.40	4.49	8.50	5153.35	0.02%	0.00%	0.00%
LHX UN Equity	L3Harris Technologies Inc	LHX	221.1	221.33	1.36	16.50	48928.32	0.23%	0.00%	0.04%
PEAK UN Equity	Healthpeak Properties Inc	PEAK	510.0	35.99	4.11	-3.50	18353.24			
HP UN Equity	Helmerich & Payne Inc	HP	109.6	40.55	7.00		0.00			
FTV UN Equity	Fortive Corp	FTV	335.8	74.93	0.37	10.00	25161.79	0.12%	0.00%	0.01%
HSY UN Equity	Hershey Co/The	HSY	148.3	155.17	1.99	7.00	23012.95	0.11%	0.00%	0.01%
SYF UN Equity	Synchrony Financial	SYF	615.9	32.41	2.72	9.50	19961.32	0.09%	0.00%	0.01%
HRL UN Equity	Hormel Foods Corp	HRL	534.7	47.26	1.97	10.50	25271.67	0.12%	0.00%	0.01%
AJG UN Equity	Arthur J Gallagher & Co	AJG	188.1	102.57	1.75	14.50	19293.42	0.09%	0.00%	0.01%
MDLZ UN Equity	Mondelez International Inc	MDLZ	1,439.8	57.38	1.99	8.50	82617.10	0.39%	0.01%	0.03%
CNP UN Equity	CenterPoint Energy Inc	CNP	501.2	26.48	4.34	10.50	13271.27	0.06%	0.00%	0.01%
HUM UN Equity	Humana Inc	HUM	132.4	336.24	0.65	12.00	44526.92	0.21%	0.00%	0.03%
WLTW UN Equity	Willis Towers Watson PLC	WLTW	128.6	211.29	1.23		0.00			
ITW UN Equity	Illinois Tool Works Inc	ITW	321.4	174.98	2.45	9.50	56239.62	0.27%	0.01%	0.03%
CDW UN Equity	CDW Corp/DE	CDW	143.7	130.45	1.17	10.50	18743.19	0.09%	0.00%	0.01%
IR UN Equity	Ingersoll-Rand PLC	IR	238.3	133.23	1.59	12.50	31750.97	0.15%	0.00%	0.02%
IPG UN Equity	Interpublic Group of Cos Inc/The	IPG	387.7	22.70	4.14	11.00	8801.52	0.04%	0.00%	0.00%

	Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	Value Line Earnings Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
IFF UN Equity	International Flavors & Fragrances Inc	IFF	106.8	131.11	2.29	8.00	13999.40	0.07%	0.00%	0.01%
J UN Equity	Jacobs Engineering Group Inc	J	133.2	92.53	0.82	14.50	12329.53	0.06%	0.00%	0.01%
HBI UN Equity	Hanesbrands Inc	HBI	361.7	13.76	4.36	3.00	4976.95	0.02%	0.00%	0.00%
K UN Equity	Kellogg Co	K	341.1	68.21	3.34	3.50	23266.02	0.11%	0.00%	0.00%
BR UN Equity	Broadridge Financial Solutions Inc	BR	114.8	119.15	1.81	11.00	13678.78	0.06%	0.00%	0.01%
PRGO UN Equity	Perrigo Co PLC	PRGO	136.1	57.04	1.47	2.00	7763.71	0.04%	0.00%	0.00%
KMB UN Equity	Kimberly-Clark Corp	KMB	342.8	143.24	2.99	7.50	49103.53	0.23%	0.01%	0.02%
KIM UN Equity	Kimco Realty Corp	KIM	431.8	19.05	5.88	5.00	8226.08	0.04%	0.00%	0.00%
KSS UN Equity	Kohl's Corp	KSS	156.6	42.75	6.27	6.50	6693.28	0.03%	0.00%	0.00%
ORCL UN Equity	Oracle Corp	ORCL	3,207.6	52.45	1.83	10.00	168241.19	0.79%	0.01%	0.08%
KR UN Equity	Kroger Co/The	KR	800.6	26.86	2.38	4.00	21503.77	0.10%	0.00%	0.00%
LEG UN Equity	Leggett & Platt Inc	LEG	131.6	47.59	3.36	9.00	6262.99	0.03%	0.00%	0.00%
LEN UN Equity	Lennar Corp	LEN	278.1	66.36	0.75	8.50	18456.04	0.09%	0.00%	0.01%
LLY UN Equity	Eli Lilly & Co	LLY	960.1	139.64	2.12	12.00	134072.69	0.63%	0.01%	0.08%
LB UN Equity	L Brands Inc	LB	276.5	23.16	5.18	-2.00	6403.16			
CHTR UN Equity	Charter Communications Inc	CHTR	210.0	517.46	n/a	17.50	108654.18			
LNC UN Equity	Lincoln National Corp	LNC	198.3	54.48	2.94	9.00	10805.07	0.05%	0.00%	0.00%
L UN Equity	Loews Corp	L	297.4	51.45	0.49	13.50	15303.24	0.07%	0.00%	0.01%
LOW UN Equity	Lowe's Cos Inc	LOW	766.5	116.24	1.89	11.50	89095.05	0.42%	0.01%	0.05%
HST UN Equity	Host Hotels & Resorts Inc	HST	717.2	16.34	4.90	-1.50	11718.69			
XRX UN Equity	Xerox Holdings Corp	XRX	216.2	35.57	2.81	12.50	7689.81	0.04%	0.00%	0.00%
IEX UN Equity	IDEX Corp	IEX	76.1	163.85	1.22	9.50	12462.43	0.06%	0.00%	0.01%
MMC UN Equity	Marsh & McLennan Cos Inc	MMC	504.7	111.86	1.63	9.00	56452.16	0.27%	0.00%	0.02%
MAS UN Equity	Masco Corp	MAS	286.1	47.52	1.14	9.50	13594.19	0.06%	0.00%	0.01%
SPGI UN Equity	S&P Global Inc	SPGI	244.4	293.73	0.91	13.00	71787.61	0.34%	0.00%	0.04%
MDT UN Equity	Medtronic PLC	MDT	1,340.4	115.44	1.87	8.50	154733.24	0.73%	0.01%	0.06%
CVS UN Equity	CVS Health Corp	CVS	1,301.0	67.82	2.95	6.50	88231.38	0.42%	0.01%	0.03%
DD UN Equity	DuPont de Nemours Inc	DD	738.6	51.18	2.34		0.00			
MU UN Equity	Micron Technology Inc	MU	1,110.9	53.09	n/a	14.00	58976.30			
MSI UN Equity	Motorola Solutions Inc	MSI	171.3	177.00	1.45	13.00	30326.47	0.14%	0.00%	0.02%
CBOE UN Equity	Cboe Global Markets Inc	CBOE	110.9	123.22	1.17	14.50	13660.29	0.06%	0.00%	0.01%
MYL UN Equity	Mylan NV	MYL	516.1	21.42	n/a	3.50	11055.57			
LH UN Equity	Laboratory Corp of America Holdings	LH	97.1	175.40	n/a	8.00	17031.34			
NEM UN Equity	Newmont Corp	NEM	834.2	45.06	1.24	11.50	37590.81	0.18%	0.00%	0.02%
NKE UN Equity	NIKE Inc	NKE	1,242.4	96.30	1.02	18.00	119638.88	0.56%	0.01%	0.10%
NI UN Equity	NiSource Inc	NI	373.5	29.31	2.87	12.50	10948.57	0.05%	0.00%	0.01%
NSC UN Equity	Norfolk Southern Corp	NSC	257.9	208.21	1.81	15.00	53698.40	0.25%	0.00%	0.04%
PFG UN Equity	Principal Financial Group Inc	PFG	277.7	52.95	4.23	5.50	14702.73	0.07%	0.00%	0.00%
ES UN Equity	Eversource Energy	ES	323.8	92.44	2.32	5.50	29928.47	0.14%	0.00%	0.01%
NOC UN Equity	Northrop Grumman Corp	NOC	167.6	374.57	1.41	9.50	62791.79	0.30%	0.00%	0.03%

	Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	Value Line Earnings Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
WFC UN Equity	Wells Fargo & Co	WFC	4,134.4	46.94	4.35	5.00	194068.74	0.92%	0.04%	0.05%
NUE UN Equity	Nucor Corp	NUE	303.2	47.49	3.39	13.00	14399.68	0.07%	0.00%	0.01%
PVH UN Equity	PVH Corp	PVH	73.0	87.17	0.17	9.00	6359.75	0.03%	0.00%	0.00%
OXY UN Equity	Occidental Petroleum Corp	OXY	893.3	39.72	7.96	24.00	35482.55			
OMC UN Equity	Omnicom Group Inc	OMC	217.7	75.31	3.45	6.50	16397.40	0.08%	0.00%	0.01%
OKE UN Equity	ONEOK Inc	OKE	413.1	74.87	5.00	17.00	30927.67	0.15%	0.01%	0.02%
RJF UN Equity	Raymond James Financial Inc	RJF	138.9	91.43	1.62	8.00	12699.63	0.06%	0.00%	0.00%
PH UN Equity	Parker-Hannifin Corp	PH	128.5	195.69	1.80	9.50	25139.32	0.12%	0.00%	0.01%
ROL UN Equity	Rollins Inc	ROL	327.4	37.95	1.26	13.00	12426.42	0.06%	0.00%	0.01%
PPL UN Equity	PPL Corp	PPL	723.0	36.19	4.56	1.50	26166.56	0.12%	0.01%	0.00%
COP UN Equity	ConocoPhillips	COP	1,097.3	59.43	2.83		0.00			
PHM UN Equity	PulteGroup Inc	PHM	270.0	44.65	1.08	9.50	12054.38	0.06%	0.00%	0.01%
PNW UN Equity	Pinnacle West Capital Corp	PNW	112.4	97.69	3.20	4.00	10981.43	0.05%	0.00%	0.00%
PNC UN Equity	PNC Financial Services Group Inc/The	PNC	433.0	148.55	3.10	8.00	64322.15	0.30%	0.01%	0.02%
PPG UN Equity	PPG Industries Inc	PPG	236.5	119.84	1.70	6.00	28337.73	0.13%	0.00%	0.01%
PGR UN Equity	Progressive Corp/The	PGR	584.6	80.69	0.50	15.50	47171.37	0.22%	0.00%	0.03%
PEG UN Equity	Public Service Enterprise Group Inc	PEG	505.7	59.20	3.18	6.00	29938.98	0.14%	0.00%	0.01%
RTN UN Equity	Raytheon Co	RTN	278.5	220.94	1.71	10.00	61527.15	0.29%	0.00%	0.03%
RHI UN Equity	Robert Half International Inc	RHI	116.1	58.17	2.13	9.00	6753.36	0.03%	0.00%	0.00%
EIX UN Equity	Edison International	EIX	358.6	76.55	3.33		0.00			
SLB UN Equity	Schlumberger Ltd	SLB	1,384.5	33.51	5.97	15.50	46395.10	0.22%	0.01%	0.03%
SCHW UN Equity	Charles Schwab Corp/The	SCHW	1,284.6	45.55	1.58	12.00	58512.57	0.28%	0.00%	0.03%
SHW UN Equity	Sherwin-Williams Co/The	SHW	92.3	556.99	0.81	10.50	51415.19	0.24%	0.00%	0.03%
SJM UN Equity	JM Smucker Co/The	SJM	114.1	103.61	3.40	3.50	11817.34	0.06%	0.00%	0.00%
SNA UN Equity	Snap-on Inc	SNA	54.8	159.63	2.71	6.00	8755.07	0.04%	0.00%	0.00%
AME UN Equity	AMETEK Inc	AME	228.6	97.15	0.58	15.50	22207.81	0.10%	0.00%	0.02%
SO UN Equity	Southern Co/The	SO	1,048.7	70.40	3.52	3.50	73830.87	0.35%	0.01%	0.01%
TFC UN Equity	Truist Financial Corp	TFC	1,342.2	51.57	3.49	10.00	69215.50	0.33%	0.01%	0.03%
LUV UN Equity	Southwest Airlines Co	LUV	526.3	54.98	1.31	10.50	28934.65	0.14%	0.00%	0.01%
WRB UN Equity	WR Berkley Corp	WRB	183.4	73.53	0.60	12.00	13486.28	0.06%	0.00%	0.01%
SWK UN Equity	Stanley Black & Decker Inc	SWK	152.0	159.33	1.73	9.00	24220.07	0.11%	0.00%	0.01%
PSA UN Equity	Public Storage	PSA	174.7	223.76	3.58	4.50	39086.40	0.18%	0.01%	0.01%
ANET UN Equity	Arista Networks Inc	ANET	76.4	223.34	n/a	12.00	17062.95			
SYYY UN Equity	Sysco Corp	SYYY	510.2	82.14	2.19	10.50	41910.05	0.20%	0.00%	0.02%
CTVA UN Equity	Corteva Inc	CTVA	748.6	28.92	1.80		0.00			
TXN UN Equity	Texas Instruments Inc	TXN	934.8	120.65	2.98	6.00	112780.60	0.53%	0.02%	0.03%
TXT UN Equity	Textron Inc	TXT	228.3	45.93	0.17	13.00	10484.12	0.05%	0.00%	0.01%
TMO UN Equity	Thermo Fisher Scientific Inc	TMO	401.0	313.19	0.24	10.00	125586.37	0.59%	0.00%	0.06%
TIF UN Equity	Tiffany & Co	TIF	121.1	134.02	1.73	10.50	16234.11	0.08%	0.00%	0.01%
TJX UN Equity	TJX Cos Inc/The	TJX	1,203.2	59.04	1.56	14.00	71035.98	0.34%	0.01%	0.05%

	Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	Value Line Earnings Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
GL UN Equity	Globe Life Inc	GL	108.3	104.26	0.66	10.00	11290.11	0.05%	0.00%	0.01%
JCI UN Equity	Johnson Controls International plc	JCI	764.0	39.45	2.64	8.00	30141.65	0.14%	0.00%	0.01%
ULTA UW Equity	Ulta Beauty Inc	ULTA	57.2	267.91	n/a	16.00	15314.00			
UNP UN Equity	Union Pacific Corp	UNP	694.2	179.42	2.16	14.50	124553.36	0.59%	0.01%	0.09%
KEYS UN Equity	Keysight Technologies Inc	KEYS	188.1	92.99	n/a	22.00	17493.74			
UNH UN Equity	UnitedHealth Group Inc	UNH	947.4	272.45	1.59	14.00	258123.22	1.22%	0.02%	0.17%
UNM UN Equity	Unum Group	UNM	206.3	26.69	4.27	9.00	5505.29	0.03%	0.00%	0.00%
MRO UN Equity	Marathon Oil Corp	MRO	799.9	11.37	1.76		0.00			
VAR UN Equity	Varian Medical Systems Inc	VAR	90.9	140.57	n/a	10.50	12779.08			
VTR UN Equity	Ventas Inc	VTR	372.7	57.86	5.48	4.00	21566.50	0.10%	0.01%	0.00%
VFC UN Equity	VF Corp	VFC	399.4	82.97	2.31	7.00	33136.06	0.16%	0.00%	0.01%
VNO UN Equity	Vornado Realty Trust	VNO	190.9	65.77	4.01	-1.50	12552.20			
VMC UN Equity	Vulcan Materials Co	VMC	132.4	141.63	0.88	14.50	18745.44	0.09%	0.00%	0.01%
WY UN Equity	Weyerhaeuser Co	WY	745.3	28.95	4.70	15.00	21576.44	0.10%	0.00%	0.02%
WHR UN Equity	Whirlpool Corp	WHR	63.2	146.17	3.28	6.50	9237.94	0.04%	0.00%	0.00%
WMB UN Equity	Williams Cos Inc/The	WMB	1,212.0	20.69	7.73	20.00	25077.29			
WEC UN Equity	WEC Energy Group Inc	WEC	315.4	99.89	2.53	6.00	31508.90	0.15%	0.00%	0.01%
ADBE UW Equity	Adobe Inc	ADBE	482.1	351.14	n/a	20.50	169295.48			
AES UN Equity	AES Corp/VA	AES	663.9	19.86	2.89		0.00			
AMGN UW Equity	Amgen Inc	AMGN	591.0	216.05	2.96	7.50	127685.55	0.60%	0.02%	0.05%
AAPL UW Equity	Apple Inc	AAPL	4,375.5	309.51	1.00	12.50	1354254.81	6.39%	0.06%	0.80%
ADSK UW Equity	Autodesk Inc	ADSK	220.0	196.85	n/a		0.00			
CTAS UW Equity	Cintas Corp	CTAS	103.8	278.97	0.91	15.50	28943.42	0.14%	0.00%	0.02%
CMCSA UW Equity	Comcast Corp	CMCSA	4,543.6	43.19	2.13	13.50	196237.65	0.93%	0.02%	0.13%
TAP UN Equity	Molson Coors Beverage Co	TAP	196.2	55.58	4.10	2.50	10907.52	0.05%	0.00%	0.00%
KLAC UW Equity	KLA Corp	KLAC	157.8	165.74	2.05	10.00	26152.78	0.12%	0.00%	0.01%
MAR UN Equity	Marriott International Inc/MD	MAR	326.9	140.06	1.37	17.50	45790.80	0.22%	0.00%	0.04%
MKC UN Equity	McCormick & Co Inc/MD	MKC	123.6	163.37	1.52	8.00	20192.37	0.10%	0.00%	0.01%
JWN UN Equity	Nordstrom Inc	JWN	155.3	36.86	4.02	5.00	5722.63	0.03%	0.00%	0.00%
PCAR UW Equity	PACCAR Inc	PCAR	346.3	74.21	1.72	7.50	25698.92	0.12%	0.00%	0.01%
COST UW Equity	Costco Wholesale Corp	COST	441.8	305.52	0.85	9.00	134965.90	0.64%	0.01%	0.06%
FRC UN Equity	First Republic Bank/CA	FRC	171.0	110.88	0.69	10.50	18962.92	0.09%	0.00%	0.01%
SYK UN Equity	Stryker Corp	SYK	374.4	210.70	1.09	13.00	78879.13	0.37%	0.00%	0.05%
TSN UN Equity	Tyson Foods Inc	TSN	295.4	82.63	2.03	8.00	24406.01	0.12%	0.00%	0.01%
LW UN Equity	Lamb Weston Holdings Inc	LW	146.1	91.31	1.01	11.00	13339.66	0.06%	0.00%	0.01%
AMAT UW Equity	Applied Materials Inc	AMAT	918.6	57.99	1.45	7.50	53270.02	0.25%	0.00%	0.02%
AAL UW Equity	American Airlines Group Inc	AAL	438.1	26.84	1.49	7.50	11757.48	0.06%	0.00%	0.00%
CAH UN Equity	Cardinal Health Inc	CAH	292.5	51.21	3.76	11.00	14978.31	0.07%	0.00%	0.01%
CERN UW Equity	Cerner Corp	CERN	314.1	71.83	1.00	9.00	22561.59	0.11%	0.00%	0.01%
CINF UW Equity	Cincinnati Financial Corp	CINF	163.4	104.95	2.29	9.50	17146.10	0.08%	0.00%	0.01%

	Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	Value Line Earnings Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
VIAC UW Equity	ViacomCBS Inc	VIAC	563.0	34.13	2.81	12.00	19214.61	0.09%	0.00%	0.01%
DHI UN Equity	DR Horton Inc	DHI	366.4	59.20	1.18	7.00	21688.75	0.10%	0.00%	0.01%
FLS UN Equity	Flowserve Corp	FLS	130.9	46.68	1.63	13.50	6108.54	0.03%	0.00%	0.00%
EA UW Equity	Electronic Arts Inc	EA	292.0	107.92	n/a	11.00	31510.37			
EXPD UW Equity	Expeditors International of Washington	EXPD	170.3	73.04	1.37	9.00	12438.79	0.06%	0.00%	0.01%
FAST UW Equity	Fastenal Co	FAST	574.1	34.88	2.87	8.50	20025.62	0.09%	0.00%	0.01%
MTB UN Equity	M&T Bank Corp	MTB	132.0	168.52	2.61	9.50	22237.90	0.10%	0.00%	0.01%
XEL UW Equity	Xcel Energy Inc	XEL	524.4	69.19	2.34	5.50	36282.41	0.17%	0.00%	0.01%
FISV UW Equity	Fiserv Inc	FISV	679.9	118.61	n/a	10.50	80642.35			
FITB UW Equity	Fifth Third Bancorp	FITB	708.9	28.45	3.37	7.00	20168.66	0.10%	0.00%	0.01%
GILD UW Equity	Gilead Sciences Inc	GILD	1,265.1	63.20	3.99	-1.50	79957.23			
HAS UW Equity	Hasbro Inc	HAS	136.8	101.87	2.67	9.50	13939.18	0.07%	0.00%	0.01%
HBAN UW Equity	Huntington Bancshares Inc/OH	HBAN	1,020.0	13.57	4.42	10.50	13841.44	0.07%	0.00%	0.01%
WELL UN Equity	Welltower Inc	WELL	405.8	84.91	4.10	10.50	34456.48	0.16%	0.01%	0.02%
BIIB UW Equity	Biogen Inc	BIIB	180.4	268.85	n/a	8.00	48511.83			
NTRS UW Equity	Northern Trust Corp	NTRS	211.9	97.81	2.86	8.50	20724.18	0.10%	0.00%	0.01%
PKG UN Equity	Packaging Corp of America	PKG	94.7	95.75	3.30	6.00	9063.50	0.04%	0.00%	0.00%
PAYX UW Equity	Paychex Inc	PAYX	358.4	85.77	2.89	10.50	30738.77	0.15%	0.00%	0.02%
PBCT UW Equity	People's United Financial Inc	PBCT	443.3	15.42	4.60	8.00	6835.29	0.03%	0.00%	0.00%
QCOM UN Equity	QUALCOMM Inc	QCOM	1,142.3	85.31	2.91	10.50	97451.83	0.46%	0.01%	0.05%
ROP UN Equity	Roper Technologies Inc	ROP	104.1	381.66	0.54	11.50	39714.78	0.19%	0.00%	0.02%
ROST UW Equity	Ross Stores Inc	ROST	358.9	112.19	0.91	9.50	40262.97	0.19%	0.00%	0.02%
IDXX UW Equity	IDEXX Laboratories Inc	IDXX	85.8	271.01	n/a	13.00	23248.05			
SBUX UW Equity	Starbucks Corp	SBUX	1,173.7	84.83	1.93	13.00	99564.97	0.47%	0.01%	0.06%
KEY UN Equity	KeyCorp	KEY	985.0	18.71	3.96	10.50	18428.56	0.09%	0.00%	0.01%
FOXA UW Equity	Fox Corp	FOXA	354.5	37.08	1.24		0.00			
FOX UW Equity	Fox Corp	FOX	266.2	36.33	1.27		0.00			
STT UN Equity	State Street Corp	STT	363.6	75.63	2.75	5.50	27500.81	0.13%	0.00%	0.01%
NCLH UN Equity	Norwegian Cruise Line Holdings Ltd	NCLH	212.8	53.85	n/a	16.00	11457.02			
USB UN Equity	US Bancorp	USB	1,534.0	53.22	3.16	6.00	81639.48	0.39%	0.01%	0.02%
AOS UN Equity	AO Smith Corp	AOS	137.1	42.69	2.25	6.50	5851.05	0.03%	0.00%	0.00%
NLOK UW Equity	NortonLifeLock Inc	NLOK	623.2	28.42	1.76	5.00	17712.68	0.08%	0.00%	0.00%
TROW UW Equity	T Rowe Price Group Inc	TROW	233.7	133.53	2.28	10.00	31202.89	0.15%	0.00%	0.01%
WM UN Equity	Waste Management Inc	WM	424.2	121.70	1.79	8.50	51630.13	0.24%	0.00%	0.02%
AGN UN Equity	Allergan PLC	AGN	328.3	186.64	1.59	3.50	61269.62	0.29%	0.00%	0.01%
STZ UN Equity	Constellation Brands Inc	STZ	167.5	188.30	1.59	8.50	31542.70	0.15%	0.00%	0.01%
XLNX UW Equity	Xilinx Inc	XLNX	248.8	84.48	1.75	8.00	21021.75	0.10%	0.00%	0.01%
XRAY UW Equity	DENTSPLY SIRONA Inc	XRAY	222.4	56.00	0.71	4.50	12455.18	0.06%	0.00%	0.00%
ZION UW Equity	Zions Bancorp NA	ZION	165.1	45.49	2.99	9.50	7508.44	0.04%	0.00%	0.00%
ALK UN Equity	Alaska Air Group Inc	ALK	123.2	64.59	2.32	5.50	7955.74	0.04%	0.00%	0.00%

	Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	Value Line Earnings Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
IVZ UN Equity	Invesco Ltd	IVZ	453.9	17.30	7.17	3.50	7852.37	0.04%	0.00%	0.00%
LIN UN Equity	Linde PLC	LIN	537.2	203.13	1.72		0.00			
INTU UW Equity	Intuit Inc	INTU	260.3	280.38	0.76	14.50	72984.88	0.34%	0.00%	0.05%
MS UN Equity	Morgan Stanley	MS	1,618.6	52.26	2.68	10.00	84587.93	0.40%	0.01%	0.04%
MCHP UW Equity	Microchip Technology Inc	MCHP	239.0	97.48	1.50	9.50	23295.58	0.11%	0.00%	0.01%
CB UN Equity	Chubb Ltd	CB	453.2	151.99	1.97	10.00	68882.17	0.33%	0.01%	0.03%
HOLX UW Equity	Hologic Inc	HOLX	263.3	53.52	n/a	25.00	14091.92			
CFG UN Equity	Citizens Financial Group Inc	CFG	434.7	37.28	4.18	12.00	16206.32	0.08%	0.00%	0.01%
ORLY UW Equity	O'Reilly Automotive Inc	ORLY	75.7	406.10	n/a	12.00	30725.12			
ALL UN Equity	Allstate Corp/The	ALL	324.0	118.54	1.69	10.50	38401.74	0.18%	0.00%	0.02%
FLIR UW Equity	FLIR Systems Inc	FLIR	134.2	51.54	1.32	12.00	6914.25	0.03%	0.00%	0.00%
EQR UN Equity	Equity Residential	EQR	371.7	83.08	2.90		0.00			
BWA UN Equity	BorgWarner Inc	BWA	206.4	34.29	1.98	4.50	7077.80	0.03%	0.00%	0.00%
INCY UW Equity	Incyte Corp	INCY	215.4	73.07	n/a		0.00			
SPG UN Equity	Simon Property Group Inc	SPG	306.9	133.15	6.31	4.50	40858.54	0.19%	0.01%	0.01%
EMN UN Equity	Eastman Chemical Co	EMN	136.0	71.27	3.70	8.00	9691.22	0.05%	0.00%	0.00%
TWTR UN Equity	Twitter Inc	TWTR	776.4	32.48	n/a		0.00			
AVB UN Equity	AvalonBay Communities Inc	AVB	139.7	216.69	2.81	2.50	30263.36	0.14%	0.00%	0.00%
PRU UN Equity	Prudential Financial Inc	PRU	402.0	91.06	4.39	7.00	36606.12	0.17%	0.01%	0.01%
UPS UN Equity	United Parcel Service Inc	UPS	700.8	103.52	3.71	8.50	72542.16	0.34%	0.01%	0.03%
AIV UN Equity	Apartment Investment & Management Co	AIV	148.9	52.71	3.11	-3.00	7847.73			
WBA UW Equity	Walgreens Boots Alliance Inc	WBA	885.9	50.85	3.60	9.00	45046.08	0.21%	0.01%	0.02%
STE UN Equity	STERIS PLC	STE	84.8	150.69	0.98	10.00	12775.95	0.06%	0.00%	0.01%
MCK UN Equity	McKesson Corp	MCK	180.2	142.61	1.15	9.00	25696.61	0.12%	0.00%	0.01%
LMT UN Equity	Lockheed Martin Corp	LMT	282.1	428.12	2.24	12.50	120760.24	0.57%	0.01%	0.07%
ABC UN Equity	AmerisourceBergen Corp	ABC	205.9	85.56	1.96	8.00	17616.12	0.08%	0.00%	0.01%
COF UN Equity	Capital One Financial Corp	COF	456.6	99.80	1.60	5.50	45568.68	0.22%	0.00%	0.01%
WAT UN Equity	Waters Corp	WAT	64.4	223.79	n/a	6.00	14419.68			
DLTR UW Equity	Dollar Tree Inc	DLTR	236.7	87.07	n/a	10.00	20606.16			
DRI UN Equity	Darden Restaurants Inc	DRI	121.5	116.43	3.02	11.00	14147.41	0.07%	0.00%	0.01%
NVR UN Equity	NVR Inc	NVR	3.6	3,816.97	n/a	13.50	13867.05			
NTAP UW Equity	NetApp Inc	NTAP	228.2	53.40	3.60	10.00	12187.27	0.06%	0.00%	0.01%
CTXS UW Equity	Citrix Systems Inc	CTXS	130.2	121.22	1.15	9.00	15785.27	0.07%	0.00%	0.01%
DXC UN Equity	DXC Technology Co	DXC	256.0	31.88	2.63	10.00	8161.22	0.04%	0.00%	0.00%
ODFL UN Equity	Old Dominion Freight Line Inc	ODFL	79.8	196.23	0.35	9.50	15663.86	0.07%	0.00%	0.01%
DVA UN Equity	DaVita Inc	DVA	128.1	79.87	n/a	12.00	10232.31			
HIG UN Equity	Hartford Financial Services Group Inc/	HIG	360.4	59.28	2.02	13.00	21365.76	0.10%	0.00%	0.01%
IRM UN Equity	Iron Mountain Inc	IRM	287.1	31.61	7.83	8.50	9076.59	0.04%	0.00%	0.00%
EL UN Equity	Estee Lauder Cos Inc/The	EL	222.6	195.16	0.98	14.00	43433.05	0.21%	0.00%	0.03%
CDNS UW Equity	Cadence Design Systems Inc	CDNS	280.6	72.11	n/a	12.50	20233.56			

	Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	Value Line Earnings Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
UHS UN Equity	Universal Health Services Inc	UHS	80.3	137.11	0.58	11.00	11013.36	0.05%	0.00%	0.01%
ETFC UW Equity	E*TRADE Financial Corp	ETFC	222.6	42.62	1.31	17.50	9488.15	0.04%	0.00%	0.01%
SWKS UW Equity	Skyworks Solutions Inc	SWKS	170.2	113.15	1.56	8.00	19253.04	0.09%	0.00%	0.01%
NOV UN Equity	National Oilwell Varco Inc	NOV	385.8	20.61	0.97	31.00	7952.00			
DGX UN Equity	Quest Diagnostics Inc	DGX	134.7	110.67	2.02	9.00	14906.92	0.07%	0.00%	0.01%
ATVI UW Equity	Activision Blizzard Inc	ATVI	768.3	58.48	0.63	9.00	44927.84	0.21%	0.00%	0.02%
ROK UN Equity	Rockwell Automation Inc	ROK	116.2	191.66	2.13	8.00	22267.83	0.11%	0.00%	0.01%
KHC UW Equity	Kraft Heinz Co/The	KHC	1,221.2	29.20	5.48	0.00	35657.90			
AMT UN Equity	American Tower Corp	AMT	442.9	231.74	1.74	7.50	102646.92	0.48%	0.01%	0.04%
HFC UN Equity	HollyFrontier Corp	HFC	161.4	44.92	3.12	17.00	7249.64	0.03%	0.00%	0.01%
REGN UW Equity	Regeneron Pharmaceuticals Inc	REGN	107.9	337.94	n/a	10.00	36479.61			
AMZN UN Equity	Amazon.com Inc	AMZN	497.8	2,008.72	n/a	39.00	999960.90			
JKHY UW Equity	Jack Henry & Associates Inc	JKHY	76.9	149.54	1.07	12.00	11505.16	0.05%	0.00%	0.01%
RL UN Equity	Ralph Lauren Corp	RL	49.7	113.50	2.42	8.00	5644.92	0.03%	0.00%	0.00%
BXP UN Equity	Boston Properties Inc	BXP	154.8	143.35	2.73	5.00	22189.15	0.10%	0.00%	0.01%
APH UN Equity	Amphenol Corp	APH	296.5	99.47	1.01	9.50	29492.06	0.14%	0.00%	0.01%
ARNC UN Equity	Arconic Inc	ARNC	432.9	29.95	0.27		0.00			
PXD UN Equity	Pioneer Natural Resources Co	PXD	165.6	135.00	1.30		0.00			
VLO UN Equity	Valero Energy Corp	VLO	410.7	84.31	4.65	11.50	34622.15	0.16%	0.01%	0.02%
SNPS UW Equity	Synopsys Inc	SNPS	150.5	147.51	n/a	8.00	22205.42			
WU UN Equity	Western Union Co/The	WU	419.3	26.90	2.97	5.00	11277.99	0.05%	0.00%	0.00%
CHRW UW Equity	CH Robinson Worldwide Inc	CHRW	135.3	72.22	2.82	9.00	9767.76	0.05%	0.00%	0.00%
ACN UN Equity	Accenture PLC	ACN	635.0	205.21	1.56	8.50	130317.38	0.62%	0.01%	0.05%
TDG UN Equity	TransDigm Group Inc	TDG	53.5	643.28	n/a	11.50	34446.36			
YUM UN Equity	Yum! Brands Inc	YUM	302.5	105.77	1.78	12.00	31991.41	0.15%	0.00%	0.02%
PLD UN Equity	Prologis Inc	PLD	631.8	92.88	2.28	6.50	58679.26	0.28%	0.01%	0.02%
FE UN Equity	FirstEnergy Corp	FE	540.3	50.79	3.07	6.50	27442.45	0.13%	0.00%	0.01%
VRSN UW Equity	VeriSign Inc	VRSN	117.4	208.14	n/a	11.00	24437.51			
PWR UN Equity	Quanta Services Inc	PWR	142.3	39.15	0.51	15.50	5570.81	0.03%	0.00%	0.00%
HSIC UW Equity	Henry Schein Inc	HSIC	146.7	68.94	n/a	7.00	10116.26			
AEE UN Equity	Ameren Corp	AEE	246.0	82.05	2.41	6.50	20186.76	0.10%	0.00%	0.01%
ANSS UW Equity	ANSYS Inc	ANSS	85.6	274.33	n/a	13.00	23479.90			
NVDA UW Equity	NVIDIA Corp	NVDA	612.0	236.43	0.27	11.50	144695.16	0.68%	0.00%	0.08%
SEE UN Equity	Sealed Air Corp	SEE	154.5	35.50	1.80	22.50	5485.32			
CTSH UN Equity	Cognizant Technology Solutions Corp	CTSH	547.6	61.38	1.30	5.00	33609.60	0.16%	0.00%	0.01%
SIVB UW Equity	SVB Financial Group	SIVB	51.7	240.33	n/a	19.50	12414.49			
ISRG UW Equity	Intuitive Surgical Inc	ISRG	115.6	559.78	n/a	14.00	64696.01			
TTWO UW Equity	Take-Two Interactive Software Inc	TTWO	113.3	124.64	n/a	23.50	14127.57			
RSG UN Equity	Republic Services Inc	RSG	319.1	95.05	1.70	11.50	30334.73	0.14%	0.00%	0.02%
EBAY UW Equity	eBay Inc	EBAY	796.1	33.56	1.91	10.00	26716.48	0.13%	0.00%	0.01%

	Name	Ticker	Shares	Outst'g	Price	Current Dividend Yield	Value Line Earnings Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
GS UN Equity	Goldman Sachs Group Inc/The	GS	354.1	237.75	2.10		10.00	84184.18	0.40%	0.01%	0.04%
SRE UN Equity	Sempra Energy	SRE	281.9	160.64	2.41		11.00	45283.77	0.21%	0.01%	0.02%
SBAC UN Equity	SBA Communications Corp	SBAC	112.6	249.56	0.59		29.50	28100.71			
MCO UN Equity	Moody's Corp	MCO	188.8	256.79	0.78		11.50	48481.95	0.23%	0.00%	0.03%
BKNG UN Equity	Booking Holdings Inc	BKNG	41.9	1,830.55	n/a		12.00	76619.50			
FFIV UN Equity	F5 Networks Inc	FFIV	60.8	122.12	n/a		12.00	7425.26			
AKAM UN Equity	Akamai Technologies Inc	AKAM	161.6	93.35	n/a		18.00	15085.45			
MKTX UN Equity	MarketAxess Holdings Inc	MKTX	37.9	354.18	0.68		14.00	13431.92	0.06%	0.00%	0.01%
DVN UN Equity	Devon Energy Corp	DVN	384.1	21.72	1.66		0.00	8342.65			
GOOGL UN Equity	Alphabet Inc	GOOGL	299.6	1,432.78	n/a			0.00			
TFX UN Equity	Teleflex Inc	TFX	46.3	371.51	0.37		15.00	17199.43	0.08%	0.00%	0.01%
NFLX UN Equity	Netflix Inc	NFLX	438.8	345.09	n/a		32.00	151427.91			
ALLE UN Equity	Allegion PLC	ALLE	92.9	129.32	0.84		9.50	12016.03	0.06%	0.00%	0.01%
A UN Equity	Agilent Technologies Inc	A	310.2	82.56	0.87		11.00	25608.71	0.12%	0.00%	0.01%
ANTM UN Equity	Anthem Inc	ANTM	253.6	265.28	1.43		18.50	67265.46	0.32%	0.00%	0.06%
CME UN Equity	CME Group Inc	CME	358.4	217.11	1.38		3.00	77803.76	0.37%	0.01%	0.01%
JNPR UN Equity	Juniper Networks Inc	JNPR	334.7	22.94	3.49		5.50	7678.18	0.04%	0.00%	0.00%
BLK UN Equity	BlackRock Inc	BLK	154.4	527.35	2.75		10.50	81407.55	0.38%	0.01%	0.04%
DTE UN Equity	DTE Energy Co	DTE	192.1	132.61	3.05		4.50	25475.04	0.12%	0.00%	0.01%
NDAQ UN Equity	Nasdaq Inc	NDAQ	163.9	116.46	1.61		8.00	19089.54	0.09%	0.00%	0.01%
CE UN Equity	Celanese Corp	CE	120.9	103.50	2.40		8.50	12510.46	0.06%	0.00%	0.01%
PM UN Equity	Philip Morris International Inc	PM	1,555.9	82.70	5.66		6.00	128670.86	0.61%	0.03%	0.04%
CRM UN Equity	salesforce.com Inc	CRM	887.0	182.31	n/a		30.00	161708.97			
HII UN Equity	Huntington Ingalls Industries Inc	HII	40.9	261.00	1.58		7.00	10674.90	0.05%	0.00%	0.00%
MET UN Equity	MetLife Inc	MET	919.6	49.71	3.54		7.50	45714.86	0.22%	0.01%	0.02%
UA UN Equity	Under Armour Inc	UA	228.9	17.96	n/a			0.00			
TPR UN Equity	Tapestry Inc	TPR	275.9	25.77	5.24		10.50	7110.87	0.03%	0.00%	0.00%
CSX UN Equity	CSX Corp	CSX	782.3	76.34	1.26		14.50	59723.61	0.28%	0.00%	0.04%
EW UN Equity	Edwards Lifesciences Corp	EW	208.6	219.86	n/a		16.50	45856.20			
AMP UN Equity	Ameriprise Financial Inc	AMP	126.7	165.41	2.35		12.50	20956.79	0.10%	0.00%	0.01%
ZBRA UN Equity	Zebra Technologies Corp	ZBRA	53.9	239.02	n/a		15.50	12888.20			
FTI UN Equity	TechnipFMC PLC	FTI	447.1	16.51	3.15			0.00			
ZBH UN Equity	Zimmer Biomet Holdings Inc	ZBH	205.7	147.90	0.65		4.50	30420.66	0.14%	0.00%	0.01%
CBRE UN Equity	CBRE Group Inc	CBRE	334.8	61.05	n/a		11.00	20436.61			
MA UN Equity	Mastercard Inc	MA	996.0	315.94	0.51		19.00	314676.24	1.49%	0.01%	0.28%
KMX UN Equity	CarMax Inc	KMX	163.4	97.04	n/a		10.50	15854.88			
ICE UN Equity	Intercontinental Exchange Inc	ICE	556.9	99.74	1.10		10.50	55540.22	0.26%	0.00%	0.03%
FIS UN Equity	Fidelity National Information Services I	FIS	614.6	143.66	0.97		7.00	88293.44	0.42%	0.00%	0.03%
CMG UN Equity	Chipotle Mexican Grill Inc	CMG	27.8	866.76	n/a		26.50	24091.59			
WYNN UN Equity	Wynn Resorts Ltd	WYNN	107.4	126.16	3.17		27.00	13543.91			

	Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	Value Line Earnings Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
LYV UN Equity	Live Nation Entertainment Inc	LYV	213.7	68.16	n/a		0.00			
AIZ UN Equity	Assurant Inc	AIZ	60.6	130.56	1.93	6.50	7916.64	0.04%	0.00%	0.00%
NRG UN Equity	NRG Energy Inc	NRG	251.6	36.89	3.25		0.00			
RF UN Equity	Regions Financial Corp	RF	964.6	15.57	3.98	14.00	15019.43	0.07%	0.00%	0.01%
MNST UN Equity	Monster Beverage Corp	MNST	537.7	66.60	n/a	14.50	35809.62			
MOS UN Equity	Mosaic Co/The	MOS	378.8	19.84	1.01	18.00	7514.66	0.04%	0.00%	0.01%
EXPE UN Equity	Expedia Group Inc	EXPE	139.4	108.45	1.25	24.00	15113.92			
EVRG UN Equity	Evergy Inc	EVRG	227.9	72.16	2.80		0.00			
DISCA UN Equity	Discovery Inc	DISCA	158.1	29.26	n/a	18.00	4627.18			
CF UN Equity	CF Industries Holdings Inc	CF	217.4	40.28	2.98		0.00			
LDOS UN Equity	Leidos Holdings Inc	LDOS	141.6	100.47	1.35	9.00	14222.94	0.07%	0.00%	0.01%
GOOG UN Equity	Alphabet Inc	GOOG	343.6	1,434.23	n/a	16.50	492731.15			
COO UN Equity	Cooper Cos Inc/The	COO	49.1	346.89	0.02	14.50	17019.12	0.08%	0.00%	0.01%
TEL UN Equity	TE Connectivity Ltd	TEL	334.1	92.18	2.00	6.50	30801.21	0.15%	0.00%	0.01%
DFS UN Equity	Discover Financial Services	DFS	310.0	75.13	2.34	7.50	23290.30	0.11%	0.00%	0.01%
V UN Equity	Visa Inc	V	1,706.0	198.97	0.60	15.00	339447.60	1.60%	0.01%	0.24%
MAA UN Equity	Mid-America Apartment Communities	MAA	114.1	137.21	2.92	1.00	15651.00	0.07%	0.00%	0.00%
XYL UN Equity	Xylem Inc/NY	XYL	180.1	81.66	1.18	14.00	14705.25	0.07%	0.00%	0.01%
MPC UN Equity	Marathon Petroleum Corp	MPC	649.3	54.50	4.26	11.00	35388.05	0.17%	0.01%	0.02%
TSCO UN Equity	Tractor Supply Co	TSCO	118.4	92.95	1.51	11.50	11003.98	0.05%	0.00%	0.01%
AMD UN Equity	Advanced Micro Devices Inc	AMD	1,113.6	47.00	n/a	33.50	52340.52			
RMD UN Equity	ResMed Inc	RMD	144.6	158.97	0.98	18.00	22989.76	0.11%	0.00%	0.02%
MTD UN Equity	Mettler-Toledo International Inc	MTD	24.4	757.18	n/a	10.00	18440.36			
CPRT UN Equity	Copart Inc	CPRT	232.5	101.46	n/a	17.50	23584.78			
ALB UN Equity	Albemarle Corp	ALB	106.0	80.28	1.83	5.50	8512.33	0.04%	0.00%	0.00%
FTNT UN Equity	Fortinet Inc	FTNT	171.0	115.36	n/a	28.00	19730.48			
ESS UN Equity	Essex Property Trust Inc	ESS	66.1	309.76	2.52	-0.50	20469.56			
O UN Equity	Realty Income Corp	O	325.9	78.41	3.56	4.50	25555.31	0.12%	0.00%	0.01%
STX UN Equity	Seagate Technology PLC	STX	262.7	56.99	4.56	4.00	14971.90	0.07%	0.00%	0.00%
WRK UN Equity	Westrock Co	WRK	258.5	39.00	4.77	8.00	10079.78	0.05%	0.00%	0.00%
INFO UN Equity	IHS Markit Ltd	INFO	392.9	78.86	0.86	18.00	30987.96	0.15%	0.00%	0.03%
WAB UN Equity	Westinghouse Air Brake Technologies (WAB	191.7	73.86	0.65	13.50	14157.63	0.07%	0.00%	0.01%
WDC UN Equity	Western Digital Corp	WDC	297.4	65.50	3.05	1.00	19480.03	0.09%	0.00%	0.00%
PEP UN Equity	PepsiCo Inc	PEP	1,394.4	142.02	2.69	6.50	198037.66	0.93%	0.03%	0.06%
FANG UN Equity	Diamondback Energy Inc	FANG	160.4	74.40	1.01	16.50	11937.11	0.06%	0.00%	0.01%
MXIM UN Equity	Maxim Integrated Products Inc	MXIM	269.4	60.12	3.19	5.50	16195.97	0.08%	0.00%	0.00%
NOW UN Equity	ServiceNow Inc	NOW	188.6	338.23	n/a		0.00			
CHD UN Equity	Church & Dwight Co Inc	CHD	245.4	74.22	1.29	9.00	18213.74	0.09%	0.00%	0.01%
DRE UN Equity	Duke Realty Corp	DRE	367.6	36.31	2.59	4.50	13346.50	0.06%	0.00%	0.00%
FRT UN Equity	Federal Realty Investment Trust	FRT	75.5	125.02	3.36	3.00	9441.89	0.04%	0.00%	0.00%

	Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	Value Line Earnings Growth	Market Cap.	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
MGM UN Equity	MGM Resorts International	MGM	515.0	31.06	1.67	25.00	15995.40			
JBHT UN Equity	JB Hunt Transport Services Inc	JBHT	106.6	107.93	1.00	9.50	11502.96	0.05%	0.00%	0.01%
LRCX UN Equity	Lam Research Corp	LRCX	142.5	298.21	1.54	9.00	42483.59	0.20%	0.00%	0.02%
MHK UN Equity	Mohawk Industries Inc	MHK	71.6	131.68	n/a	1.50	9431.18			
PNR UN Equity	Pentair PLC	PNR	168.1	42.93	1.77	6.00	7216.23	0.03%	0.00%	0.00%
VRTX UN Equity	Vertex Pharmaceuticals Inc	VRTX	259.0	227.05	n/a	50.00	58804.36			
AMCR UN Equity	Amcor PLC	AMCR	1,620.1	10.59	4.34		0.00			
FB UN Equity	Facebook Inc	FB	2,405.7	201.91	n/a	17.50	485744.17			
TMUS UN Equity	T-Mobile US Inc	TMUS	855.6	79.19	n/a	18.50	67752.98			
URI UN Equity	United Rentals Inc	URI	74.4	135.69	n/a	14.50	10091.94			
ABMD UN Equity	ABIOMED Inc	ABMD	45.2	186.29	n/a	12.50	8411.92			
ARE UN Equity	Alexandria Real Estate Equities Inc	ARE	129.5	163.20	2.52		0.00			
DAL UN Equity	Delta Air Lines Inc	DAL	646.7	55.74	2.89	9.50	36049.45	0.17%	0.00%	0.02%
UAL UN Equity	United Airlines Holdings Inc	UAL	253.0	74.80	n/a	8.50	18927.69			
NWS UN Equity	News Corp	NWS	199.6	13.97	1.43		0.00			
CNC UN Equity	Centene Corp	CNC	583.9	62.81	n/a	15.50	36674.95			
MLM UN Equity	Martin Marietta Materials Inc	MLM	62.5	263.80	0.83	9.50	16487.76	0.08%	0.00%	0.01%
PYPL UN Equity	PayPal Holdings Inc	PYPL	1,173.0	113.89	n/a	20.00	133592.97			
COTY UN Equity	Coty Inc	COTY	757.9	10.26	4.87	5.00	7775.97	0.04%	0.00%	0.00%
DISH UN Equity	DISH Network Corp	DISH	284.5	36.76	n/a	1.00	10456.79			
DOW UN Equity	Dow Inc	DOW	743.2	46.07	6.08		0.00			
ALXN UN Equity	Alexion Pharmaceuticals Inc	ALXN	221.3	99.39	n/a	42.00	21994.11			
RE UN Equity	Everest Re Group Ltd	RE	40.8	276.57	2.24	18.50	11279.08	0.05%	0.00%	0.01%
NWSA UN Equity	News Corp	NWSA	388.6	13.62	1.47		0.00			
EXC UN Equity	Exelon Corp	EXC	970.0	47.59	3.22	9.00	46160.02	0.22%	0.01%	0.02%
GPV UN Equity	Global Payments Inc	GPV	300.5	195.45	0.40	20.00	58742.11			
CCI UN Equity	Crown Castle International Corp	CCI	415.8	149.84	3.20	12.50	62298.68	0.29%	0.01%	0.04%
APTV UN Equity	Aptiv PLC	APTV	255.3	84.79	1.04	11.00	21645.87	0.10%	0.00%	0.01%
AAP UN Equity	Advance Auto Parts Inc	AAP	69.3	131.75	0.18	14.00	9124.87	0.04%	0.00%	0.01%
CPRI UN Equity	Capri Holdings Ltd	CPRI	151.6	29.96	n/a	10.50	4542.98			
ALGN UN Equity	Align Technology Inc	ALGN	78.8	257.10	n/a	17.00	20262.82			
ILMN UN Equity	Illumina Inc	ILMN	147.0	290.07	n/a	14.00	42640.29			
ADS UN Equity	Alliance Data Systems Corp	ADS	46.1	102.79	2.45	9.00	4734.10	0.02%	0.00%	0.00%
LKQ UN Equity	LKQ Corp	LKQ	306.5	32.69	n/a	10.00	10016.71			
NLSN UN Equity	Nielsen Holdings PLC	NLSN	355.8	20.40	1.18	45.50	7258.52			
GRMN UN Equity	Garmin Ltd	GRMN	190.1	96.95	2.35	10.50	18430.49	0.09%	0.00%	0.01%
XEC UN Equity	Cimarex Energy Co	XEC	101.8	43.89	1.82	8.50	4468.44	0.02%	0.00%	0.00%
ZTS UN Equity	Zoetis Inc	ZTS	476.3	134.21	0.60	13.50	63924.09	0.30%	0.00%	0.04%
EQIX UN Equity	Equinix Inc	EQIX	85.3	589.73	1.67	23.50	50291.58			
DLR UN Equity	Digital Realty Trust Inc	DLR	208.6	122.99	3.51	7.00	25654.12	0.12%	0.00%	0.01%

								Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	Value Line Earnings Growth	Market Cap.	% of Total Market Cap.		
LVS UN Equity	Las Vegas Sands Corp	LVS	768.0	65.31	4.84	7.50	50160.50	0.24%	0.01%
DISCK UW Equity	Discovery Inc	DISCK	360.7	27.77	n/a		0.00		
SUM								2.26%	10.06%
REQUIRED RETURN									12.43%

Pandhandle Eastern Pipe Line Company, LP

Market Risk Premium Derived from S&P Earnings and Estimate Report

[1] S&P's estimate of the S&P 500 Dividend Yield	1.88%
[2] S&P's estimate of the S&P 500 Growth Rate	11.40%
[3] S&P 500 Estimated Required Market Return	13.38%

Notes:

[1] Source: S&P Dow Jones Indices, S&P 500 Earnings and Estimate Report, January 30, 2020

[2] Source: S&P Dow Jones Indices, S&P 500 Earnings and Estimate Report, January 30, 2020

[3] Equals $([1] \times (1 + (0.5 \times [2]))) + [2]$

**ValueLine EPS Growth Rates - Market
2/4/2020**

Company Name	Ticker	Projected EPS Growth 3 To 5 Yr
Agilent Technologies	A	11
Alcoa Corp.	AA	6
Amer. Airlines	AAL	7.5
Aarons Inc	AAN	15.5
AAON Inc	AAON	17
Advance Auto Parts	AAP	14
Apple Inc	AAPL	12.5
Atlas Air Worldwide Holdings	AAWW	15
Axon Enterprise	AAXN	27
AllianceBernstein Holding LP	AB	6.5
ABB Ltd	ABB	13
AbbVie Inc	ABBV	10.5
AmerisourceBergen Corp	ABC	8
Asbury Automotive Group Inc	ABG	6
ABM Industries Inc	ABM	15
ABIOMED Inc	ABMD	12.5
Abbott Laboratories	ABT	10
Acco Brands Corporation	ACCO	7
Arch Cap Group Ltd	ACGL	15
Acacia Communications	ACIA	10
ACI Worldwide Inc	ACIW	16.5
AECOM	ACM	9.5
Accenture Plc New	ACN	8.5
Adobe Inc.	ADBE	20.5
Analog Devices Inc	ADI	9
Archer Daniels Midland Company	ADM	9.5
Automatic Data Processing Inc	ADP	13.5
Alliance Data Systems	ADS	9
Ameren Corp	AEE	6.5
AEGON Insurance Group	AEG	32.5
Aegion Corporation	AEGN	10.5
Advanced Energy	AEIS	3.5
Agnico Eagle Mines Ltd	AEM	26
American Eagle Outfitters Inc	AEO	8.5
American Electric Power Company Inc	AEP	4
AerCap Hldgs. NV	AER	10.5
American Financial Group	AFG	7
AFLAC Inc	AFL	8
AGCO Corp	AGCO	14.5
Allergan plc	AGN	3.5
Assured Guaranty Municipal Holdings Inc	AGO	5
AVANGRID Inc.	AGR	8.5
Altra Industrial Motion Corporation	AIMC	14
Albany International Corp	AIN	15.5
Apollo Investment Corporation	AINV	41
AAR Corp	AIR	11.5
Applied Industrial Technologies Inc	AIT	15
Apartment Investment and Management Company	AIV	-3
Assurant Inc	AIZ	6.5
Arthur J Gallagher and Company	AJG	14.5
Aerojet Rocketdyne	AJRD	22
Akamai Technologies Inc	AKAM	18

Akorn Inc.	AKRX	0
Albemarle Corp	ALB	5.5
Allete Inc	ALE	5
Align Technology Inc	ALGN	17
Allegiant Travel Company	ALGT	9
Alaska Air Group	ALK	5.5
Allstate Corporation	ALL	10.5
Allegion Plc	ALLE	9.5
Ally Financial	ALLY	14.5
Alaska Communications Systems Group Inc	ALSK	18
Transmission Holdings Inc	ALSN	10
Altair Engineering Inc	ALTR	4
Autoliv Inc	ALV	5
Alexion Pharmaceuticals Inc	ALXN	42
Applied Materials Inc	AMAT	7.5
Ambarella Inc.	AMBA	-2
AMC Entertainment Hldgs.	AMC	17.5
AMC Networks Inc	AMCX	9
Advanced Micro Devices Inc	AMD	33.5
AMETEK Inc.	AME	15.5
Amedisys Inc	AMED	18
Affiliated Managers Group Inc	AMG	10
Amgen Inc	AMGN	7.5
Amkor Technology	AMKR	9
AMN Healthcare Services Inc	AMN	8
Ameriprise Financial Inc	AMP	12.5
American Tower Corporation	AMT	7.5
TD Ameritrade Holding Corporation	AMTD	12
American Woodmark Corp	AMWD	11
America Movil SAB de CV	AMX	21.5
Amazon com	AMZN	39
AutoNation Inc	AN	7.5
Arista Networks	ANET	12
Abercrombie and Fitch Co	ANF	23
ANSYS Inc	ANSS	13
Anthem Inc.	ANTM	18.5
Amer. Outdoor Brands	AOBC	8.5
Aon PLC	AON	11
AO Smith Corp	AOS	6.5
Ampco Pittsburgh Corp	AP	9
Air Products and Chemicals Inc	APD	12
Amphenol Corp	APH	9.5
Apollo Global Mgmt	APO	10.5
Apogee Enterprises Inc	APOG	8
Aptiv PLC	APTV	11
Antero Resources	AR	-9.5
ArcBest Corporation	ARCB	16
Argo Group Int'l	ARGO	27.5
Alliance Resource Partners LP	ARLP	4.5
Aramark	ARMK	10
Arrow Electronics Inc	ARW	7.5
Associated Banc Corp	ASB	7.5
ASGN Inc.	ASGN	16.5
AdvanSix Inc.	ASIX	3.5
Astec Industries Inc	ASTE	6.5

Ali. Couche-Tard	ATDB.TO	12.5
Adtalem Global Educ.	ATGE	6.5
Athene Holding Ltd.	ATH	11
Allegheny Technologies Inc	ATI	35.5
ATN International	ATNI	16
Atmos Energy Corp	ATO	7.5
AptarGroup Inc	ATR	9.5
Astronics Corporation	ATRO	20.5
Atento S.A.	ATTO	47
Activision Blizzard Inc	ATVI	9
AngloGold Ashanti Ltd	AU	33.5
AudioCodes Ltd	AUDC	13
Yamana Gold Inc	AUY	21
Avista Corp	AVA	3.5
AeroVironment Inc	AVAV	11
Avalonbay Communities Inc	AVB	2.5
American Vanguard Corporation	AVD	11
Broadcom Inc.	AVGO	33.5
Avid Technology Inc	AVID	41.5
Avnet Inc	AVT	9
AVX Corp	AVX	11
Avery Dennison Corp	AVY	11
Armstrong World Industries Inc	AWI	13
American Water Works	AWK	9.5
American States Water Co	AWR	8
Anixter International Inc	AXE	10.5
American Axle and Manufacturing Holdings Inc	AXL	-1
American Express Company	AXP	10
Axis Capital Holdings Ltd	AXS	33.5
Axalta Coating	AXTA	27.5
Acuity Brands Inc	AYI	11
Aircastle Limited	AYR	12.5
AstraZeneca PLC	AZN	15.5
AutoZone Inc	AZO	13.5
Barnes Group Inc	B	13
Boeing Co	BA	12
Alibaba Group Hldg Ltd.	BABA	10
Bank of America Corporation	BAC	10.5
Booz Allen Hamilton Holding Corporation	BAH	13
Brookfield Asset Management Inc	BAM	13
Baxter International Inc	BAX	10.5
Bed Bath and Beyond Inc	BBBY	0
Bombardier Inc (Class B)	BBDB.TO	8.5
Barrett Business Serv.	BBSI	13.5
Best Buy Company	BBY	10.5
Brunswick Corp	BC	11
Boise Cascade	BCC	13
BCE Inc	BCE	5
Brinks Company	BCO	14.5
Balchem Corp.	BCPC	17
Belden Inc	BDC	12.5
Becton Dickinson and Company	BDX	9.5
Beacon Roofing Supply Inc	BECN	20.5
Franklin Resources Inc	BEN	10
Berry Global Group	BERY	12.5

Bright Horizons Family	BFAM	13.5
Brown Forman Corp (Class B)	BF/B	14.5
Bunge Ltd	BG	10.5
Big 5 Sporting Goods	BGFV	8.5
Briggs and Stratton Corp	BGG	10.5
B and G Foods Inc	BGS	7
Biglari Holdings Inc	BH	2.5
Bausch Health	BHC	3.5
Benchmark Electronics Inc	BHE	9.5
BHP Group Ltd. ADR	BHP	14.5
Baidu Inc	BIDU	10.5
Big Lots Inc	BIG	4.5
Biogen	BIIB	8
Bio Rad Laboratories Inc	BIO	11.5
Brookfield Infrastruc.	BIP	18
BJs Restaurants Inc	BJRI	11.5
Bank of New York Mellon Corporation	BK	7
Buckle Inc	BKE	-0.5
Black Hills Corp	BKH	5
Black Knight Inc.	BKI	12.5
Booking Holdings	BKNG	12
TopBuild Corp.	BLD	13.5
Builders FirstSource	BLDR	16
BlackRock Inc	BLK	10.5
Ball Corp	BLL	25
Bloomin Brands Inc	BLMN	13.5
Badger Meter Inc	BMI	10.5
Bank of Montreal	BMO.TO	7.5
Bristol Myers Squibb Co	BMJ	9
Bank of Nova Scotia	BNS.TO	5
Bank of Hawaii	BOH	8.5
BOK Financial Corporation	BOKF	8.5
DMC Global	BOOM	42
Boot Barn Holdings	BOOT	17.5
BP Plc	BP	28.5
Popular Inc	BPOP	12.5
Broadridge Fin'l	BR	11
Brady Corp	BRC	10.5
Craft Brew Alliance Inc	BREW	24
Berkshire Hathaway Inc New (Class B)	BRK/B	6
Bruker Corporation	BRKR	10
Brooks Automation Inc	BRKS	20
Brown and Brown Inc	BRO	12
Bassett Furniture Industries Inc	BSET	10
Black Stone Minerals	BSM	9
Boston Scientific Corp	BSX	16
Brit. Am. Tobacco ADR	BTI	9.5
Anheuser Busch Inbev SA NV	BUD	19.5
Burlington Stores Inc	BURL	16
BorgWarner Inc	BWA	4.5
BWX Technologies	BWXT	11
Blackstone Group	BX	9
Boston Properties Inc	BXP	5
BancorpSouth Bank	BXS	10
Boyd Gaming Corp	BYD	15

Beazer Homes USA Inc New	BZH	7
Citigroup Inc	C	10
China Automotive Systems Inc	CAAS	5.5
Cable One	CABO	15
Credit Acceptance Corporation	CACC	13.5
CACI International Inc	CACI	12.5
CAE Inc	CAE.TO	13.5
Conagra Brands	CAG	5.5
Cardinal Health Inc	CAH	11
Canon Inc	CAJ	12
Cheesecake Factory Inc	CAKE	9
Caleres Inc.	CAL	8.5
Cal Maine Foods Inc	CALM	39.5
CalAmp Corp	CAMP	15.5
Avis Budget Group Inc	CAR	8
Caseys General Stores Inc	CASY	6.5
Caterpillar Inc	CAT	12
Cato Corp	CATO	5
Chubb Ltd.	CB	10
Cboe Global Markets	CBOE	14.5
CBRE Group Inc	CBRE	11
Cracker Barrel Old Country Store Inc	CBRL	11
Commerce Bancshares Inc	CBSH	8
Cabot Corp	CBT	9.5
Chemours Co. (The)	CC	11.5
Cogeco Communic.	CCA.TO	8
Crown Castle International Corporation	CCI	12.5
Crown Holdings Inc	CCK	8.5
Carnival Corp	CCL	10
Cabot Microelectronics Corp	CCMP	20.5
Cameco Corp	CCO.TO	20
Centennial Resource Dev.	CDEV	17.5
CDK Global Inc.	CDK	15
Cadence Design Systems Inc	CDNS	12.5
CDW Corp.	CDW	10.5
Celanese Corp	CE	8.5
Central Garden and Pet Co	CENT	18
Cerner Corp	CERN	9
CEVA Inc	CEVA	14.5
Capitol Federal Financial Inc	CFFN	4
Citizens Fin'l Group	CFG	12
Cullen Frost Bankers Inc	CFR	6
Colfax Corporation	CFX	8.5
Carlyle Group	CG	20.5
China Green Agriculture Inc	CGA	7
Cognex Corporation	CGNX	13
Church and Dwight Co Inc	CHD	9
Churchill Downs Inc	CHDN	11
Chemed Corporation	CHE	14
Chefs' Warehouse	CHEF	20
Choice Hotels International Inc	CHH	7.5
Check Point Software Technologies Inc	CHKP	8.5
China Mobile (ADR)	CHL	4.5
CH Robinson Worldwide Inc	CHRW	9
Chicos FAS Inc	CHS	-2

Charter Communic.	CHTR	17.5
Cigna Corporation	CI	14.5
Ciena Corporation	CIEN	12
Cincinnati Financial Corp	CINF	9.5
CIT Group Inc	CIT	18
Colgate Palmolive Co	CL	5.5
Core Laboratories	CLB	13.5
Cleveland-Cliffs Inc.	CLF	-3
CoreLogic	CLGX	7
Mack Cali Realty Corporation	CLI	5.5
Continental Resources Inc	CLR	36
Clorox Co	CLX	3.5
Canadian Imperial Bank of Commerce	CM.TO	3.5
Comerica Inc	CMA	9.5
Commercial Metals Company	CMC	11
Columbus McKinnon Corp	CMCO	14.5
Comcast Corporation	CMCSA	13.5
Cantel Medical Corp	CMD	17.5
CME Group Inc	CME	3
Chipotle Mexican Grill Inc	CMG	26.5
Cummins Inc	CMI	8
Compass Minerals International Inc	CMP	15.5
Cimpress plc	CMPR	45
CMS Energy Corp	CMS	7
Comtech Telecommunications Corp	CMTL	21
CNA Financial Corporation	CNA	11
Centene Corp.	CNC	15.5
CNH Industrial N.V.	CNHI	29
Canadian National Railway Co	CNI	10
Cinemark Holdings Inc	CNK	10.5
Conmed Corp	CNMD	13
CenterPoint Energy Inc	CNP	10.5
CNX Resources	CNX	8.5
PC Connection Inc	CNXN	11
Capital One Financial Corporation	COF	5.5
Cabot Oil and Gas Corp	COG	46.5
Coherent Inc	COHR	8
Coca-Cola Consol.	COKE	17
Columbia Sportswear Company	COLM	12.5
CommScope Holding	COMM	5.5
Cooper Companies Inc	COO	14.5
Core Mark Holding Co Inc	CORE	10.5
Costco Wholesale Corporation	COST	9
Coty Inc	COTY	5
Canadian Pacific Railway Inc	CP	12
Copa Holdings SA	CPA	11.5
Campbell Soup Co	CPB	2
Callon Petroleum	CPE	31
Chesapeake Utilities	CPK	9
Capri Holdings Ltd.	CPRI	10.5
Copart Inc	CPRT	17.5
Computer Programs and Systems Inc	CPSI	13
Camden Property Trust	CPT	-1
Crane Co	CR	8.5
Crawford and Company (Class B)	CRDB	11

Carters Inc	CRI	9
Charles River Laboratories International Inc	CRL	12
Salesforce Com Inc	CRM	30
Carpenter Technology Corp	CRS	21
Cirrus Logic Inc	CRUS	6
CryoLife Inc	CRY	28
Cisco Systems Inc	CSCO	7.5
CoStar Group Inc	CSGP	21.5
CSG Systems International Inc	CSGS	10
Carlisle Companies Inc	CSL	13
Cornerstone OnDemand Inc	CSOD	34.5
Capstar Financial Holdings Inc	CSTR	15.5
Carriage Services Inc	CSV	15.5
CSX Corporation	CSX	14.5
Cintas Corp	CTAS	15.5
Cooper Tire and Rubber Co	CTB	7
Canadian Tire 'A'	CTCA.TO	8
CenturyLink Inc	CTL	1
Catalent Inc.	CTLT	18
Citi Trends Inc	CTRN	14.5
CTS Corporation	CTS	11.5
Cognizant Technology Solutions Corp	CTSH	5
Citrix Systems Inc	CTXS	9
Cubic Corp	CUB	34.5
Culp Inc	CULP	8.5
Cutera Inc	CUTR	25.5
Commercial Vehicle Group Inc	CVGI	11
Calavo Growers Inc	CVGW	13
CVR Energy	CVI	28
CVS Caremark Corporation	CVS	6.5
Chevron Corporation	CVX	16.5
Curtiss Wright Corp	CW	10.5
Consolidated Water	CWCO	20.5
Camping World Holdings	CWH	2.5
California Water Service Group	CWT	8
Cemex SaB De Cv	CX	21.5
Concho Resources	CXO	21
CoreCivic Inc.	CXW	5.5
Cypress Semiconductor Corporation	CY	12
Dominion Energy	D	6.5
Daktronics Inc	DAKT	23
Delta Air Lines Inc	DAL	9.5
Dana Inc.	DAN	8
Darling Ingredients Inc	DAR	18
Diebold Nixdorf	DBD	22
Designer Brands	DBI	8
Dropbox Inc.	DBX	14.5
Donaldson Co	DCI	11.5
DCP Midstream LP	DCP	17.5
Daimler AG	DDAIF	1.5
Dillard's Inc	DDS	5
Deere and Co	DE	13.5
Deckers Outdoor	DECK	12
Denny's Corp.	DENN	22.5
Diageo Plc	DEO	8.5

Dean Foods Company New	DFODQ	-11.5
Discover Financial Services	DFS	7.5
Dollar General Corporation	DG	12
Quest Diagnostics Inc	DGX	9
D R Horton Inc	DHI	7
Danaher Corp	DHR	14
Dine Brands Global	DIN	16.5
Diodes Inc	DIOD	31
Walt Disney Co	DIS	7.5
Discovery Inc.	DISCA	18
DISH Network Corporation	DISH	1
Delek US Holdings	DK	27
Dicks Sporting Goods Inc	DKS	7.5
Dolby Laboratories Inc	DLB	11
Digital Realty Trust Inc	DLR	7
Dollar Tree Inc	DLTR	10
Deluxe Corp	DLX	12
Dunkin Brands Group Inc	DNKN	10
Denbury Resources Inc	DNR	18
Masonite Int'l	DOOR	10
Dorman Products Inc	DORM	6.5
Dover Corp	DOV	12.5
Amdocs Ltd	DOX	10
Diplomat Pharmacy	DPLO	7.5
Dominos Pizza Inc	DPZ	15
Duke Realty Corporation	DRE	4.5
Darden Restaurants Inc	DRI	11
DTE Energy Company	DTE	4.5
Deutsche Telekom AG	DTEGY	12
Duke Energy Corp New	DUK	6
DaVita Inc.	DVA	12
Devon Energy Corp	DVN	0
DXC Technology	DXC	10
Dycom Industries Inc	DY	11
Electronic Arts Inc	EA	11
Brinker International Inc	EAT	8
EBay Inc	EBAY	10
Ennis Inc.	EBF	3
Ecolab Inc	ECL	10
US Ecology Inc	ECOL	13.5
Consolidated Edison Inc	ED	3
New Oriental Education and Technology Group Inc	EDU	18
El Paso Electric Co	EE	3
Equifax Inc	EFX	8.5
Encompass Health	EHC	12
Estee Lauder Companies Inc	EL	14
e.l.f. Beauty	ELF	8.5
Callaway Golf Co	ELY	15.5
Emera Inc.	EMA.TO	10
EMCOR Group Inc	EME	9
Eastman Chemical Co	EMN	8
Empire Company Limited (Class A)	EMPA.TO	16.5
Emerson Electric Co	EMR	11.5
Enbridge Inc	ENB.TO	6.5
Enable Midstream Part.	ENBL	18.5

Endo International PLC	ENDP	-9
Energizer Holdings	ENR	11
Energys	ENS	10.5
Entegris Inc.	ENTG	16
EOG Resources Inc	EOG	31.5
Enerpac Tool Group	EPAC	3
EPAM Systems	EPAM	22.5
Edgewell Personal Care	EPC	8.5
Enterprise Products Partners LP	EPD	10.5
Equinix Inc	EQIX	23.5
EQM Midstream Part.	EQM	2
Enerplus Corporation	ERF.TO	10
Eldorado Resorts	ERI	35.5
Erie Indemnity Company	ERIE	12.5
Embraer SA	ERJ	25
Eversource Energy	ES	5.5
ESCO Technologies Inc	ESE	12
Elbit Systems Ltd	ESLT	6.5
Essex Property Trust Inc	ESS	-0.5
Elastic N.V.	ESTC	10
Energy Transfer LP	ET	13
E Trade Financial Corporation	ETFC	17.5
Ethan Allen Interiors Inc	ETH	9.5
Entercom Communic.	ETM	-5
Eaton Corp New	ETN	7
Entergy Corp	ETR	2
Eaton Vance Corp	EV	7.5
Entravision Communications Corp	EVC	31
Edwards Lifesciences	EW	16.5
East West Bancorp Inc	EWBC	6.5
Exelon Corp	EXC	9
Exelixis Inc.	EXEL	26
Eagle Materials Inc	EXP	6.5
Expeditors International of Washington Inc	EXPD	9
Expedia Group	EXPE	24
Express Inc	EXPR	3
Extra Space Storage	EXR	4
Extreme Networks Inc	EXTR	15.5
EZCORP Inc	EZPW	23
Ford Motor Company	F	3
First American Fin'l	FAF	9.5
Diamondback Energy	FANG	16.5
FARO Technologies Inc	FARO	24.5
Fastenal Co	FAST	8.5
Facebook Inc	FB	17.5
Fortune Brands Home and Security Inc	FBHS	8.5
Fiat Chrysler	FCAU	12
First Commonwealth Financial Corp	FCF	12
FirstCash Inc.	FCFS	13.5
FTI Consulting Inc	FCN	13.5
Freep't-McMoRan Inc.	FCX	22.5
Fresh Del Monte Produce Inc	FDP	10.5
FactSet Research Systems Inc	FDS	12
FedEx Corp	FDX	7.5
FirstEnergy Corp	FE	6.5

Franklin Electric Co Inc	FELE	8.5
Flushing Financial Corp	FFIC	3
F5 Networks	FFIV	12
First Horizon National Corporation	FHN	6
Fair Isaac Inc	FICO	13.5
Federated Investors Inc	FII	10.5
Fidelity Nat'l Info.	FIS	7
Fiserv Inc	FISV	10.5
Fifth Third Bancorp	FITB	7
Five Below Inc	FIVE	19
National Beverage	FIZZ	1
Foot Locker Inc	FL	9.5
Flex Ltd.	FLEX	10.5
FLIR Systems Inc	FLIR	12
Flowers Foods Inc	FLO	6
Fluor Corp	FLR	17
Flowserve Corp	FLS	13.5
FleetCor Technologies Inc	FLT	12.5
1 800 Flowers Com	FLWS	11
First Midwest Bancorp Inc	FMBI	11
FMC Corp	FMC	15
Fresenius Medical ADR	FMS	4.5
Fidelity Nat'l Fin'l	FNF	11
Franco Nevada Corp	FNV	14
Ferro Corp	FOE	8
FormFactor Inc.	FORM	11.5
Forrester Research Inc	FORR	9
Fossil Group Inc	FOSL	21
Fox Factory Holding	FOXF	19
Francescas Holdings Corporation	FRAN	0
First Republic Bank	FRC	10.5
Fiesta Restaurant	FRGI	12.5
Federal Realty Investment Trust	FRT	3
Federal Signal Corp	FSS	17
Fuel Tech Inc	FTEK	22
Fortinet Inc	FTNT	28
Fortis Inc	FTS.TO	2.5
Finning Int'l	FTT.TO	18.5
Fortive Corp.	FTV	10
FUJIFILM Holdings Corporation	FUJIY	10.5
H B Fuller Co	FUL	9.5
Cedar Fair LP	FUN	10.5
Forward Air Corp	FWRD	12
Genpact Limited	G	12.5
GATX Corp	GATX	5
Greenbrier Companies Inc	GBX	6
Genesco Inc	GCO	10
GCP Applied Tech.	GCP	10
General Dynamics Corporation	GD	6
General Electric Company	GE	2
Greif Inc	GEF	8.5
GEO Group (The)	GEO	1.5
Guess? Inc.	GES	21.5
Griffon Corporation	GFF	17
Graco Inc	GGG	12.5

Graham Holdings Company	GHC	11
Greenhill & Co.	GHL	20
G-III Apparel Group	GIII	16.5
Gildan Activewear	GIL	7
Gilead Sciences Inc	GILD	-1.5
General Mills Inc	GIS	4.5
Globe Life Inc.	GL	10
Gladstone Capital Corporation	GLAD	19.5
Glatfelter (P.H.)	GLT	47.5
Corning Inc	GLW	15
Gen'l Motors	GM	2
Globus Medical Inc	GMED	11
GNC Holdings Inc	GNC	-7.5
Generac Holding Inc	GNRC	15
Gentex Corp	GNTX	8.5
Barrick Gold Corporation	GOLD	4
Alphabet Inc.	GOOG	16.5
Canada Goose Hldgs.	GOOS.TO	28
Genuine Parts Co	GPC	8
Group 1 Automotive Inc	GPI	7.5
Graphic Packaging	GPK	11
Global Payments Inc	GPN	20
Gap Inc	GPS	3
Grace (W.R.) & Co.	GRA	12
Gorman Rupp Co	GRC	7.5
Garmin Ltd	GRMN	10.5
Grubhub Inc.	GRUB	10.5
Goldman Sachs Group Inc	GS	10
GlaxoSmithKline PLC	GSK	4
Goodyear Tire and Rubber Company	GT	3
Chart Industries Inc	GTLS	28
Gray Television	GTN	13.5
Granite Construction Inc	GVA	19
Guidewire Software	GWRE	36.5
WW Grainger Inc	GWW	8.5
Hyatt Hotels Corporation	H	13.5
Hawaiian Holdings Inc	HA	1.5
Haemonetics Corp	HAE	18
Hain Celestial Group Inc	HAIR	4.5
Halliburton Co	HAL	19.5
Hasbro Inc	HAS	9.5
Huntington Bancshares Inc	HBAN	10.5
Hanesbrands Inc	HBI	3
HCA Healthcare	HCA	12.5
Warrior Met Coal Inc	HCC	5.5
Healthcare Services Group Inc	HCSG	9.5
Home Depot Inc	HD	9
HD Supply Holdings Inc	HDS	10.5
Hawaiian Electric Industries Inc	HE	2.5
HEICO Corp	HEI	14.5
Helen of Troy Ltd	HELE	6.5
Holly Energy Part.	HEP	2.5
HollyFrontier Corporation	HFC	17
Hilton Grand Vacations	HGV	9
Howard Hughes Corporation	HHC	12

Hillenbrand Inc	HI	7
Hibbett Sports Inc	HIBB	3.5
Hartford Financial Services Group Inc	HIG	13
Huntington Ingalls Industries Inc	HII	7
Herbalife Nutrition	HLF	9.5
Houlihan Lokey	HLI	11
Helios Technologies	HLIO	13.5
Honda Motor Co Ltd	HMC	5.5
HNI Corporation	HNI	11.5
Harley Davidson Inc	HOG	8.5
Hologic Inc	HOLX	25
At Home Group	HOME	16
Honeywell International Inc	HON	8.5
Hewlett Packard Ent.	HPE	6.5
HP Inc.	HPQ	8
HealthEquity Inc.	HQY	19
Healthcare Realty Trust Inc	HR	20
H and R Block Inc	HRB	7
Hill Rom Holdings	HRC	105
Hormel Foods Corporation	HRL	10.5
HSBC Holdings PLC	HSBC	16.5
Harsco Corporation	HSC	17.5
Husky Energy Inc	HSE.TO	8.5
Henry Schein Inc	HSIC	7
Heidrick and Struggles International Inc	HSII	28.5
Host Hotels and Resorts Inc	HST	-1.5
Hershey Company	HSY	7
Hitachi Ltd	HTHIY	10.5
Heartland Express Inc	HTLD	14
Hubbell Inc.	HUBB	8.5
Hub Group Inc	HUBG	12
Humana Inc	HUM	12
Huntsman Corporation	HUN	13
Huron Consulting Group Inc	HURN	8.5
Haverty Furniture Companies Inc	HVT	7
Hancock Whitney Corp.	HWC	9
Hexcel Corporation	HXL	10
Hyster-Yale Materials	HY	14.5
MarineMax Inc	HZO	9
IAC InterActiveCorp	IAC	23
Integra LifeSciences Holdings Corporation	IART	12
Interactive Brokers	IBKR	11
International Business Machines Corp	IBM	1
Intercontinental Exch.	ICE	10.5
ICON plc	ICLR	9
ICU Medical Inc	ICUI	5
IDACORP Inc	IDA	3.5
InterDigital Inc	IDCC	-3.5
IDT Corp.	IDT	12.5
IDEXX Laboratories Inc	IDXX	13
IDEX Corporation	IEX	9.5
International Flavors and Fragrances Inc	IFF	8
Int'l Game Tech. PLC	IGT	12
Insteel Industries Inc	IIIN	8
II VI Incorporated	IIVI	17.5

Illumina Inc	ILMN	14
IMAX Corporation	IMAX	43.5
Ingles Markets Incorporated	IMKTA	7.5
Imperial Oil Limited	IMO	16
IHS Markit	INFO	18
Infosys Limited	INFY	13.5
Inogen Inc.	INGN	25.5
Ingredion Incorporated	INGR	5.5
World Fuel Services Corporation	INT	43.5
Intel Corporation	INTC	10.5
Intuit Inc	INTU	14.5
ION Geophysical Corporation	IO	28.5
Innospec Inc	IOSP	11.5
International Paper Co	IP	9
Inter Parfums Inc	IPAR	14
Interpublic Group of Companies Inc	IPG	11
IPG Photonics	IPGP	9.5
Inphi Corp.	IPHI	23
IQVIA Holdings	IQV	12.5
Ingersoll Rand Plc	IR	12.5
iRobot Corporation	IRBT	16
Iridium Communic.	IRDM	22.5
Iron Mountain Inc	IRM	8.5
Investors Bancorp Inc	ISBC	4.5
Intuitive Surgical Inc	ISRG	14
Gartner Inc	IT	13.5
Integer Holdings	ITGR	15
Itron Inc	ITRI	71
ITT Inc.	ITT	12
Illinois Tool Works Inc	ITW	9.5
Invesco Ltd	IVZ	3.5
Jacobs Engineering Group Inc	J	14.5
Jack in the Box Inc	JACK	9.5
Jazz Pharmac. plc	JAZZ	12
J B Hunt Transport Services Inc	JBHT	9.5
Jabil Inc.	JBL	16
JetBlue Airways Corporation	JBLU	8.5
Sanfilippo (John B.)	JBSS	5
John Bean Tech.	JBT	14
Johnson Ctrls. Int'l plc	JCI	8
j2 Global Inc	JCOM	9.5
Jefferies Fin'l Group	JEF	18
Janus Henderson plc	JHG	6
J and J Snack Foods Corp	JJSF	9.5
Jack Henry and Associates Inc	JKHY	12
Jones Lang LaSalle	JLL	9.5
Johnson and Johnson	JNJ	12
Juniper Networks Inc	JNPR	5.5
St Joe Company	JOE	16.5
JP Morgan Chase and Co	JPM	6
Wiley John and Sons Inc (Class A)	JWA	8
Nordstrom Inc	JWN	5
Kellogg Company	K	3.5
Kadant Inc	KAI	12
Kaman Corporation	KAMN	11.5

KAR Auction Svcs.	KAR	3
Kimball Int'l	KBAL	11.5
KB Home	KBH	10
KBR Inc	KBR	26.5
Kelly Services Inc	KELYA	7.5
KEMET Corp.	KEM	7
Kirby Corporation	KEX	14.5
KeyCorp	KEY	10.5
Keysight Technologies	KEYS	22
Kforce Inc.	KFRC	13.5
Korn Ferry	KFY	9
Kinross Gold Corporation	KGC	29
Kraft Heinz Co.	KHC	0
Kimco Realty Corporation	KIM	5
KKR & Co.	KKR	10.5
KLA Corp.	KLAC	10
Kulicke and Soffa Industries Inc	KLIC	10
Kimberly Clark Corp	KMB	7.5
Kinder Morgan Inc	KMI	35.5
Kemper Corporation	KMPR	19.5
Kennametal Inc	KMT	10
CarMax Group	KMX	10.5
Knowles Corporation	KN	12.5
Knoll Inc.	KNL	10
Coca Cola Company	KO	6.5
Kroger Co	KR	4
Kraton Corp.	KRA	5
Kronos Worldwide Inc	KRO	10
Kohls Corporation	KSS	6.5
Kansas City Southern	KSU	12
Kratos Defense & Sec.	KTOS	8
Quaker Chemical Corporation	KWR	18.5
Kyocera Corporation	KYOCY	8
Loews Corporation	L	13.5
Loblaw Cos. Ltd.	L.TO	12.5
Lithia Motors Inc	LAD	7.5
Lamar Advertising Company	LAMR	8
Lancaster Colony Corporation	LANC	7.5
Lazard Ltd	LAZ	11
L Brands Inc	LB	-2
LCI Industries	LCII	10.5
Leidos Holdings Inc	LDOS	9
Lear Corp	LEA	5.5
Lincoln Electric Holdings Inc	LECO	10.5
Leggett and Platt Inc	LEG	9
Lennar Corp	LEN	8.5
Littelfuse Inc	LFUS	3.5
Lions Gate 'A'	LGFA	37
Laboratory Corp	LH	8
Harris Corp.	LHX	16.5
Lennox International Inc	LII	12.5
Lumentum Holdings	LITE	39
LKQ Corporation	LKQ	10
Eli Lilly and Co	LLY	12
Legg Mason Inc	LM	7.5

Lockheed Martin Corp	LMT	12.5
Lincoln National Capital VI	LNC	9
Lindsay Corporation	LNN	15.5
Linamar Corp	LNK.TO	3
Alliant Energy Corp	LNT	6.5
Logitech International SA	LOGI	13
LogMeIn Inc.	LOGM	38
Grand Canyon Educ.	LOPE	10
Lowes Companies Inc	LOW	11.5
Laredo Petroleum	LPI	31.5
LPL Financial Holdings Inc	LPLA	17
Liberty Property Trust	LPT	2
Louisiana Pacific Corp	LPX	5
Lam Research Corp	LRCX	9
Lattice Semiconductor Corp	LSCC	36.5
Learning Tree International Inc	LTRE	2.5
Lululemon Athletica Inc	LULU	20
Southwest Airlines Co	LUV	10.5
Las Vegas Sands Corp	LVS	7.5
Lamb Weston Holdings	LW	11
LyondellBasell Industries NV	LYB	5.5
La Z Boy Inc	LZB	9
Macys Inc	M	2
Mastercard Incorporated	MA	19
Mid-America Apartment	MAA	1
Macerich Co	MAC	3
ManpowerGroup	MAN	3.5
Manhattan Associates Inc	MANH	4
ManTech International Corporation	MANT	11.5
Marriott International Inc	MAR	17.5
Masco Corp	MAS	9.5
Masimo Corporation	MASI	7.5
Matthews International Corp	MATW	4.5
Matson Inc	MATX	9.5
McDonalds Corp	MCD	8.5
Microchip Technology Inc	MCHP	9.5
McKesson Corp	MCK	9
Moodys Corp	MCO	11.5
Monarch Casino	MCRI	11.5
Marcus Corp	MCS	10
Mercury General Corp	MCY	23
Mednax Inc	MD	6.5
M D C Holdings Inc	MDC	10.5
Mondelez International Inc	MDLZ	8.5
Meredith Corp	MDP	14.5
Allscripts Healthcare Solutions Inc	MDRX	12
Medtronic plc	MDT	8.5
MDU Resources Group Inc	MDU	12.5
Medifast Inc.	MED	21.5
Medpace Holdings	MEDP	28
Methode Electronics	MEI	7
Mercadolibre Inc.	MELI	19.5
Methanex Corp	MEOH	8
MetLife Inc	MET	7.5
Manulife Financial Corporation	MFC	7.5

Maple Leaf Foods	MFI.TO	13
Magna International Inc	MGA	10.5
MGE Energy Inc	MGEE	6
MGM Resorts International	MGM	25
MGM Growth Properties	MGP	27
MGP Ingredients	MGPI	11
Mohawk Industries Inc	MHK	1.5
Macquarie Infra.	MIC	10
Middleby Corp	MIDD	12.5
Michaels Cos. (The)	MIK	2.5
Mobile Mini	MINI	14
McCormick and Co	MKC	8
Markel Corp	MKL	45.5
MKS Instruments	MKSI	15
MarketAxess Holdings	MKTX	14
Melco Resorts & Entert.	MLCO	31
Herman Miller Inc	MLHR	11.5
Mueller Industries Inc	MLI	12.5
Martin Marietta Materials Inc	MLM	9.5
MellanoX Technologies Ltd	MLNX	40.5
Marsh and McLennan Companies Inc	MMC	9
3M Company	MMM	6
Magellan Midstream Partners LP	MMP	6
MAXIMUS Inc	MMS	11
McClatchy Co	MNI	6
Mallinckrodt plc	MNK	15
Monro Inc.	MNRO	12.5
Monster Beverage Corporation	MNST	14.5
Altria Group Inc	MO	8.5
Modine Manufacturing Co	MOD	10
Moog Inc (Class A)	MOGA	13
Molina Healthcare	MOH	25
Morningstar Inc	MORN	12.5
Mosaic Company New	MOS	18
Movado Group	MOV	12.5
Motorcar Parts Of Amer.	MPAA	11.5
Marathon Petroleum Corporation	MPC	11
MPLX LP	MPLX	21
Monolithic Power Sys.	MPWR	23.5
Montage Resources Corp.	MR	10.5
Mercury Systems Inc	MRCY	20.5
Merck and Co Inc	MRK	9
Metro Inc	MRU.TO	8.5
Marvell Technology Group Ltd	MRVL	22.5
Morgan Stanley	MS	10
MSA Safety	MSA	11
MSCI Inc	MSCI	18.5
Middlesex Water Co	MSEX	7.5
Microsoft Corporation	MSFT	14
Madison Square Garden	MSG	15.5
MSG Networks	MSGN	6.5
Motorola Solutions Inc	MSI	13
MSC Industrial Direct Co Inc	MSM	8
Arcelor Mittal	MT	1
M&T Bank Corporation	MTB	9.5

Match Group	MTCH	19
Mettler Toledo International Inc	MTD	10
MGIC Investment Corp	MTG	16.5
Meritage Homes Corp	MTH	12
Vail Resorts	MTN	18
Meritor Inc	MTOR	13.5
Materion Corporation	MTRN	14.5
MTS Systems Corp	MTSC	19
MACOM Tech. Solutions	MTSI	8
Minerals Technologies Inc	MTX	4.5
MasTec Inc	MTZ	15
Micron Technology Inc	MU	14
Murphy USA Inc	MUSA	8.5
Mueller Water Products Inc	MWA	15
Maxim Integrated Products Inc	MXIM	5.5
Myers Industries Inc	MYE	26.5
Myriad Genetics Inc	MYGN	10
Mylan N.V.	MYL	3.5
National Bank of Canada	NA.TO	6
National Instruments Corp	NATI	15
Navistar International Corp	NAV	32.5
Navient Corporation	NAVI	5.5
Noble Energy Inc	NBL	0
Norwegian Cruise Line Holdings Ltd	NCLH	16
National CineMedia Inc	NCMI	20
NCR Corp	NCR	7.5
Nasdaq Inc.	NDAQ	8
Nordson Corp	NDSN	8
NextEra Energy Inc	NEE	10.5
Newmont Corp.	NEM	11.5
Neogen Corp	NEOG	7.5
NewMarket Corporation	NEU	2
National Fuel Gas Co	NFG	27.5
Netflix Inc	NFLX	32
Ingevity Corp.	NGVT	15.5
Nisource Inc	NI	12.5
New Jersey Resources Corp	NJR	2.5
Nike Inc	NKE	18
Nektar Therapeutics	NKTR	6.5
NortonLifeLock Inc.	NLOK	5
Nautilus Inc	NLS	0.5
Nielsen Hldgs. plc	NLSN	45.5
Annaly Capital Management Inc	NLY	0
NMI Holdings Inc	NMIH	24.5
Northrop Grumman Corp Holding Co	NOC	9.5
Nokia Corp	NOK	11
National Oilwell Varco Inc	NOV	31
Neenah Inc.	NP	6
Northland Power Inc	NPI.TO	15
National Presto Industries Inc	NPK	6
EnPro Industries Inc	NPO	18
Natural Resource Partners Ltd	NRP	4
NuStar Energy LP	NS	9.5
Nissan Motor Company Ltd	NSANY	2.5
Norfolk Southern Corp	NSC	15

Insight Enterprises Inc	NSIT	15.5
Insperty Inc	NSP	17.5
Nestle SA	NSRGY	10
NetApp Inc	NTAP	10
NETGEAR Inc	NTGR	6.5
Northern Trust Corp	NTRS	8.5
Natus Medical	NTUS	45
Nucor Corporation	NUE	13
Nu Skin Enterprises Inc	NUS	7
Nuvasive Inc	NUVA	30
NVIDIA Corp	NVDA	11.5
Novo Nordisk	NVO	7
NVR Inc	NVR	13.5
Novartis AG	NVS	10.5
Northwest Bancshares Inc	NWBI	7.5
NorthWestern Corporation	NWE	2
Newell Brands	NWL	4
Northwest Natural	NWN	27
Quanex Corp	NX	24
NextGen Healthcare	NXGN	13
XP Semiconductors NV	NXPI	10.5
Nexstar Media Group	NXST	22.5
New York Community Bancorp Inc	NYCB	5
New York Times Co	NYT	33.5
Realty Income Corporation	O	4.5
Owens Corning Inc	OC	7.5
Old Dominion Freight Line Inc	ODFL	9.5
Office Depot Inc	ODP	-4.5
OGE Energy Corp	OGE	6.5
ONE Gas Inc.	OGS	8
O-I Glass	OI	5.5
ONEOK Inc	OKE	17
Universal Display Corp	OLED	25
Ollie's Bargain Outlet	OLLI	18
Olin Corp	OLN	12.5
Omnicom Group Inc	OMC	6.5
Omniceil Inc	OMCL	37
Owens and Minor Inc	OMI	-8
ON Semiconductor	ON	13
Old National Bancorp	ONB	7.5
Ormat Technologies Inc	ORA	8.5
Oracle Corp	ORCL	10
Old Republic International Corp	ORI	14.5
O Reilly Automotive Inc	ORLY	12
OSI Systems Inc	OSIS	22.5
Oshkosh Corporation	OSK	11
Open Text Corp	OTEX	20.5
Otter Tail Corp	OTTR	5
OUTFRONT Media	OUT	12.5
Ovintiv Inc.	OVV	14
Oxford Industries Inc	OXM	7.5
Occidental Petroleum Corporation	OXY	24
Plains All American Pipeline	PAA	12
Pan American Silver Corp	PAAS	20
Penske Automotive Group Inc	PAG	6

Phibro Animal Health	PAHC	6
Par Pacific Holdings	PARR	35.5
Paycom Software	PAYC	26
Paychex Inc	PAYX	10.5
Peoples United Financial Inc	PBCT	8
PBF Energy	PBF	18
Pitney Bowes Inc	PBI	-1.5
PACCAR Inc	PCAR	7.5
Pacific Gas and Electric Company	PCG	7.5
PotlatchDeltic Corp.	PCH	6.5
Panasonic Corporation	PCRFY	15
Paylocity Holding	PCTY	34
Patterson Companies Inc	PDCO	18.5
PDL BioPharma Inc	PDLI	13.5
Healthpeak Properties	PEAK	-3.5
Public Service Enterprise Group Inc	PEG	6
Penn National Gaming Inc	PENN	22
PepsiCo Inc	PEP	6.5
Petmed Express Inc	PETS	5.5
Pfizer Inc	PFE	10
Principal Financial Group Inc	PFG	5.5
Performance Food	PFGC	16
Provident Financial Services Inc	PFS	5.5
Procter and Gamble Co	PG	9
Progressive Corp.	PGR	15.5
Parker Hannifin Corp	PH	9.5
Koninklijke Philips NV	PHG	14
PulteGroup Inc	PHM	9.5
Polaris Inc.	PII	14
Premier Inc.	PINC	10.5
Piper Sandler Cos.	PIPR	6
Pier 1 Imports Inc	PIR	0.5
Park Aerospace	PKE	2.5
Packaging Corp	PKG	6
PerkinElmer Inc	PKI	11
ParkOhio Holdings Corp	PKOH	12
Posco	PKX	12
Photronics Inc	PLAB	20
Dave & Buster's Ent.	PLAY	11.5
Childrens Place Inc	PLCE	4.5
Prologis	PLD	6.5
Planet Fitness	PLNT	28.5
Douglas Dynamics Inc	PLOW	12.5
Plantronics Inc	PLT	9
Plexus Corp	PLXS	11.5
Philip Morris International Inc	PM	6
PNC Financial Services Group Inc	PNC	8
PNM Resources Inc	PNM	7
Pentair Inc	PNR	6
Pinnacle West Capital Corp	PNW	4
PolyOne Corp.	POL	2.5
Pool Corporation	POOL	12.5
Portland General Electric Company	POR	4.5
Post Holdings Inc	POST	15.5
Paramount Resources	POU.TO	39

Power Integrations Inc	POWI	8
Pilgrims Pride Corp	PPC	8.5
PPG Industries Inc	PPG	6
PPL Corporation	PPL	1.5
Pembina Pipeline	PPL.TO	12.5
PRA Health Sciences	PRAH	15
Perdoceo Education	PRDO	34.5
Perrigo Company Plc Ireland	PRGO	2
Primerica Inc.	PRI	9.5
Primoris Services	PRIM	19.5
Park National Corp	PRK	5.5
Primo Water Corp.	PRMW	17
Party City Holdco	PRTY	7
Prudential Financial Inc	PRU	7
Public Storage	PSA	4.5
PriceSmart	PSMT	3.5
Phillips 66	PSX	10
Phillips 66 Partners	PSXP	14
PVH Corp	PVH	9
Power Financial	PWF.TO	10
Quanta Services Inc	PWR	15.5
PayPal Holdings	PYPL	20
Papa Johns International Inc	PZZA	5.5
Qualcomm Inc	QCOM	10.5
Qiagen	QGEN	18
Qurate Retail	QRTEA	9
Restaurant Brands Int'l	QSR	17
Quad/Graphics Inc.	QUAD	-11
Ryder System Inc	R	5
Ferrari N.V.	RACE	10
Raven Industries Inc	RAVN	14
Ritchie Brothers Auctioneers Inc	RBA	13
Regal Beloit Corp	RBC	8.5
Rogers Communications Inc (Class B)	RCIB.TO	9
Rent A Center Inc	RCII	23
Royal Caribbean Cruises Ltd	RCL	12.5
Royal Dutch Shell Plc (Class B)	RDSB	30
Everest Re Group Ltd	RE	18.5
Resources Connection Inc	RECN	17
Regency Centers Corporation	REG	16
Regeneron Pharmaceuticals Inc	REGN	10
RPC Inc	RES	37.5
Resideo Technologies	REZI	24.5
Regions Financial Corporation	RF	14
Reinsurance Group of America Inc	RGA	8.5
Royal Gold Inc	RGLD	22
Sturm Ruger and Co	RGR	6.5
RH	RH	24
Robert Half International Inc	RHI	9
Ryman Hospitality Properties Inc	RHP	2.5
Transocean Ltd	RIG	43.5
Rio Tinto Plc	RIO	11
Raymond James Financial Inc	RJF	8
Ralph Lauren Corporation	RL	8
Realogy Holdings	RLGY	0.5

RLI Corp	RLI	14.5
Rambus Inc	RMBS	9.5
ResMed Inc	RMD	18
RingCentral Inc.	RNG	25.5
Renaissancere Holdings Ltd	RNR	31.5
Gibraltar Industries Inc	ROCK	18.5
Rogers Corp	ROG	9
Rockwell Automation Inc	ROK	8
Rollins Inc	ROL	13
RBC Bearings Incorporated	ROLL	12
Roper Tech.	ROP	11.5
Ross Stores Inc	ROST	9.5
RPM International Inc	RPM	14.5
Range Resources	RRC	9.5
Red Robin Gourmet Burgers Inc	RRGB	10
Red Rock Resorts	RRR	8
Reliance Steel and Aluminum Co	RS	12.5
Republic Services Inc	RSG	11.5
Raytheon Co	RTN	10
Russel Metals Inc	RUS.TO	5
Rush Enterprises 'A'	RUSHA	14.5
Rexnord Corporation	RXN	19
Royal Bank of Canada	RY.TO	7
Rayonier Advanced Mat.	RYAM	-3
Rayonier Inc	RYN	4.5
Sabre Corp.	SABR	12.5
Sanderson Farms Inc	SAFM	21.5
Sonic Automotive Inc	SAH	10
Science Applications International Corporation	SAIC	9.5
Boston Beer Company Inc	SAM	15
Sanmina Corporation	SANM	10
SAP AE	SAP	9.5
Saputo Inc.	SAP.TO	8
EchoStar Corporation	SATS	5.5
Spirit Airlines Inc	SAVE	12.5
SBA Communications	SBAC	29.5
Sinclair Broadcast Group Inc	SBGI	9
Sally Beauty Holdings Inc	SBH	9.5
Signature Bank	SBNY	9.5
Starbucks Corporation	SBUX	13
Santander Consumer USA	SC	12.5
Southern Copper Corp	SCCO	15
Scholastic Corporation	SCHL	13
Schnitzer Steel Industries Inc	SCHN	10
Charles Schwab Corporation	SCHW	12
Service Corp International Inc	SCI	12.5
Stepan Company	SCL	7.5
Steelcase Inc	SCS	12
Sealed Air	SEE	22.5
SEI Investments Company	SEIC	10.5
Medical Holdings Corporation	SEM	13.5
ServiceMaster Global	SERV	12
Stifel Financial Corp	SF	11
SFL Corp. Ltd	SFL	5
Sprouts Farmers Market	SFM	9.5

Shake Shack	SHAK	24.5
Shenandoah Telecommunications Co	SHEN	19.5
Shell Midstream L.P.	SHLX	12.5
Steven Madden Ltd	SHOO	12.5
Shopify Inc.	SHOP	92.5
Sherwin Williams	SHW	10.5
Siemens AG	SIEGY	10.5
Signet Jewelers Ltd	SIG	-2.5
Selective Insurance Group Inc	SIGI	8.5
Sirius XM Holdings Inc	SIRI	26.5
SVB Fin'l Group	SIVB	19.5
Six Flags Entertainment Corporation	SIX	7.5
South Jersey Industries Inc	SJI	10.5
JM Smucker Company	SJM	3.5
Shaw Communications Inc (Class B)	SJRB.TO	21
SJW Group	SJW	7
Skechers USA	SKX	14.5
SkyWest Inc	SKYW	14
Silicon Labs	SLAB	16.5
Schlumberger Ltd	SLB	15.5
U.S. Silica Holdings	SLCA	0.5
Sun Life Fin'l Svcs.	SLF.TO	8
SL Green Realty Corporation	SLG	5.5
Silgan Holdings Inc	SLGN	8.5
SLM Corporation	SLM	19
Scotts Miracle Gro Company	SMG	8
Standard Motor Products Inc	SMP	10.5
Stein Mart Inc	SMRT	8.5
Semtech Corp	SMTC	9.5
Snap on Inc	SNA	6
Sleep Number Corp.	SNBR	21
SNC-Lavalin Group	SNC.TO	9.5
Sony Corporation	SNE	12.5
Synopsys Inc	SNPS	8
Synovus Financial Corporation New	SNV	15
Synnex Corp	SNX	9.5
Sanofi	SNY	5.5
Southern Co	SO	3.5
Sohu.com Ltd. ADS	SOHU	0
Sonoco Products	SON	7
Spartan Motors Inc	SPAR	20
Simon Property Group Inc	SPG	4.5
S&P Global	SPGI	13
Suburban Propane	SPH	20.5
Telecom Corp of New Zealand Ltd	SPKKY	6.5
Splunk Inc	SPLK	0
Spirit Aerosystems Holdings Inc	SPR	10.5
SpartanNash Company	SPTN	5
SPX Corp	SPXC	17
Spire Inc.	SR	5.5
Stericycle Inc	SRCL	4.5
SurModics Inc	SRDX	29.5
Sempra Energy	SRE	11
Stoneridge Inc.	SRI	3.5
Simpson Manufacturing Co Inc	SSD	12.5

Stage Stores Inc	SSI	2.5
SS&C Techn. Hldgs	SSNC	14
EW Scripps	SSP	28.5
Sensata Techn. plc	ST	9
Extended Stay America	STAY	27.5
STERIS plc	STE	10
Steel Dynamics Inc	STLD	8
STMicroelectronics	STM	17.5
Stantec Inc.	STN.TO	9.5
Strategic Education	STRA	28
State Street Corporation	STT	5.5
Seagate Technology	STX	4
Constellation Brands	STZ	8.5
Suncor Energy Inc	SU.TO	21
Summit Materials	SUM	23
Superior Industries International	SUP	10.5
Service Properties	SVC	7.5
Stanley Black and Decker Inc	SWK	9
Skyworks Solutions Inc	SWKS	8
Schweitzer Mauduit International Inc	SWM	6.5
Southwestern Energy	SWN	11
Southwest Gas	SWX	9
Standex International Corp	SXI	6
Sensient Technologies Corp	SXT	6.5
Synchrony Financial	SYF	9.5
Stryker Corp	SYK	13
Synaptics Incorporated	SYNA	17.5
Sysco Corp	SYI	10.5
AT&T	T	5.5
Telus Corp	T.TO	7.5
Molson Coors Beverage	TAP	2.5
TrueBlue Inc.	TBI	10
Trip.com Ltd.	TCOM	59.5
Container Store Group	TCS	26
Toronto Dominion Bank	TD.TO	9
Teradata Corporation	TDC	12.5
Transdigm Group Incorporated	TDG	11.5
Telephone and Data Systems Inc New	TDS	7.5
Teledyne Technologies	TDY	13.5
Tech Data	TECD	12
Bio-Techne Corp.	TECH	14.5
Teck Resources 'B'	TECKB.TO	12
Telefonica SA	TEF	5.5
TE Connectivity Ltd	TEL	6.5
Tenneco Inc	TEN	-0.5
Teradyne Inc	TER	10
Teva Pharmaceutical Industries Ltd	TEVA	-5
Terex Corp	TEX	13
Truist Fin'l	TFC	10
Teleflex Inc	TFX	15
Tredegar Corp	TG	13
Triumph Group Inc	TGI	0
TEGNA Inc.	TGNA	7.5
Target Corp	TGT	9.5
Tenet Healthcare Corporation New	THC	22

Hanover Insurance Group Inc	THG	13.5
ThermoGenesis Holdings Inc.	THMO	10.5
Thor Industries	THO	8.5
Thermon Group	THR	24.5
Gentherm Inc	THRM	10.5
Treehouse Foods Inc	THS	4.5
Tiffany and Co	TIF	10.5
Millicom Int'l Cellular	TIGO	7
Toromont Inds.	TIH.TO	14
Interface Inc	TILE	12.5
TJX Companies Inc	TJX	14
Timken Co	TKR	12.5
Tailored Brands	TLRD	-4
Tilly's Inc.	TLYS	12
Toyota Motor Corporation	TM	5.5
Taylor Morrison Home Corporation	TMHC	12.5
Thermo Fisher Scientific Inc	TMO	10
T Mobile US	TMUS	18.5
Tennant Co	TNC	15.5
TriNet Group	TNET	16.5
Toll Brothers	TOL	5
Total S.A. ADR	TOT	14
Tutor Perini	TPC	10
TRI Pointe Group	TPH	13.5
TPI Composites	TPIC	26.5
Tapestry Inc.	TPR	10.5
Tempur Sealy International Inc	TPX	9.5
Tootsie Roll	TR	5.5
Trex Company Inc	TREX	16.5
Thomson Reuters Corp	TRI.TO	12.5
TripAdvisor Inc	TRIP	20
Trimble Inc.	TRMB	22
Trinity Industries Inc	TRN	4.5
T Rowe Price Group Inc	TROW	10
TC Energy Corp.	TRP	17
Trimas Corporation	TRS	10
The Travelers Companies Inc	TRV	9
Tenaris S.A. ADS	TS	23
Tractor Supply Co	TSCO	11.5
Trinseo SA	TSE	22.5
Tower Semiconductor	TSEM	6
Taiwan Semiconductor Manufacturing Co Ltd	TSM	11.5
Tyson Foods	TSN	8
Toro Co	TTC	11
Trade Desk (The)	TTD	38
TTEC Holdings	TTEC	15
Tetra Tech	TTEK	12.5
Tata Motors Ltd	TTM	26.5
TTM Technologies	TTMI	19
Tile Shop Holdings Inc	TTSH	12.5
TakeTwo Interactive Software Inc	TTWO	23.5
Tupperware Brands	TUP	7.5
Tivity Health	TVTY	9
Hostess Brands	TWNK	10.5
Texas Instruments Incorporated	TXN	6

Texas Roadhouse Inc	TXRH	14.5
Textron Inc	TXT	13
Tyler Technologies	TYL	12.5
Under Armour 'A'	UAA	18
United Airlines Hldgs.	UAL	8.5
UDR Inc	UDR	5.5
Universal Electronics	UEIC	34.5
Unifi Inc New	UFI	-3
Universal Forest Products Inc	UFPI	12
Domtar Corporation	UFS	10
UGI Corp	UGI	10.5
AMERCO	UHAL	4.5
Universal Health 'B'	UHS	11
Ubiquiti Inc.	UI	15.5
Unilever PLC	UL	10
Ulta Beauty	ULTA	16
UniFirst Corp	UNF	7.5
United Natural Foods	UNFI	1
UnitedHealth Group	UNH	14
Unum Group	UNM	9
Union Pacific Corp	UNP	14.5
United Parcel Service	UPS	8.5
Urban Outfitters	URBN	14
United Rentals	URI	14.5
US Bancorp	USB	6
US Foods Hldg.	USFD	14.5
US Cellular Corp	USM	15
USANA Health Sciences	USNA	3.5
United Therapeutics	UTHR	-1
United Technologies Corporation	UTX	9
Universal Corp	UVV	6.5
Visa Inc	V	15
Marriott Vacations	VAC	13.5
Vale S.A. ADR	VALE	11
Varian Medical System	VAR	10.5
Visteon Corporation	VC	15.5
Veeva Systems	VEEV	22.5
V F Corp	VFC	7
Vonage Holdings Corp	VG	20.5
ViacomCBS Inc.	VIAC	12
Viavi Solutions	VIAV	14.5
Meridian Bioscience	VIVO	2
Village Super Market Inc	VLGEA	8
Valero Energy Corporation	VLO	11.5
Vulcan Materials	VMC	14.5
Valmont Industries	VMI	11
Vmware Inc	VMW	11
Vornado Realty Trust	VNO	-1.5
Vodafone Group	VOD	13
Voya Financial	VOYA	50
Vera Bradley Inc	VRA	19
Verisk Analytics Inc	VRSK	9.5
VeriSign Inc	VRSN	11
Vertex Pharmaceuticals Inc	VRTX	50
Vishay Intertechnology	VSH	12

Ventas Inc	VTR	4
Viad Corp New	VVI	11
Valvoline Inc.	VVV	8.5
Verizon Communications Inc	VZ	4
Wabtec Corp	WAB	13.5
Washington Federal Inc	WAFD	9.5
Waters Corp	WAT	6
Walgreens Boots	WBA	9
Wabco Holdings Inc	WBC	9
Webster Financial Corporation	WBS	11.5
Welbilt Inc.	WBT	8.5
WESCO International Inc	WCC	7.5
Waste Connections	WCN	15.5
Western Digital Corporation	WDC	1
WD 40 Co	WDFC	8.5
WEC Energy Group	WEC	6
Welltower Inc.	WELL	10.5
Wendys Company	WEN	18
Werner Enterprises Inc	WERN	11.5
Western Midstream Part.	WES	7
WEX Inc	WEX	13
Wells Fargo and Company	WFC	5
West Fraser Timber	WFT.TO	2
Winnebago Industries Inc	WGO	13.5
Whirlpool Corp	WHR	6.5
Wingstop Inc.	WING	17
Westlake Chemical Corp	WLK	9.5
Williams Industrial Svcs Grp	WLMS	12
Waste Management	WM	8.5
Williams Companies Inc	WMB	20
Wright Medical N.V.	WMGI	4.5
Weis Markets	WMK	5
Advanced Drainage Systems Inc	WMS	6.5
Walmart Inc.	WMT	7.5
George Weston Ltd	WN.TO	3
Wabash National	WNC	10.5
Worthington Industries	WOR	12
WP Carey Inc	WPC	-0.5
Wheaton Precious Met.	WPM	13
WPP PLC	WPP	7.5
WR Berkley Corp	WRB	12
Washington REIT	WRE	-1
Weingarten Realty Investors	WRI	-8.5
WestRock Co.	WRK	8
Williams Sonoma	WSM	7
Watsco Inc	WSO	9
West Pharmaceutical Services Inc	WST	16
Wintrust Financial Corporation	WTFC	7.5
Aqua America Inc	WTR	8
Watts Water Technologies Inc	WTS	10.5
Western Union Company	WU	5
WW International	WW	7.5
Woodward Inc	WWD	13.5
World Wrestling Entertainment	WWE	33.5
Wolverine World Wide	WWW	13

Weyerhaeuser Company	WY	15
Wyndham Destinations	WYND	7.5
Wynn Resorts Ltd	WYNN	27
US Steel Corp	X	20
Cimarex Energy Co	XEC	8.5
Xcel Energy Inc	XEL	5.5
Xilinx Inc	XLNX	8
Exxon Mobil Corp	XOM	11
Xperi Corp.	XPER	7.5
XPO Logistics	XPO	26.5
Dentsply Sirona	XRAY	4.5
Xerox Holdings	XRX	12.5
Xylem Inc	XYL	14
Alleghany Corp	Y	24.5
York Water Company	YORW	9.5
Yum Brands Inc	YUM	12
Yum China Holdings	YUMC	16
Zayo Group Holdings Inc	ZAYO	26.5
Zimmer Biomet Hldgs.	ZBH	4.5
Zebra Technologies Corp	ZBRA	15.5
Zions Bancorporation	ZION	9.5
Zoetis Inc	ZTS	13.5
Zumiez Inc	ZUMZ	13
Zovio Inc.	ZVO	9.5

S&P 500
3,225.52
-58.14 (-1.77%)

Dow 30
28,256.03
-603.41 (-2.09%)

Enbridge Inc. (ENB)

NYSE - NYSE Delayed Price. Currency in USD

☆ Add to watchlist

2W ↑ 10W ↑ 9M ↑

Quote Lookup

40.67 -0.59 (-1.43%) **37.90** -2.77 (-6.81%)

At close: 4:03PM EST

After hours: 5:41PM EST

Summary Company Outlook Chart Conversations Statistics Historical Data Profile Financials **Analysis** Options Holders Sustainability

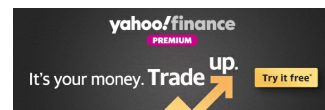
Earnings Estimate				
Currency in USD				
	Current Qtr. (Dec 2017)	Next Qtr. (Mar 2018)	Current Year (2017)	Next Year (2018)
No. of Analysts	9	7	9	10
Avg. Estimate	0.44	0.49	1.47	1.84
Low Estimate	0.37	0.4	1.28	1.47
High Estimate	0.5	0.59	1.58	2.09
Year Ago EPS	0.46	0.46	1.84	1.47

Revenue Estimate				
Currency in USD				
	Current Qtr. (Dec 2017)	Next Qtr. (Mar 2018)	Current Year (2017)	Next Year (2018)
No. of Analysts	5	4	8	7
Avg. Estimate	8.68B	9.82B	34.4B	37.21B
Low Estimate	7.66B	8.43B	32.34B	31.84B
High Estimate	9.72B	10.87B	41.21B	49.25B
Year Ago Sales	7.61B	9.08B	28.16B	34.4B
Sales Growth (year/est)	14.00%	8.20%	22.20%	8.20%

Earnings History				
	12/30/2016	3/30/2017	6/29/2017	9/29/2017
EPS Est.	0.48	0.48	0.37	0.37
EPS Actual	0.46	0.46	0.33	0.31
Difference	-0.02	-0.02	-0.04	-0.06
Surprise %	-4.20%	-4.20%	-10.80%	-16.20%

EPS Trend				
	Current Qtr. (Dec 2017)	Next Qtr. (Mar 2018)	Current Year (2017)	Next Year (2018)
Current Estimate	0.44	0.49	1.47	1.84
7 Days Ago	0.45	0.49	1.48	1.85
30 Days Ago	0.45	0.5	1.52	1.82
60 Days Ago	0.43	0.5	1.49	1.83
90 Days Ago	0.46	0.54	1.6	2.01

EPS Revisions				
	Current Qtr. (Dec 2017)	Next Qtr. (Mar 2018)	Current Year (2017)	Next Year (2018)
Up Last 7 Days	N/A	2	1	2
Up Last 30 Days	2	2	1	4



Advertise With Us

Data Disclaimer Help Suggestions
Privacy Dashboard
Privacy (Updated) About Our Ads Terms
(Updated) Sitemap

© 2020 Verizon Media. All rights reserved.

EPS Revisions	Current Qtr. (Dec 2017)	Next Qtr. (Mar 2018)	Current Year (2017)	Next Year (2018)
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	2	N/A	1	N/A

Growth Estimates	ENB	Industry	Sector	S&P500
Current Qtr.	-4.30%	N/A	N/A	0.01
Next Qtr.	6.50%	N/A	N/A	0.09
Current Year	-20.10%	N/A	N/A	0.00
Next Year	25.20%	N/A	N/A	0.14
Next 5 Years (per annum)	5.49%	N/A	N/A	0.08
Past 5 Years (per annum)	4.27%	N/A	N/A	N/A

S&P 500

3,225.52

-58.14 (-1.77%)

Dow 30

28,256.03

-603.41 (-2.09%)

Kinder Morgan, Inc. (KMI)

NYSE - NYSE Delayed Price. Currency in USD

☆ Add to watchlist

2W ↓ 10W ↑ 9M ↑

Quote Lookup

20.87 -0.55 (-2.57%) **20.87** 0.00 (0.00%)

At close: 4:01PMEST

After hours: 5:29PMEST

Summary Company Outlook Chart Conversations Statistics Historical Data Profile Financials **Analysis** Options Holders Sustainability

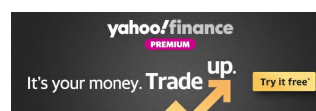
Earnings Estimate				
	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	14	14	17	19
Avg. Estimate	0.26	0.24	1.01	1.03
Low Estimate	0.21	0.21	0.83	0.84
High Estimate	0.3	0.27	1.09	1.15
Year Ago EPS	0.25	0.22	0.95	1.01

Revenue Estimate				
	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	8	8	12	12
Avg. Estimate	3.42B	3.31B	13.9B	14.12B
Low Estimate	3.29B	3.19B	13.32B	13.53B
High Estimate	3.61B	3.83B	15.17B	15.62B
Year Ago Sales	3.66B	N/A	13.21B	13.9B
Sales Growth (year/est)	-6.40%	N/A	5.20%	1.60%

Earnings History				
	3/30/2019	6/29/2019	9/29/2019	12/30/2019
EPS Est.	0.24	0.24	0.24	0.26
EPS Actual	0.25	0.22	0.22	0.26
Difference	0.01	-0.02	-0.02	0
Surprise %	4.20%	-8.30%	-8.30%	0.00%

EPS Trend				
	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	0.26	0.24	1.01	1.03
7 Days Ago	0.27	0.26	1.06	1.04
30 Days Ago	0.26	0.24	1.04	1.08
60 Days Ago	0.25	0.24	1.03	1.06
90 Days Ago	0.25	0.24	1.03	1.08

EPS Revisions				
	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	1	1	2	1
Up Last 30 Days	3	2	7	3



Advertise With Us

Data Disclaimer Help Suggestions
Privacy Dashboard
Privacy (Updated) About Our Ads Terms
(Updated) Sitemap

© 2020 Verizon Media. All rights reserved.

EPS Revisions	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	3	4	6	6

Growth Estimates	KMI	Industry	Sector	S&P500
Current Qtr.	4.00%	N/A	N/A	0.01
Next Qtr.	9.10%	N/A	N/A	0.09
Current Year	6.30%	N/A	N/A	0.00
Next Year	2.00%	N/A	N/A	0.14
Next 5 Years (per annum)	8.05%	N/A	N/A	0.08
Past 5 Years (per annum)	1.40%	N/A	N/A	N/A

S&P 500
3,225.52
-58.14 (-1.77%)

Dow 30
28,256.03
-603.41 (-2.09%)

TC PipeLines, LP (TCP)
NYSE - NYSE Delayed Price. Currency in USD

☆ Add to watchlist

2W ↓ 10W ↑ 9M ↑

Quote Lookup

39.92 -1.40 (-3.39%) **39.92** 0.00 (0.00%)

At close: 4:02PMEST

After hours: 4:23PMEST

Summary Company Outlook Chart Conversations Statistics Historical Data Profile Financials **Analysis** Options Holders Sustainability

Currency in USD

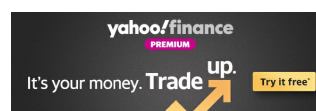
Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	7	6	5	7
Avg. Estimate	0.94	1.24	3.72	3.77
Low Estimate	0.86	1.04	3.65	3.63
High Estimate	1.05	1.33	3.84	4.12
Year Ago EPS	1.06	1.28	4.18	3.72

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	2	2	2	2
Avg. Estimate	150.66M	166.59M	564.66M	566.7M
Low Estimate	150.46M	163.94M	564.46M	560.64M
High Estimate	150.86M	169.25M	564.86M	572.76M
Year Ago Sales	220M	132.64M	549M	564.66M
Sales Growth (year/est)	-31.50%	25.60%	2.90%	0.40%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.92	1.12	0.83	0.73
EPS Actual	1.06	1.28	0.75	0.76
Difference	0.14	0.16	-0.08	0.03
Surprise %	15.20%	14.30%	-9.60%	4.10%

EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	0.94	1.24	3.72	3.77
7 Days Ago	0.94	1.24	3.72	3.77
30 Days Ago	0.94	1.24	3.72	3.78
60 Days Ago	0.94	1.24	3.72	3.78
90 Days Ago	0.89	1.22	3.69	3.68

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	1	1	1	1



Advertise With Us

Data Disclaimer Help Suggestions
Privacy Dashboard
Privacy (Updated) About Our Ads Terms
(Updated) Sitemap

© 2020 Verizon Media. All rights reserved.

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	TCP	Industry	Sector	S&P500
Current Qtr.	-11.30%	N/A	N/A	0.01
Next Qtr.	-3.10%	N/A	N/A	0.09
Current Year	-11.00%	N/A	N/A	0.00
Next Year	1.30%	N/A	N/A	0.14
Next 5 Years (per annum)	9.30%	N/A	N/A	0.08
Past 5 Years (per annum)	7.54%	N/A	N/A	N/A

S&P 500
3,225.52
-58.14 (-1.77%)

Dow 30
28,256.03
-603.41 (-2.09%)

TC Energy Corporation (TRP)
NYSE - NYSE Delayed Price. Currency in USD

★ Add to watchlist

2W↓ 10W↑ 9M↑

Quote Lookup

54.82 -0.36 (-0.65%) **54.84** +0.02 (0.04%)
At close: 4:02PMEST After hours: 4:34PMEST

Summary Company Outlook Chart Conversations Statistics Historical Data Profile Financials **Analysis** Options Holders Sustainability

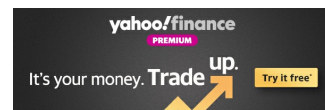
Earnings Estimate				
	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	7	6	10	13
Avg. Estimate	0.67	0.57	2.51	2.88
Low Estimate	0.6	0.53	2.39	2.35
High Estimate	0.75	0.6	2.75	3.79
Year Ago EPS	0.64	0.6	2.43	2.51

Revenue Estimate				
	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	3	3	5	7
Avg. Estimate	2.38B	2.26B	9.3B	12.16B
Low Estimate	2.13B	2B	7.77B	8.89B
High Estimate	2.75B	2.63B	11.1B	17.96B
Year Ago Sales	2.67B	2.53B	10.59B	9.3B
Sales Growth (year/est)	-10.90%	-10.60%	-12.20%	30.80%

Earnings History				
	3/30/2017	6/29/2017	9/29/2017	12/30/2017
EPS Est.	0.58	0.53	0.55	0.62
EPS Actual	0.64	0.6	0.55	0.65
Difference	0.06	0.07	0	0.03
Surprise %	10.30%	13.20%	0.00%	4.80%

EPS Trend				
	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	0.67	0.57	2.51	2.88
7 Days Ago	0.7	0.61	2.62	2.89
30 Days Ago	0.7	0.61	2.63	2.92
60 Days Ago	0.7	0.62	2.6	2.88
90 Days Ago	0.69	0.61	2.54	2.8

EPS Revisions				
	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	1	2	5	6
Up Last 30 Days	3	4	7	7



Advertise With Us

Data Disclaimer Help Suggestions
Privacy Dashboard
Privacy (Updated) About Our Ads Terms
(Updated) Sitemap

© 2020 Verizon Media. All rights reserved.

EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	2	2	4	1

Growth Estimates	TRP	Industry	Sector	S&P500
Current Qtr.	4.70%	N/A	N/A	0.01
Next Qtr.	-5.00%	N/A	N/A	0.09
Current Year	3.30%	N/A	N/A	0.00
Next Year	14.70%	N/A	N/A	0.14
Next 5 Years (per annum)	5.81%	N/A	N/A	0.08
Past 5 Years (per annum)	9.18%	N/A	N/A	N/A

S&P 500
3,225.52
-58.14 (-1.77%)

Dow 30
28,256.03
-603.41 (-2.09%)

The Williams Companies, Inc. (WMB)
NYSE - NYSE Delayed Price. Currency in USD

Add to watchlist

2W → 10W ↑ 9M ↑

Quote Lookup

20.69 -0.58 (-2.73%) **20.69** 0.00 (0.00%)
At close: 4:02PMEST After hours: 5:28PMEST

Summary Company Outlook Chart Conversations Statistics Historical Data Profile Financials **Analysis** Options Holders Sustainability

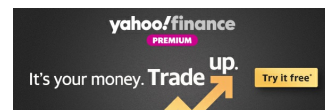
Earnings Estimate				
	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	13	13	8	18
Avg. Estimate	0.24	0.25	0.95	1.06
Low Estimate	0.19	0.2	0.83	0.79
High Estimate	0.27	0.35	1.01	1.54
Year Ago EPS	0.19	0.22	0.79	0.95

Revenue Estimate				
	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	6	6	11	11
Avg. Estimate	2.1B	2.11B	8.23B	8.58B
Low Estimate	2.07B	2.07B	7.93B	7.54B
High Estimate	2.15B	2.17B	8.5B	9B
Year Ago Sales	2.2B	2.25B	8.69B	8.23B
Sales Growth (year/est)	-4.50%	-6.20%	-5.30%	4.20%

Earnings History				
	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.24	0.22	0.22	0.25
EPS Actual	0.19	0.22	0.26	0.26
Difference	-0.05	0	0.04	0.01
Surprise %	-20.80%	0.00%	18.20%	4.00%

EPS Trend				
	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	0.24	0.25	0.95	1.06
7 Days Ago	0.24	0.25	0.95	1.06
30 Days Ago	0.24	0.26	0.96	1.05
60 Days Ago	0.26	0.25	0.95	1.1
90 Days Ago	0.27	0.26	0.94	1.11

EPS Revisions				
	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	2	1	2	4



Advertise With Us

Data Disclaimer Help Suggestions
Privacy Dashboard
Privacy (Updated) About Our Ads Terms
(Updated) Sitemap

© 2020 Verizon Media. All rights reserved.

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	WVB	Industry	Sector	S&P500
Current Qtr.	26.30%	N/A	N/A	0.01
Next Qtr.	13.60%	N/A	N/A	0.09
Current Year	20.30%	N/A	N/A	0.00
Next Year	11.60%	N/A	N/A	0.14
Next 5 Years (per annum)	9.75%	N/A	N/A	0.08
Past 5 Years (per annum)	18.23%	N/A	N/A	N/A

S&P 500

3,225.52

-58.14 (-1.77%)

Dow 30

28,256.03

-603.41 (-2.09%)

Enable Midstream Partners, LP (ENBL)

NYSE - NYSE Delayed Price. Currency in USD

☆ Add to watchlist

2W → 10W ↑ 9M ↑

Quote Lookup

9.40 -0.35 (-3.59%) **9.40** 0.00 (0.00%)

At close: 4:02PM EST

After hours: 4:23PM EST

Summary Company Outlook Chart Conversations Statistics Historical Data Profile Financials **Analysis** Options Holders Sustainability

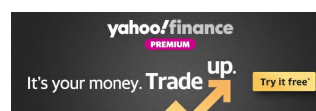
Earnings Estimate				
Currency in USD				
	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	6	5	7	7
Avg. Estimate	0.25	0.24	1.05	0.99
Low Estimate	0.22	0.2	1.01	0.91
High Estimate	0.28	0.28	1.1	1.1
Year Ago EPS	0.38	0.26	1.11	1.05

Revenue Estimate				
Currency in USD				
	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	4	2	5	4
Avg. Estimate	845.91M	866.15M	3.14B	3.45B
Low Estimate	772M	829.31M	3B	3.21B
High Estimate	898M	903M	3.39B	3.66B
Year Ago Sales	950M	N/A	3.43B	3.14B
Sales Growth (year/est)	-11.00%	N/A	-8.60%	9.80%

Earnings History				
	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.27	0.25	0.24	0.27
EPS Actual	0.38	0.26	0.26	0.28
Difference	0.11	0.01	0.02	0.01
Surprise %	40.70%	4.00%	8.30%	3.70%

EPS Trend				
	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	0.25	0.24	1.05	0.99
7 Days Ago	0.25	0.24	1.05	0.99
30 Days Ago	0.24	0.24	1.05	0.99
60 Days Ago	0.24	0.26	1.05	0.99
90 Days Ago	0.23	0.27	1.05	1

EPS Revisions				
	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	2	N/A	2	2



Advertise With Us

Data Disclaimer Help Suggestions
Privacy Dashboard
Privacy (Updated) About Our Ads Terms
(Updated) Sitemap

© 2020 Verizon Media. All rights reserved.

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A
Growth Estimates	ENBL	Industry	Sector	S&P500
Current Qtr.	-34.20%	N/A	N/A	0.01
Next Qtr.	-7.70%	N/A	N/A	0.09
Current Year	-5.40%	N/A	N/A	0.00
Next Year	-5.70%	N/A	N/A	0.14
Next 5 Years (per annum)	-4.50%	N/A	N/A	0.08
Past 5 Years (per annum)	4.60%	N/A	N/A	N/A

S&P 500

3,225.52

-58.14 (-1.77%)

Dow 30

28,256.03

-603.41 (-2.09%)

Enterprise Products Partners L.P. (EPD)

NYSE - NYSE Delayed Price. Currency in USD

★ Add to watchlist

2W↑ 10W↑ 9M↑

Quote Lookup

25.77 -0.76 (-2.86%) **26.15** +0.38 (1.47%)

At close: 4:03PMEST

After hours: 5:59PMEST

Summary Company Outlook Chart Conversations Statistics Historical Data Profile Financials **Analysis** Options Holders Sustainability

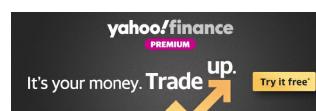
Earnings Estimate				
	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	17	17	24	20
Avg. Estimate	0.52	0.55	2.22	2.3
Low Estimate	0.47	0.48	1.94	2.1
High Estimate	0.57	0.59	2.37	2.49
Year Ago EPS	0.57	0.55	2.09	2.22

Revenue Estimate				
	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	6	6	11	7
Avg. Estimate	8.67B	8.66B	36.08B	36.53B
Low Estimate	8.23B	8.33B	33.36B	34.03B
High Estimate	9.58B	9.74B	42.34B	44.11B
Year Ago Sales	8.54B	N/A	32.79B	36.08B
Sales Growth (year/est)	1.50%	N/A	10.00%	1.30%

Earnings History				
	3/30/2019	6/29/2019	9/29/2019	12/30/2019
EPS Est.	0.48	0.51	0.53	0.54
EPS Actual	0.57	0.55	0.46	0.5
Difference	0.09	0.04	-0.07	-0.04
Surprise %	18.70%	7.80%	-13.20%	-7.40%

EPS Trend				
	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	0.52	0.55	2.22	2.3
7 Days Ago	0.54	0.56	2.25	2.29
30 Days Ago	0.53	0.55	2.22	2.31
60 Days Ago	0.54	0.55	2.24	2.32
90 Days Ago	0.54	0.55	2.24	2.32

EPS Revisions				
	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	N/A	N/A	2	N/A
Up Last 30 Days	3	2	5	2



Advertise With Us

Data Disclaimer Help Suggestions
Privacy Dashboard
Privacy (Updated) About Our Ads Terms
(Updated) Sitemap

© 2020 Verizon Media. All rights reserved.

EPS Revisions	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	1	2	N/A

Growth Estimates	EPD	Industry	Sector	S&P500
Current Qtr.	-8.80%	N/A	N/A	0.01
Next Qtr.	N/A	N/A	N/A	0.09
Current Year	6.20%	N/A	N/A	0.00
Next Year	3.60%	N/A	N/A	0.14
Next 5 Years (per annum)	7.96%	N/A	N/A	0.08
Past 5 Years (per annum)	11.37%	N/A	N/A	N/A

S&P 500
3,225.52
-58.14 (-1.77%)

Dow 30
28,256.03
-603.41 (-2.09%)

EQM Midstream Partners, LP (EQM)

NYSE - NYSE Delayed Price. Currency in USD

★ Add to watchlist

2W↑ 10W↑ 9M↑

Quote Lookup

23.15 -0.45 (-1.91%) **23.59** +0.44 (1.90%)

At close: 4:02PMEST

After hours: 4:54PMEST

Summary Company Outlook Chart Conversations Statistics Historical Data Profile Financials **Analysis** Options Holders Sustainability

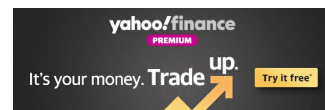
Currency in USD				
Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	12	12	5	12
Avg. Estimate	1.15	1.18	4.52	4.56
Low Estimate	0.94	1	3.24	3.79
High Estimate	1.43	1.52	5.06	5.92
Year Ago EPS	1.28	1.56	5.07	4.52

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	7	6	8	8
Avg. Estimate	419.67M	422.17M	1.62B	1.69B
Low Estimate	411.54M	413.09M	1.62B	1.64B
High Estimate	432.1M	428M	1.64B	1.78B
Year Ago Sales	384.79M	389.78M	1.5B	1.62B
Sales Growth (year/est)	9.10%	8.30%	8.70%	4.10%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	1.3	1.14	1.03	1.07
EPS Actual	1.28	1.56	0.62	1.31
Difference	-0.02	0.42	-0.41	0.24
Surprise %	-1.50%	36.80%	-39.80%	22.40%

EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	1.15	1.18	4.52	4.56
7 Days Ago	1.15	1.18	4.52	4.55
30 Days Ago	1.15	1.18	4.52	4.54
60 Days Ago	1.15	1.18	4.44	4.51
90 Days Ago	1.12	1.14	4.63	4.33

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	N/A	N/A	N/A	1
Up Last 30 Days	1	1	1	2



Advertise With Us

Data Disclaimer Help Suggestions
Privacy Dashboard
Privacy (Updated) About Our Ads Terms
(Updated) Sitemap

© 2020 Verizon Media. All rights reserved.

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	1	1	1	1

Growth Estimates	EQM	Industry	Sector	S&P500
Current Qtr.	-10.20%	N/A	N/A	0.01
Next Qtr.	-24.40%	N/A	N/A	0.09
Current Year	-10.80%	N/A	N/A	0.00
Next Year	0.90%	N/A	N/A	0.14
Next 5 Years (per annum)	-2.12%	N/A	N/A	0.08
Past 5 Years (per annum)	3.49%	N/A	N/A	N/A

S&P 500
3,225.52
-58.14 (-1.77%)

Dow 30
28,256.03
-603.41 (-2.09%)

Energy Transfer LP (ET)
NYSE - NYSE Delayed Price. Currency in USD

☆ Add to watchlist

2W ↑ 10W ↑ 9M ↑

Quote Lookup

12.59 -0.19 (-1.49%) **12.62** +0.03 (0.24%)
At close: 4:02PMEST After hours: 5:19PMEST

Summary Company Outlook Chart Conversations Statistics Historical Data Profile Financials **Analysis** Options Holders Sustainability

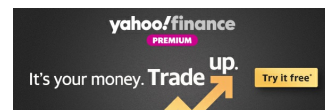
Earnings Estimate				
	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	16	13	14	18
Avg. Estimate	0.36	0.37	1.41	1.53
Low Estimate	0.3	0.3	1.27	1.16
High Estimate	0.45	0.48	1.86	2.1
Year Ago EPS	0.27	0.34	1.21	1.41

Revenue Estimate				
	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	9	7	11	11
Avg. Estimate	13.05B	13.72B	55.22B	58.1B
Low Estimate	10.11B	10.09B	50.93B	44.08B
High Estimate	15.01B	15.79B	63.94B	68.41B
Year Ago Sales	13.57B	14.55B	54.09B	55.22B
Sales Growth (year/est)	-3.80%	-5.70%	2.10%	5.20%

Earnings History				
	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.34	0.4	0.37	0.37
EPS Actual	0.27	0.34	0.33	0.32
Difference	-0.07	-0.06	-0.04	-0.05
Surprise %	-20.60%	-15.00%	-10.80%	-13.50%

EPS Trend				
	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	0.36	0.37	1.41	1.53
7 Days Ago	0.36	0.37	1.41	1.57
30 Days Ago	0.36	0.37	1.42	1.55
60 Days Ago	0.36	0.36	1.42	1.52
90 Days Ago	0.36	0.36	1.45	1.53

EPS Revisions				
	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	N/A	1	N/A	N/A
Up Last 30 Days	3	5	3	5



Advertise With Us

Data Disclaimer Help Suggestions
Privacy Dashboard
Privacy (Updated) About Our Ads Terms
(Updated) Sitemap

© 2020 Verizon Media. All rights reserved.

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	ET	Industry	Sector	S&P500
Current Qtr.	33.30%	N/A	N/A	0.01
Next Qtr.	8.80%	N/A	N/A	0.09
Current Year	16.50%	N/A	N/A	0.00
Next Year	8.50%	N/A	N/A	0.14
Next 5 Years (per annum)	16.50%	N/A	N/A	0.08
Past 5 Years (per annum)	4.44%	N/A	N/A	N/A

S&P 500

3,225.52

-58.14 (-1.77%)

Dow 30

28,256.03

-603.41 (-2.09%)

Nasdaq

9,150.94

-148.00 (-1.59%)

National Fuel Gas Company (NFG)

NYSE - NYSE Delayed Price. Currency in USD

Add to watchlist

2W↑ 10W↑ 9M↑

Quote Lookup

43.19 +1.20 (+2.86%) **43.19** 0.00 (0.00%)

At close: 4:02PMEST

After hours: 4:41PMEST

Summary Company Outlook Chart Conversations Statistics Historical Data Profile Financials Analysis Options Holders Sustainability

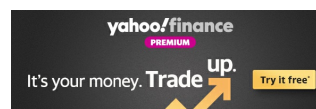
Earnings Estimate				
	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	5	5	6	5
Avg. Estimate	1.03	0.63	3.07	3.01
Low Estimate	0.92	0.56	2.88	2.83
High Estimate	1.21	0.73	3.46	3.18
Year Ago EPS	1.07	0.71	3.45	3.07

Revenue Estimate				
	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	2	2	2	1
Avg. Estimate	597.59M	388.05M	1.83B	1.78B
Low Estimate	556.8M	356.5M	1.71B	1.78B
High Estimate	638.38M	419.61M	1.96B	1.78B
Year Ago Sales	N/A	N/A	1.69B	1.83B
Sales Growth (year/est)	N/A	N/A	8.20%	-2.90%

Earnings History				
	3/30/2019	6/29/2019	9/29/2019	12/30/2019
EPS Est.	1.17	0.68	0.54	0.97
EPS Actual	1.07	0.71	0.54	1.01
Difference	-0.1	0.03	0	0.04
Surprise %	-8.50%	4.40%	0.00%	4.10%

EPS Trend				
	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	1.03	0.63	3.07	3.01
7 Days Ago	1.04	0.63	3.09	3.04
30 Days Ago	1.1	0.62	3.13	3.05
60 Days Ago	1.12	0.64	3.17	3.17
90 Days Ago	1.2	0.69	3.36	3.12

EPS Revisions				
	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	N/A	1	N/A	N/A
Up Last 30 Days	1	2	1	1



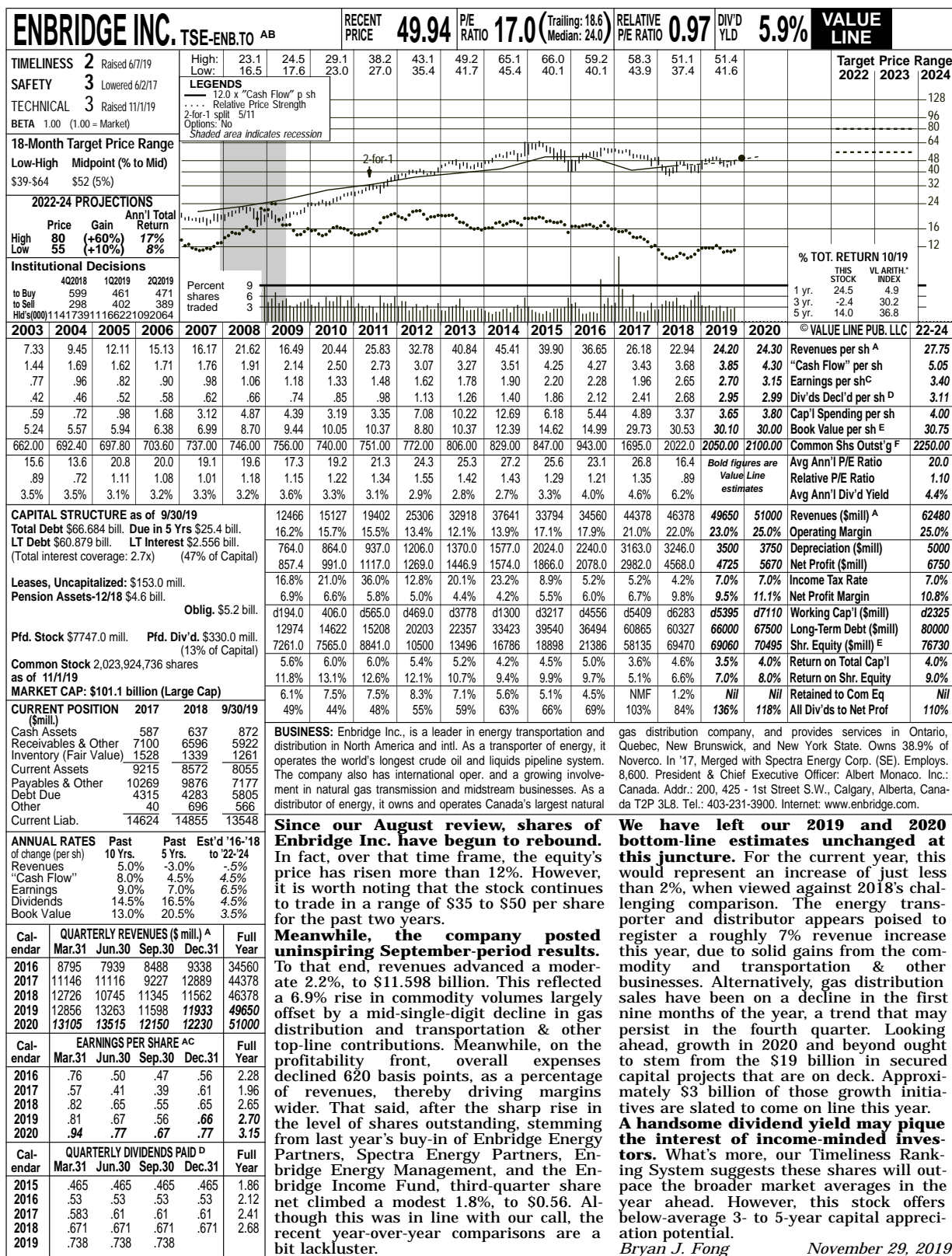
Advertise With Us

Data Disclaimer Help Suggestions
Privacy Dashboard
Privacy (Updated) About Our Ads Terms
(Updated) Sitemap

© 2020 Verizon Media. All rights reserved.

EPS Revisions	Current Qtr. (Mar 2020)	Next Qtr. (Jun 2020)	Current Year (2020)	Next Year (2021)
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	2	1	1	1

Growth Estimates	NFG	Industry	Sector	S&P500
Current Qtr.	-3.70%	N/A	N/A	0.01
Next Qtr.	-11.30%	N/A	N/A	0.09
Current Year	-11.00%	N/A	N/A	0.00
Next Year	-2.00%	N/A	N/A	0.14
Next 5 Years (per annum)	8.50%	N/A	N/A	0.08
Past 5 Years (per annum)	1.50%	N/A	N/A	N/A



(A) All figures in CAD. (B) Also trades on the NYSE ('ENB'). (C) Canadian GAAP. Dil. egs. Qtrly. figs. may not sum due to rounding. Exc. nonrec. gains/(losses): '08, \$1.53; '09, \$1.92; '10, (0.09c); '11, (0.18c); '12, (0.84c); '13, (\$1.23); '14, (0.58c); '15, (\$2.24); '16, (0.33); '17, (0.31c). Next egs. report due mid-Feb. (D) Divs. paid in March, June, Sept., and Dec. (E) Inc. intang. In '18: \$36831.0 million, \$18.22 a share. (F) In millions, adj. for split.

Subject to 15% nonresident withholding tax. 2% discount on shares purchased with reinv. divs. (E) Inc. intang. In '18: \$36831.0 million, \$18.22 a share. (F) In millions, adj. for split.

Company's Financial Strength B++
Stock's Price Stability 70
Price Growth Persistence 40
Earnings Predictability 75

To subscribe call 1-800-VALUELINE

[illegible]

<p>(A) Diluted P Class earnings. Next earnings report due mid-January. Earnings may not sum due to rounding.</p> <p>(B) Includes intangibles. In 2018, \$24.8 billion</p>	<p>or \$10.98 per share.</p> <p>(C) Dividends historically paid mid-February, May, August, and November.</p> <p>(D) In millions.</p>	<p>Company's Financial Strength B</p> <p>Stock's Price Stability 40</p> <p>Price Growth Persistence 5</p> <p>Earnings Predictability 15</p>
<p>© 2019 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.</p>		
<p>To subscribe call 1-800-VALUELINE</p>		

TC PIPELINES NYSE-TCP				RECENT PRICE	39.44	TRAILING P/E RATIO	NMF	RELATIVE P/E RATIO	NMF	DIV'D YLD	6.6%	VALUE LINE					
RANKS		54.95 39.24	47.75 38.20	52.61 40.60	80.46 44.92	73.76 41.09	60.48 34.25	65.03 48.55	57.08 22.64	42.11 30.36		High Low					
PERFORMANCE	2	Above Average															
Technical	2	Above Average															
SAFETY	3	Average															
BETA	1.20	(1.00 = Market)															
Financial Strength	B																
Price Stability	25																
Price Growth Persistence	10																
Earnings Predictability	10																
© VALUE LINE PUBLISHING LLC																	
SALES PER SH	1.32	1.22	5.47	5.29	5.35	5.22	5.92	7.70	--	--	--						
"CASH FLOW" PER SH	3.23	2.71	3.82	4.00	4.62	4.82	4.89	d1.18	--	--	--						
EARNINGS PER SH	3.02	2.51	2.13	2.67	3.08	3.21	3.16	d2.68	NA	NA/NA	NA/NA						
DIV'DS DECL'D PER SH	3.06	3.11	3.21	3.33	3.51	3.71	3.88	2.95	--	--	--						
CAP'L SPENDING PER SH	.07	.04	.24	.16	.84	.41	.41	.56	--	--	--						
BOOK VALUE PER SH	24.41	23.83	21.19	20.81	17.90	16.75	14.98	8.29	--	--	--						
COMMON SHS OUTST'G (MILL)	53.47	53.47	62.33	63.56	64.32	68.42	71.31	71.30	--	--	--						
AVG ANN'L P/E RATIO	15.8	17.6	22.2	20.9	18.9	16.1	17.7	--	NA	NA/NA	NA/NA						
RELATIVE P/E RATIO	.99	1.13	1.25	1.10	.97	.88	.89	--	--	--	--						
AVG ANN'L DIV'D YIELD	6.4%	7.0%	6.8%	6.0%	6.0%	7.2%	6.9%	8.4%	--	--	--						
SALES (\$MILL)	70.4	65.0	341.0	336.0	344.0	357.0	422.0	549.0	--	--	--	Bold figures are consensus earnings estimates and, using the recent prices, P/E ratios.					
OPERATING MARGIN	66.9%	64.6%	81.2%	81.3%	82.0%	84.0%	75.1%	86.7%	--	--	--						
DEPRECIATION (\$MILL)	15.2	11.0	86.0	86.0	85.0	86.0	97.0	98.0	--	--	--						
NET PROFIT (\$MILL)	157.4	134.0	152.0	168.0	212.0	244.0	252.0	d182.0	--	--	--						
INCOME TAX RATE	--	--	--	--	--	--	.4%	--	--	--	--						
NET PROFIT MARGIN	223.6%	206.2%	44.6%	50.0%	61.6%	68.3%	59.7%	NMF	--	--	--						
WORKING CAP'L (\$MILL)	29.1	1.0	14.0	d223.0	22.0	36.0	d10.0	7.0	--	--	--						
LONG-TERM DEBT (\$MILL)	739.8	685.0	1575.0	1446.0	1896.0	1835.0	2352.0	2072.0	--	--	--						
SHR. EQUITY (\$MILL)	1305.4	1274.0	1321.0	1323.0	1151.0	1146.0	1068.0	591.0	--	--	--						
RETURN ON TOTAL CAP'L	8.1%	7.4%	6.2%	7.0%	7.9%	9.3%	8.3%	NMF	--	--	--						
RETURN ON SHR. EQUITY	12.1%	10.5%	11.5%	12.7%	18.4%	21.3%	23.6%	NMF	--	--	--						
RETAINED TO COM EQ	.4%	NMF	NMF	NMF	NMF	NMF	NMF	NMF	--	--	--						
ALL DIV'DS TO NET PROF	96%	124%	121%	123%	112%	107%	124%	NMF	--	--	--						
Note: No analyst estimates available.																	
ANNUAL RATES					ASSETS (\$mill.)			2017			2018			9/30/19			
of change (per share)					Cash Assets			33.0			33.0			90.0			
Sales					Receivables			42.0			44.0			39.0			
"Cash Flow"					Inventory			8.0			8.0			9.0			
Earnings					Other			7.0			12.0			2.0			
Dividends					Current Assets			90.0			97.0			140.0			
Book Value																	
Fiscal Year	QUARTERLY SALES (\$mill.)				Full Year	Property, Plant & Equip, at cost			3304.0	2639.0	--						
	1Q	2Q	3Q	4Q		Accum Depreciation			1181.0	1110.0	--						
12/31/17	112.0	101.0	100.0	109.0	422.0	Net Property			2123.0	1529.0	1094.0						
12/31/18	115.0	111.0	103.0	220.0	549.0	Other			1346.0	1273.0	1588.0						
12/31/19	113.0	93.0	93.0			Total Assets			3559.0	2899.0	2822.0						
12/31/20																	
Fiscal Year	EARNINGS PER SHARE				Full Year	LIABILITIES (\$mill.)			36.0	42.0	37.0						
	1Q	2Q	3Q	4Q		Debt Due			51.0	36.0	123.0						
12/31/16	1.10	.76	.65	.70	3.21	Other			13.0	12.0	20.0						
12/31/17	1.05	.73	.61	.77	3.16	Current Liab			100.0	90.0	180.0						
12/31/18	1.33	1.00	.79	d5.80	d2.68												
12/31/19	1.28	.75	.76														
12/31/20																	
Cal-endar	QUARTERLY DIVIDENDS PAID				Full Year	LONG-TERM DEBT AND EQUITY as of 9/30/19											
	1Q	2Q	3Q	4Q		Total Debt \$1994.0 mill.			Due in 5 Yrs. NA								
2016	.89	.89	.94	.94	3.66	LT Debt \$1871.0 mill.			(75% of Cap'l)								
2017	.94	.94	1.00	1.00	3.88	Including Cap. Leases NA											
2018	1.00	.65	.65	.65	2.95	Leases, Uncapitalized Annual rentals NA											
2019	.65	.65	.65	.65													
INSTITUTIONAL DECISIONS					Pension Liability None in '18 vs. None in '17												
4Q'18					1Q'19	2Q'19	Pfd Stock None					Pfd Div'd Paid None					
to Buy					57	62	49	Common Stock 71,306,396 shares					(25% of Cap'l)				
to Sell					66	52	54										
Hld's(000)					44790	45068	61432										
INDUSTRY: Pipeline MLPs																	
BUSINESS: TC PipeLines, LP, a wholly owned subsidiary of TransCanada Corp., acquires, owns, and participates in the management of energy infrastructure assets in North America. The company owns interests in six natural gas interstate pipeline systems, through which it transports approximately 9.1 billion cubic feet of natural gas per day from producing regions and import facilities to market hubs and consuming markets, primarily in the western and midwestern United States. It serves large utilities, local distribution companies, and natural gas marketers and producing companies. Also, the company invests in long-term critical energy infrastructure that provides reliable delivery of energy to customers in the United States; develops or acquires assets that provide stable cash distributions and opportunities for new capital additions; and maximize the utilization of pipeline systems, with a commitment to safe and reliable operations. President: Nathaniel A. Brown Address: 700 Louisiana Street Suite 700, Houston, TX 77002. Tel.: (877) 290-2772. Internet: www.tcpipe-lineslp.com.																	
N.A.																	
November 29, 2019																	
TOTAL SHAREHOLDER RETURN																	
Dividends plus appreciation as of 10/31/2019																	
3 Mos. 6 Mos. 1 Yr. 3 Yrs. 5 Yrs.																	
1.09% 16.79% 41.33% -4.94% -9.59%																	

TC ENERGY CORP. NYSE-TRP						RECENT PRICE	51.24	P/E RATIO	16.7 (Trailing: 16.8 Median: 22.0)	RELATIVE P/E RATIO	0.95	DIV YLD	5.9%	VALUE LINE				
TIMELINESS	2	Lowered 11/22/19	High:	41.5	34.6	38.6	45.1	47.8	49.7	58.4	49.6	51.8	49.9	52.7	Target Price	Range		
SAFETY	3	Lowered 3/3/17	Low:	23.5	20.0	25.5	36.1	39.7	42.4	42.2	29.9	28.4	34.6	35.2	2022	2023		
TECHNICAL	2	Lowered 11/22/19	<div>LEGENDS 10.0 x "Cash Flow" p sh Relative Price Strength Options: Yes Shaded area indicates recession</div>															
BETA	1.05	(1.00 = Market)																
18-Month Target Price Range																		
Low-High Midpoint (% to Mid)																		
\$38-\$58 \$48 (-5%)																		
2022-24 PROJECTIONS																		
Price Gain Ann'l Total																		
High Low 100 65 (+95%)(+25%) 22% 17%																		
U.S. Institutional Decisions																		
4Q2018 1Q2019 2Q2019																		
to Buy 193 215 191																		
to Sell 204 167 190																		
Hld's (\$000) 580382 531404 541851																		
Percent shares traded 9 6 3																		
© VALUE LINE PUB. LLC 22-24																		
THIS STOCK VL ARITH' INDEX																		
1 yr. 42.4 4.9																		
3 yr. 33.0 30.2																		
5 yr. 35.1 36.8																		
% TOT. RETURN 10/19																		
2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	
.77	.83	.87	.86	1.01	.82	.95	1.00	.98	1.00	.94	.86	.72	.74	.79	.73	.75	.75	
8.54	8.74	10.81	13.23	16.36	11.46	12.47	11.58	12.71	11.36	11.70	12.38	11.59	10.77	12.13	10.92	11.35	11.85	
2.73	2.87	3.30	3.36	4.29	3.50	3.83	3.71	4.25	3.79	4.25	4.08	.54	1.78	3.84	4.71	4.85	5.00	
1.28	1.35	1.53	1.63	2.30	2.07	2.01	1.77	2.12	1.84	2.28	2.12	d1.26	.12	2.00	2.87	3.10	3.35	
.83	.96	1.06	1.10	1.36	1.18	1.45	1.60	1.65	1.76	1.73	1.66	1.50	1.68	1.99	2.02	2.25	2.35	
.62	.81	1.33	2.76	3.06	4.17	7.54	7.23	4.55	3.68	5.93	5.30	4.02	4.31	6.66	7.52	7.00	6.75	
9.71	9.29	12.39	13.54	18.13	17.16	21.17	22.27	22.39	22.25	22.22	20.44	14.30	17.47	19.00	20.25	22.00	23.10	
483.20	484.91	487.24	488.98	539.77	616.47	684.36	696.20	704.00	705.00	707.00	709.00	702.61	863.76	881.38	918.00	935.00	940.00	
13.8	15.7	17.6	19.0	15.6	17.2	14.1	20.1	19.4	23.9	20.2	22.5	--	NMF	24.2	14.8	16.92	18.00	
.79	.83	.94	1.03	.83	1.04	.94	1.28	1.22	1.52	1.13	1.18	--	NMF	1.22	.80	1.41	4.8%	
4.7%	4.5%	3.9%	3.6%	3.8%	3.3%	5.1%	4.5%	4.0%	4.0%	3.8%	3.5%	4.0%	4.0%	10.6%	10.02%	10625	11160	
CAPITAL STRUCTURE as of 9/30/19																		
Total Debt \$31341.6 mill. Due in 5 Yrs \$8000 mill.																		
LT Debt \$27655.6 mill. LT Int. \$1250.0 mill.																		
(Tot. int. coverage: 2.7x)																		
(54% of Cap'l)																		
Leases, Uncapitalized Annual rentals \$59.4 mill.																		
Pension Assets-12/18 \$2434.3 mill.																		
Oblig. \$2677.2 mill.																		
Pfd Stock \$3025.0 bill. Pfd Div'd \$77.5 million																		
Common Stock 934,000,000 shs.																		
MARKET CAP: \$47.9 billion (Large Cap)																		
CURRENT POSITION 2017 2018 9/30/19																		
(\$MILL.)																		
Cash Assets 865.8 321.1 1709.2																		
Other 2854.4 3376.1 4579.0																		
Current Assets 3720.2 3697.2 6288.2																		
Accts Payable 3680.1 3893.8 3688.3																		
Debt Due 3656.9 4481.3 3686.0																		
Other 515.2 946.0 1006.2																		
Current Liab. 7852.2 9321.1 8380.5																		
ANNUAL RATES Past Past Est'd 16-'18																		
of change (per ADR) 10 Yrs. 5 Yrs. to 22-'24																		
Revenues -2.0% -1.0% 3.0%																		
"Cash Flow" -1.0% -3.5% 11.0%																		
Earnings -2.0% -4.5% 17.0%																		
Dividends 4.5% 2.0% 5.5%																		
Book Value 1.5% -3.0% 6.5%																		
Cal-endar	QUARTERLY REVENUES (\$ mill.) E				Full Year													
	Mar.31	Jun.30	Sep.30	Dec.31														
2016	1862	2047	2702	2693	9303.7													
2017	2696	2557	2563	2876	10692.0													
2018	2510	2342	2313	2862	10026.7													
2019	2615	2563	2381	3066	10625.5													
2020	2700	2650	2710	3100	11160.0													
Cal-endar	EARNINGS PER SHARE BE				Full Year													
	Mar.31	Jun.30	Sep.30	Dec.31														
2016	.27	.39	d.13	d.32	.12													
2017	.59	.80	.56	.05	2.00													
2018	.61	.65	.75	.87	2.87													
2019	.82	.76	.60	.92	3.10													
2020	.80	.75	.85	.95	3.35													
Cal-endar	QUARTERLY DIVIDENDS PAID A				Full Year													
	Mar.31	Jun.30	Sep.30	Dec.31														
2015	.346	.374	.374	.374	1.47													
2016	.387	.42	.42	.42	1.65													
2017	.497	.497	.497	.497	1.99													
2018	.506	.506	.506	.506	1.99													
2019	.563	.563	.57															
(A) At yearend. In US\$.																		
(B) Diluted EPS. Excl. nonrecurring gains/(losses): '03, 9c; '04, (40c); '05, 62c; '06, 22c; '07, 58c, 22c; '10, (18c). Next earnings																		
© 2019 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic, or other form, or used for generating or marketing any printed or electronic publication, service or product.																		
report due early February.						vestment plan available.						Company's Financial Strength B++						
(C) Dividends subject to 15% Canadian non-resident tax. Dividends historically paid: late January, April, July, and October. Div'd rein-						(D) In millions.						Stock's Price Stability 80						
						(E) Quaterlies may not sum due to translation.						Price Growth Persistence 15						
												Earnings Predictability 5						
To subscribe call 1-800-VALUELINE																		

WILLIAMS COS.

NYSE-WMB

RECENT PRICE

22.14

P/E RATIO

20.7

Trailing: 38.0

Median: 36.0

RELATIVE P/E RATIO

1.18

DIV YLD

6.9%

VALUE LINE

TIMELINESS

3

Raised 2/23/18

SAFETY

3

Raised 12/14/07

TECHNICAL

3

Raised 10/25/19

BETA

1.90

(1.00 = Market)

LEGENDS

10.0 x "Cash Flow" p sh

Relative Price Strength

Options: Yes

Shaded area indicates recession

18-Month Target Price Range

Low-High

Midpoint (% to Mid)

\$14-\$27

\$21 (-5%)

2022-24 PROJECTIONS

Price

Gain

Ann'l Total Return

High 50

+125%

27%

Low 30

+35%

14%

Institutional Decisions

4Q2018

10Q2019

20Q2019

Percent shares traded

36

24

12

To Buy

354

405

388

Hld's (\$MM)

1084038

1069387

1087909

% TOT. RETURN 10/19

THIS STOCK

VL ARITH. INDEX

1 yr.

-2.9

4.9

3 yr.

-11.9

30.8

5 yr.

-46.3

36.2

2003

2004

2005

2006

2007

2008

2009

2010

2011

2012

2013

2014

2015

2016

2017

2018

2019

2020

@ VALUE LINE PUB. LLC

22-24

32.48

22.33

21.95

19.78

18.02

21.37

14.16

16.44

13.42

10.99

10.04

10.22

9.83

10.00

9.72

7.18

6.70

7.30

Revenues per sh

10.40

1.26

1.67

2.04

2.32

3.34

4.55

3.27

3.88

4.30

2.13

2.01

2.35

2.86

2.95

2.73

2.07

2.40

2.70

"Cash Flow" per sh

4.10

.02

.49

.72

.86

1.44

2.23

.75

1.30

1.55

1.11

.81

.80

.54

.60

.63

.79

1.00

1.15

Earnings per sh

2.00

.04

.08

.25

.35

.39

.43

.44

.49

.78

1.20

1.41

1.96

2.45

1.68

1.20

1.36

1.52

1.64

Div'ds Decl'd per sh

2.00

1.85

1.41

2.27

4.20

4.81

6.01

4.09

4.77

4.73

3.71

5.23

5.40

4.23

2.73

2.95

2.70

2.05

2.20

Cap'l Spending per sh

2.40

7.92

8.88

9.47

10.17

10.88

14.60

14.49

12.46

3.03

6.98

7.12

11.75

8.21

6.19

11.69

12.09

12.65

13.55

Book Value per sh

16.15

518.23

558.00

573.40

597.10

586.00

578.00

583.00

585.00

591.00

681.00

683.00

747.00

749.00

750.00

826.00

1210.00

1230.00

1230.00

Common Shs Outst'g

1250.00

NMF

24.2

27.7

27.4

21.7

13.2

21.6

16.4

18.8

28.4

43.9

NMF

NMF

39.0

46.9

34.6

20.0

20.0

Avg Ann'l P/E Ratio

20.0

NMF

1.28

1.47

1.48

1.15

.79

1.44

1.04

1.18

1.81

2.47

NMF

NMF

2.05

2.36

1.87

1.10

1.10

Relative P/E Ratio

1.10

.6%

.7%

1.3%

1.5%

1.2%

1.5%

2.7%

2.3%

2.7%

3.8%

4.0%

4.0%

5.4%

7.2%

4.1%

5.0%

5.0%

Avg Ann'l Div'd Yield

5.0%

CAPITAL STRUCTURE as of 9/30/19

Total Debt \$22,257 mill.

Due in 5 Yrs \$3161 mill.

LT Debt \$2,0719 mill.

LT Interest \$1,300.0 mill.

(62% of Cap'l)

Leases, Uncapitalized

\$32.0 mill.

Pension Assets-12/18

\$1132.0 mill.

Oblig. \$1187.0 mill.

Pfd Stock

None

Common Stock

1,212,048,836 shares as of 10/28/19

MARKET CAP:

\$26.8 billion (Large Cap)

CURRENT POSITION

2017

2018

9/30/19

(\$MILL.)

899

168

247

Cash Assets

976

992

875

Receivables

113

130

129

Inventory

191

174

183

Other

2179

1464

1434

Current Assets

978

662

602

Accts Payable

501

47

1538

Debt Due

1167

1102

1184

Other

2646

1811

3324

Current Liab.

ANNUAL RATES

Past 10 Yrs.

Past 5 Yrs.

Est'd '16-'18 to '22-'24

Revenues

-7.5%

-5.0%

2.5%

"Cash Flow"

-2.5%

-1.5%

8.0%

Earnings

-8.0%

-10.5%

20.0%

Dividends

13.5%

4.5%

6.0%

Book Value

-1.5%

12.0%

8.5%

Cal-endar

QUARTERLY REVENUES (\$mill.)

Mar.31

Jun.30

Sep.30

Dec.31

Full Year

2016

1660

1736

1905

2198

7499

2017

1988

1924

1891

2228

8031

2018

2088

2091

2303

2204

8686

2019

2054

2041

1999

2106

8200

2020

2100

2200

2300

2400

9000

Cal-endar

EARNINGS PER SHARE

Mar.31

Jun.30

Sep.30

Dec.31

Full Year

2016

.03

.19

.20

.18

.60

2017

.14

.13

.15

.21

.63

2018

.19

.17

.24

.19

.79

2019

.22

.26

.26

.26

1.00

2020

.27

.28

.30

.30

1.15

Cal-endar

QUARTERLY DIVIDENDS PAID

Mar.31

Jun.30

Sep.30

Dec.31

Full Year

2015

.58

.59

.64

.64

2.45

2016

.64

.64

.20

.20

1.68

2017

.30

.30

.30

.30

1.20

2018

.34

.34

.34

.34

1.36

2019

.38

.38

.38

.38

Business:

The Williams Companies, Inc., gathers, processes, and transports natural gas throughout the United States. It also performs gas marketing services. Acquired Access Midstream Partners, 7/14; Barrett Resources, 8/01; MAPCO, 3/98. Sold Texas Gas Pipeline, 5/03; Kern River Pipeline, 3/02. Spun off Williams Communications, 4/01; WPX Energy, 1/12. Initial public offering for Williams Partners L.P., 8/05; Williams Pipeline Partners L.P., 1/08. Has about 5,425 employees. Off/dir. own less than 1.0% of common shares; FMR LLC, 8.1%; The Vanguard Group, 7.5%; BlackRock, Inc., 9.4% (4/19 Proxy). President and CEO: Alan S. Armstrong. Inc. DE. Address: One Williams Center, Tulsa, Oklahoma 74172. Tel.: 918-573-2000. Internet:www.williams.com.

The Williams Cos. recorded mixed third-quarter results.

Revenues fell to \$1.999 billion, as asset divestitures and lower commodity prices more than offset higher volumes due to a few capital projects being placed into service. Still, operating margins expanded, as lower maintenance and depreciation costs were incurred. These factors allowed adjusted earnings per share to rise to \$0.26 during the quarter. The company remains on track for improved operations in the fourth quarter, as it gains from new projects placed into service. Still, the divestitures and lower commodity prices may hold back the top line. Overall, we think adjusted earnings will reach \$1.00 per share this year.

The company should have a better performance in the years ahead.

Revenues will likely expand as further projects are placed into service. Several Transco enhancement projects are expected to reach completion in 2020 should current schedules hold. Additionally, it is working with New York and New Jersey to pursue water quality permits, which would allow the Northeast Supply Enhancement project to commence. The in-service date on this project has now slipped into the fourth quarter of 2020, and it could be delayed further. Around 98% of revenues are fee-for-service, which limits exposure to underlying commodity prices. However, recent commodity price weakness may cause some of Williams' natural gas transportation customers to scale back drilling plans. Even so, the company has a well-diversified income stream, which should allow it to surpass any operational difficulties. We think that adjusted earnings will expand to \$1.15 per share in 2020 and \$2.00 per share by the 2022-2024 period.

The dividend is a top draw.

The yield is quite high when compared to others in the Survey. Cash flows cover the payout, and we project steady increases in the years ahead, as the company has reached its target leverage ratios.

Shares of the Williams Cos. are neutrally ranked for Timeliness.

The stock holds above-average 3- to 5-year appreciation potential, and total return potential is attractive. This issue should appeal to a wide array of investors.

John E. Seibert III

November 29, 2019

(A) Diluted eggs. Excl. nonrec. gains (losses): '03, (\$1.54); '04, (31c); '05, (19c); '06, (31c); '07, (44c); '08, 3c; '09, (47c); '10, (\$3.17); '11, (21c); '12, 4c; '13, (17c). Excl. gains (losses) from disc. op.: '03, 49c; '04, 13c; '06, (4c); '07, 23c; '08, 14c; '09, (45c); '10, (1c); '11, (71c); '12, 22c; '13, (2c); '14, \$2.11; '15, (\$1.28); '16, (\$1.17); '17, \$1.99; '18, (95c); '19 (7c). Eggs may not sum due to rounding. Next eggs. report due in late January. (B) Div's paid in Mar., June, Sep., and Dec. (C) In mill.

Company's Financial Strength

Stock's Price Stability

Price Growth Persistence

Earnings Predictability

B+

10

20

55

© 2019 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic, or other form, or used for generating or marketing any printed or electronic publication, service or product.

To subscribe call 1-800-VALUELINE

TC PIPELINES NYSE--TCP				RECENT PRICE	40.63	TRAILING P/E RATIO	NMF	RELATIVE P/E RATIO	NMF	DIV'D YLD	6.4%	VALUE LINE												
RANKS				54.95	39.24	47.75	38.20	52.61	40.60	80.46	44.92	73.76	41.09	60.48	34.25	65.03	48.55	57.08	22.64	43.93	30.36	44.65	39.12	High Low
PERFORMANCE	2	Above Average	<div>LEGENDS</div> <div>— 12 Mos Mov Avg</div> <div>- - - Rel Price Strength</div> <div>Shaded area indicates recession</div>																					
Technical	2	Above Average																						
SAFETY	3	Average																						
BETA	1.30	(1.00 = Market)																						
Financial Strength	B																							
Price Stability	25																							
Price Growth Persistence	10																							
Earnings Predictability	10																							
© VALUE LINE PUBLISHING LLC				2011	2012	2013	2014	2015	2016	2017	2018	2019	2020/2021											
SALES PER SH				1.32	1.22	5.47	5.29	5.35	5.22	5.92	7.70	--												
"CASH FLOW" PER SH				3.23	2.71	3.82	4.00	4.62	4.82	4.89	d1.18	--												
EARNINGS PER SH				3.02	2.51	2.13	2.67	3.08	3.21	3.16	d2.68	NA	NA/NA											
DIV'DS DECL'D PER SH				3.06	3.11	3.21	3.33	3.51	3.71	3.88	2.95	--												
CAP'L SPENDING PER SH				.07	.04	.24	.16	.84	.41	.41	.56	--												
BOOK VALUE PER SH				24.41	23.83	21.19	20.81	17.90	16.75	14.98	8.29	--												
COMMON SHS OUTST'G (MILL)				53.47	53.47	62.33	63.56	64.32	68.42	71.31	71.30	--												
AVG ANN'L P/E RATIO				15.8	17.6	22.2	20.9	18.9	16.1	17.7	--	NA	NA/NA											
RELATIVE P/E RATIO				.99	1.13	1.25	1.10	.97	.88	.89	--	--												
AVG ANN'L DIV'D YIELD				6.4%	7.0%	6.8%	6.0%	6.0%	7.2%	6.9%	8.4%	--												
SALES (\$MILL)				70.4	65.0	341.0	336.0	344.0	357.0	422.0	549.0	--		Bold figures are consensus earnings estimates and, using the recent prices, P/E ratios.										
OPERATING MARGIN				66.9%	64.6%	81.2%	81.3%	82.0%	84.0%	75.1%	86.7%	--												
DEPRECIATION (\$MILL)				15.2	11.0	86.0	86.0	85.0	86.0	97.0	98.0	--												
NET PROFIT (\$MILL)				157.4	134.0	152.0	168.0	212.0	244.0	252.0	d182.0	--												
INCOME TAX RATE				--	--	--	--	--	--	.4%	--	--												
NET PROFIT MARGIN				223.6%	206.2%	44.6%	50.0%	61.6%	68.3%	59.7%	NMF	--												
WORKING CAP'L (\$MILL)				29.1	1.0	14.0	d223.0	22.0	36.0	d10.0	7.0	--												
LONG-TERM DEBT (\$MILL)				739.8	685.0	1575.0	1446.0	1896.0	1835.0	2352.0	2072.0	--												
SHR. EQUITY (\$MILL)				1305.4	1274.0	1321.0	1323.0	1151.0	1146.0	1068.0	591.0	--												
RETURN ON TOTAL CAP'L				8.1%	7.4%	6.2%	7.0%	7.9%	9.3%	8.3%	NMF	--												
RETURN ON SHR. EQUITY				12.1%	10.5%	11.5%	12.7%	18.4%	21.3%	23.6%	NMF	--												
RETAINED TO COM EQ				.4%	NMF	NMF	NMF	NMF	NMF	NMF	NMF	--												
ALL DIV'DS TO NET PROF				96%	124%	121%	123%	112%	107%	124%	NMF	--												
Note: No analyst estimates available.																								
ANNUAL RATES				ASSETS (\$mill.)				2017	2018	9/30/19	INDUSTRY: Pipeline MLPs													
of change (per share)	5 Yrs.	1 Yr.		Cash Assets				33.0	33.0	90.0	BUSINESS: TC PipeLines, LP, a wholly owned subsidiary of TransCanada Corp., acquires, owns, and participates in the management of energy infrastructure assets in North America. The company owns interests in six natural gas interstate pipeline systems, through which it transports approximately 9.1 billion cubic feet of natural gas per day from producing regions and import facilities to market hubs and consuming markets, primarily in the western and midwestern United States. It serves large utilities, local distribution companies, and natural gas marketers and producing companies. Also, the company invests in long-term critical energy infrastructure that provides reliable delivery of energy to customers in the United States; develops or acquires assets that provide stable cash distributions and opportunities for new capital additions; and maximize the utilization of pipeline systems, with a commitment to safe and reliable operations. President: Nathaniel A. Brown Address: 700 Louisiana Street Suite 700, Houston, TX 77002. Tel.: (877) 290-2772. Internet: www.tcpipe-lineslp.com.													
Sales	18.5%	30.0%		Receivables				42.0	44.0	39.0														
"Cash Flow"	-2.5%	--		Inventory				8.0	8.0	9.0														
Earnings	-13.5%	--		Other				7.0	12.0	2.0														
Dividends	2.5%	-24.0%		Current Assets				90.0	97.0	140.0														
Book Value	-10.5%	-44.5%																						
Fiscal Year	QUARTERLY SALES (\$mill.)				Full Year	LIABILITIES (\$mill.)				Full Year														
	1Q	2Q	3Q	4Q		Accts Payable																		
12/31/17	112.0	101.0	100.0	109.0	422.0	Debt Due																		
12/31/18	115.0	111.0	103.0	220.0	549.0	Other																		
12/31/19	113.0	93.0	93.0			Current Liab																		
12/31/20																								
Fiscal Year	EARNINGS PER SHARE				Full Year	LONG-TERM DEBT AND EQUITY				Full Year														
	1Q	2Q	3Q	4Q		as of 9/30/19																		
12/31/16	1.10	.76	.65	.70	3.21	Total Debt \$1994.0 mill.																		
12/31/17	1.05	.73	.61	.77	3.16	LT Debt \$1871.0 mill.																		
12/31/18	1.33	1.00	.79	d5.80	d2.68	Including Cap. Leases NA																		
12/31/19	1.28	.75	.76			Leases, Uncapitalized Annual rentals NA																		
12/31/20																								
Cal-endar	QUARTERLY DIVIDENDS PAID				Full Year	Pension Liability				Full Year														
	1Q	2Q	3Q	4Q		None in '18 vs. None in '17																		
2017	.94	.94	1.00	1.00	3.88	Pfd Stock None																		
2018	1.00	.65	.65	.65	2.95	Pfd Div'd Paid None																		
2019	.65	.65	.65	.65	2.60	Common Stock 71,306,396 shares																		
2020	.65					(25% of Cap'l)																		
INSTITUTIONAL DECISIONS																								
	1Q'19	2Q'19	3Q'19																					
to Buy	62	49	64																					
to Sell	52	54	36																					
Hld's(000)	45068	61432	59899																					
© 2020 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.														To subscribe call 1-800-VALUELINE										

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 98.52

P/E RATIO 21.4 (Trailing: 21.5) (Median: 18.0)

RELATIVE P/E RATIO 1.18

DIV YLD 2.5%

VALUE LINE

TIMELINESS 3 Lowered 11/30/18

SAFETY 1 Raised 6/6/14

TECHNICAL 2 Lowered 5/29/20

BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High Midpoint (% to Mid)

\$83-\$183 \$133 (35%)

2023-25 PROJECTIONS

Price Ann'l Total Return

Low 160 (+60%/-30%) 15%

High 130 9%

Institutional Decisions

To Buy 202019 302019 402019

To Sell 231 262 272

Hld's (\$mm) 99796 99815 10274

Percent shares traded 24 16 8

LEGENDS

1.25 x Dividends p sh divided by Interest Rate

Relative Price Strength

Options: Yes

Shaded area indicates recession

% TOT. RETURN 4/20

THIS STOCK 1.2

VL ARITH. INDEX 15.6

1 yr. 33.5

5 yr. 110.6

2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021

46.50 61.75 75.27 66.03 79.52 53.69 53.12 48.15 38.10 42.88 49.22 40.82 32.23 26.01 28.00 24.32 22.50 23.25

2.91 3.90 4.26 4.14 4.19 4.29 4.64 4.72 4.76 5.14 5.42 5.81 6.19 6.62 7.24 7.57 7.95 8.30

1.58 1.72 2.00 1.94 2.00 1.97 2.16 2.26 2.10 2.50 2.96 3.09 3.38 3.60 4.00 4.35 4.60 4.85

1.22 1.24 1.26 1.28 1.30 1.32 1.34 1.36 1.38 1.40 1.48 1.56 1.68 1.80 1.94 2.10 2.30 2.46

3.03 4.14 5.20 4.39 5.20 5.51 6.02 6.90 8.12 9.32 8.32 9.61 10.46 10.72 13.19 14.19 15.20 15.40

18.05 19.90 20.16 22.01 22.60 23.52 24.16 24.98 26.14 28.47 30.74 31.48 33.32 36.74 42.87 48.18 52.80 55.40

62.80 80.54 81.74 89.33 90.81 92.55 90.16 90.30 90.24 90.64 100.39 101.48 103.93 106.10 111.27 119.34 125.00 130.00

15.9 16.1 13.5 15.9 13.8 12.5 13.2 14.4 15.9 15.9 16.1 17.5 20.8 22.0 21.7 23.2 23.2 23.2

.84 .86 .73 .84 .82 .83 .84 .90 1.01 .89 .85 .88 1.09 1.11 1.17 1.27 1.27 1.27

4.9% 4.5% 4.7% 4.2% 4.8% 5.3% 4.7% 4.2% 4.1% 3.5% 3.1% 2.9% 2.4% 2.3% 2.2% 2.1% 2.1% 2.1%

CAPITAL STRUCTURE as of 3/31/20

Total Debt \$4529.0 mill. Due in 5 Yrs \$465.0 mill.

LT Debt \$4328.9 mill. LT Interest \$255.0 mill.

(LT interest expense): 7.3x; total interest coverage: 7.3x

Leases, Uncapitalized Annual rentals \$21.0 mill.

Pfd Stock None

Pension Assets-9/19 \$530.1 mill.

Oblig. \$577.3 mill.

Common Stock 122,311,513 shs.

as of 5/1/20

MARKET CAP: \$12.1 billion (Large Cap)

CURRENT POSITION

2018 2019 3/31/20

Cash Assets 13.8 24.5 320.1

Other 465.1 433.5 509.5

Current Assets 478.9 458.0 829.6

Accts Payable 217.3 265.0 190.1

Debt Due 1150.8 464.9 200.1

Other 547.0 479.5 543.2

Current Liab. 1915.1 1209.4 933.4

Fix. Chg. Cov. 926% 990% 950%

ANNUAL RATES

Past 10 Yrs. Past 5 Yrs. Est'd '17-'19 of change (per sh)

Revenues -9.0% -9.5% 6.5%

"Cash Flow" 5.5% 7.0% 5.5%

Earnings 7.5% 9.5% 7.0%

Dividends 4.0% 6.5% 7.5%

Book Value 6.5% 8.5% 7.5%

Fiscal Year Ends

QUARTERLY REVENUES (\$ mill.) A

Dec.31 Mar.31 Jun.30 Sep.30

2017 780.2 988.2 526.5 464.8 2759.7

2018 889.2 1219.4 562.2 444.7 3115.5

2019 877.8 1094.6 485.7 443.7 2901.8

2020 875.6 977.6 501.8 460 2815

2021 900 1075 565 480 3020

Fiscal Year Ends

EARNINGS PER SHARE A B E

Dec.31 Mar.31 Jun.30 Sep.30

2017 1.08 1.52 .67 .34 3.60

2018 1.40 1.57 .64 .41 4.00

2019 1.38 1.82 .68 .49 4.35

2020 1.47 1.95 .69 .49 4.60

2021 1.48 2.05 .76 .56 4.85

Cal-endar

QUARTERLY DIVIDENDS PAID C

Mar.31 Jun.30 Sep.30 Dec.31

2016 .42 .42 .42 .45 1.71

2017 .45 .45 .45 .48 1.84

2018 .485 .485 .485 .525 1.98

2019 .525 .525 .525 .575 2.15

2020 .575 .575

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '10, 5c; '11, (1c); '18, \$1.43. Excludes discontinued operations: '11, 10c; '12, 27c; '13, 14c; '17, 13c. Next eqs. rpt. due early Aug.

(C) Dividends historically paid in early March, June, Sept., and Dec. = Div. reinvestment plan. Direct stock purchase plan avail.

(D) In millions.

(E) Qtrs may not add due to change in shrs outstanding.

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2019: 66%, residential; 27%, commercial; 5%, industrial; and 2% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately 1.4% of common stock (12/19 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy posted a solid, 7% increase in share net through the first six months of fiscal 2020 (concludes September 30th), compared to the prior-year total. This was made possible partly by the natural gas distribution unit, which benefited from higher rates, mainly in the Mississippi, Mid-Tex, Louisiana, and West Texas divisions. Customer growth, largely in the Mid-Tex operation, also contributed. Meanwhile, the performance of the pipeline and storage division enjoyed an increase in revenue from a Gas Reliability Infrastructure Program filing approved in fiscal 2019. Lastly, the company's interest charges were lower.

But prospects for the remainder of the year are a bit unclear. The coronavirus is hampering the economy, evidenced by such factors as rising unemployment and disrupted supply chains. However, the severity of the pandemic cannot be determined at this juncture, since developments are constantly changing. Leadership contends that preventative measures have been taken, which include a greater emphasis on employees working remotely and adherence to social distancing and other government guidelines when working in the service territories. Still, erring on the side of caution, we currently expect full-year profits to be around \$4.60 a share (around 6% growth), which is on the low side of the company's range of \$4.58 to \$4.73. Looking at fiscal 2021, a similar rate of increase, to \$4.85 a share, seems plausible, assuming that the health crisis fades away.

Rate-filing efforts continue. During the first six months of fiscal 2020, Atmos was able to complete eight regulatory proceedings, resulting in a \$59.2 million increase in annual operating income. What's more, some ratemaking initiatives were in progress at the time of this report, seeking \$170 million of annual operating income. Of course, there are no guarantees that the company will get everything it wants.

Long-term total return potential is not outstanding, relative to other natural gas equities. In spite of the recent stock-price weakness (due to pandemic concerns), rebound potential over 2023-2025 remains unspectacular. The dividend yield is subpar, as well.

Frederick L. Harris, III May 29, 2020

Company's Financial Strength A+

Stock's Price Stability 95

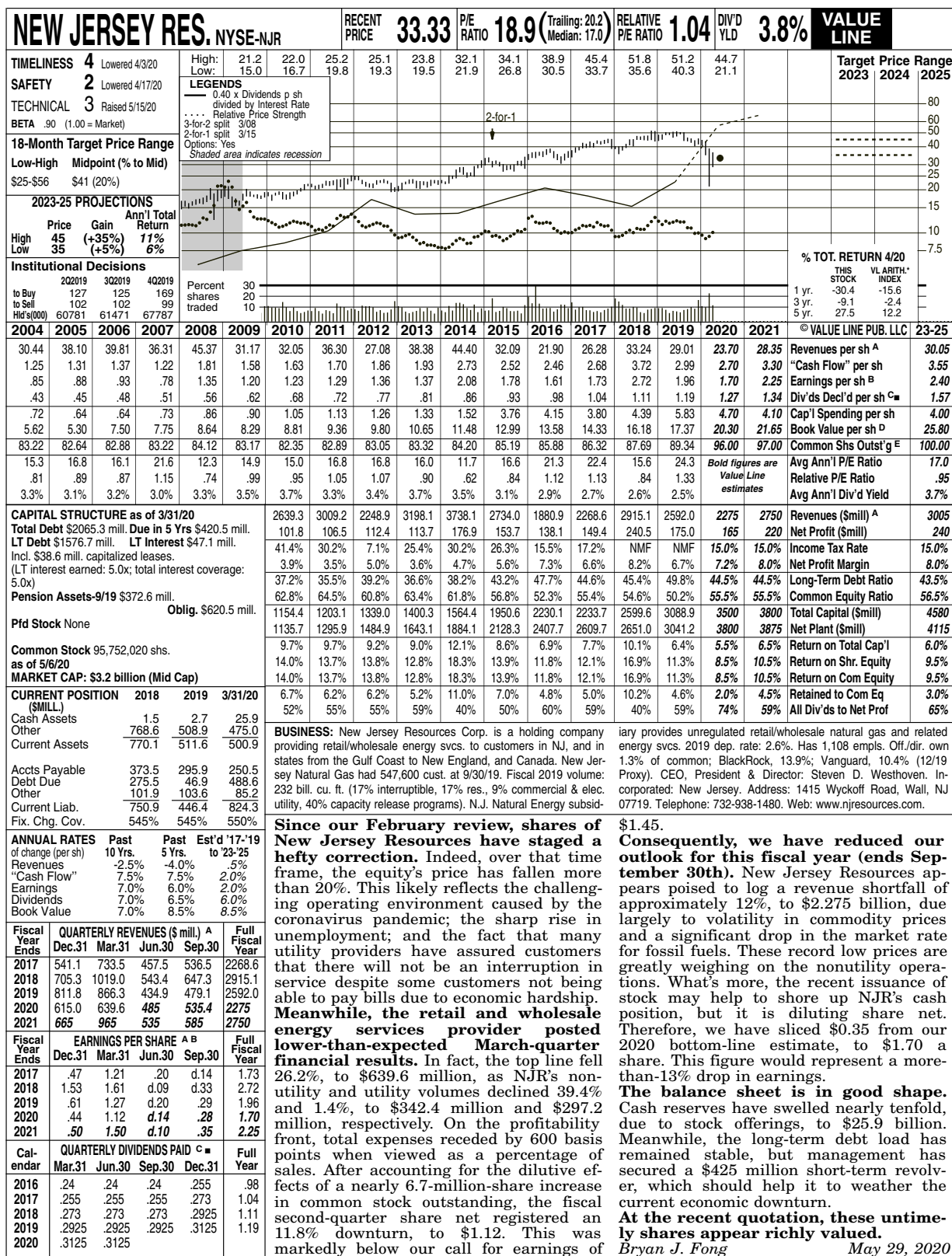
Price Growth Persistence 100

Earnings Predictability 100

[illegible]

<p>(A) Diluted shrs. Excludes nonrecurring items: '08, d7c; '15, 6c; '17, 87c. Excludes discontinued operations: '04, d1c; '19, 24c; '20, d1c. Quarters for 2019 don't equal total because of</p>	<p>rounding. Next earnings report due early Aug. (B) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan. Direct stock purchase plan available.</p>	<p>(C) In millions, adjusted for split.</p>	<p>Company's Financial Strength A Stock's Price Stability 85 Price Growth Persistence 90 Earnings Predictability 90</p>
<p>© 2020 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any product, or electronic publication, service or product.</p>			<p>To subscribe call 1-800-VALUeline</p>

NISOURCE INC. NYSE-NI					RECENT PRICE	23.17	P/E RATIO	17.8	(Trailing: 18.4 Median: 21.0)	RELATIVE P/E RATIO	0.98	DIV'D YLD	3.6%	VALUE LINE	Target Price Range							
TIMELINESS	3	Lowered 4/5/19	High:	15.8	18.0	24.0	26.2	33.5	44.9	49.2	26.9	27.8	28.1	30.7	30.5		2023	2024	2025			
SAFETY	2	Raised 11/29/19	Low:	7.8	14.1	17.7	22.3	24.8	32.1	16.0	19.0	21.7	22.4	24.7	19.6							
TECHNICAL	3	Raised 4/24/20	LEGENDS — 0.55 x Dividends p sh divided by Interest Rate ... Relative Price Strength Options: Yes Shaded area indicates recession																			
BETA	.85	(1.00 = Market) <th colspan="16">18-Month Target Price Range Low-High Midpoint (% to Mid) \$19-\$37 \$28 (20%)</th>	18-Month Target Price Range Low-High Midpoint (% to Mid) \$19-\$37 \$28 (20%)																			
2023-25 PROJECTIONS																						
Price	Gain	Ann'l Total Return																				
High	40	(+75%)	18%																			
Low	30	(+30%)	10%																			
Institutional Decisions																						
202019 302019 402019			Percent shares traded																			
to Buy	227	228	255																			
to Sell	197	192	203																			
Hld's(000)	346571	343395	347952																			
© VALUE LINE PUB. LLC																						
2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	23-25				
24.63	28.97	27.37	28.96	32.36	24.02	22.99	21.33	16.31	18.04	20.47	14.58	13.90	14.46	13.74	13.63	13.55	14.30	Revenues per sh	17.50			
3.47	3.14	3.18	3.20	3.32	2.96	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.07	2.82	3.03	3.10	3.30	"Cash Flow" per sh	4.15			
1.62	1.08	1.14	1.14	1.34	.84	1.06	1.05	1.37	1.57	1.67	.63	1.00	.39	1.30	1.32	1.30	1.45	Earnings per sh ^A	2.15			
.92	.92	.92	.92	.92	.92	.92	.92	.94	.98	1.02	.83	.64	.70	.78	.80	.86	.92	Div'd Decl'd per sh ^B	1.16			
1.91	2.17	2.33	2.88	3.54	2.81	2.88	3.99	4.83	5.99	6.42	4.26	4.57	5.03	4.88	4.72	4.70	4.70	Cap'l Spending per sh	4.70			
17.69	18.09	18.32	18.52	17.24	17.54	17.63	17.71	17.90	18.77	19.54	12.04	12.60	12.82	13.08	13.36	13.75	14.25	Book Value per sh ^C	16.40			
270.63	272.62	273.65	274.18	274.26	276.79	279.30	282.18	310.28	313.68	316.04	319.11	323.16	337.02	372.36	382.14	383.00	384.00	Common Shs Outst'g ^D	385.00			
13.0	21.4	19.2	18.8	12.1	14.3	15.3	19.4	17.9	18.9	22.7	37.3	23.2	64.4	19.3	21.2	21.0	21.0	Avg Ann'l P/E Ratio	16.0			
.69	1.14	1.04	1.00	.73	.95	.97	1.22	1.14	1.06	1.19	1.88	1.22	3.24	1.04	1.15	1.04	1.15	Relative P/E Ratio	.90			
4.4%	4.0%	4.2%	4.3%	5.7%	7.6%	5.7%	4.5%	3.8%	3.3%	2.7%	3.5%	2.8%	2.8%	3.1%	2.9%	2.9%	2.9%	Avg Ann'l Div'd Yield	4.2%			
CAPITAL STRUCTURE as of 3/31/20																						
Total Debt \$9872.2 mill. Due in 5 Yrs \$2196 mill.						6422.0	6019.1	5061.2	5657.3	6470.6	4651.8	4492.5	4874.6	5114.5	5208.9	5200	5500	Revenues (\$mill)	6735			
LT Debt \$7817.9 mill. LT Interest \$379 mill.						294.6	303.8	410.6	490.9	530.7	198.6	328.1	128.6	463.3	494.7	490	550	Net Profit (\$mill)	810			
(Interest cov. earned: 2.2x) (62% of Cap'l)						32.4%	35.0%	34.4%	34.8%	36.9%	41.6%	35.7%	71.0%	19.7%	20.2%	21.0%	21.0%	Income Tax Rate	22.0%			
						--	--	--	--	--	--	--	--	2.9%	2.0%	2.0%	2.0%	AFUDC % to Net Profit	2.0%			
Leases, Uncapitalized Annual rentals \$27.2 mill.						54.7%	55.6%	55.1%	56.3%	56.9%	60.7%	59.8%	63.5%	55.3%	56.8%	53.0%	52.0%	Long-Term Debt Ratio	50.0%			
Pension Assets-12/18 \$2.3 bill. Oblig. \$2.7 bill.						45.3%	44.4%	44.9%	43.7%	43.1%	39.3%	40.2%	36.5%	37.9%	36.9%	47.0%	48.0%	Common Equity Ratio	50.0%			
Pfd Stock \$880 mill. Pfd Div'd \$28.5 mill.						10859	11264	12373	13480	14331	9792.0	10129	11832	12856	13843	14900	15125	Total Capital (\$mill)	16125			
Common Stock 382,799,472 shs. as of 4/29/20						11097	11800	12916	14365	16017	12112	13068	14360	15543	16912	15750	16000	16000	Net Plant (\$mill)	17250		
MARKET CAP: \$8.9 billion (Large Cap)						4.5%	4.4%	5.0%	5.2%	5.3%	4.0%	5.0%	2.6%	5.0%	4.9%	3.5%	3.5%	Return on Total Cap'l	5.0%			
CURRENT POSITION						6.0%	6.1%	7.4%	8.3%	8.6%	5.2%	8.1%	3.0%	8.1%	8.3%	8.0%	8.5%	Return on Shr. Equity	11.0%			
2018 2019 3/31/20						6.0%	6.1%	7.4%	8.3%	8.6%	5.2%	8.1%	3.0%	9.3%	8.6%	8.0%	8.5%	Return on Com Equity	11.0%			
(SMILL)						.8%	.9%	2.5%	3.1%	3.4%	NMF	3.0%	NMF	3.7%	2.7%	2.0%	2.5%	Retained to Com Eq	4.5%			
Cash Assets						87%	85%	67%	62%	61%	NMF	63%	NMF	61%	72%	70%	70%	All Div'ds to Net Prof	59%			
Other						BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 472,000 electric in Indiana, 3.5 million gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, Massachusetts through its Columbia subsidiaries. Revenue breakdown, 2019: electrical, 33%; gas, 67%; other, less than 1%. Generating sources, 2018: coal, 69.4%; purchased & other, 30.6%. 2019 reported depreciation rates: 2.9% electric, 2.2% gas. Has 8,087 employees. Chairman: Richard L. Thompson. President & Chief Executive Officer: Joseph Hamrock. Incorporated: Indiana. Address: 801 East 86th Ave., Merrillville, Indiana 46410. Tel.: 877-647-5990. Internet: www.nisource.com.																
Current Assets						Since our February review, shares of NiSource have registered a significant correction. Indeed, over that interim, the equity's price has fallen almost 25%. This downturn reflects the challenging operating environment caused by the COVID-19 pandemic which has applied pressure to end-use consumer demand, coupled with the difficult time Russia and OPEC had in order to agree on reducing oil output. The oversupply of fossil fuels on a global scale caused a record selloff in commodity prices. Meanwhile, the company posted lower-than-expected March-period financial results. To that point, revenues fell 14.1% on a year-over-year basis, to \$1.606 billion, stemming from double-digit declines in Gas Distribution and Electric volumes. On the profitability front, operating expenses fell 670 basis points as a percentage of the top line (excludes a \$280 million nonrecurring charge on the divestiture of Columbia Gas of Massachusetts). On balance, after accounting for the dilutive effects of continued stock issuances, NI's first-quarter share net fell 7.3%, to \$0.76. This was modestly below our call of \$0.85.																
Accts Payable						As a result, we have sliced a dime off our 2020 earnings estimate, to \$1.30 per share. This figure would represent a bottom-line decline of about 1.5%, when compared to 2019's figure. At this point, NiSource appears poised to log a low single-digit decline in revenues, to \$5.2 billion as volumes slump for its commercial and industrial customers. At the same time, management anticipates that some accounts will fall into the bad-debt category, and sustained customer attrition will likely persist in the near term. A hefty capital expenditure budget and rate cases augur well for prospects. Management did reduce its plan for growth spending by \$100 million, to firm up its balance sheet and conserve cash. The company will likely still invest about \$1.7 billion-\$1.8 billion into its business this year alone. At the same time, NiSource applied for a rate case increase in Pennsylvania that would bring in another \$100.4 million annually. At the recent quotation, NiSource shares are not overly compelling. Bryan J. Fong May 29, 2020																
Debt Due																						
Other																						
Current Liab.																						
Fix. Chg. Cov.																						
ANNUAL RATES																						
Past 10 Yrs.																						
Revenues																						
"Cash Flow"																						
Earnings																						
Dividends																						
Book Value																						
Cal-endar																						
QUARTERLY REVENUES (\$ mill.)																						
Mar.31 Jun.30 Sep.30 Dec.31																						
2017																						
2018																						
2019																						
2020																						
2021																						
Cal-endar																						
EARNINGS PER SHARE ^A																						
Mar.31 Jun.30 Sep.30 Dec.31																						
2017						.65	d.14	.04	d.16	.39												
2018						.77	.07	.10	.38	1.30												
2019						.82	.05	--	.45	1.32												
2020						.76	.10	.09	.35	1.30												
2021						.80	.14	.12	.39	1.45												
Cal-endar																						
QUARTERLY DIVIDENDS PAID ^B																						
Mar.31 Jun.30 Sep.30 Dec.31																						
2016						.155	.155	.165	.165	.64												
2017						.175	.175	.175	.175	.70												
2018						.195	.195	.195	.195	.78												
2019						.200	.200	.200	.200	.80												
2020						.21	.21															
(A) Dil. EPS. Excl. nonrec. gains (losses): '05, (4c); gains (losses) on disc. ops.: '05, 10c; '06, (11c); '07, 3c; '08, (\$1.14); '15, (30c); '18, (\$1.48). Next eps. report due late Aug. City																			egs. may not sum to total due to rounding.	\$3.89/sh.	Company's Financial Strength	B+
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. = Div'd rein. avail.																			(D) In mill.	(E) Spun off Columbia Pipeline Group (7/15)	Stock's Price Stability	95
(C) Incl. intang. in rev.: \$1485.9 million,																					Price Growth Persistence	25
																					Earnings Predictability	40



(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qly. sales and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due early Aug.
(C) Dividends historically paid in early Jan., April, July, and October. Dividend reinvestment plan available.
(D) Includes regulatory assets in 2019: \$496.6 million, \$5.56/share.
(E) In millions, adjusted for splits.

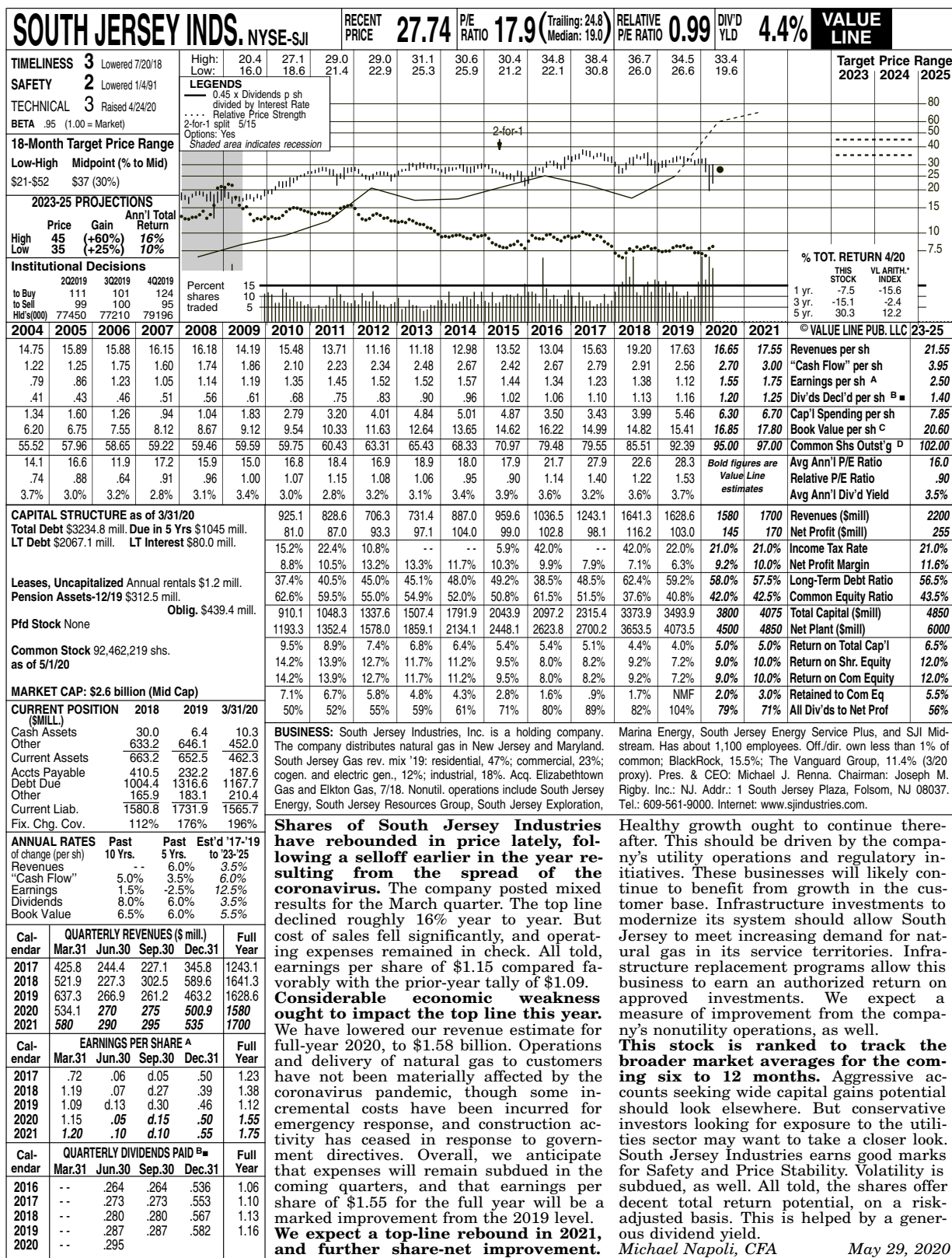
Company's Financial Strength A+
Stock's Price Stability 85
Price Growth Persistence 70
Earnings Predictability 45

To subscribe call 1-800-VALUELINE

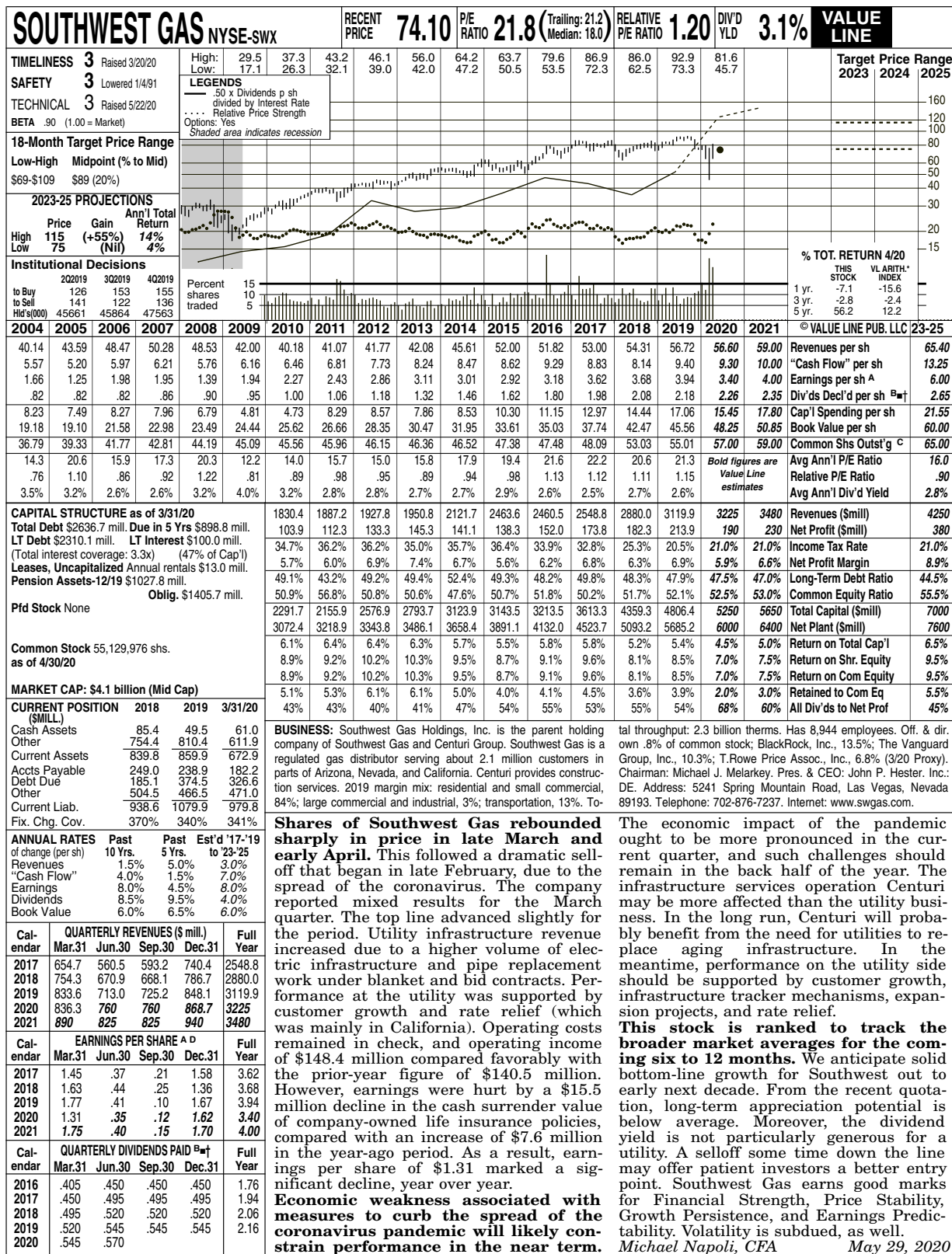
© 2020 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.

N.W. NATURAL NYSE-NWN				RECENT PRICE		62.54		P/E RATIO		25.5		(Trailing: 27.2 Median: 23.0)		RELATIVE P/E RATIO		1.41		DIV'D YLD		3.1%		VALUE LINE													
TIMELINESS 3 Lowered 5/22/20				High: 46.5		50.9		49.0		50.8		46.6		52.6		52.3		66.2		69.5		71.8		74.1		77.3		77.3		50.5		Target Price Range		2023 2024 2025	
SAFETY 1 Raised 3/18/05				Low: 37.7		41.1		39.6		41.0		40.0		40.1		42.0		48.9		56.5		51.5		57.2		50.5									
TECHNICAL 3 Raised 4/3/20																																			
BETA .80 (1.00 = Market)																																			
18-Month Target Price Range																																			
Low-High Midpoint (% to Mid)																																			
\$47-\$104 \$76 (20%)																																			
2023-25 PROJECTIONS																																			
Price Gain Ann'l Total																																			
High 85 70 (+35%) 10%																																			
Low 70 70 (+10%) 6%																																			
Institutional Decisions																																			
202019 302019 402019																																			
to Buy 124 107 120																																			
to Sell 70 90 95																																			
Hld's(000) 21542 21608 23102																																			
2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021																																			
25.69 33.01 37.20 39.13 39.16 38.17 30.56 31.72 27.14 28.02 27.64 26.39 23.61 26.52 24.45 24.49 24.50 25.75																																			
3.92 4.34 4.76 5.41 5.31 5.20 5.18 5.00 4.94 5.04 5.05 4.91 4.93 1.04 5.28 5.15 4.90 5.30																																			
1.86 2.11 2.35 2.76 2.57 2.83 2.73 2.39 2.22 2.24 2.16 1.96 2.12 d1.94 2.33 2.19 2.45 2.70																																			
1.30 1.32 1.39 1.44 1.52 1.60 1.68 1.75 1.79 1.83 1.85 1.86 1.87 1.88 1.89 1.90 1.91 1.92																																			
5.52 3.48 3.56 4.48 3.92 5.09 9.35 3.76 4.91 5.13 4.40 4.37 4.87 7.43 7.43 7.95 7.80 6.15																																			
20.64 21.28 22.01 22.52 23.71 24.88 26.08 26.70 27.23 27.77 28.12 28.47 29.71 25.85 26.41 28.42 29.65 31.80																																			
27.55 27.58 27.24 26.41 26.50 26.53 26.58 26.76 26.92 27.08 27.28 27.43 28.63 28.74 28.88 30.47 31.00 31.00																																			
16.7 17.0 15.9 16.7 18.1 15.2 17.0 19.0 21.1 19.4 20.7 23.7 26.9 -- 26.6 30.9																																			
.88 .91 .86 .89 1.09 1.01 1.08 1.19 1.34 1.09 1.09 1.19 1.41 -- 1.44 1.68																																			
4.2% 3.7% 3.7% 3.1% 3.3% 3.7% 3.6% 3.9% 3.8% 4.2% 4.1% 4.0% 3.3% 3.0% 3.0% 2.8%																																			
CAPITAL STRUCTURE as of 3/31/20																																			
Total Debt \$1504.0 mill. Due in 5 Yrs \$910.0 mill.																																			
LT Debt \$954.0 mill. LT Interest \$40.0 mill.																																			
(Total interest coverage: 3.4x)																																			
Pension Assets-12/19 \$313.1 mill.																																			
Oblig. \$515.7 mill.																																			
Pfd Stock None																																			
Common Stock 30,528,958 shares as of 4/28/20																																			
MARKET CAP \$1.9 billion (Mid Cap)																																			
CURRENT POSITION 2018 2019 3/31/20																																			
(SMILL.)																																			
Cash Assets 12.6 9.6 471.1																																			
Other 283.3 284.1 249.2																																			
Current Assets 295.9 293.7 720.3																																			
Accts Payable 115.9 113.4 23.9																																			
Debt Due 247.6 224.2 550.0																																			
Other 145.6 144.6 225.0																																			
Current Liab. 509.1 482.2 798.9																																			
Fix. Chg. Cov. 357% 336% 336%																																			
ANNUAL RATES of change (per sh)																																			
Past 10 Yrs. Past 5 Yrs. Est'd 17-19																																			
Revenues -4.0% -2.0% 2.5%																																			
"Cash Flow" -3.0% -5.5% 9.0%																																			
Earnings -1.0% -17.0% 26.5%																																			
Dividends 2.0% .5% .5%																																			
Book Value 1.5% -.5% 2.0%																																			
QUARTERLY REVENUES (\$ mill.)																																			
Cal-endar Mar.31 Jun.30 Sep.30 Dec.31 Full Year																																			
2017 297.3 136.3 88.2 240.4 762.2																																			
2018 264.7 124.6 91.2 226.7 706.1																																			
2019 285.4 123.4 90.3 247.3 746.4																																			
2020 285.2 125 100 249.8 760																																			
2021 305 145 110 260 820																																			
EARNINGS PER SHARE ^A																																			
Cal-endar Mar.31 Jun.30 Sep.30 Dec.31 Full Year																																			
2017 1.40 .10 d.30 d3.14 d1.94																																			
2018 1.46 d.01 d.39 1.27 2.33																																			
2019 1.50 .07 d.61 1.26 2.19																																			
2020 1.58 .02 d.40 1.25 2.45																																			
2021 1.60 .10 d.35 1.35 2.70																																			
QUARTERLY DIVIDENDS PAID ^B																																			
Cal-endar Mar.31 Jun.30 Sep.30 Dec.31 Full Year																																			
2016 .4675 .4675 .4675 .470 1.87																																			
2017 .470 .470 .470 .4725 1.88																																			
2018 .4725 .4725 .4725 .475 1.89																																			
2019 .475 .475 .475 .4775 1.90																																			
.4775 .4775																																			
(A) Diluted earnings per share. Excludes non-recurring items: '06, (\$0.06); '08, (\$0.03); '09, \$0.06; May not sum due to rounding. Next earnings report due in early August.																																			
(B) Dividends historically paid in mid-February, May, August, and November.																																			
(C) Dividend reinvestment plan available.																																			
(D) In millions.																																			
(E) Includes intangibles. In 2019: \$343.2 million, \$11.26/share.																																			
(F) Company's Financial Strength																																			
Stock's Price Stability																																			
Price Growth Performance																																			
Earnings Predictability																																			
To subscribe call 1-800-VALUELINE																																			

ONE GAS, INC. NYSE-OGS				RECENT PRICE	80.66	P/E RATIO	23.4	(Trailing: 23.2 Median: NMF)	RELATIVE P/E RATIO	1.29	DIV'D YLD	2.8%	VALUE LINE					
TIMELINESS	3	Lowered 2/28/20		High:	44.3	51.8	67.4	79.5	87.8	96.7	97.0		Target Price Range 2023 2024 2025					
SAFETY	2	New 6/2/17		Low:	31.9	38.9	48.0	61.4	62.2	75.8	63.7							
TECHNICAL	3	Raised 5/8/20																
BETA	.80	(1.00 = Market)																
18-Month Target Price Range																		
Low-High Midpoint (% to Mid)																		
\$64-\$137 \$101 (25%)																		
2023-25 PROJECTIONS																		
High Low																		
Price Gain Ann'l Total																		
145 105 (+80%) 18%																		
105 105 (+30%) 9%																		
Institutional Decisions																		
202019 3Q2019 4Q2019																		
to Buy 135 133 153																		
to Sell 145 132 132																		
Hld's(000) 40275 40475 41714																		
Percent shares traded																		
21 14 7																		
The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.																		
CAPITAL STRUCTURE as of 3/31/20																		
Total Debt \$1760.9 mill. Due in 5 Yrs \$1030.0 mill.																		
LT Debt \$1286.2 mill. LT Interest \$75.0 mill.																		
(LT interest earned: 4.7x; total interest coverage: 4.7x)																		
Leases, Uncapitalized Annual rentals \$7.6 mill.																		
Pfd Stock None																		
Pension Assets-12/19 \$908.0 mill.																		
Oblig. \$1001.4 mill.																		
Common Stock 52,865,557 shs.																		
as of 4/20/20																		
MARKET CAP: \$4.3 billion (Mid Cap)																		
CURRENT POSITION (MILL)																		
Cash Assets																		
21.3 17.9 11.1																		
Other																		
522.0 488.3 396.6																		
Current Assets																		
543.3 506.2 407.7																		
Accts Payable																		
174.5 120.5 82.1																		
Debt Due																		
299.5 516.5 474.7																		
Other																		
224.9 235.7 219.4																		
Current Liab.																		
698.9 872.7 776.2																		
Fix. Chg. Cov.																		
677% 567% 550%																		
ANNUAL RATES Past 10 Yrs. Past 5 Yrs. Est'd '17-'19 to '23-'25																		
Revenues																		
-- -2.5% 4.5%																		
"Cash Flow"																		
-- 7.0% 6.5%																		
Earnings																		
-- 9.5% 6.5%																		
Dividends																		
-- 17.0% 7.5%																		
Book Value																		
-- 2.5% 4.0%																		
Cal-endar																		
QUARTERLY REVENUES (\$ mill.)																		
Mar.31 Jun.30 Sep.30 Dec.31																		
2017 550.4 279.7 247.1 462.4 1539.6																		
2018 638.5 292.5 238.3 464.4 1633.7																		
2019 661.0 290.6 248.6 452.5 1652.7																		
2020 528.2 285 245 456.8 1515																		
2021 580 315 260 465 1620																		
Cal-endar																		
EARNINGS PER SHARE A																		
Mar.31 Jun.30 Sep.30 Dec.31																		
2017 1.34 .39 .36 .93 3.02																		
2018 1.72 .39 .31 .83 3.25																		
2019 1.76 .46 .33 .96 3.51																		
2020 1.72 .46 .32 .95 3.45																		
2021 1.80 .50 .36 .99 3.65																		
Cal-endar																		
QUARTERLY DIVIDENDS PAID B																		
Mar.31 Jun.30 Sep.30 Dec.31																		
2016 .35 .35 .35 .35 1.40																		
2017 .42 .42 .42 .42 1.68																		
2018 .46 .46 .46 .46 1.84																		
2019 .50 .50 .50 .50 2.00																		
2020 .54 .54																		
(A) Diluted EPS. Excludes nonrecurring gain: 2017, \$0.06. Next earnings report due early Aug. Quarterly EPS for 2018 don't add up due to rounding.				(B) Dividends historically paid in early March, June, Sept., and Dec. B Dividend reinvestment plan. Direct stock purchase plan.					(C) In millions.									
© 2020 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any written, electronic or other form, or used for generation or marketing any printed electronic publication, service or product.				BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 174 Bcf of natural gas supply in 2019, compared to 180 Bcf in 2018. Total volumes delivered by customer (fiscal 2019): transportation, 56.6%; residential, 32.5%; commercial & industrial, 10.3%; other, .6%. ONE Gas has around 3,600 employees. BlackRock owns 12.1% of common stock; The Vanguard Group, 10.1%; T. Rowe Price Associates, 7.0%; officers and directors, 1.9% (4/20 Proxy). CEO: Pierce H. Norton II. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Tel.: 918-947-7000. Internet: www.onegas.com.					course, the health crisis diminishes in intensity. Finances are healthy. When the first quarter ended, cash and equivalents stood at around \$11 million, and cash flows were decent (although they may slow some in the months ahead). Too, long-term debt resided at a reasonable 37% of total capital, and short-term commitments did not appear to be a major problem. Furthermore, there was \$474.7 million available (out of \$700 million) under a commercial paper program. ONE Gas also holds a \$700 million revolving credit facility expiring October 2024, and in April, it entered into a 364-day, \$250 million revolving credit agreement. All things considered, the company ought to continue to satisfy its various obligations, such as working capital and dividend payments. The stock offers decent long-term total return potential for a natural gas utility. The dividend should remain on a steady, upward trajectory. Moreover, the recent price drop (given pandemic concerns), has increased 3- to 5-year recovery possibilities. <i>Frederick L. Harris, III</i>					May 29, 2020				
				Company's Financial Strength A					Stock's Price Stability 95									
				Price Growth Persistence 90					Earnings Predictability 95									
To subscribe call 1-800-VALUELINE																		



SPIRE INC. NYSE:SR					RECENT PRICE	71.77	P/E RATIO	20.7	(Trailing: 24.3 Median: 18.0)	RELATIVE P/E RATIO	1.15	DIV'D YLD	3.6%	VALUE LINE	
TIMELINESS	3	Lowered 11/30/18	High: 48.3	37.8	42.8	44.0	48.5	55.2	61.0	71.2	82.9	81.1	88.0	88.0	Target Price Range 2023 2024 2025
SAFETY	2	Raised 6/20/03	Low: 29.3	30.8	32.9	36.5	37.4	44.0	49.1	57.1	62.3	60.1	71.7	57.4	
TECHNICAL	3	Raised 5/1/20	LEGENDS 1.00 x Dividends p sh divided by Interest Rate Relative Price Strength Options: Yes Shaded area indicates recession												
BETA	.80	(1.00 = Market)													
18-Month Target Price Range															
Low-High Midpoint (% to Mid)															
\$60-\$125 \$93 (30%)															
2023-25 PROJECTIONS															
Price Gain Ann'l Total High 120 (+65%) 16% Low 90 (+25%) 9%															
Institutional Decisions															
202019 302019 402019 to Buy 116 115 127 to Sell 131 117 114 Hld's(000) 40622 41800 42195 Percent shares traded 15 10 5															
2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021															
59.59 75.43 93.51 93.40 100.44 85.49 77.83 71.48 49.90 31.10 37.68 45.59 33.68 36.07 38.78 38.30 35.60 37.25															
2.79 2.98 3.81 3.87 4.22 4.56 4.11 4.62 4.58 3.12 3.87 6.15 6.16 6.54 7.55 7.12 7.10 7.70															
1.82 1.90 2.37 2.31 2.64 2.92 2.43 2.86 2.79 2.02 2.35 3.16 3.24 3.43 4.33 3.52 3.40 3.70															
1.35 1.37 1.40 1.45 1.49 1.53 1.57 1.61 1.66 1.70 1.76 1.84 1.96 2.10 2.25 2.37 2.49 2.61															
2.45 2.84 2.97 2.72 2.57 2.36 2.56 3.02 4.83 4.00 3.96 6.68 6.42 9.08 9.86 16.15 12.30 12.60															
16.96 17.31 18.85 19.79 22.12 23.32 24.02 25.56 26.67 32.00 34.93 36.30 38.73 41.26 44.51 45.14 54.00 59.05															
20.98 21.17 21.36 21.65 21.99 22.17 22.29 22.43 22.55 32.70 43.18 43.36 45.65 48.26 50.67 50.97 52.00 52.50															
15.7 16.2 13.6 14.2 14.3 13.4 13.7 13.0 14.5 21.3 19.8 16.5 19.6 19.8 16.7 22.8															
.83 .86 .73 .75 .86 .89 .87 .82 .92 1.20 1.04 .83 1.03 1.00 .90 1.24															
4.7% 4.4% 4.3% 4.4% 3.9% 3.9% 4.7% 4.3% 4.1% 4.0% 3.8% 3.5% 3.1% 3.1% 3.0%															
CAPITAL STRUCTURE as of 3/31/20															
Total Debt \$3050.8 mill. Due in 5 Yrs \$725.0 mill.															
LT Debt \$2484.8 mill. LT Interest \$120.0 mill.															
(Total interest coverage: 3.1x)															
Leases, Uncapitalized Annual rentals \$8.2 mill.															
Pension Assets-9/19 \$521.8 mill.															
Oblig. \$751.4 mill.															
Pfd Stock \$242.0 mill. Pfd Div'd \$3.4 mill.															
Common Stock 51,235,146 shs. as of 5/5/20															
MARKET CAP: \$3.7 billion (Mid Cap)															
CURRENT POSITION 2018 2019 3/31/20															
(SMILL.)															
Cash Assets 4.4 5.8 108.4															
Other 655.2 608.7 610.4															
Current Assets 659.6 614.5 718.8															
Accts Payable 290.1 301.5 221.4															
Debt Due 729.1 783.2 566.0															
Other 302.5 384.1 365.1															
Current Liab. 1321.7 1468.8 1152.5															
Fix. Chg. Cov. 284% 272% 280%															
ANNUAL RATES															
Past 10 Yrs. Past 5 Yrs. Est'd '17-'19															
of change (per sh)															
Revenues -8.5% -1.0% 7.5%															
"Cash Flow" 5.5% 13.0% 5.5%															
Earnings 3.5% 9.5% 5.5%															
Dividends 4.0% 5.5% 5.0%															
Book Value 7.0% 7.0% 8.5%															
Fiscal Year Ends															
QUARTERLY REVENUES (\$ mill.) ^A															
Dec.31 Mar.31 Jun.30 Sep.30 Full Fiscal Year															
2017 495.1 663.4 323.5 258.7 1740.7															
2018 561.8 813.4 350.6 239.2 1965.0															
2019 602.0 803.5 321.3 225.6 1952.4															
2020 566.9 715.5 340 227.6 1850															
2021 590 770 360 235 1955															
Fiscal Year Ends															
EARNINGS PER SHARE ^{A B F}															
Dec.31 Mar.31 Jun.30 Sep.30 Full Fiscal Year															
2017 .99 2.36 .45 d.28 3.43															
2018 2.39 2.03 .52 d.51 4.33															
2019 1.32 3.04 d.09 d.74 3.52															
2020 1.24 2.54 .37 d.75 3.40															
2021 1.30 2.66 .45 d.71 3.70															
Cal-endar															
QUARTERLY DIVIDENDS PAID ^C															
Mar.31 Jun.30 Sep.30 Dec.31 Full Year															
2016 .49 .49 .49 .49 1.96															
2017 .525 .525 .525 .525 2.10															
2018 .5625 .5625 .5625 .5625 2.25															
2019 .5925 .5925 .5925 .5925 2.37															
2020 .6225 .6225															
(A) Fiscal year ends Sept. 30th. (B) Based on diluted shares outstanding. Excludes nonrecurring losses: '06, '76. Excludes gain from discontinued operations: '08, '94c. Next earnings report due late July. (C) Dividends paid in early January, April, July, and October. (D) Dividend reinvestment plan available. (E) Incl. deferred charges. In '19: \$1,171.6 mill., \$22.99/sh. (F) In millions. (G) City, egs. may not sum due to rounding or change in shares outstanding.															
Company's Financial Strength B++															
Stock's Price Stability 95															
Price Growth Persistence 60															
Earnings Predictability 65															
To subscribe call 1-800-VALUELINE															



(A) Diluted earnings. Excl. nonrec. gains (losses): '05, (11c); '06, 7c. Next eggs. report due early August. (B) Dividends historically paid early March, June, September, and December. † Div'd reinvestment and stock purchase plan avail. (C) In millions. (D) Totals may not sum due to rounding.

© 2020 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.

Company's Financial Strength A
Stock's Price Stability 80
Price Growth Persistence 75
Earnings Predictability 95

To subscribe call 1-800-VALUELINE

UGI CORP. NYSE-UGI				RECENT PRICE		30.96		P/E RATIO		10.4		Trailing: 11.2 Median: 17.0		RELATIVE P/E RATIO		0.57		DIV'D YLD		4.3%		VALUE LINE							
TIMELINESS 4 Lowered 12/13/19				High: 18.3		21.7		22.4		22.4		28.8		39.7		38.6		48.1		52.0		59.3		57.3		45.3		Target Price Range	
SAFETY 2 Raised 9/17/04				Low: 14.1		15.9		16.0		17.3		21.9		26.8		31.5		31.6		45.0		42.5		40.5		21.8		2023 2024 2025	
TECHNICAL 4 Lowered 3/20/20				<div>LEGENDS</div> <div>— 0.60 x Dividends p sh divided by Interest Rate</div> <div>- - - - Relative Price Strength</div> <div>3-for-2 split 9/14</div> <div>Options: Yes</div> <div>Shaded area indicates recession</div>																									
BETA .95 (1.00 = Market)				<div>3-for-2</div>																									
18-Month Target Price Range				<div>Target Price Range</div> <div>2023 2024 2025</div> <div>128</div> <div>96</div> <div>80</div> <div>64</div> <div>48</div> <div>40</div> <div>32</div> <div>24</div> <div>16</div> <div>12</div>																									
Low-High Midpoint (% to Mid)				<div>\$23-\$63 \$43 (40%)</div>																									
2023-25 PROJECTIONS				<div>Price Gain Ann'l Total</div> <div>High 70 (+125%) 25%</div> <div>Low 50 (+60%) 16%</div>																									
Institutional Decisions				<div>202019 302019 402019</div> <div>to Buy 175 321 217</div> <div>to Sell 255 166 251</div> <div>Hld's(000) 148912 160038 164809</div> <div>Percent shares traded 18 12 6</div>																									
2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021				© VALUE LINE PUB. LLC 23-25																									
24.63 31.10 33.01 34.24 41.27 35.25 34.01 36.31 38.56 42.10 47.92 38.65 32.84 35.18 43.94 35.03 35.95 38.10				Revenues per sh ^A 42.85																									
1.63 2.09 2.05 2.26 2.48 2.82 2.87 2.75 3.05 3.75 4.05 4.20 4.39 4.73 5.40 4.12 5.05 5.45				"Cash Flow" per sh 6.05																									
.81 1.15 1.10 1.18 1.33 1.57 1.59 1.37 1.17 1.59 1.92 2.01 2.05 2.29 2.74 2.28 2.90 3.25				Earnings per sh ^{AB} 3.70																									
.40 .43 .46 .48 .50 .52 .60 .68 .71 .74 .79 .89 .93 .96 1.02 1.15 1.32 1.34				Div'ds Decl'd per sh ^C 1.46																									
.87 1.01 1.21 1.39 1.44 1.85 2.11 2.15 2.01 2.84 2.64 2.83 3.26 3.67 3.30 3.37 3.35 3.45				Cap'l Spending per sh 3.55																									
5.43 6.35 6.95 8.26 8.80 9.78 11.10 11.79 13.21 14.59 15.39 15.55 16.46 18.18 21.14 18.27 20.00 21.95				Book Value per sh ^D 28.35																									
153.63 157.20 158.18 159.97 161.09 162.78 164.38 167.75 169.06 170.88 172.73 173.12 173.15 173.99 174.14 209.01 210.00 210.00				Common Shs Outst'g ^E 210.00																									
13.4 13.8 14.0 15.1 13.3 10.3 10.9 15.0 16.4 15.4 15.8 17.7 19.3 20.8 17.8 23.4 23.4 23.4				Avg Ann'l P/E Ratio 16.0																									
.71 .73 .76 .80 .80 .69 .69 .94 1.04 .87 .83 .89 1.01 1.05 .96 1.28 1.28 1.28				Relative P/E Ratio .90																									
3.7% 2.7% 3.0% 2.7% 2.9% 3.2% 3.5% 3.3% 3.7% 3.0% 2.6% 2.5% 2.3% 2.0% 2.1% 2.2% 2.1% 2.2%				Avg Ann'l Div'd Yield 2.4%																									
CAPITAL STRUCTURE as of 3/31/20				Total Debt \$6480.8 mill. Due in 5 Yrs \$2047 mill. LT Debt \$5800.2 mill. LT Interest \$257.8 mill. (Total interest coverage: 4.0x) (59% of Cap'l)																									
Leases, Uncapitalized Annual rentals \$100.4 mill. Pension Assets-9/19 \$563 mill. Oblig. \$773 mill.				32.0% 29.8% 34.8% 27.6% 30.6% 30.0% 31.4% 26.5% 26.5% 16.6% 17.0% 17.0% Income Tax Rate 17.0% 4.7% 3.8% 3.1% 3.9% 4.1% 5.3% 6.3% 6.6% 6.3% 5.6% 8.1% 8.6% Net Profit Margin 8.7% 44.0% 48.4% 40.0% 41.3% 43.6% 43.9% 43.1% 44.2% 47.0% 39.8% 42.0% 44.0% Long-Term Debt Ratio 51.0% 3256.7 4088.0 5580.7 6034.7 6092.7 6133.8 6616.9 7157.9 7827.9 9597.4 10000 10505 Common Equity Ratio 49.0% 3053.2 3204.5 4233.1 4480.2 4543.7 4994.1 5238.0 5537.0 5808.2 6687.8 7700 8865 Total Capital (\$mill) 12150 10.1% 7.4% 5.6% 6.6% 7.5% 7.7% 7.2% 7.2% 7.7% 5.6% 6.0% 6.5% Net Plant (\$mill) 13535 14.3% 11.8% 8.9% 11.2% 12.7% 13.1% 12.6% 12.9% 13.2% 10.8% 14.5% 15.0% Return on Total Cap'l 6.5% 14.3% 11.8% 8.9% 11.2% 12.7% 13.1% 12.6% 12.9% 13.2% 10.8% 14.5% 15.0% Return on Shr. Equity 13.0% 8.9% 6.0% 3.6% 6.1% 7.6% 7.4% 7.0% 7.5% 8.4% 5.6% 8.0% 9.0% Return on Com Equity 13.0% 38% 49% 60% 45% 40% 43% 45% 42% 36% 48% 45% 41% Retained to Com Eq 8.0% All Div'ds to Net Prof 39%																									
Pfd Stock None																													
Common Stock 208,267,174 shares as of 4/30/20																													
MARKET CAP: \$6.4 bill. (Large Cap)																													
CURRENT POSITION (SMILL.)																													
Cash Assets 452.6 447.1 297.3				BUSINESS: UGI Corp. operates six business segments: AmeriGas Propane (accounted for 24.3% of net income in 2019), UGI International (19.3%), Gas Utility (20.7%), Midstream & Marketing (27.4%), and Corp. & Other (8.3%). UGI Utilities distributes natural gas and electricity to over 655,000 customers mainly in Pennsylvania; 26%-owned AmeriGas Partners is the largest U.S. propane marketer, serving about 1.3 million users in 50 states. Acquired remaining 80% interest in Antargaz (3/04); Energy Transfer Partners (1/12). Vanguard Group owns 10.6% of stock; Blackrock, 10.3%; Officers/directors, 2.2% (12/19 proxy). Has 12,800 empl. President & CEO: John L. Walsh, Inc.: PA. Address: 460 N. Gulph Rd., King of Prussia, PA 19406. Tel.: 610-337-1000. Internet: www.ugicorp.com.																									
Other 1435.5 1119.1 1581.5																													
Current Assets 1888.1 1566.2 1878.8																													
Accts Payable 561.8 438.8 464.7																													
Debt Due 525.3 820.4 680.6																													
Other 645.0 767.7 970.8																													
Current Liab. 1732.1 2026.9 2116.1																													
Fix. Chg. Cov. 445% 445% 450%																													
ANNUAL RATES																													
Past 10 Yrs. Past 5 Yrs. Est'd '17-'19 to '23-'25																													
Revenues 5% -2.5% 2.0%																													
"Cash Flow" 6.5% 5.5% 4.0%																													
Earnings 6.0% 9.5% 7.0%																													
Dividends 7.5% 7.0% 6.0%																													
Book Value 8.0% 6.0% 6.5%																													
Fiscal Year Ends																													
QUARTERLY REVENUES (\$ mill.) ^A																													
Dec.31 Mar.31 Jun.30 Sep.30 Full Fiscal Year																													
2017 1680 2174 1153 1114 6120.7																													
2018 2125 2812 1441 1273 7651.2																													
2019 2200 2606 1364 1150 7320.4																													
2020 2007 2228 1755 1560 7550																													
2021 2120 2340 1865 1675 8000																													
Fiscal Year Ends																													
EARNINGS PER SHARE ^{A B}																													
Dec.31 Mar.31 Jun.30 Sep.30 Full Fiscal Year																													
2017 .91 1.31 .09 d.02 2.29																													
2018 1.01 1.69 .09 d.05 2.74																													
2019 .81 1.43 .13 d.09 2.28																													
2020 1.17 1.56 .22 d.05 2.90																													
2021 1.27 1.66 .35 d.03 3.25																													
Cal-endar																													
QUARTERLY DIVIDENDS PAID ^C																													
Mar.31 Jun.30 Sep.30 Dec.31 Full Year																													
2016 .23 .238 .238 .238 .94																													
2017 .238 .238 .25 .25 .98																													
2018 .25 .25 .26 .26 1.02																													
2019 .26 .26 .30 .325 1.15																													
2020 .325 .325																													
(A) Fiscal year ends Sept. 30. Quarterly sales and earnings may not sum to total due to rounding and/or change in share count. (B) Diluted earnings. Excludes nonrecurr. gains/(losses): '04, d6c; '05, 3c; '06, 5c; '07, 12c; '15, (41c); '16, 3c; '17, 17c; '18, \$1.32. Next egs. report due late July. (C) Dividends historically paid in early Jan., April, July, and Oct. (D) Div. reinvest. plan available. (E) Incl. intang. At 9/19: \$4,165 mill., \$19.93/sh. (F) In mill., adjusted for stock splits.																													
Company's Financial Strength				B++																									
Stock's Price Stability				90																									
Price Growth Persistence				75																									
Earnings Predictability				75																									
To subscribe call 1-800-VALUELINE																													

our fiscal 2020 (ends September 30th) bottom-line estimate, to \$2.90 per share. This would still represent a more-than-25% rise in share net, supported by a low single-digit revenue increase. However, we may need to temper our revenue and earnings estimates further, depending on how long the COVID-19 pandemic weighs on UGI's service territory. **Despite the challenging operating environment, the board recently approved a quarterly dividend hike.** The increase in the payout was more modest than UGI historically does, at about 1.5%, to \$0.33 per share. That said, when a good percentage of energy-related companies are slashing dividends, even a moderate increase seems like a bold move. **These shares are not overly compelling at the moment.** Our Timeliness Ranking System has UGI stock pegged to underperform the broader market averages in the coming year (Timeliness: 4). What's more, even after the recent downturn in UGI's price, the equity's 3- to 5-year appreciation potential is well below the Value Line median.

Bryan J. Fong May 29, 2020

The Value Line Investment Survey - Lookup Company Reports

Search Results (1)

Company ↑	Ticker	Alert	PDF	HTML	Industry ↑	Time/Perf Rank	Report Date
Dominion Energy	D				Electric Utility (East)	1 (T)	May 15, 2020

© 2020 Value Line, Inc. All Rights Reserved. This product is strictly for subscriber's own non-commercial, internal use. No part of it may be reproduced, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. VALUE LINE IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN OR ANY DAMAGES OR LOSSES ARISING FROM ANY USE OF THE INFORMATION CONTAINED HEREIN. Officers, directors, or employees of Value Line, Inc. and its affiliates and subsidiaries, and EULAV Asset Management, may own securities that are featured in this product. Nothing herein should be construed as an offer to buy or sell securities or to give individual investment advice. Value Line, the Value Line logo, The Value Line Investment Survey, The Most Trusted Name In Investment Research, "Smart research. Smarter investing.", Timeliness, and Safety are trademarks or registered trademarks of Value Line, Inc. and/or its affiliates in the United States and other countries. All other trademarks are the property of their respective owners. Value Line Arithmetic and Geometric Indices calculated by Thomson Reuters. Information supplied by Thomson Reuters. If we experience technical difficulty, online access is not guaranteed. The Timeliness rank on a particular stock may be suspended in the event of news developments.

S&P Dow Jones Indices

1/31/2020

S&P 500 EARNINGS AND ESTIMATE REPORT

S&P Senior Index Analyst

howard.silverblatt@spglobal.com

S&P Dow Jones Indices

S&P 500 Index and Sector tax rates

SECTOR	Q3 2019	Q2 2019	Q3 2018	Q3 2017	S&P 500 quarterly tax rates		S&P 500 annual tax rates	
S&P 500	18.94%	18.59%	18.38%	25.44%	Sep-19	18.94%	9MoSep,'19	18.94%
Communication Services	18.88%	17.90%	15.71%	34.53%	Jun-19	18.59%	2018	17.72%
Consumer Discretionary	17.63%	20.93%	17.66%	31.53%	Mar-19	19.29%	2017	24.37%
Consumer Staples	20.78%	26.81%	19.94%	27.35%	Dec-18	13.22%	2016	26.44%
Energy	63.60%	36.09%	27.09%	20.05%	Sep-18	18.38%		
Financials	19.57%	19.29%	19.56%	29.16%	Jun-18	19.58%		
Health Care	17.27%	16.47%	16.91%	21.57%	Mar-18	18.81%		
Industrials	19.70%	22.15%	37.06%	29.16%	Dec-17	20.38%		
Information Technology	15.23%	12.16%	11.55%	18.39%	Sep-17	25.44%		
Materials	22.01%	29.18%	24.17%	27.33%	Jun-17	25.89%		
Real Estate	4.02%	2.10%	2.62%	2.99%	Mar-17	25.44%		
Utilities	13.45%	11.84%	16.31%	29.93%	Dec-16	24.29%		

Q4 2019

Issues with diluted share counts for Q4 2019 over Q4 2018 EPS

-> Therefore adding at least a 4% tailwind to their current EPS

Issues	223	% of issues
Q4,'19 lower shares than Q4,'18	159	71.30%
4% lower shares	61	27.35%
Q4,'19 higher shares than Q4,'18	60	26.91%
4% higher shares	8	3.59%

OPERATING EARNINGS CONTRIBUTION

	estimate Dec-20	estimate Sep-20	estimate Jun-20	estimate Mar-20	estimate Dec-19	Sep-19	Jun-19	Mar-19	Dec-18	Sep-18	Jun-18	Mar-18	Dec-17	Sep-17	Jun-17	Mar-17	Dec-16
Energy	4.31%	4.84%	4.80%	4.19%	3.19%	4.96%	4.29%	3.10%	8.27%	6.34%	5.28%	5.24%	2.63%	3.62%	2.75%	4.07%	0.45%
Materials	2.39%	2.53%	3.01%	2.38%	2.30%	2.36%	2.84%	2.29%	2.66%	2.43%	3.34%	3.18%	2.23%	2.77%	3.28%	3.27%	1.98%
Industrials	9.27%	9.67%	9.84%	8.37%	8.87%	10.24%	9.82%	9.44%	10.91%	10.21%	10.77%	10.54%	9.97%	10.96%	11.23%	9.41%	10.06%
Consumer Discretionary	7.91%	8.51%	8.35%	7.52%	7.73%	8.39%	8.02%	7.67%	8.80%	8.10%	10.93%	10.45%	11.80%	11.77%	11.89%	11.62%	12.70%
Consumer Staples	6.49%	6.80%	6.70%	6.42%	7.42%	6.97%	6.81%	6.59%	7.25%	6.65%	7.06%	6.91%	8.19%	8.59%	8.52%	8.13%	9.26%
Health Care	15.55%	15.99%	16.50%	16.85%	14.41%	13.15%	14.36%	14.52%	13.63%	12.64%	12.80%	12.80%	13.05%	13.99%	14.80%	13.95%	14.20%
Financials	17.58%	17.38%	17.94%	19.30%	18.87%	21.59%	21.56%	24.32%	10.44%	20.28%	20.10%	18.34%	16.71%	16.81%	19.69%	20.37%	18.06%
Information Technology	22.48%	19.41%	18.73%	19.83%	23.04%	17.69%	17.76%	17.13%	22.67%	18.65%	21.85%	24.09%	29.31%	22.30%	20.33%	20.57%	25.74%
Communication Services	10.39%	9.85%	10.11%	10.35%	10.05%	8.84%	9.73%	10.00%	11.33%	9.32%	3.69%	3.29%	1.90%	2.95%	3.09%	3.15%	3.08%
Utilities	2.38%	3.84%	2.75%	3.51%	2.66%	4.13%	2.72%	3.47%	2.08%	3.82%	2.75%	3.59%	2.65%	4.36%	2.91%	3.77%	2.48%
Real Estate	1.26%	1.18%	1.27%	1.28%	1.48%	1.69%	2.08%	1.47%	1.96%	1.55%	1.44%	1.56%	1.55%	1.89%	1.51%	1.69%	1.99%
S&P 500	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

	S&P 500 2020 EST OPER P/E	S&P 500 5YR PROJ ANNUAL GROWTH %	S&P 500 PEG	MIDCAP 2020 EST OPER P/E	MIDCAP 5YR PROJ ANNUAL GROWTH %	MIDCAP PEG	SMALLCAP 2020 EST OPER P/E	SMALLCAP 5YR PROJ ANNUAL GROWTH %	SMALLCAP PEG
Index	18.81	11.40	1.65	17.80	11.03	1.61	17.64	12.52	1.41
Communication Services	19.27	14.48	1.33	15.04	14.06	1.07	43.67	24.05	1.82
Consumer Discretionary	22.26	16.42	1.36	16.28	12.71	1.28	13.48	13.43	1.00
Consumer Staples	20.43	6.81	3.00	16.85	15.29	1.10	19.27	10.60	1.82
Energy	16.24	8.87	1.83	31.08	1.65	18.82	64.22	1.02	63.26
Financials	13.19	10.12	1.30	12.19	10.90	1.12	12.40	14.08	0.88
Health Care	16.05	10.43	1.54	25.91	14.95	1.73	28.01	13.99	2.00
Industrials	18.32	9.42	1.95	17.41	12.61	1.38	16.39	13.09	1.25
Information Technology	22.80	13.31	1.71	20.96	13.43	1.56	19.02	14.79	1.29
Materials	18.28	9.65	1.89	15.57	7.75	2.01	14.83	3.04	4.88
Real Estate	44.70	6.89	6.49	32.19	3.11	10.35	45.46	6.93	6.56
Utilities	21.16	5.65	3.75	21.24	5.81	3.66	27.37	6.47	4.23

S&P 500 operating margins:

QTR	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008*	2007	2006
Q4 (Q4'19 est)	10.73%	10.10%	10.27%	9.27%	7.98%	8.98%	9.76%	8.04%	8.70%	8.68%	7.27%	-0.04%	5.68%	8.86%
Q3	11.21%	12.13%	10.16%	9.86%	8.97%	10.10%	9.63%	8.92%	9.51%	8.95%	6.94%	5.96%	8.06%	9.60%
Q2	11.41%	11.55%	10.14%	9.03%	9.29%	10.07%	9.51%	9.41%	9.44%	8.83%	6.19%	6.11%	9.41%	9.35%
Q1	11.21%	11.40%	9.84%	8.75%	9.45%	9.76%	9.52%	9.07%	8.99%	8.34%	4.56%	6.25%	9.23%	9.03%

*Q4,'08 is the only negative in index history

OBSERVATION	Q4 2019E	2019E	2020E	PRICE	2019E P/E	2020E P/E	OBSERVATION
3/29/2018	\$46.27	\$172.62		2640.87	15.30		3/29/2018
6/29/2018	\$46.69	\$175.01		2716.31	15.52		6/29/2018
9/28/2018	\$46.95	\$176.49		2913.98	16.51		9/28/2018
12/31/2018	\$45.32	\$171.74		2506.85	14.60		12/31/2018
3/29/2019	\$44.41	\$165.34	\$186.36	2883.71	17.44	15.47	3/29/2019
6/28/2019	\$43.81	\$164.18	\$184.01	2941.76	17.92	15.99	6/28/2019
9/30/2019	\$42.21	\$161.15	\$180.06	2976.74	18.47	16.53	9/30/2019
12/31/2019	\$40.19	\$158.14	\$175.52	3230.78	20.43	18.41	12/31/2019
Current	\$39.18	\$157.13	\$174.59	3225.52	20.53	18.47	Current
Change QTD	-2.51%	-0.64%	-0.53%	-0.16%	0.48%	0.37%	Change QTD
Change Fr 3/2019	-11.78%	-4.97%	-6.32%	11.85%	17.70%	19.39%	Change Fr 3/2019

Q4 2019

Of the 227 issues (505 in the index) with full operating comparative data

152 beat, 57 missed, and 18 met their estimates; 144 of 224 (64.3%) beat on sales

SECTOR	ISSUES				PERCENTAGE			
	REPORTED	BEAT	MISSED	MET	REPORTED	BEAT	MISSED	MET
Energy	10	5	5	0	35.71%	50.00%	50.00%	0.00%
Materials	15	9	5	1	53.57%	60.00%	33.33%	6.67%
Industrials	45	25	17	3	64.29%	55.56%	37.78%	6.67%
Consumer Discretionary	19	15	3	1	29.69%	78.95%	15.79%	5.26%
Consumer Staples	16	10	1	5	48.48%	62.50%	6.25%	31.25%
Health Care	25	17	4	4	40.98%	68.00%	16.00%	16.00%
Financials	45	33	10	2	68.18%	73.33%	22.22%	4.44%
Information Technology	31	27	3	1	44.29%	87.10%	9.68%	3.23%
Communication Services	7	5	2	0	26.92%	71.43%	28.57%	0.00%
Utilities	4	2	2	0	14.29%	50.00%	50.00%	0.00%
Real Estate	10	4	5	1	32.26%	40.00%	50.00%	10.00%
S&P 500	227	152	57	18	44.95%	66.96%	25.11%	7.93%

Data as of the close of:

S&P 500 close of:	1/31/2020
Dividend yield (last 12 months: Jan,'20)	3225.52
Dividend yield (current indicated rate)	1.82%
	1.88%

QUARTER END	PRICE	OPERATING EARNINGS	AS REPORTED EARNINGS		OPERATING EARNINGS	AS REPORTED EARNINGS	12 MONTH EARNINGS PER SHARE	
		PER SHR (ests are bottom up)	PER SHR (ests are bottom up)		P/E (ests are bottom up)	P/E (ests are bottom up)	OPERATING EARNINGS (ests are bottom up)	AS REPORTED EARNINGS (ests are bottom up)
ESTIMATES								
12/31/2021		\$50.95	\$43.71	111.249%	16.61	18.64	\$194.23	\$173.08
9/30/2021		\$50.35	\$45.06		17.04	18.90	\$189.34	\$170.69
6/30/2021		\$48.15	\$43.23		17.48	19.10	\$184.56	\$168.84
3/31/2021		\$44.78	\$41.09		17.96	19.46	\$179.55	\$165.75
12/31/2020		\$46.06	\$41.31	111.119%	18.47	19.87	\$174.59	\$162.33
9/30/2020		\$45.57	\$43.21		19.23	20.79	\$167.71	\$155.12
6/30/2020		\$43.14	\$40.15		19.92	22.11	\$161.95	\$145.91
3/31/2020		\$39.82	\$37.66	103.641%	20.29	22.93	\$158.95	\$140.69
12/31/2019 (61.0%)	3230.78	\$39.18	\$34.11	-1.583%	20.53	23.37	\$157.12	\$138.05
				11.847%	20.56	23.40 (P/E on Dec,'19 price)		
ACTUALS								
9/30/2019	2976.74	\$39.81	\$33.99		19.46	22.40	\$152.97	\$132.90
6/30/2019	2941.76	\$40.14	\$34.93		19.04	21.75	\$154.54	\$135.27
3/31/2019	2834.40	\$37.99	\$35.02		18.52	21.09	\$153.05	\$134.39
12/31/2018	2506.85	\$35.03	\$28.96		16.54	18.94	\$151.60	\$132.39
9/30/2018	2913.98	\$41.38	\$36.36		19.37	22.35	\$150.42	\$130.39
6/30/2018	2718.37	\$38.65	\$34.05		19.37	22.19	\$140.37	\$122.48
3/31/2018	2640.87	\$36.54	\$33.02		19.97	22.88	\$132.23	\$115.44
12/31/2017	2673.61	\$33.85	\$26.96		21.47	24.33	\$124.51	\$109.88
9/30/2017	2519.36	\$31.33	\$28.45		21.25	23.53	\$118.56	\$107.08
6/30/2017	2423.41	\$30.51	\$27.01		20.91	23.30	\$115.92	\$104.02
3/31/2017	2362.72	\$28.82	\$27.46		21.26	23.56	\$111.11	\$100.29
12/31/2016	2238.83	\$27.90	\$24.16		21.07	23.68	\$106.26	\$94.55
9/30/2016	2168.27	\$28.69	\$25.39		21.38	24.34	\$101.42	\$89.09
6/30/2016	2098.86	\$25.70	\$23.28		21.38	24.15	\$98.17	\$86.92
3/31/2016	2059.74	\$23.97	\$21.72		20.89	23.83	\$98.61	\$86.44

12/31/2015	2043.94	\$23.06	\$18.70	20.35	23.62	\$100.45	\$86.53
9/30/2015	1920.03	\$25.44	\$23.22	18.44	21.18	\$104.14	\$90.66
6/30/2015	2063.11	\$26.14	\$22.80	19.05	21.74	\$108.30	\$94.91
3/31/2015	2067.89	\$25.81	\$21.81	18.55	20.84	\$111.50	\$99.25
12/31/2014	2058.90	\$26.75	\$22.83	18.22	20.12	\$113.01	\$102.31
9/30/2014	1972.29	\$29.60	\$27.47	17.22	18.61	\$114.51	\$105.96
6/30/2014	1960.23	\$29.34	\$27.14	17.53	19.01	\$111.83	\$103.12
3/31/2014	1872.34	\$27.32	\$24.87	17.20	18.57	\$108.85	\$100.85
12/31/2013	1848.36	\$28.25	\$26.48	17.23	18.45	\$107.30	\$100.20
9/30/2013	1681.55	\$26.92	\$24.63	16.45	17.82	\$102.20	\$94.37
6/30/2013	1606.28	\$26.36	\$24.87	16.18	17.66	\$99.28	\$90.95
3/31/2013	1569.19	\$25.77	\$24.22	15.96	17.89	\$98.35	\$87.70
12/31/2012	1426.19	\$23.15	\$20.65	14.73	16.49	\$96.82	\$86.51
9/30/2012	1440.67	\$24.00	\$21.21	14.79	16.66	\$97.40	\$86.50
6/30/2012	1362.16	\$25.43	\$21.62	13.80	15.49	\$98.69	\$87.92
3/31/2012	1408.47	\$24.24	\$23.03	14.35	15.91	\$98.12	\$88.54
12/31/2011	1257.60	\$23.73	\$20.64	13.04	14.46	\$96.44	\$86.95
9/30/2011	1131.42	\$25.29	\$22.63	11.95	13.01	\$94.64	\$86.98
6/30/2011	1320.64	\$24.86	\$22.24	14.53	15.75	\$90.91	\$83.87
3/31/2011	1325.83	\$22.56	\$21.44	15.25	16.31	\$86.95	\$81.31
12/31/2010	1257.64	\$21.93	\$20.67	15.01	16.26	\$83.77	\$77.35
9/30/2010	1141.20	\$21.56	\$19.52	14.45	15.88	\$79.00	\$71.86
6/30/2010	1030.71	\$20.90	\$19.68	14.08	15.36	\$73.22	\$67.10
3/31/2010	1169.43	\$19.38	\$17.48	17.68	19.19	\$66.13	\$60.93
12/31/2009	1115.10	\$17.16	\$15.18	19.61	21.88	\$56.86	\$50.97
9/30/2009	1057.08	\$15.78	\$14.76	26.69	84.30	\$39.61	\$12.54
6/30/2009	919.32	\$13.81	\$13.51	23.10	122.41	\$39.79	\$7.51
3/31/2009	797.87	\$10.11	\$7.52	18.56	116.31	\$43.00	\$6.86
12/31/2008	903.25	-\$0.09	-\$23.25	18.24	60.70	\$49.51	\$14.88
9/30/2008	1166.36	\$15.96	\$9.73	17.99	25.38	\$64.82	\$45.95
6/30/2008	1280.00	\$17.02	\$12.86	18.36	24.92	\$69.73	\$51.37
3/31/2008	1322.70	\$16.62	\$15.54	17.23	21.90	\$76.77	\$60.39
12/31/2007	1468.36	\$15.22	\$7.82	17.79	22.19	\$82.54	\$66.18
9/30/2007	1526.75	\$20.87	\$15.15	17.09	19.42	\$89.31	\$78.60
6/30/2007	1503.35	\$24.06	\$21.88	16.44	17.70	\$91.47	\$84.92
3/31/2007	1420.86	\$22.39	\$21.33	15.90	17.09	\$89.36	\$83.15
12/31/2006	1418.30	\$21.99	\$20.24	16.17	17.40	\$87.72	\$81.51
9/30/2006	1335.85	\$23.03	\$21.47	15.55	17.00	\$85.92	\$78.57
6/30/2006	1270.20	\$21.95	\$20.11	15.54	17.05	\$81.73	\$74.49
3/31/2006	1294.83	\$20.75	\$19.69	16.35	17.82	\$79.20	\$72.67
12/31/2005	1248.29	\$20.19	\$17.30	16.33	17.85	\$76.45	\$69.93
9/30/2005	1228.81	\$18.84	\$17.39	16.56	18.46	\$74.21	\$66.57
6/30/2005	1191.33	\$19.42	\$18.29	16.49	18.80	\$72.25	\$63.36
3/31/2005	1180.59	\$18.00	\$16.95	16.91	19.57	\$69.81	\$60.32
12/31/2004	1211.92	\$17.95	\$13.94	17.91	20.70	\$67.68	\$58.55
9/30/2004	1114.58	\$16.88	\$14.18	17.25	19.29	\$64.61	\$57.77
6/30/2004	1140.84	\$16.98	\$15.25	18.36	20.32	\$62.14	\$56.15
3/31/2004	1126.21	\$15.87	\$15.18	19.39	21.66	\$58.08	\$52.00
12/31/2003	1111.92	\$14.88	\$13.16	20.33	22.81	\$54.69	\$48.74
9/30/2003	995.97	\$14.41	\$12.56	19.25	25.82	\$51.75	\$38.58
6/30/2003	974.50	\$12.92	\$11.10	19.91	28.21	\$48.95	\$34.55
3/31/2003	848.18	\$12.48	\$11.92	17.79	27.97	\$47.67	\$30.32
12/31/2002	879.82	\$11.94	\$3.00	19.11	31.89	\$46.04	\$27.59
9/30/2002	815.28	\$11.61	\$8.53	18.51	27.14	\$44.04	\$30.04
6/30/2002	989.81	\$11.64	\$6.87	23.80	37.02	\$41.59	\$26.74
3/31/2002	1147.39	\$10.85	\$9.19	29.44	46.45	\$38.97	\$24.70
12/31/2001	1148.08	\$9.94	\$5.45	29.55	46.50	\$38.85	\$24.69
9/30/2001	1040.94	\$9.16	\$5.23	24.77	36.77	\$42.02	\$28.31
6/30/2001	1224.38	\$9.02	\$4.83	26.03	33.28	\$47.03	\$36.79
3/31/2001	1160.33	\$10.73	\$9.18	21.94	25.54	\$52.89	\$45.44
12/31/2000	1320.28	\$13.11	\$9.07	23.52	26.41	\$56.13	\$50.00
9/30/2000	1436.51	\$14.17	\$13.71	25.30	26.75	\$56.79	\$53.70
6/30/2000	1454.60	\$14.88	\$13.48	26.17	28.02	\$55.59	\$51.92
3/31/2000	1498.58	\$13.97	\$13.74	27.79	29.41	\$53.92	\$50.95
12/31/1999	1469.25	\$13.77	\$12.77	28.43	30.50	\$51.68	\$48.17
9/30/1999	1282.71	\$12.97	\$11.93	25.98	29.18	\$49.38	\$43.96
6/30/1999	1372.71	\$13.21	\$12.51	29.29	33.46	\$46.86	\$41.02
3/31/1999	1286.37	\$11.73	\$10.96	28.54	33.52	\$45.08	\$38.38
12/31/1998	1229.23	\$11.47	\$8.56	27.77	32.60	\$44.27	\$37.71
9/30/1998	1017.01	\$10.45	\$8.99	23.07	26.70	\$44.09	\$38.09
6/30/1998	1133.84	\$11.43	\$9.87	25.38	29.10	\$44.67	\$38.97
3/31/1998	1101.75	\$10.92	\$10.29	24.83	27.86	\$44.37	\$39.54
12/31/1997	970.43	\$11.29	\$8.94	22.05	24.43	\$44.01	\$39.72
9/30/1997	947.28	\$11.03	\$9.87	21.66	23.31	\$43.73	\$40.64
6/30/1997	885.14	\$11.13	\$10.44	20.77	21.83	\$42.62	\$40.55
3/31/1997	757.12	\$10.56	\$10.47	18.11	18.82	\$41.80	\$40.24
12/31/1996	740.74	\$11.01	\$9.86	18.23	19.13	\$40.63	\$38.73
9/30/1996	687.33	\$9.92	\$9.78	17.44	19.09	\$39.40	\$36.00
6/30/1996	670.63	\$10.31	\$10.13	17.08	19.21	\$39.26	\$34.91
3/31/1996	645.50	\$9.39	\$8.96	16.79	18.96	\$38.45	\$34.04
12/31/1995	615.93	\$9.78	\$7.13	16.34	18.14	\$37.70	\$33.96
9/30/1995	584.41	\$9.78	\$8.69	15.92	16.61	\$36.72	\$35.18
6/30/1995	544.75	\$9.50	\$9.26	15.58	15.82	\$34.97	\$34.43

3/31/1995	500.71	\$8.64	\$8.88	15.07	15.38	\$33.22	\$32.55
12/31/1994	459.27	\$8.80	\$8.35	14.47	15.01	\$31.75	\$30.60
9/30/1994	462.71	\$8.03	\$7.94	15.37	16.93	\$30.11	\$27.33
6/30/1994	444.27	\$7.75	\$7.38	15.32	17.63	\$29.00	\$25.20
3/31/1994	445.77	\$7.17	\$6.93	16.02	19.63	\$27.82	\$22.71
12/31/1993	466.45	\$7.16	\$5.08	17.34	21.31	\$26.90	\$21.89
9/30/1993	458.93	\$6.92	\$5.81	18.10	22.49	\$25.35	\$20.41
6/30/1993	450.53	\$6.57	\$4.89	19.13	23.31	\$23.55	\$19.33
3/31/1993	451.67	\$6.25	\$6.11	20.35	22.77	\$22.19	\$19.84
12/31/1992	435.71	\$5.61	\$3.60	20.88	22.82	\$20.87	\$19.09
9/30/1992	417.80	\$5.12	\$4.73	21.01	23.16	\$19.89	\$18.04
6/30/1992	408.14	\$5.21	\$5.40	20.53	23.94	\$19.88	\$17.05
3/31/1992	403.69	\$4.93	\$5.36	20.74	24.93	\$19.46	\$16.19
12/31/1991	417.09	\$4.63	\$2.55	21.61	26.12	\$19.30	\$15.97
9/30/1991	387.86	\$5.11	\$3.74	19.71	21.77	\$19.68	\$17.62
6/30/1991	371.16	\$4.79	\$4.54	18.07	19.12	\$20.54	\$19.41
3/31/1991	375.22	\$4.77	\$5.14	17.20	17.92	\$21.81	\$20.94
12/31/1990	330.22	\$5.01	\$4.40	14.58	15.47	\$22.65	\$21.34
9/30/1990	306.05	\$5.97	\$5.33	13.03	14.08	\$23.48	\$21.74
6/30/1990	358.02	\$6.06	\$6.07	15.53	16.84	\$23.05	\$21.26
3/31/1990	339.94	\$5.61	\$5.54	14.45	15.69	\$23.52	\$21.67
12/31/1989	353.40	\$5.84	\$4.80	14.53	15.45	\$24.32	\$22.87
9/30/1989	349.15	\$5.54	\$4.85	14.05	14.74	\$24.85	\$23.69
6/30/1989	317.98	\$6.53	\$6.48	12.46	12.61	\$25.53	\$25.22
3/31/1989	294.87	\$6.41	\$6.74	11.77	11.81	\$25.05	\$24.96
12/31/1988	277.72	\$6.37	\$5.62	11.51	11.69	\$24.12	\$23.75
9/30/1988	271.91	\$6.22	\$6.38				
6/30/1988	273.50	\$6.05	\$6.22				
3/31/1988	258.89	\$5.48	\$5.53				

Operating earnings: Income from product (goods and services), excludes corporate (M&A, financing, layoffs), and unusual items
As Reported earnings: Income from continuing operations, also known GAAP (Generally Accepted Accounting Principles) and As Reported
Bottom up estimate: Capital IQ consensus estimate for specific issue, building from the bottom up to the index level estimate

Actual earnings are bottom up

Please note the disclaimer, which refers to the entire file's content:

These materials have been prepared solely for informational purposes based upon information generally available to the public from sources believed to be reliable. S&P Dow Jones Indices, its affiliates, and its third-party data providers and licensors (collectively "S&P Dow Jones Indices Parties") do not guarantee the accuracy, completeness, timeliness or availability of the Content (index data, ratings, credit-related analyses and data, model, software or other application or output therefore). S&P Dow Jones Indices Parties are not responsible for any errors or omissions, regardless of the cause, for the results obtained from the use of the Content. THE CONTENT IS PROVIDED ON AN "AS IS" BASIS. S&P DOW JONES INDICES PARTIES DISCLAIM ANY AND ALL EXPRESS OR IMPLIED WARRANTIES, INCLUDING, BUT NOT LIMITED TO, ANY WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE OR USE, FREEDOM FROM BUGS, SOFTWARE ERRORS OR DEFECTS, THAT THE CONTENT'S FUNCTIONING WILL BE UNINTERRUPTED OR THAT THE CONTENT WILL OPERATE WITH ANY SOFTWARE OR HARDWARE CONFIGURATION. In no event shall S&P Dow Jones Indices Parties be liable to any party for any direct, indirect, incidental, exemplary, compensatory, punitive, special or consequential damages, costs, expenses, legal fees, or losses (including, without limitation, lost income or lost profits and opportunity costs) in connection with any use of the Content even if advised of the possibility of such damages. Past performance of the Index is not an indication of future results. The Index returns shown do not represent the results of actual trading of investible assets/securities.

Dominion Energy MediaRoom

Dominion Energy Agrees to Sell Gas Transmission, Storage Assets to Berkshire Hathaway Energy-- Strategic Repositioning Toward 'Pure-Play' State-Regulated, Sustainability-Focused Utility Operations

- Pro forma company combines premier state-regulated utility operations with comprehensive net zero targets including one of the nation's largest zero-carbon power generation investment programs
- Upward revision to long-term operating earnings-per-share growth rate guidance
- Rebased dividend to reflect revised model; peer-aligned payout and increased long-term growth rate
- Improved credit profile and balance sheet position company for largest-ever capex plan
- All-cash transaction valued at nearly \$10 billion, including assumption of debt
- Cash proceeds expected to be used to repurchase shares
- Divestiture expected to close in fourth quarter of 2020, subject to regulatory approvals

RICHMOND, Va., July 5, 2020 /PRNewswire/ -- Dominion Energy (NYSE: D) today announced that it has executed a definitive agreement to sell substantially all of its Gas Transmission & Storage segment assets to an affiliate of Berkshire Hathaway Inc. (NYSE: BRK.A) in a transaction valued at \$9.7 billion, including the assumption of \$5.7 billion of existing indebtedness.

Thomas F. Farrell, II, Dominion Energy chairman, president, and chief executive officer, said:

"Today's announcement further reflects Dominion Energy's focus on its premier state-regulated, sustainability-focused utilities that operate in some of the most attractive regions in the country.

"Over the past several years the company has taken a series of steps – including mergers with Questar Corporation and SCANA Corporation, and the divestiture of Blue Racer Midstream and merchant generation assets – to increase materially the state-regulated nature of our profile, enhance the customer experience, strengthen our balance sheet, and improve transparency and predictability. Our mission over that period has remained the same: providing round-the-clock affordable and sustainable energy, world-class customer service, and meaningful community engagement.

"We offer an industry-leading clean-energy profile which includes a comprehensive net zero target by 2050 for both carbon and methane emissions as well as one of the nation's largest zero-carbon electric generation and storage investment programs. Over the next 15 years we plan to invest up to \$55 billion in emissions reduction technologies including zero-carbon generation and energy storage, gas distribution line replacement, and renewable natural gas. In addition, between 2018 and 2025 we expect to retire more than four gigawatts of coal- and oil-fired electric generation.

"This narrowing of focus will also allow us to increase our long-term earnings growth rate guidance by around 30 percent. Our rebased dividend policy better reflects our revised operating and financial strengths, aligns with our best-in-class industry peers and allows us to grow our dividend much more rapidly than before.

"This transaction represents another significant step in our evolution as a company, allowing us to focus even more on fulfilling utility customer needs and positioning us for a bright and increasingly sustainable future."

Warren Buffett, chairman of Berkshire Hathaway, said: "I admire Tom Farrell for his exceptional leadership across the energy industry as well as within Dominion Energy. We are very proud to be adding such a great portfolio of natural gas assets to our already strong energy business."

Pro-forma operating profile

Dominion Energy expects that up to 90 percent of its future operating earnings will come from its portfolio of best-in-class electric and natural gas state-regulated utility companies centered around five key states: Virginia, the Carolinas, Ohio, and Utah. Retained non-state regulated utility operations, most notably a 50 percent passive and unlevered interest in Cove Point — a bidirectional LNG facility in Maryland — and the company's zero-carbon nuclear and solar contracted generation fleet, represent high-quality, long-term contracted, regulated-like assets with virtually no direct commodity exposure.

The Gas Transmission & Storage segment will be eliminated from Dominion Energy's future reporting and operating structure. Dominion Energy's retained interest in Cove Point will be reported under the Contracted Generation operating segment (which will be renamed Contracted Assets). The company will also retain its investments in renewable natural gas, earnings from which will be reported in Gas Distribution segment results.

Transaction overview

Dominion Energy has executed a definitive agreement to sell gas transmission and storage assets – including more than 7,700 miles of natural gas storage and transmission pipelines and about 900 billion cubic feet of gas storage that the company currently operates – to an affiliate of Berkshire Hathaway Energy in a transaction valued at approximately \$9.7 billion, including the assumption of about \$5.7 billion of existing indebtedness which will reduce Dominion Energy's total leverage. The buyer will also make a cash payment of approximately \$4 billion to Dominion Energy upon closing.

Said Farrell:

"Dominion Energy's best-in-class gas transmission and storage business has been a major component of our success. Our talented employees set the standard for industry operating, environmental and safety performance and provide our customers with reliable, affordable, and safe service. They will be joining another of the foremost corporate organizations in Berkshire Hathaway Energy which has agreed to provide significant protections for existing employees and to honor existing union commitments."

Assets covered by the sale agreement include the company's ownership interests in Dominion Energy Transmission, Questar Pipeline (including Overthrust and White River Hub), Carolina Gas Transmission, Iroquois Gas Transmission System (50 percent interest), legacy gathering and processing operations, farmout acreage, as well as a 25 percent operating interest in Cove Point. These assets will be reclassified as discontinued operations for GAAP reporting and excluded from operating earnings for full-year 2020. The company's interest in the Atlantic Coast Pipeline is not included in the transaction.

The transaction is expected to close during the fourth quarter. It requires Hart-Scott-Rodino clearance as well as approval from the U.S. Department of Energy.

Use of proceeds

The Dominion Energy Board of Directors has authorized the repurchase of common shares using after-tax adjusted transaction proceeds which the company estimates could total approximately \$3 billion. This new authority has immediate effect and material repurchases are planned for late 2020 following transaction closing. Share repurchases are subject to market conditions, applicable securities laws, and other factors.

Operating earnings guidance

To reflect today's announcements, Dominion Energy is revising its 2020 operating earnings guidance. The company now expects 2020 operating earnings of \$3.37 to \$3.63 per share. The company's previous guidance was \$4.25 to \$4.60 per-share.

Dominion Energy expects 2021 operating earnings per share to grow around 10 to 11 percent over 2020, reflecting the full-year impact of planned share repurchases, and by about 6.5 percent annually starting in 2022, off a 2021 base. This represents a 1.5 percentage point, or approximately 30 percent, increase from previous long-term earnings per share growth guidance.

Dividend guidance

The company now expects to target an approximately 65 percent payout ratio to be effective upon completion of the transaction. This new payout ratio implies a 2021 dividend payment of around \$2.50 per share. The projected reduction in the annual dividend reflects the absence of income from the divested assets and a revision to the company's target payout ratio to align with best-in-class industry peers.

Beginning in 2022, the company expects annual dividend-per-share increases of approximately 6 percent per year. This represents a significant increase from previous long-term dividend per-share growth guidance of 2.5 percent.

For 2020, the company has made two quarterly payments of 94 cents per share in March and June. The company expects to make an additional payment of 94 cents per share in September and currently expects a fourth payment in December 2020 of approximately 63 cents reflecting the expected timing of transaction closing.

As is customary, all dividend declarations are subject to approval by the Board of Directors.

Credit and fixed income

Dominion Energy expects this strategic repositioning to be credit positive given the reduction of nearly \$6 billion of debt, the material increase in the percentage of cash flow that comes from state-regulated utilities, the retention of 50 percent of Cove Point unlevered cash flows, and a peer-aligned dividend payout ratio.

Dominion Energy continues to target single-A ratings for OpCos and high-BBB ratings for the parent company (DEI). Similarly, the company expects funds from operations (or cash from operations pre-working capital) to debt to continue to be in the "mid-teens" percent range.

Existing Dominion Energy Gas Holdings (DEGH) and Questar Pipeline as well as Iroquois Gas Transmission unconsolidated indebtedness will convey to the buyer. Berkshire Hathaway Energy, which is A-rated, has indicated it plans to support the existing credit profile of DEGH by foregoing the refinancing of some \$1.2 billion of scheduled maturities over the next 12 months as well as consideration of other credit-enhancing measures including additional deleveraging past 2021, as needed.

Conference call

The company will host an investor update conference call at 9 a.m. ET on Monday, July 6, 2020 to discuss today's announcement.

Domestic callers should dial 1-800-341-6228. International callers should dial 1-334-777-6993. The passcode for the conference call is 64801632#. Participants should dial in 20 to 30 minutes prior to the scheduled start time.

Call materials will be posted in advance and are available at investors.dominionenergy.com. A live webcast of the conference call will also be available on the website.

A replay of the conference call will be available beginning at about 2 p.m. ET July 6 and lasting until 11 p.m. ET July 12. Domestic callers may access the recording by dialing 1-877-919-4059. International callers should dial 1-334-323-0140. The PIN for the replay is 95663196. Additionally, a replay of the webcast will be available on the investor website by the end of the day July 6.

Legal and financial advisors

McGuireWoods LLP served as legal counsel to Dominion Energy. Barclays acted as the company's lead

financial advisor for the transaction. Morgan Stanley acted as financial advisor to the company.

Use of Non-GAAP Financial Measures

This release includes certain financial measures that have not been prepared in accordance with U.S. generally accepted accounting principles (GAAP). In providing its full-year operating earnings per share guidance (non-GAAP), the company notes that there could be differences between such non-GAAP financial measure and the GAAP equivalent of reported net income per share. Reconciliation of such non-GAAP measure to net income per share is not provided, because the company cannot, without unreasonable effort, estimate or predict with certainty various components of net income. These components, net of tax, include but are not limited to, acquisitions, divestitures, impairment charges, changes in accounting principles, extreme weather events and other natural disasters.

About Dominion Energy

More than 7 million customers in 20 states energize their homes and businesses with electricity or natural gas from Dominion Energy (NYSE: D), headquartered in Richmond, Va. The company is committed to sustainable, reliable, affordable and safe energy and is one of the nation's largest producers and transporters of energy with more than \$100 billion of assets providing electric generation, transmission and distribution, as well as natural gas storage, transmission, distribution and import/export services. The company is committed to achieving net zero carbon dioxide and methane emissions from its power generation and gas infrastructure operations by 2050. Please visit DominionEnergy.com to learn more.

About Berkshire Hathaway Energy

From our roots in renewable energy, Berkshire Hathaway Energy has grown to a \$100.8 billion portfolio of locally managed businesses that share a vision of being the best energy company in serving our customers, while delivering sustainable energy solutions. These businesses deliver low-cost, safe and reliable service each day to more than 12 million electric and natural gas customers and end-users around the world. Our employees pride themselves in putting customers first in all they do, and as a result, our businesses consistently rank high among energy companies in customer satisfaction. Berkshire Hathaway Energy is headquartered in Des Moines, Iowa, U.S.A. Learn more at www.brkenergy.com.

This release contains certain forward-looking statements, including 2020 operating earnings guidance and projected dividends for the remainder of 2020 and beyond which are subject to various risks and uncertainties. Factors that could cause actual results to differ include, but are not limited to: the expected timing and likelihood of completion of the proposed transaction with Berkshire Hathaway Energy; the risk that Dominion Energy or Berkshire Hathaway Energy may be unable to obtain necessary regulatory approvals for the transaction or required regulatory approvals may delay the transaction; the risk that conditions to the closing of the transaction may not be satisfied; the repurchase of less than \$3 billion of Dominion Energy common stock through a share repurchase program; unusual weather conditions and their effect on energy sales to customers and energy commodity prices; extreme weather events and other natural disasters; extraordinary external events, such as the current pandemic health event resulting from COVID-19; federal, state and local legislative and regulatory developments; changes to federal, state and local environmental laws and regulations, including proposed carbon regulations; cost of environmental compliance; changes in enforcement practices of regulators relating to environmental standards and litigation exposure for remedial activities; capital market conditions, including the availability of credit and the ability to obtain financing on reasonable terms; fluctuations in interest rates; changes in rating agency requirements or credit ratings and their effect on availability and cost of capital; impacts of acquisitions, divestitures, transfers of assets by Dominion Energy to joint ventures, and retirements of assets based on asset portfolio reviews; receipt of approvals for, and timing of, closing dates for acquisitions and divestitures; changes in demand for Dominion Energy's services; additional competition in Dominion Energy's industries; changes to regulated rates collected by Dominion Energy; changes in operating, maintenance and construction costs; timing and receipt of regulatory approvals necessary for planned construction or expansion projects and compliance with conditions associated with such regulatory approvals; adverse outcomes in litigation matters or regulatory proceedings; and the inability to complete planned construction projects within time frames initially anticipated. Other risk factors are detailed from time to time in

Dominion Energy's quarterly reports on Form 10-Q and most recent annual report on Form 10-K filed with the Securities and Exchange Commission.

SOURCE Dominion Energy

For further information: Media, Ryan Frazier, (804) 836-2083, C.Ryan.Frazier@dominionenergy.com;
Financial analysts, Steven Ridge, (804) 929-6865, Steven.D.Ridge@dominionenergy.com

<https://news.dominionenergy.com/2020-07-05-Dominion-Energy-Agrees-to-Sell-Gas-Transmission-Storage-Assets-to-Berkshire-Hathaway-Energy-Strategic-Repositioning-Toward-Pure-Play-State-Regulated-Sustainability-Focused-Utility-Operations>

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2019

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File Number
001-08489
000-55337
001-37591

Exact name of registrants as specified in their charters
DOMINION ENERGY, INC.
VIRGINIA ELECTRIC AND POWER COMPANY
DOMINION ENERGY GAS HOLDINGS, LLC
VIRGINIA
(State or other jurisdiction of incorporation or organization)
120 TREDEGAR STREET
RICHMOND, VIRGINIA
(Address of principal executive offices)
(804) 819-2000
(Registrants' telephone number)

I.R.S. Employer
Identification Number
54-1229715
54-0418825
46-3639580

23219
(Zip Code)

Securities registered pursuant to Section 12(b) of the Act:

Registrant
DOMINION ENERGY, INC.

Trading
Symbol
D
DRUA
DCUE

Title of Each Class
Common Stock, no par value
2016 Series A 5.25% Enhanced Junior Subordinated Notes
2019 Series A Corporate Units
2014 Series C 4.6% Senior Notes

Name of Each Exchange
on Which Registered
New York Stock Exchange
New York Stock Exchange
New York Stock Exchange
New York Stock Exchange

DOMINION ENERGY GAS
HOLDINGS, LLC

Securities registered pursuant to Section 12(g) of the Act:
VIRGINIA ELECTRIC AND POWER COMPANY
Common Stock, no par value
DOMINION ENERGY GAS HOLDINGS, LLC
Limited Liability Company Membership Interests

Indicate by check mark whether the registrant is a well-known seasoned issuer as defined in Rule 405 of the Securities Act.

Dominion Energy, Inc. Yes ☒ No ☐ Virginia Electric and Power Company Yes ☒ No ☐ Dominion Energy Gas Holdings, LLC Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Dominion Energy, Inc. Yes ☐ No ☒ Virginia Electric and Power Company Yes ☐ No ☒ Dominion Energy Gas Holdings, LLC Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Dominion Energy, Inc. Yes ☒ No ☐ Virginia Electric and Power Company Yes ☒ No ☐ Dominion Energy Gas Holdings, LLC Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

Dominion Energy, Inc. Yes ☒ No ☐ Virginia Electric and Power Company Yes ☒ No ☐ Dominion Energy Gas Holdings, LLC Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "non-accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Dominion Energy, Inc.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
Emerging growth company ☐

Virginia Electric and Power Company

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ Smaller reporting company ☐
Emerging growth company ☐

Dominion Energy Gas Holdings, LLC

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ Smaller reporting company ☐
Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Act).

Dominion Energy, Inc. Yes ☐ No ☒ Virginia Electric and Power Company Yes ☐ No ☒ Dominion Energy Gas Holdings, LLC Yes ☐ No ☒

The aggregate market value of Dominion Energy, Inc. common stock held by non-affiliates of Dominion Energy was approximately \$62.0 billion based on the closing price of Dominion Energy's common stock as reported on the New York Stock Exchange as of the last day of Dominion Energy's most recently completed second fiscal quarter. Dominion Energy is the sole holder of Virginia Electric and Power Company common stock. At February 14, 2020, Dominion Energy had 838,000,325 shares of common stock outstanding and Virginia Power had 274,723 shares of common stock outstanding. Dominion Energy Questar Corporation, a wholly-owned subsidiary of Dominion Energy, Inc., holds all of the membership interests of Dominion Energy Gas Holdings, LLC.

DOCUMENT INCORPORATED BY REFERENCE

Portions of Dominion Energy's 2020 Proxy Statement are incorporated by reference in Part III.

This combined Form 10-K represents separate filings by Dominion Energy, Inc., Virginia Electric and Power Company and Dominion Energy Gas Holdings, LLC. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Virginia Electric and Power Company and Dominion Energy Gas Holdings, LLC make no representations as to the information relating to Dominion Energy, Inc.'s other operations. VIRGINIA ELECTRIC AND POWER COMPANY AND DOMINION ENERGY GAS HOLDINGS, LLC MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTION I(1)(a) AND (b) OF FORM 10-K AND ARE FILING THIS FORM 10-K UNDER THE REDUCED DISCLOSURE FORMAT.

Combined Notes to Consolidated Financial Statements, Continued

- (1) Includes Virginia Power's nonjurisdictional generation operations.
(2) Includes gathering and processing activities.
(3) Includes Wexpro's natural gas development and production operations.

In addition to the operating segments above, the Companies also report a Corporate and Other segment.

DOMINION ENERGY

The Corporate and Other Segment of Dominion Energy includes its corporate, service companies and other functions (including unallocated debt). In addition, Corporate and Other includes specific items attributable to Dominion Energy's operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

In 2019, Dominion Energy reported after-tax net expenses of \$2.6 billion in the Corporate and Other segment, with \$2.0 billion of the net expenses attributable to specific items related to its operating segments.

The net expenses for specific items in 2019 primarily related to the impact of the following items:

- A \$1.0 billion (\$756 million after-tax) charge for refunds of amounts previously collected from retail electric customers of DESC for the NND Project, attributable to Dominion Energy South Carolina;
- \$641 million (\$480 million after-tax) of charges associated with litigation acquired in the SCANA Combination, attributable to Dominion Energy South Carolina;
- \$484 million (\$315 million after-tax) of charges for merger and integration-related costs associated with the SCANA Combination, including a \$444 million (\$332 million after-tax) charge related to a voluntary retirement program, attributable to:
 - Dominion Energy Virginia (\$151 million after-tax);
 - Gas Distribution (\$56 million after-tax);
 - Dominion Energy South Carolina (\$75 million after-tax); and
 - Contracted Generation (\$38 million after-tax); partially offset by
 - Gas Transmission & Storage (\$5 million after-tax benefit);
- A \$346 million (\$257 million after-tax) charge related to the early retirement of certain Virginia Power electric generation facilities, attributable to Dominion Energy Virginia;
- A \$194 million tax charge for \$258 million of income tax-related regulatory assets acquired in the SCANA Combination for which Dominion Energy committed to forgo recovery, attributable to Dominion Energy South Carolina;
- A \$160 million (\$119 million after-tax) charge related to Virginia Power's planned early retirement of certain automated meter reading infrastructure, attributable to Dominion Energy Virginia;
- A \$135 million (\$100 million after-tax) charge related to Virginia Power's contract termination with a non-utility generator, attributable to Dominion Energy Virginia;
- A \$114 million (\$86 million after-tax) charge for property, plant and equipment acquired in the SCANA Combination primarily for which Dominion Energy committed to forgo recovery, attributable to Dominion Energy South Carolina; partially offset by

- A \$553 million (\$411 million after-tax) net gain related to investments in nuclear decommissioning trust funds attributable to:
 - Dominion Energy Virginia (\$49 million after-tax); and
 - Contracted Generation (\$362 million after-tax); and
- A \$113 million (\$84 million after-tax) benefit from the revision of future ash pond and landfill closure costs as a result of Virginia legislation enacted in March 2019, attributable to Dominion Energy Virginia.

In 2018, Dominion Energy reported after-tax net expenses of \$611 million in the Corporate and Other segment, with \$88 million of the net expenses attributable to specific items related to its operating segments.

The net expenses for specific items in 2018 primarily related to the impact of the following items:

- A \$219 million (\$164 million after-tax) charge related to the impairment of certain gathering and processing assets attributable to Gas Transmission & Storage;
- A \$215 million (\$160 million after-tax) charge associated with Virginia legislation enacted in March 2018 that requires one-time rate credits of certain amounts to utility customers, attributable to Dominion Energy Virginia;
- A \$170 million (\$134 million after-tax) net loss related to our investments in nuclear decommissioning trust funds attributable to:
 - Dominion Energy Virginia (\$14 million after-tax); and
 - Contracted Generation (\$120 million after-tax);
- A \$124 million (\$88 million after-tax) charge for disallowance of FERC-regulated plant attributable to Gas Transmission & Storage;
- An \$81 million (\$60 million after-tax) charge associated primarily with the asset retirement obligations for ash ponds and landfills at certain utility generation facilities in connection with the enactment of Virginia legislation in April 2018 attributable to Dominion Energy Virginia; and
- A \$70 million (\$52 million after-tax) charge associated with major storm damage and service restoration attributable to Dominion Energy Virginia; partially offset by
- An \$828 million (\$619 million after-tax) benefit associated with the sale of certain merchant generation facilities and equity method investments attributable to:
 - Contracted Generation (\$229 million after-tax); and
 - Gas Transmission & Storage (\$390 million after-tax).

In 2017, Dominion Energy reported after-tax net benefits of \$377 million in the Corporate and Other segment, with \$861 million of the net benefits attributable to specific items related to its operating segments.

The net benefits for specific items in 2017 primarily related to the impact of the following items:

- A \$1.0 billion tax benefit resulting from the remeasurement of deferred income taxes as a result of the 2017 Tax Reform Act, primarily attributable to:
 - Dominion Energy Virginia (\$83 million);
 - Gas Transmission & Storage (\$302 million);
 - Gas Distribution (\$56 million);
 - Contracted Generation (\$569 million); partially offset by
- \$158 million (\$96 million after-tax) of charges associated with equity method investments in wind-powered generation facilities, attributable to Contracted Generation.

The following table presents segment information pertaining to Dominion Energy's operations:

Year Ended December 31, (millions)	Dominion Energy Virginia	Gas Transmission & Storage	Gas Distribution	Dominion Energy South Carolina	Contracted Generation	Corporate and Other	Adjustments & Eliminations	Consolidated Total
2019								
Total revenue from external customers	\$8,170	\$3,074	\$2,367	\$2,948	\$1,135	\$(1,122)	\$ —	\$16,572
Intersegment revenue	(13)	247	18	4	15	1,199	(1,470)	—
Total operating revenue	8,157	3,321	2,385	2,952	1,150	77	(1,470)	16,572
Depreciation, depletion and amortization	1,216	400	335	452	179	73	—	2,655
Equity in earnings of equity method investees	—	161	2	(4)	(1)	10	—	168
Interest income	11	211	4	9	92	160	(386)	101
Interest and related charges	530	405	116	242	98	768	(386)	1,773
Income tax expense (benefit)	482	262	114	163	20	(690)	—	351
Net income (loss) attributable to Dominion Energy	1,786	934	488	430	276	(2,556)	—	1,358
Investment in equity method investees	—	1,517	32	—	74	23	—	1,646
Capital expenditures	3,002	431	848	562	367	111	—	5,321
Total assets (billions)	43.7	20.9	16.0	15.8	10.2	6.9	(9.7)	103.8
2018								
Total revenue from external customers	\$8,401	\$1,867	\$1,769	\$ —	\$1,487	\$ (249)	\$ 91	\$13,366
Intersegment revenue	(552)	723	16	—	8	723	(918)	—
Total operating revenue	7,849	2,590	1,785	—	1,495	474	(827)	13,366
Depreciation, depletion and amortization	1,158	348	263	—	213	18	—	2,000
Equity in earnings of equity method investees	—	178	—	—	18	1	—	197
Interest income	10	143	—	—	80	122	(271)	84
Interest and related charges	516	262	79	—	124	784	(272)	1,493
Income tax expense (benefit)	380	236	95	—	75	(206)	—	580
Net income (loss) attributable to Dominion Energy	1,596	844	373	—	245	(611)	—	2,447
Investment in equity method investees	—	1,159	—	—	82	37	—	1,278
Capital expenditures	2,640	765	647	—	247	106	—	4,405
Total assets (billions)	39.1	22.6	11.8	—	9.0	8.3	(12.9)	77.9
2017								
Total revenue from external customers	\$8,254	\$1,054	\$1,778	\$ —	\$1,345	\$ (27)	\$ 182	\$12,586
Intersegment revenue	(688)	946	17	—	9	724	(1,008)	—
Total operating revenue	7,566	2,000	1,795	—	1,354	697	(826)	12,586
Depreciation, depletion and amortization	1,141	260	258	—	200	46	—	1,905
Equity in earnings of equity method investees	—	158	—	—	(171)	(5)	—	(18)
Interest income	19	114	—	—	77	94	(222)	82
Interest and related charges	497	100	72	—	110	648	(222)	1,205
Income tax expense (benefit)	865	291	195	—	(160)	(1,221)	—	(30)
Net income (loss) attributable to Dominion Energy	1,466	552	351	—	253	377	—	2,999
Capital expenditures	2,726	1,489	452	—	979	263	—	5,909

Intersegment sales and transfers for Dominion Energy are based on contractual arrangements and may result in intersegment profit or loss that is eliminated in consolidation.

**U.S. Natural Gas Pipeline & Storage Proxy Companies
Growth Rate Forecasts**

Company	Ticker	Sep-18	Dec-18	Mar-19	Jun-19	Sep-19	Dec-19	Mar-20	Apr-20	May-20
Dominion Resources, Inc.	D	6.35%	6.68%	5.53%	4.60%	4.59%	4.41%	4.88%	4.88%	4.88%
Enable Midstream Partners LP	ENBL	6.50%	8.10%	7.20%	3.85%	5.40%	-4.50%	-4.00%	-27.50%	-27.50%
Enbridge Inc.	ENB	5.49%	5.49%	4.86%	5.49%	5.49%	5.49%	5.49%	5.49%	5.49%
Energy Transfer Partners LP	ET	60.20%	16.39%	21.48%	14.80%	16.50%	16.50%	-1.94%	-3.04%	-3.04%
Enterprise Products Partners L.P.	EPD	5.30%	9.39%	8.31%	9.58%	12.12%	7.59%	-1.27%	-6.75%	-6.75%
EQT Midstream Partners, LP	EQM	8.50%	8.50%	3.71%	2.95%	2.48%	-2.12%	-3.70%	-7.59%	-7.59%
Kinder Morgan, Inc.	KMI	12.00%	12.00%	12.00%	5.30%	6.50%	8.04%	-5.75%	-5.18%	-5.18%
National Fuel Gas Company	NFG	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%
TC Energy Corp	TRP	5.81%	5.81%	5.81%	5.81%	5.81%	5.81%	5.81%	5.81%	5.81%
TC PipeLines, LP	TCP	5.70%	9.30%	9.30%	9.30%	9.30%	9.30%	-0.60%	-0.70%	-0.70%
Williams Companies, Inc.	WMB	10.00%	8.00%	8.96%	10.80%	8.78%	11.15%	6.92%	1.98%	1.98%

Source: Thomson Reuters' First Call, provided by Yahoo! Finance

[S&P Global Ratings > Commentaries](#)

Supply And Demand Shocks Are Throwing The U.S. Midstream Industry Off Balance

Mar 24, 2020

[Current Ratings](#)

[View Analyst Contact Information](#)

[Table of Contents](#)

[Rate This Article](#)

Global events of the last few weeks have created a perfect storm for the oil and gas industry, and the falling dominoes will likely significantly affect the North American midstream industry's credit quality. The supply shock of a possibly prolonged oil price war between Saudi Arabia and Russia, coupled with a significant demand shock from the global spread of COVID-19, has management teams on the defensive. Indeed, a few companies have announced capital spending and distribution cuts, and we expect more in the coming weeks.

We believe the risk factors we've outlined are going to have significant, but somewhat uneven, reverberations across the midstream industry. Over the next several weeks we will continue to conduct reviews of the midstream companies in our portfolio, both speculative-grade and investment-grade. What follows are our thoughts concerning credit drivers for the industry, with additional details on some of the larger, diversified investment-grade companies.

Key Takeaways

- The combination of the COVID-19 pandemic and the oil price war is hurting the U.S. midstream industry.
- Some of the corrective measures companies took during the last downturn might not be as effective this time.
- We believe companies with investment-grade ratings are better positioned to navigate the challenging environment.
- We've already taken rating actions on some companies in the sector, and we expect more.

S&P Global Ratings acknowledges a high degree of uncertainty about the rate of spread and peak of the coronavirus outbreak. Some government authorities estimate the pandemic will peak between June and August, and we are using this assumption in assessing the economic and credit implications. We believe measures to contain COVID-19 have pushed the global economy into recession and could cause a surge of defaults among nonfinancial corporate borrowers (see our macroeconomic and credit updates here: www.spglobal.com/ratings). As the situation evolves, we will update our assumptions and estimates accordingly.

Counterparty credit risk will continue to weigh on the midstream sector. We've already taken rating actions (see Related Research) on a number of gathering and processing companies that are tied to one particular producer, either through a parent-subsidary relationship or because they derive all or a significant portion of their revenue from that producer (Antero Midstream Partners LP, CNX Midstream Partners LP, or EQM Midstream Partners LP). These rating actions were linked to rating changes at the producer. However, widespread credit deterioration among exploration and production companies could have broader implications for producer-push pipelines and companies with significant volume and commodity price exposure, such as gatherers and processors that are closer to the wellhead.

Companies with investment-grade ratings are generally better positioned to navigate market and macroeconomic uncertainties than their speculative-grade peers. We believe investment-grade midstream companies are better positioned to deal with the severe supply and demand shocks rippling through the energy sector. Many companies are self-funding and either refinanced early in the year or do not have debt maturities in 2020 or 2021. In addition, most credit facilities have been extended, and liquidity on revolvers is sufficient.

That said, we still believe many of these companies' financial policies could change if the cycle is in a prolonged trough. We believe it will start with significant cuts to capital-spending budgets on projects that are not in flight, and we think that distribution cuts are on the table given anemic equity prices. Ratings could come under pressure the longer the commodity trough lasts, particularly given the now-certain U.S. recession. In our view, 2020 volumes and cash flows might not be affected much, but operations for most companies could be harmed in 2021. We will be adjusting forecasts and discussing with management teams what strategies they intend to implement.

Some of the tools that worked during the last low point in the cycle will not work this time. During the 2015-2017 downturn, the midstream industry was able to conserve excess cash through distribution cuts, raising preferred equity, or selling assets. We believe this time, the effectiveness of these tools is somewhat limited. Distribution cuts are on the table for all companies, in our opinion, but during this downturn they might only be effective for investment-grade companies. In general, we believe that speculative-grade companies already cut distributions significantly in 2016-2017, and even a suspension of the distribution this time around might not be enough to preserve liquidity and financial flexibility or repay maturing debt.

That said, two speculative-grade companies--[Targa Resources Corp.](#) and [DCP Midstream LP](#)--announced significant cuts to their distributions and capital spending to strengthen balance sheets and preserve liquidity. Targa announced a 90% cut to its quarterly distribution starting with the first quarter ending March 31, which will save about \$755 million of cash flow to reduce debt. It also announced a 32% decrease in its 2020 growth capital plans to \$800 million-\$900 million. DCP announced a 50% distribution reduction, which will save \$325 million, in conjunction with a 75% cut to growth capital spending to \$150 million. Both companies' EBITDA is exposed to volumes and commodity prices, and we believe their actions are evidence of the potential threats to credit quality that most of the industry will face.

Midstream companies had a moderate amount of success with asset sales a few years ago, which we believe will be difficult to repeat. We think in-flight deals such as Blackstone's acquisition of [Tallgrass Energy Partners LP](#) and the merger between [Equitrans Midstream Corp.](#) and [EQM Midstream Partners LP](#) will move forward, but we will not factor into our forecast any aspirational deals companies were hoping to complete. Most of the deals in the market are gathering and processing assets close to the wellhead, which are the least attractive, and the bid-ask spread between buyer and seller will continue to widen with commodity prices so low.

We also don't believe it likely that private equity, infrastructure funds, or other third-party funding will provide any relief. While some sponsors have provided additional equity investments for midstream assets they already own, this was mostly to finish some in-flight growth projects or help meet certain obligations. We believe most private capital will take their idle cash balances and look elsewhere.

We are watching the capital market windows and monitoring liquidity and uses of excess cash. We believe these three factors will become more critical to midstream ratings over the next 12-18 months. While most midstream debt maturities are manageable over this time period, there are some speculative-grade companies--such as [Martin Midstream Partners LP](#) and [Ferrellgas Partners LP](#)--facing liquidity issues due to near-term maturities and an inability to refinance in the public debt markets. Investment-grade companies have significantly more financial flexibility, with ample capacity on large revolving credit facilities. Most investment-grade companies can stay out of the public debt markets through 2021 and possibly tap their revolvers for debt maturities if they want to roll them. The other option is using excess cash flow to actually repay some debt, which we believe could happen if this downturn continues into 2021.

We've been asking management teams if they are considering fully drawing-down on their revolving credit facilities as a defensive measure. We'd expect the companies to hold the entire amount on their balance sheets and not deploy it for uses we'd deem harmful to creditworthiness, such as share repurchases or funding distributions. However, a full draw would still be slightly leveraging because we do not fully net cash against total debt. Credit ratios will also likely be pressured given our view of the high probability of lower EBITDA in the next 12-18 months.

We also believe companies could consider repurchasing debt in the open market because the whole sector's unsecured notes have traded lower. We are not sure how this will play out in the nascent downturn, but we believe companies will choose to hold onto liquidity for now. That said, if companies do market repurchases of debt, we could view this as a distressed exchange, particularly for speculative-grade companies rated 'B' and lower, even if doing so improves the balance sheet. This is because deep speculative-grade companies would likely be viewed as distressed at this time, and their investors would be receiving less than they were originally promised. If the same practice was executed by an investment-grade company, we'd instead view it as opportunistic.

Download Table

Select North American Midstream Investment-Grade Companies

Issuer	Rating as of March 24, 2020	Comments
Rockies Express	BBB-/Watch Neg/	REX has meaningful exposure to lower-rated counterparties. Many of REX's anchor shippers are gas-focused companies concentrated in the Appalachian region that we've downgraded recently, and many still have negative outlooks. Although we expect the level of associated gas to decline, we believe REX faces headwinds that could complicate recontracting efforts in

Pipeline LLC (REX)		Zones 1 and 2 (DJ basin). Benefiting REX is its low leverage, which gives it a cushion to withstand some financial stress, but deteriorating counterparty credit could drive future rating actions.
Western Midstream Operating LP (WES)	BBB-/Negative/-	Our rating in WES is capped by our rating on Occidental Petroleum Corp. as its majority owner and main customer. We currently view WES's credit metrics as stressed, and WES will be assessing initiatives that will help the partnership to deleverage its balance sheet. The current market and economic headwinds will likely complicate the deleveraging plans, and we have revised our expectations for EBITDA growth and potential asset sales.
Enable Midstream Partners LP	BBB-/Stable/--	We believe 2020 volumes will mostly be in line with previous expectations, though there will likely be a decrease in 2021 as drilling activity slows in the basins the company serves. We expect Enable to cut costs and defer growth capital spending to shore up its balance sheet.
Energy Transfer LP	BBB-/Stable/A-3	Energy Transfer has strong liquidity and significant financial flexibility. The partnership has about \$4 billion available under its revolving credit facility and can manage debt maturities through 2021 without the need to tap the capital markets. We believe debt to EBITDA will remain below 5x in the current cycle, and we view the significant excess cash flow (about 1.8x distributions) as a powerful tool that can be used to deleverage the balance sheet.
Gibson Energy Inc.	BBB-/Stable/--	Gibson's business remains positioned to weather the recent commodity headwinds, largely due to its strong contractual structure, which provides at least 60% of cash flows from take-or-pay contracts. Counterparty quality is reasonable, with a large proportion of revenue coming from investment-grade or government-owned entities. However, the company's refined products sub-segment—which produces products such as road asphalt, roofing flux, wellsite fluids, and distillates—is exposed to recession risk, as the demand for these products is affected by the level of economic and exploration and production activity.
Plains All American Pipeline LP	BBB-/Stable/A-3	Plains likely will see some pressure on crude volumes over the next 24 months, but it has some downside volume protection from take-or-pay contracts and minimum volume commitments in the transportation segment. The company could also benefit in the short term from its storage segment due to contango (when future crude prices are higher than current prices). The company currently has somewhat of a buffer in its leverage metrics relative to our downgrade trigger, allowing it to weather the weak crude environment. We believe significant cuts in growth capital spending are likely. The company has sufficient liquidity.
Kinder Morgan Inc.	BBB-/Stable/A-2	Kinder Morgan is well diversified, with sufficient liquidity over the medium term. The sale of approximately 25 million shares of Pembina Pipeline Corp. (after-tax proceeds of \$764 million) positions the company to weather the next 12-24 months. Approximately 10% of cash flows are either hedged or exposed to commodity prices, split about evenly between the two. We view the CO2 business as the segment with the most risk, but it makes up less than 10% of the company's total EBITDA. We believe the recent improvements to adjusted leverage position Kinder well during this period of low commodity prices.
MPLX LP	BBB-/Stable/--	We are currently reviewing both MPLX and its parent company, Marathon Petroleum Corp. Given current market conditions, we expect that asset sales in this market will be limited. That said, perhaps the most notable credit factor for MPLX is related to its direct and indirect commodity price exposure. Approximately 35% of MPLX's 2019 EBITDA was tied to its gathering and processing business segment, which also has direct commodity price exposure. As of year-end, the company had over \$4.4 billion of liquidity, which positions it well for the medium term. Following the conclusion of our review, we will provide a more detailed update on forecasted 2020 credit ratios.
ONEOK Inc.	BBB-/Stable/A-2	Despite the recent drop in crude prices and NGLs, we believe there is good visibility into ONEOK's 2020 EBITDA growth, mostly from additional volumes out of the Bakken onto its assets recently placed into service. We are forecasting debt to EBITDA in the 4.3x area for 2020.
The Williams Cos. Inc.	BBB-/Stable/A-2	We believe Williams' balance sheet could see some pressure, particularly in its northeast and western gathering and processing segments. We'd expect the company to cut back on capital spending and use excess cash flow to reduce debt to offset any EBITDA declines. We believe the sale of its western gathering and processing business is unlikely at this time. The company has sufficient liquidity.
Pembina Pipeline Corp.	BBB-/Stable/--	About 90% of Pembina's EBITDA is fee-based, with approximately two-thirds under a take-or-pay or cost-of-service contract regime. Moreover, approximately 60% of its customers have investment-grade ratings, with a sizable proportion of those in the 'A' rating category. At this time, Pembina has sufficient liquidity to manage its 2020 and 2021 maturities.
Inter Pipeline Ltd. (IPL)	BBB+/Negative/-	IPL derives its core credit strength from the stability in its oil sands transportation business (about 50% of EBITDA), which is highly contracted, operating on a cost-of-service model with no volume risk or commodity price risk. Counterparties currently are mostly investment-grade, and the remaining contract term is 20 years. IPL's conventional oil pipelines, bulk liquid storage, and NGL processing businesses are exposed to varying degrees of commodity price risk, both direct and indirect. IPL is also in the process of expanding its NGL business segment through the construction of the Heartland Petrochemical Complex (HPC), which has put considerable pressure on its credit metrics. Also, IPL is exploring the sale of its bulk storage terminal business to finance the equity portion of the HPC. While details around valuation are unknown at this point, we believe that the current environment is not very conducive to a potential sale. If commodity prices remain lower for a prolonged period, we believe IPL will have to seek alternative funding solutions, as its incremental debt capacity appears maxed out for the rating.
Enbridge Inc.	BBB-/Stable/A-2	Enbridge is well diversified with highly predictable cash flows. Following asset divestitures of approximately \$8 billion over the last 12-18 months, about 98% of its cash flows come from low-risk take-or-pay, fixed fee, or cost-of-service type contracts. While we expect Enbridge's counterparty credit quality to deteriorate given the revision to our price-deck, the majority (93%) of its customers have investment-grade ratings.
Enterprise Products Partners LP	BBB+/Stable/A-2	We expect the downturn in commodity prices to have a relatively minor impact on EPD. We believe that EPD also is largely insulated from counterparty credit risk with its diversified and high-quality customer base. We expect the partnership to maintain debt to EBITDA in the mid 3x area and distribution coverage of about 1.5x over the next two years. We also expect the company to continue to repurchase units on an opportunistic basis.
Magellan Midstream	BBB+/Stable/A-2	We expect the current downturn to have a small impact on Magellan's cash flows. The volumes in the company's refined products segment could be modestly hurt due to lower demand for refined products. However, we expect the company to

**Partners
LP**

maintain leverage in the low to mid 3x area in 2020 and 2021. The company also has a high-quality customer base. We do believe the company could opportunistically look to repurchase units in a prudent manner to maintain appropriate credit metrics.

TC Energy Corp. BBB+/Stable/A-
2

TC Energy's EBITDA is very stable, with a strong contractual foundation of take-or-pay or cost-of-service contracts. Although credit measures are at the lower end of the range for the current rating, we do not expect them to fall below our thresholds in the next few years. If KXL moves forward, we'd expect it to be financed in a manner that would not change this view.

What's Next?

We'll be continuing our portfolio review for the next several weeks, starting with the companies we consider most vulnerable and then moving to the more resilient ones. We'll continue to provide periodic updates on the sector during this turbulent time.

Related Research

- [S&P Global Ratings Cuts WTI And Brent Crude Oil Price Assumptions Amid Continued Near-Term Pressure](#), March 19, 2020
- [EQM Midstream Downgraded To 'BB' On Consolidation With Equitrans; Issue-Level Ratings Lowered; Outlook Stable](#), Feb. 27, 2020
- [CNX Midstream Partners L.P. Rating Lowered To 'B+' From 'BB-' On Downgrade Of Parent; Outlook Negative](#), Feb. 5, 2020
- [Antero Midstream Partners L.P. Rating Lowered To 'B+'; Outlook Negative](#), Feb. 4, 2020

This report does not constitute a rating action.

Primary Credit Analyst: Michael V Grande, New York (1) 212-438-2242;
michael.grande@spglobal.com

Secondary Contacts: Luqman Ali, CFA, Toronto (1) 416-507-2589;
luqman.ali@spglobal.com
Jacqueline R Banks, New York + (212) 438-3409;
Jacqueline.Banks@spglobal.com
Stephen R Goltz, Toronto + 1 (416) 507 2592;
stephen.goltz@spglobal.com
Mike Llanos, New York (1) 212-438-4849;
mike.llanos@spglobal.com
Michael Pastrich, New York + 1 (212) 438 0604;
michael.pastrich@spglobal.com
Stephen Scovotti, New York (1) 212-438-5882;
stephen.scovotti@spglobal.com

Rate This Article

How helpful was this article?

Do you have any comments?

Go

No content (including ratings, credit-related analyses and data, valuations, model, software or other application or output therefrom) or any part thereof (Content) may be modified, reverse engineered, reproduced or distributed in any form by any means, or stored in a database or retrieval system, without the prior written permission of S&P Global Market Intelligence or its affiliates (collectively, S&P Global). The Content shall not be used for any unlawful or unauthorized purposes. S&P Global and any third-party providers, as well as their directors, officers, shareholders, employees or agents (collectively S&P Global Parties) do not guarantee the accuracy, completeness, timeliness or availability of the Content. S&P Global Parties are not responsible for any errors or omissions (negligent or otherwise), regardless of the cause, for the results obtained from the use of the Content, or for the security or maintenance of any data input by the user. The Content is provided on an "as is" basis. S&P GLOBAL PARTIES DISCLAIM ANY AND ALL EXPRESS OR IMPLIED WARRANTIES, INCLUDING, BUT NOT LIMITED TO, ANY WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE OR USE, FREEDOM FROM BUGS, SOFTWARE ERRORS OR DEFECTS, THAT THE CONTENT'S FUNCTIONING WILL BE UNINTERRUPTED OR THAT THE CONTENT WILL OPERATE WITH ANY SOFTWARE OR HARDWARE CONFIGURATION. In no event shall S&P Global Parties be liable to any party for any direct, indirect, incidental, exemplary, compensatory, punitive, special or consequential damages, costs, expenses, legal fees, or losses (including, without limitation, lost income or lost profits and opportunity costs or losses caused by negligence) in connection with any use of the Content even if advised of the possibility of such damages.

Credit-related and other analyses, including ratings, and statements in the Content are statements of opinion as of the date they are expressed and not statements of fact. S&P Global Market Intelligence's opinions, analyses and rating acknowledgment decisions (described below) are not recommendations to purchase, hold, or sell any securities or to make any investment decisions, and do not address the suitability of any security. S&P Global Market Intelligence assumes no obligation to update the Content following publication in any form or format. The Content should not be relied on and is not a substitute for the skill, judgment and experience of the user, its management, employees, advisors and/or clients when making investment and other business decisions. S&P Global Market Intelligence does not act as a fiduciary or an investment advisor except where registered as such. While S&P Global Market Intelligence has obtained information from sources it believes to be reliable, S&P Global Market Intelligence does not perform an audit and undertakes no duty of due diligence or independent verification of any information it receives. Rating-related publications may be published for a variety of reasons that are not necessarily dependent on action by rating committees, including, but not limited to, the publication of a periodic update on a credit rating and related analyses.

S&P Global keeps certain activities of its divisions separate from each other in order to preserve the independence and objectivity of their respective activities. As a result, certain divisions of S&P Global may have information that is not available to other S&P Global divisions. S&P Global has established policies and procedures to maintain the confidentiality of certain non-public information received in connection with each analytical process.

S&P Global Ratings does not contribute to or participate in the creation of credit scores generated by S&P Global Market Intelligence. Lowercase nomenclature is used to differentiate S&P Global Market Intelligence PD credit model scores from the credit ratings issued by S&P Global Ratings.

S&P Global may receive compensation for its ratings and certain analyses, normally from issuers or underwriters of securities or from obligors. S&P Global reserves the right to disseminate its opinions and analyses. S&P Global's public ratings and analyses are made available on its Web sites, www.standardandpoors.com (free of charge), and www.capitaliq.com (subscription), and may be distributed through other means, including via S&P Global publications and third-party redistributors. Additional information about our ratings fees is available at www.standardandpoors.com/usratingsfees.

Moody's INVESTORS SERVICE

OUTLOOK

10 June 2020

✓ Rate this Research

Contacts

Andrew Brooks +1.212.553.1065
VP-Sr Credit Officer
andrew.brooks@moodys.com

Steven Wood +1.212.553.0591
MD-Corporate Finance
steven.wood@moodys.com

CLIENT SERVICES

Americas 1-212-553-1653
Asia Pacific 852-3551-3077
Japan 81-3-5408-4100
EMEA 44-20-7772-5454

Midstream Energy – Global

Outlook turns negative as E&P sector's volumetric declines weigh on EBITDA

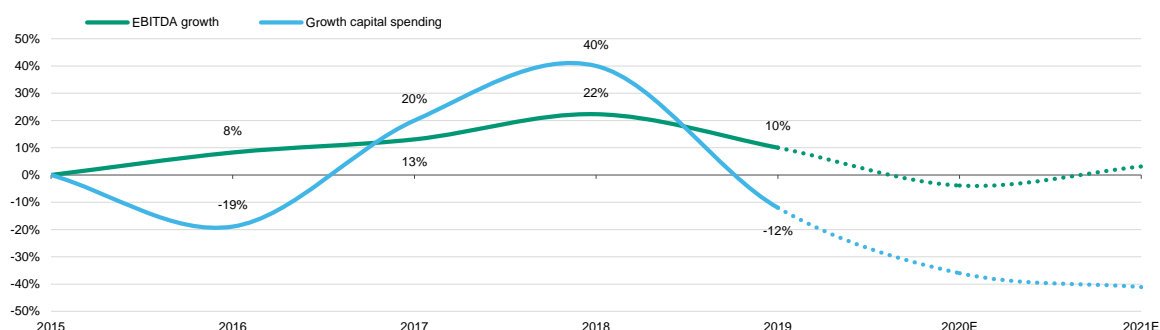
Our outlook for the global midstream energy sector is negative. This outlook reflects our expectation for the fundamental business conditions over the next 12 to 18 months.

- » **We have changed our midstream energy industry outlook to negative from stable, the first time our outlook for that sector has been negative.** While the midstream sector has structural attributes that give it stability, the broader energy sector today grapples with a simultaneous demand shock and a supply shock. Although midstream cash flow is largely insulated from the full brunt of commodity price and volumetric instability, the rapid pace and the magnitude of production declines have finally spilled into the midstream sector, compromising its aggregate credit quality.
- » **We project that EBITDA in the midstream sector will decline by at least 5% in 2020, below our -5% to 5% EBITDA growth range that would indicate a stable outlook for the sector.** We anticipate a slight return to EBITDA growth in 2021. While the midstream asset base is largely "must-run" infrastructure, striving for contractually-supported fixed-fee cash flow, not all of the midstream sector's revenue and earnings are fully insulated from commodity price and volume risk.
- » **Certain midstream segments are more vulnerable than others.** Pipeline revenue for crude and refined products is susceptible to variable throughput volumes, which have recently declined. Natural gas gathering and processing entails both direct and indirect commodity price risk based on gathering field economics, and volumetric risk, based on the structures of processing contracts. But interstate natural gas pipelines operate with regulated, fee-based contracts, and have little price or volume risk.
- » **Midstream throughput has fallen in line with cuts in exploration and production (E&P) volumes, whose size will depend on the extent of the economic downturn.** The US Energy Information Administration anticipates a 12.2% two-year decline in US crude output during 2019-21, and a 7.4% decline in natural gas production. Contract structures and pricing will ease the full impact of these volume declines on midstream companies' performance, but not enough to avoid an aggregate 5%-plus decline in EBITDA. The credit quality of individual midstream companies will largely depend on the size and composition of their own assets.

- » **Midstream firms also face risk from the deteriorating credit quality of their E&P customers, some of which face heightened bankruptcy risk today.** During the 2015-16 energy downturn, midstream contract rejections were not widespread, with most contracts affirmed in bankruptcy. Today, however, E&P companies will ratchet up demands for contractual concessions from the midstream operators, particularly if the economic contraction deepens.
- » **Midstream growth capital spending will decline in 2020-21, furthering declines in future EBITDA as spending cuts continue.** Growth in midstream capital investment in recent years had responded robustly to the infrastructure needs of the North American oil and gas shale expansion, powering the midstream sector's substantial historical EBITDA growth. Now midstream companies are cutting their growth capital spending as E&P requirements for new infrastructure ebbs, and also rationing capital investment to help generate positive free cash flow. Midstream growth capital spending began to decline in 2019, falling 19% among a group of large midstream companies, and is accelerating to a 20%-30% annual drop in 2020-21 (see Exhibit 1). Once capital spending winds down for projects now under construction, EBITDA growth will have less support in the future as midstream rapidly evolves into more of a slow-growth sector.

Exhibit 1 1

Decline in midstream growth capital spending will accelerate into 2021



Source: Moody's Financial Metrics™, Moody's Investors Service, company reports

Industry outlooks reflect our view of fundamental business conditions for an industry over the next 12-18 months. Since outlooks represent our forward-looking view on business conditions that factor into our ratings, a negative (positive) outlook suggests that negative (positive) rating actions are more likely on average. However, the industry outlook does not represent a sum of upgrades, downgrades or ratings under review, or an average of the rating outlooks of issuers in the industry, but rather our assessment of the main direction of business fundamentals within the overall industry.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the ratings tab on the issuer/entity page on www.moodys.com for the most updated credit rating action information and rating history.

Moody's related publications

Outlooks:

- » [Exploration and Production – Global: Unprecedented drop in crude price and demand will severely stress producers, 26 March 2020](#)
- » [Midstream Energy – Global: Outlook changes to stable as stressed E&P sector's production slows, 26 March 2020](#)
- » [Oilfield Services and Drilling – Global: Cash flow will be crushed as oil and gas producers slash their capital budgets, 26 March 2020](#)
- » [Refining and Marketing – Global: Weak demand for refined products will weigh on earnings through at least 2020, 26 March 2020](#)
- » [Integrated Oil and Gas – Global: Outlook turns negative as low oil prices, coronavirus will hit 2020 earnings, 26 March 2020](#)

Sector comments:

- » [Oil & Gas – Cross Region: Medium term oil prices trend lower as industry focuses on lowest-cost reserves, 27 May 2020](#)
- » [Oil & Gas – Global: Recession and uncertain demand recovery weigh on oil prices in 2020-21, 28 April 2020](#)
- » [Oil and Gas – North America: Limits of physical market deepen oil-price decline, accelerating production shut-ins, 21 April 2020](#)
- » [Oil and Gas – Global: Low oil and natural gas prices will persist through 2020, 26 March 2020](#)
- » [Oil and Gas – Cross Region: Low oil prices persisting for longer would imply additional risk for producers, 20 March 2020](#)
- » [Coronavirus and oil price shocks: managing ratings in turbulent times, 17 March 2020](#)
- » [Oil and Gas – Global: Low oil prices heighten financial risks in 2020, 10 March 2020](#)

Sector in-depth reports:

- » [Oil and Gas – Cross Region: Frequently asked investor questions, 10 June 2020](#)
- » [Exploration & Production – US: Weak oil and natural gas prices will lead to lower borrowing bases, reducing liquidity, 28 May 2020](#)
- » [Oilfield Services and Drilling – North America: Stressed sector faces high refinancing risk with \\$32 billion maturing during 2020-24, 18 March 2020](#)
- » [Corporates – Global: Heat map: Coronavirus hurts travel-driven sectors, disrupts supply chains, effects compounded with global spread, 16 March 2020](#)
- » [Exploration & Production – North America: \\$86 billion debt-maturity burden strains weaker and natural gas-focused producers, 19 February 2020](#)
- » [Corporate Defaults and Recoveries – US: Lessons from the 2019 energy default cycle: Liquidity is not recovery, 9 January 2020](#)
- » [Oil & Gas – Cross Region: Commodity prices, access to capital, regulation rank among top risks for 2020, 6 January 2020](#)

Sector profile:

- » [Oil and Gas – North America: January-April 2020 newsletter, 29 April 2020](#)

Rating methodology:

- » [Midstream Energy, December 2018](#)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

MOODY'S INVESTORS SERVICE

CORPORATES

© 2020 Moody's Corporation, Moody's Investors Service, Inc., Moody's Analytics, Inc. and/or their licensors and affiliates (collectively, "MOODY'S"). All rights reserved.

CREDIT RATINGS ISSUED BY MOODY'S INVESTORS SERVICE, INC. AND/OR ITS CREDIT RATINGS AFFILIATES ARE MOODY'S CURRENT OPINIONS OF THE RELATIVE FUTURE CREDIT RISK OF ENTITIES, CREDIT COMMITMENTS, OR DEBT OR DEBT-LIKE SECURITIES, AND MATERIALS, PRODUCTS, SERVICES AND INFORMATION PUBLISHED BY MOODY'S (COLLECTIVELY, "PUBLICATIONS") MAY INCLUDE SUCH CURRENT OPINIONS. MOODY'S INVESTORS SERVICE DEFINES CREDIT RISK AS THE RISK THAT AN ENTITY MAY NOT MEET ITS CONTRACTUAL FINANCIAL OBLIGATIONS AS THEY COME DUE AND ANY ESTIMATED FINANCIAL LOSS IN THE EVENT OF DEFAULT OR IMPAIRMENT. SEE MOODY'S RATING SYMBOLS AND DEFINITIONS PUBLICATION FOR INFORMATION ON THE TYPES OF CONTRACTUAL FINANCIAL OBLIGATIONS ADDRESSED BY MOODY'S INVESTORS SERVICE CREDIT RATINGS. CREDIT RATINGS DO NOT ADDRESS ANY OTHER RISK, INCLUDING BUT NOT LIMITED TO: LIQUIDITY RISK, MARKET VALUE RISK, OR PRICE VOLATILITY. CREDIT RATINGS, NON-CREDIT ASSESSMENTS ("ASSESSMENTS"), AND OTHER OPINIONS INCLUDED IN MOODY'S PUBLICATIONS ARE NOT STATEMENTS OF CURRENT OR HISTORICAL FACT. MOODY'S PUBLICATIONS MAY ALSO INCLUDE QUANTITATIVE MODEL-BASED ESTIMATES OF CREDIT RISK AND RELATED OPINIONS OR COMMENTARY PUBLISHED BY MOODY'S ANALYTICS, INC. AND/OR ITS AFFILIATES. MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS AND PUBLICATIONS DO NOT CONSTITUTE OR PROVIDE INVESTMENT OR FINANCIAL ADVICE, AND MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS AND PUBLICATIONS ARE NOT AND DO NOT PROVIDE RECOMMENDATIONS TO PURCHASE, SELL, OR HOLD PARTICULAR SECURITIES. MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS AND PUBLICATIONS DO NOT COMMENT ON THE SUITABILITY OF AN INVESTMENT FOR ANY PARTICULAR INVESTOR. MOODY'S ISSUES ITS CREDIT RATINGS, ASSESSMENTS AND OTHER OPINIONS AND PUBLISHES ITS PUBLICATIONS WITH THE EXPECTATION AND UNDERSTANDING THAT EACH INVESTOR WILL, WITH DUE CARE, MAKE ITS OWN STUDY AND EVALUATION OF EACH SECURITY THAT IS UNDER CONSIDERATION FOR PURCHASE, HOLDING, OR SALE.

MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS, AND PUBLICATIONS ARE NOT INTENDED FOR USE BY RETAIL INVESTORS AND IT WOULD BE RECKLESS AND INAPPROPRIATE FOR RETAIL INVESTORS TO USE MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS OR PUBLICATIONS WHEN MAKING AN INVESTMENT DECISION. IF IN DOUBT YOU SHOULD CONTACT YOUR FINANCIAL OR OTHER PROFESSIONAL ADVISER. ALL INFORMATION CONTAINED HEREIN IS PROTECTED BY LAW, INCLUDING BUT NOT LIMITED TO, COPYRIGHT LAW, AND NONE OF SUCH INFORMATION MAY BE COPIED OR OTHERWISE REPRODUCED, REPACKAGED, FURTHER TRANSMITTED, TRANSFERRED, DISSEMINATED, REDISTRIBUTED OR RESOLD, OR STORED FOR SUBSEQUENT USE FOR ANY SUCH PURPOSE, IN WHOLE OR IN PART, IN ANY FORM OR MANNER OR BY ANY MEANS WHATSOEVER, BY ANY PERSON WITHOUT MOODY'S PRIOR WRITTEN CONSENT.

MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS AND PUBLICATIONS ARE NOT INTENDED FOR USE BY ANY PERSON AS A BENCHMARK AS THAT TERM IS DEFINED FOR REGULATORY PURPOSES AND MUST NOT BE USED IN ANY WAY THAT COULD RESULT IN THEM BEING CONSIDERED A BENCHMARK.

All information contained herein is obtained by MOODY'S from sources believed by it to be accurate and reliable. Because of the possibility of human or mechanical error as well as other factors, however, all information contained herein is provided "AS IS" without warranty of any kind. MOODY'S adopts all necessary measures so that the information it uses in assigning a credit rating is of sufficient quality and from sources MOODY'S considers to be reliable including, when appropriate, independent third-party sources. However, MOODY'S is not an auditor and cannot in every instance independently verify or validate information received in the rating process or in preparing its Publications.

To the extent permitted by law, MOODY'S and its directors, officers, employees, agents, representatives, licensors and suppliers disclaim liability to any person or entity for any indirect, special, consequential, or incidental losses or damages whatsoever arising from or in connection with the information contained herein or the use of or inability to use any such information, even if MOODY'S or any of its directors, officers, employees, agents, representatives, licensors or suppliers is advised in advance of the possibility of such losses or damages, including but not limited to: (a) any loss of present or prospective profits or (b) any loss or damage arising where the relevant financial instrument is not the subject of a particular credit rating assigned by MOODY'S.

To the extent permitted by law, MOODY'S and its directors, officers, employees, agents, representatives, licensors and suppliers disclaim liability for any direct or compensatory losses or damages caused to any person or entity, including but not limited to by any negligence (but excluding fraud, willful misconduct or any other type of liability that, for the avoidance of doubt, by law cannot be excluded) on the part of, or any contingency within or beyond the control of, MOODY'S or any of its directors, officers, employees, agents, representatives, licensors or suppliers, arising from or in connection with the information contained herein or the use of or inability to use any such information.

NO WARRANTY, EXPRESS OR IMPLIED, AS TO THE ACCURACY, TIMELINESS, COMPLETENESS, MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE OF ANY CREDIT RATING, ASSESSMENT, OTHER OPINION OR INFORMATION IS GIVEN OR MADE BY MOODY'S IN ANY FORM OR MANNER WHATSOEVER.

Moody's Investors Service, Inc., a wholly-owned credit rating agency subsidiary of Moody's Corporation ("MCO"), hereby discloses that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by Moody's Investors Service, Inc. have, prior to assignment of any credit rating, agreed to pay to Moody's Investors Service, Inc. for credit ratings opinions and services rendered by it fees ranging from \$1,000 to approximately \$2,700,000. MCO and Moody's Investors Service also maintain policies and procedures to address the independence of Moody's Investors Service credit ratings and credit rating processes. Information regarding certain affiliations that may exist between directors of MCO and rated entities, and between entities who hold credit ratings from Moody's Investors Service and have also publicly reported to the SEC an ownership interest in MCO of more than 5%, is posted annually at www.moody.com under the heading "Investor Relations — Corporate Governance — Director and Shareholder Affiliation Policy."

Additional terms for Australia only: Any publication into Australia of this document is pursuant to the Australian Financial Services License of MOODY'S affiliate, Moody's Investors Service Pty Limited ABN 61 003 399 657 AFSL 336969 and/or Moody's Analytics Australia Pty Ltd ABN 94 105 136 972 AFSL 383569 (as applicable). This document is intended to be provided only to "wholesale clients" within the meaning of section 761G of the Corporations Act 2001. By continuing to access this document from within Australia, you represent to MOODY'S that you are, or are accessing the document as a representative of, a "wholesale client" and that neither you nor the entity you represent will directly or indirectly disseminate this document or its contents to "retail clients" within the meaning of section 761G of the Corporations Act 2001. MOODY'S credit rating is an opinion as to the creditworthiness of a debt obligation of the issuer, not on the equity securities of the issuer or any form of security that is available to retail investors.

Additional terms for Japan only: Moody's Japan K.K. ("MJKK") is a wholly-owned credit rating agency subsidiary of Moody's Group Japan G.K., which is wholly-owned by Moody's Overseas Holdings Inc., a wholly-owned subsidiary of MCO. Moody's SF Japan K.K. ("MSFJ") is a wholly-owned credit rating agency subsidiary of MJKK. MSFJ is not a Nationally Recognized Statistical Rating Organization ("NRSRO"). Therefore, credit ratings assigned by MSFJ are Non-NRSRO Credit Ratings. Non-NRSRO Credit Ratings are assigned by an entity that is not a NRSRO and, consequently, the rated obligation will not qualify for certain types of treatment under U.S. laws. MJKK and MSFJ are credit rating agencies registered with the Japan Financial Services Agency and their registration numbers are FSA Commissioner (Ratings) No. 2 and 3 respectively.

MJKK or MSFJ (as applicable) hereby disclose that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by MJKK or MSFJ (as applicable) have, prior to assignment of any credit rating, agreed to pay to MJKK or MSFJ (as applicable) for credit ratings opinions and services rendered by it fees ranging from JPY125,000 to approximately JPY250,000,000.

MJKK and MSFJ also maintain policies and procedures to address Japanese regulatory requirements.

REPORT NUMBER 1233368



PEPL-Staff-6.35

Referencing Exhibit Nos. S-0106, S-0107 and S-0108, please provide all exhibits in electronic format with working formulas.

Response:

See response to PEPL-Staff-5.1. See also PEP-Staff-6.35_Attachment 1 and 2, CAPM working papers that were inadvertently excluded from the response to PEPL-Staff-5.1.

Prepared By:

John Johnson

Date:

April 13, 2020

PEPL-Staff-6.37

Referencing Exhibit No. S-0106, at page 12, please confirm that Mr. Johnson is aware of the Commission's Opinion No. 554-A that was issued on January 24, 2020.

- a. Please confirm that Mr. Johnson is aware that in this opinion, FERC provided the opportunity for participants to provide additional evidence on the revised methodology proposed in the Coakley Briefing Order (as defined in Opinion No. 554-A) and the MISO Briefing Order (as defined in Opinion No. 554-A) to help determine the ROE in the PATH ROE. See Opinion No. 554-A at P 26.
- b. Please explain how Mr. Johnson's analysis provides any guidance to FERC on additional methodologies that should be considered in establishing the ROE in the instant proceeding.

Response:

Mr. Johnson is aware of Commission Opinion No. 554-A.

- a. Mr. Johnson is aware that in Commission Opinion 554-A FERC provided the opportunity for participants to provide additional evidence on the revised methodology proposed in the Coakley Briefing Order.
- b. Mr. Johnson testifies, after analyzing additional methodologies, that only the DCF should be used to establish the ROE in this proceeding, as set forth in Exhibit No. S-0106.

Prepared By:

John Johnson

Date:

April 13, 2020

Panhandle Eastern Pipe Line Company, LP
Docket No. RP19-78, et al.

Panhandle Data Requests to MPSC, Set 2
MPSC Responses

PEPL-MPSC-2.11

With respect to Exhibit No. MPC-0015 at page 10, line 13 through page 11, line 2.

- a. Please explain what “grade” is referred to with respect to Value Line.
Please provide all documents reviewed, relied on or considered by Ms. Janssen that relate to this answer.
- b. Please identify all FERC orders and opinions that Ms. Janssen reviewed, relied on or considered that rely on the lack of a grade from Value Line to exclude a company from the proxy group.
- c. Please identify all FERC orders and opinions that Ms. Janssen reviewed, relied on or considered that relied on Value Line as a source for any information.
- d. Please provide all FERC orders and opinions that Ms. Janssen reviewed, relied on or considered that have included TC Pipelines as a proxy company.
- e. Please provide all FERC orders and opinions that Ms. Janssen reviewed, relied on or considered that have excluded a pipeline company from the proxy group because the company is a stand-alone operating subsidiary of another company.

Response:

- a. Referencing my testimony at page 8, lines 5-8, Value Line provides research on approximately 1,700 individual stocks. In my testimony if I stated that there was no grade for Value Line, that would be that Value Line was not providing research on that stock and thus no grade. The data is provided on the Value Line website.
- b. *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 123 FERC ¶ 61,048, Docket No. PL07-02-000 (April 17, 2008); FERC Opinion No. 569, 169 FERC ¶ 61,129, Docket Nos. EL14-12-003 and EL15-45-000 (Nov. 21, 2019).
- c. *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 123 FERC ¶ 61,048, Docket No. PL07-02-000 (April 17, 2008); FERC Opinion No. 569, 169 FERC ¶ 61,129, Docket Nos. EL14-12-003 and EL15-45-000 (Nov. 21, 2019).
- d. I am not aware of any FERC order or opinion that included TC Pipelines as a proxy company.
- e. I am not aware of any FERC orders and opinions that have excluded a pipeline company from the proxy group because the company is a stand-alone operating subsidiary of another company.

Panhandle Eastern Pipe Line Company, LP
Docket No. RP19-78, et al.

Panhandle Data Requests to MPSC, Set 2
MPSC Responses

Responsible Preparer: Bonnie Janssen

Date: April 13, 2020

Rule 403(c) Statement: I hereby certify that the above response is true and accurate to the best of my knowledge, information and belief formed after a reasonable inquiry.

/s/ Bonnie Janssen

PEPL-PMDG-1.17 Referencing Exhibit No. PMG-0010, at page 2, please confirm that the percentage of earnings from National Fuel Gas's Pipeline and Storage operation in 2019 is 24% of the total operations, not 44% listed in the exhibit.

Response: The 44% calculation includes National Fuel's distribution (utility) segment, as indicated in Ms. Crowe's testimony at page 40, lines 14-17, and is correct.

Response prepared by Elizabeth Crowe

Response Date: April 13, 2020

Exhibit No. PMG-0010
Workpaper

Panhandle Eastern Pipe Line Company, LP
Docket No. RP19-1523-000

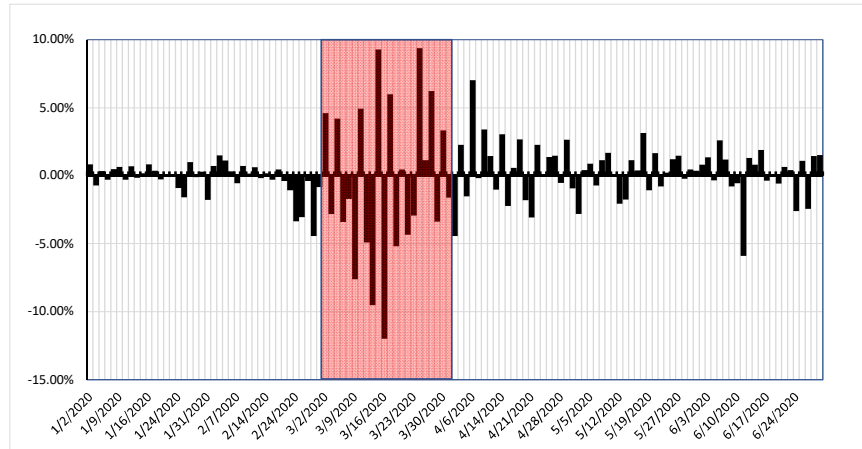
<u>Month</u>	<u>High</u>	<u>Low</u>	<u>Average</u>	<u>Quarterly Dividend</u>	<u>Annual Dividend</u>	<u>Yield</u>	<u>6-Mo. Running Avg Yield</u>	<u>Current Analyst Est</u>
National Fuel Gas (NFG)								
3/2/2020	38.66	36.56	37.61	0.435	1.74	4.63%	4.07%	8.50%
2/1/2020	44.82	35.29	40.06	0.435	1.74	4.34%	3.90%	8.50%
1/1/2020	46.67	41.34	44.01	0.435	1.74	3.95%	3.78%	8.50%
12/1/2019	47.70	44.37	46.04	0.435	1.74	3.78%	3.70%	8.50%
11/1/2019	47.05	44.01	45.53	0.435	1.74	3.82%	3.61%	
TC Energy Corporation (TRP)								
3/2/2020	53.67	51.98	52.83	0.573	2.29	4.34%	4.35%	5.81%
2/1/2020	57.92	50.86	54.39	0.573	2.29	4.21%	4.37%	5.81%
1/1/2020	55.70	52.25	53.98	0.573	2.29	4.25%	4.44%	5.81%
12/1/2019	53.95	49.97	51.96	0.573	2.29	4.41%	4.49%	5.81%
11/1/2019	51.75	48.81	50.28	0.565	2.26	4.49%	4.53%	
Williams Cos. (WMB)								
3/2/2020	19.60	18.48	19.04	0.380	1.52	7.98%	6.99%	9.57%
2/1/2020	22.80	18.25	20.53	0.380	1.52	7.41%	6.70%	
1/1/2020	24.17	20.58	22.38	0.380	1.52	6.79%	6.50%	9.75%
12/1/2019	24.06	22.03	23.05	0.380	1.52	6.60%	6.32%	11.15%
11/1/2019	23.55	21.90	22.73	0.380	1.52	6.69%	6.15%	
Kinder Morgan Inc. (KMI)								
3/2/2020	20.28	19.10	19.69	0.250	1.00	5.08%	4.92%	0.23%
2/1/2020	22.58	18.40	20.49	0.250	1.00	4.88%	4.89%	8.05%
1/1/2020	21.68	20.76	21.22	0.250	1.00	4.71%	4.90%	8.05%
12/1/2019	21.36	19.13	20.25	0.250	1.00	4.94%	4.92%	8.04%
11/1/2019	20.73	19.50	20.12	0.250	1.00	4.97%	4.90%	
10/1/2019	20.74	19.63	20.18	0.250	1.00	4.95%	4.93%	8.04%
Enable Midstream Partners, LP (ENBL)								
3/2/2020	7.03	6.14	6.59	0.331	1.32	20.11%	14.86%	-4.00%
2/1/2020	9.57	6.03	7.80	0.331	1.32	16.97%	13.29%	-4.00%
1/1/2020	10.81	9.39	10.10	0.331	1.32	13.11%	12.17%	-4.50%
12/1/2019	10.65	8.82	9.74	0.331	1.32	13.60%	11.49%	-4.50%
11/1/2019	10.70	8.87	9.79	0.331	1.32	13.53%	10.82%	
10/1/2019	12.14	10.22	11.18	0.331	1.32	11.84%	10.13%	5.40%

Exhibit No. PMG-0010
Workpaper

Panhandle Eastern Pipe Line Company, LP
Docket No. RP19-1523-000

<u>Month</u>	<u>High</u>	<u>Low</u>	<u>Average</u>	<u>Quarterly Dividend</u>	<u>Annual Dividend</u>	<u>Yield</u>	<u>6-Mo. Running Avg Yield</u>	<u>Current Analyst Est</u>
EQM Midstream Partners, L.P. (EQM)								
3/2/2020	17.73	15.66	16.70	1.16	4.64	27.79%	19.78%	-3.70%
2/1/2020	23.91	15.26	19.59	1.16	4.64	23.69%	17.65%	-3.70%
1/1/2020	30.70	22.81	26.76	1.16	4.64	17.34%	16.02%	-2.12%
12/1/2019	30.05	21.43	25.74	1.16	4.64	18.03%	14.97%	2.48%
11/1/2019	30.92	22.47	26.70	1.16	4.64	17.38%	13.69%	
10/1/2019	33.63	30.69	32.16	1.16	4.64	14.43%	12.50%	2.48%
Tallgrass Energy LP (TGE)								
3/2/2020	22.11	21.34	21.73	0.55	2.20	10.13%	10.72%	-14.05%
2/1/2020	22.36	21.94	22.15	0.55	2.20	9.93%	10.85%	-14.05%
1/1/2020	22.38	22.10	22.24	0.55	2.20	9.89%	11.30%	-14.05%
12/1/2019	22.18	17.58	19.88	0.55	2.20	11.07%	11.40%	-14.05%
11/1/2019	18.82	17.47	18.15	0.55	2.20	12.12%	11.15%	
10/1/2019	20.14	18.41	19.28	0.54	2.16	11.21%	10.60%	
Dominion Energy, Inc. (D)								
3/2/2020	84.32	78.45	81.39	0.94	3.76	4.62%	4.49%	4.88%
2/1/2020	90.89	76.39	83.64	0.918	3.67	4.39%	4.49%	4.88%
1/1/2020	86.69	81.26	83.98	0.918	3.67	4.37%	4.57%	4.41%
12/1/2019	82.95	79.77	81.36	0.918	3.67	4.51%	4.64%	4.41%
11/1/2019	83.93	79.52	81.73	0.918	3.67	4.49%	4.69%	
10/1/2019	83.23	78.95	81.09	0.918	3.67	4.53%	4.75%	4.60%

^S&P 500		Daily Price
	PRICECLOSE	Change
12/31/2019	3,230.78	
1/2/2020	3,257.85	0.84%
1/3/2020	3,234.85	-0.71%
1/6/2020	3,246.28	0.35%
1/7/2020	3,237.18	-0.28%
1/8/2020	3,253.05	0.49%
1/9/2020	3,274.70	0.67%
1/10/2020	3,265.35	-0.29%
1/13/2020	3,288.13	0.70%
1/14/2020	3,283.15	-0.15%
1/15/2020	3,289.29	0.19%
1/16/2020	3,316.81	0.84%
1/17/2020	3,329.62	0.39%
1/21/2020	3,320.79	-0.27%
1/22/2020	3,321.75	0.03%
1/23/2020	3,325.54	0.11%
1/24/2020	3,295.47	-0.90%
1/27/2020	3,243.63	-1.57%
1/28/2020	3,276.24	1.01%
1/29/2020	3,273.40	-0.09%
1/30/2020	3,283.66	0.31%
1/31/2020	3,225.52	-1.77%
2/3/2020	3,248.92	0.73%
2/4/2020	3,297.59	1.50%
2/5/2020	3,334.69	1.13%
2/6/2020	3,345.78	0.33%
2/7/2020	3,327.71	-0.54%
2/10/2020	3,352.09	0.73%
2/11/2020	3,357.75	0.17%
2/12/2020	3,379.45	0.65%
2/13/2020	3,373.94	-0.16%
2/14/2020	3,380.16	0.18%
2/18/2020	3,370.29	-0.29%
2/19/2020	3,386.15	0.47%
2/20/2020	3,373.23	-0.38%
2/21/2020	3,337.75	-1.05%
2/24/2020	3,225.89	-3.35%
2/25/2020	3,128.21	-3.03%
2/26/2020	3,116.39	-0.38%
2/27/2020	2,978.76	-4.42%
2/28/2020	2,954.22	-0.82%
3/2/2020	3,090.23	4.60%
3/3/2020	3,003.37	-2.81%
3/4/2020	3,130.12	4.22%
3/5/2020	3,023.94	-3.39%
3/6/2020	2,972.37	-1.71%
3/9/2020	2,746.56	-7.60%
3/10/2020	2,882.23	4.94%
3/11/2020	2,741.38	-4.89%
3/12/2020	2,480.64	-9.51%
3/13/2020	2,711.02	9.29%
3/16/2020	2,386.13	-11.98%
3/17/2020	2,529.19	6.00%
3/18/2020	2,398.10	-5.18%
3/19/2020	2,409.39	0.47%
3/20/2020	2,304.92	-4.34%
3/23/2020	2,237.40	-2.93%
3/24/2020	2,447.33	9.38%
3/25/2020	2,475.56	1.15%
3/26/2020	2,630.07	6.24%
3/27/2020	2,541.47	-3.37%
3/30/2020	2,626.65	3.35%
3/31/2020	2,584.59	-1.60%
4/1/2020	2,470.50	-4.41%
4/2/2020	2,526.90	2.28%
4/3/2020	2,488.65	-1.51%
4/6/2020	2,663.68	7.03%
4/7/2020	2,659.41	-0.16%
4/8/2020	2,749.98	3.41%
4/9/2020	2,789.82	1.45%
4/13/2020	2,761.63	-1.01%
4/14/2020	2,846.06	3.06%
4/15/2020	2,783.36	-2.20%
4/16/2020	2,799.55	0.58%
4/17/2020	2,874.56	2.68%
4/20/2020	2,823.16	-1.79%
4/21/2020	2,736.56	-3.07%
4/22/2020	2,799.31	2.29%
4/23/2020	2,797.80	-0.05%



^S&P 500		Daily Price Change
	PRICECLOSE	
4/24/2020	2,836.74	1.39%
4/27/2020	2,878.48	1.47%
4/28/2020	2,863.39	-0.52%
4/29/2020	2,939.51	2.66%
4/30/2020	2,912.43	-0.92%
5/1/2020	2,830.71	-2.81%
5/4/2020	2,842.74	0.43%
5/5/2020	2,868.44	0.90%
5/6/2020	2,848.42	-0.70%
5/7/2020	2,881.19	1.15%
5/8/2020	2,929.80	1.69%
5/11/2020	2,930.32	0.02%
5/12/2020	2,870.12	-2.05%
5/13/2020	2,820.00	-1.75%
5/14/2020	2,852.50	1.15%
5/15/2020	2,863.70	0.39%
5/18/2020	2,953.91	3.15%
5/19/2020	2,922.94	-1.05%
5/20/2020	2,971.61	1.67%
5/21/2020	2,948.51	-0.78%
5/22/2020	2,955.45	0.24%
5/26/2020	2,991.77	1.23%
5/27/2020	3,036.13	1.48%
5/28/2020	3,029.73	-0.21%
5/29/2020	3,044.31	0.48%
6/1/2020	3,055.73	0.38%
6/2/2020	3,080.82	0.82%
6/3/2020	3,122.87	1.36%
6/4/2020	3,112.35	-0.34%
6/5/2020	3,193.93	2.62%
6/8/2020	3,232.39	1.20%
6/9/2020	3,207.18	-0.78%
6/10/2020	3,190.14	-0.53%
6/11/2020	3,002.10	-5.89%
6/12/2020	3,041.31	1.31%
6/15/2020	3,066.59	0.83%
6/16/2020	3,124.74	1.90%
6/17/2020	3,113.49	-0.36%
6/18/2020	3,115.34	0.06%
6/19/2020	3,097.74	-0.57%
6/22/2020	3,117.86	0.65%
6/23/2020	3,131.29	0.43%
6/24/2020	3,050.33	-2.59%
6/25/2020	3,083.76	1.10%
6/26/2020	3,009.05	-2.42%
6/29/2020	3,053.24	1.47%
6/30/2020	3,100.29	1.54%

Source: S&P Global Market Intelligence © 2020 S&P Global Market Intelligence (and its affiliates, as applicable) (individually and collectively, "S&P"). All rights reserved. For intended recipient only. No further distribution or reproduction permitted without S&P's prior written permission. A reference to or any observation concerning a particular investment, security or credit rating in the S&P information is not a recommendation to buy, sell, or hold such investment or security or make any other investment decisions. S&P and its third party licensors: (1) do not guarantee the accuracy, completeness, timeliness or availability of any information and are not responsible for any errors or omissions or for the results obtained from the use of such content; and (2) give no express or implied warranties of any kind. In no event shall S&P or its third party licensors be liable for any damages, including, without limitation, direct and indirect damages in connection with any use of the S&P information.

Price Changes	S&P 500	DJIA	NASDAQ
2/24/20-2/28/20	-8.42%	-9.13%	-7.09%
2/24/20-3/23/20	-30.64%	-33.51%	-25.60%

S&P 500

Date	Open	High	Low	Close	Adj Close	Volume	% Change
1/2/2020	3244.67	3258.14	3235.53	3257.85	3257.85	3458250000	
1/3/2020	3226.36	3246.15	3222.34	3234.85	3234.85	3461290000	-0.71%
1/6/2020	3217.55	3246.84	3214.64	3246.28	3246.28	3674070000	0.35%
1/7/2020	3241.86	3244.91	3232.43	3237.18	3237.18	3420380000	-0.28%
1/8/2020	3238.59	3267.07	3236.67	3253.05	3253.05	3720890000	0.49%
1/9/2020	3266.03	3275.58	3263.67	3274.7	3274.7	3638390000	0.67%
1/10/2020	3281.81	3282.99	3260.86	3265.35	3265.35	3212970000	-0.29%
1/13/2020	3271.13	3288.13	3268.43	3288.13	3288.13	3456380000	0.70%
1/14/2020	3285.35	3294.25	3277.19	3283.15	3283.15	3665130000	-0.15%
1/15/2020	3282.27	3298.66	3280.69	3289.29	3289.29	3716840000	0.19%
1/16/2020	3302.97	3317.11	3302.82	3316.81	3316.81	3535080000	0.84%
1/17/2020	3323.66	3329.88	3318.86	3329.62	3329.62	3698170000	0.39%
1/21/2020	3321.03	3329.79	3316.61	3320.79	3320.79	4105340000	-0.27%
1/22/2020	3330.02	3337.77	3320.04	3321.75	3321.75	3619850000	0.03%
1/23/2020	3315.77	3326.88	3301.87	3325.54	3325.54	3764860000	0.11%
1/24/2020	3333.1	3333.18	3281.53	3295.47	3295.47	3707130000	-0.90%
1/27/2020	3247.16	3258.85	3234.5	3243.63	3243.63	3823100000	-1.57%
1/28/2020	3255.35	3285.78	3253.22	3276.24	3276.24	3526720000	1.01%
1/29/2020	3289.46	3293.47	3271.89	3273.4	3273.4	3584500000	-0.09%
1/30/2020	3256.45	3285.91	3242.8	3283.66	3283.66	3787250000	0.31%
1/31/2020	3282.33	3282.33	3214.68	3225.52	3225.52	4527830000	-1.77%
2/3/2020	3235.66	3268.44	3235.66	3248.92	3248.92	3757910000	0.73%
2/4/2020	3280.61	3306.92	3280.61	3297.59	3297.59	3995320000	1.50%
2/5/2020	3324.91	3337.58	3313.75	3334.69	3334.69	4117730000	1.13%
2/6/2020	3344.92	3347.96	3334.39	3345.78	3345.78	3868370000	0.33%
2/7/2020	3335.54	3341.42	3322.12	3327.71	3327.71	3730650000	-0.54%
2/10/2020	3318.28	3352.26	3317.77	3352.09	3352.09	3450350000	0.73%
2/11/2020	3365.87	3375.63	3352.72	3357.75	3357.75	3760550000	0.17%
2/12/2020	3370.5	3381.47	3369.72	3379.45	3379.45	3926380000	0.65%
2/13/2020	3365.9	3385.09	3360.52	3373.94	3373.94	3498240000	-0.16%
2/14/2020	3378.08	3380.69	3366.15	3380.16	3380.16	3398040000	0.18%
2/18/2020	3369.04	3375.01	3355.61	3370.29	3370.29	3746720000	-0.29%
2/19/2020	3380.39	3393.52	3378.83	3386.15	3386.15	3600150000	0.47%
2/20/2020	3380.45	3389.15	3341.02	3373.23	3373.23	4007320000	-0.38%
2/21/2020	3360.5	3360.76	3328.45	3337.75	3337.75	3899270000	-1.05%
2/24/2020	3257.61	3259.81	3214.65	3225.89	3225.89	4842960000	-3.35%
2/25/2020	3238.94	3246.99	3118.77	3128.21	3128.21	5591510000	-3.03%
2/26/2020	3139.9	3182.51	3108.99	3116.39	3116.39	5478110000	-0.38%
2/27/2020	3062.54	3097.07	2977.39	2978.76	2978.76	7058840000	-4.42%
2/28/2020	2916.9	2959.72	2855.84	2954.22	2954.22	8563850000	-0.82%
3/2/2020	2974.28	3090.96	2945.19	3090.23	3090.23	6376400000	4.60%
3/3/2020	3096.46	3136.72	2976.63	3003.37	3003.37	6355940000	-2.81%
3/4/2020	3045.75	3130.97	3034.38	3130.12	3130.12	5035480000	4.22%
3/5/2020	3075.7	3083.04	2999.83	3023.94	3023.94	5575550000	-3.39%
3/6/2020	2954.2	2985.93	2901.54	2972.37	2972.37	6552140000	-1.71%
3/9/2020	2863.89	2863.89	2734.43	2746.56	2746.56	8423050000	-7.60%
3/10/2020	2813.48	2882.59	2734	2882.23	2882.23	7635960000	4.94%
3/11/2020	2825.6	2825.6	2707.22	2741.38	2741.38	7374110000	-4.89%
3/12/2020	2630.86	2660.95	2478.86	2480.64	2480.64	8829380000	-9.51%
3/13/2020	2569.99	2711.33	2492.37	2711.02	2711.02	8258670000	9.29%
3/16/2020	2508.59	2562.98	2380.94	2386.13	2386.13	7781540000	-11.98%
3/17/2020	2425.66	2553.93	2367.04	2529.19	2529.19	8358500000	6.00%
3/18/2020	2436.5	2453.57	2280.52	2398.1	2398.1	8755780000	-5.18%
3/19/2020	2393.48	2466.97	2319.78	2409.39	2409.39	7946710000	0.47%
3/20/2020	2431.94	2453.01	2295.56	2304.92	2304.92	9044690000	-4.34%
3/23/2020	2290.71	2300.73	2191.86	2237.4	2237.4	7402180000	-2.93%
3/24/2020	2344.44	2449.71	2344.44	2447.33	2447.33	7547350000	9.38%
3/25/2020	2457.77	2571.42	2407.53	2475.56	2475.56	8285670000	1.15%
3/26/2020	2501.29	2637.01	2500.72	2630.07	2630.07	7753160000	6.24%
3/27/2020	2555.87	2615.91	2520.02	2541.47	2541.47	6194330000	-3.37%
3/30/2020	2558.98	2631.8	2545.28	2626.65	2626.65	5746220000	3.35%
3/31/2020	2614.69	2641.39	2571.15	2584.59	2584.59	6568290000	-1.60%

Source: YahooFinance

Dow Jones Industrial Average

Date	Open	High	Low	Close	Adj Close	Volume	% Change
1/2/2020	28638.97	28872.8	28627.77	28868.8	28868.8	251820000	
1/3/2020	28553.33	28716.31	28500.36	28634.88	28634.88	239590000	-0.81%
1/6/2020	28465.5	28708.02	28418.63	28703.38	28703.38	252760000	0.24%
1/7/2020	28639.18	28685.5	28565.28	28583.68	28583.68	258900000	-0.42%
1/8/2020	28556.14	28866.18	28522.51	28745.09	28745.09	291750000	0.56%
1/9/2020	28851.97	28988.01	28844.31	28956.9	28956.9	275060000	0.74%
1/10/2020	28977.52	29009.07	28789.1	28823.77	28823.77	237830000	-0.46%
1/13/2020	28869.01	28909.91	28819.43	28907.05	28907.05	249830000	0.29%
1/14/2020	28895.5	29054.16	28872.27	28939.67	28939.67	287440000	0.11%
1/15/2020	28901.8	29127.59	28897.35	29030.22	29030.22	260270000	0.31%
1/16/2020	29131.95	29300.32	29131.95	29297.64	29297.64	252110000	0.92%
1/17/2020	29313.31	29373.62	29289.91	29348.1	29348.1	321820000	0.17%
1/21/2020	29269.05	29341.21	29146.47	29196.04	29196.04	320640000	-0.52%
1/22/2020	29263.63	29320.2	29172.26	29186.27	29186.27	283440000	-0.03%
1/23/2020	29111.02	29190.47	28966.98	29160.09	29160.09	307060000	-0.09%
1/24/2020	29230.39	29288.79	28843.31	28989.73	28989.73	380010000	-0.58%
1/27/2020	28542.49	28671.79	28440.47	28535.8	28535.8	337270000	-1.57%
1/28/2020	28594.28	28823.23	28575.75	28722.85	28722.85	330140000	0.66%
1/29/2020	28820.53	28944.24	28728.19	28734.45	28734.45	302290000	0.04%
1/30/2020	28640.16	28879.71	28489.76	28859.44	28859.44	326850000	0.43%
1/31/2020	28813.04	28813.04	28169.53	28256.03	28256.03	403890000	-2.09%
2/3/2020	28319.65	28630.39	28319.65	28399.81	28399.81	307910000	0.51%
2/4/2020	28696.74	28904.88	28696.74	28807.63	28807.63	332750000	1.44%
2/5/2020	29048.73	29308.89	29000.85	29290.85	29290.85	357540000	1.68%
2/6/2020	29388.58	29408.05	29246.93	29379.77	29379.77	263700000	0.30%
2/7/2020	29286.92	29286.92	29056.98	29102.51	29102.51	252860000	-0.94%
2/10/2020	28995.66	29278.07	28995.66	29276.82	29276.82	250510000	0.60%
2/11/2020	29390.71	29415.39	29210.47	29276.34	29276.34	279540000	0.00%
2/12/2020	29406.75	29568.57	29406.75	29551.42	29551.42	309530000	0.94%
2/13/2020	29436.03	29535.4	29345.93	29423.31	29423.31	291150000	-0.43%
2/14/2020	29440.47	29463.04	29283.18	29398.08	29398.08	231000000	-0.09%
2/18/2020	29282.78	29330.16	29116.81	29232.19	29232.19	256600000	-0.56%
2/19/2020	29312.7	29409.09	29274.38	29348.03	29348.03	240640000	0.40%
2/20/2020	29296.25	29368.45	28959.65	29219.98	29219.98	287780000	-0.44%
2/21/2020	29146.53	29146.53	28892.7	28992.41	28992.41	311210000	-0.78%
2/24/2020	28402.93	28402.93	27912.44	27960.8	27960.8	452580000	-3.56%
2/25/2020	28037.65	28149.2	26997.62	27081.36	27081.36	513270000	-3.15%
2/26/2020	27159.46	27542.78	26890.97	26957.59	26957.59	472450000	-0.46%
2/27/2020	26526	26775.31	25752.82	25766.64	25766.64	664980000	-4.42%
2/28/2020	25270.83	25494.24	24681.01	25409.36	25409.36	915990000	-1.39%
3/2/2020	25590.51	26706.17	25391.96	26703.32	26703.32	637200000	5.09%
3/3/2020	26762.47	27084.59	25706.28	25917.41	25917.41	647080000	-2.94%
3/4/2020	26383.68	27102.34	26286.31	27090.86	27090.86	457590000	4.53%
3/5/2020	26671.92	26671.92	25943.33	26121.28	26121.28	477370000	-3.58%
3/6/2020	25457.21	25994.38	25226.62	25864.78	25864.78	599780000	-0.98%
3/9/2020	24992.36	24992.36	23706.07	23851.02	23851.02	750430000	-7.79%
3/10/2020	24453	25020.99	23690.34	25018.16	25018.16	654860000	4.89%
3/11/2020	24604.63	24604.63	23328.32	23553.22	23553.22	663960000	-5.86%
3/12/2020	22184.71	22837.95	21154.46	21200.62	21200.62	908260000	-9.99%
3/13/2020	21973.82	23189.76	21285.37	23185.62	23185.62	843080000	9.36%
3/16/2020	20917.53	21768.28	20116.46	20188.52	20188.52	770130000	-12.93%
3/17/2020	20487.05	21379.35	19882.26	21237.38	21237.38	793060000	5.20%
3/18/2020	20188.69	20489.33	18917.46	19898.92	19898.92	871360000	-6.30%
3/19/2020	19830.01	20442.63	19177.13	20087.19	20087.19	780300000	0.95%
3/20/2020	20253.15	20531.26	19094.27	19173.98	19173.98	872290000	-4.55%
3/23/2020	19028.36	19121.01	18213.65	18591.93	18591.93	787970000	-3.04%
3/24/2020	19722.19	20737.7	19649.25	20704.91	20704.91	799340000	11.37%
3/25/2020	21050.34	22019.93	20538.34	21200.55	21200.55	796320000	2.39%
3/26/2020	21468.38	22595.06	21427.1	22552.17	22552.17	705180000	6.38%
3/27/2020	21898.47	22327.57	21469.27	21636.78	21636.78	588830000	-4.06%
3/30/2020	21678.22	22378.09	21522.08	22327.48	22327.48	545540000	3.19%
3/31/2020	22208.42	22480.37	21852.08	21917.16	21917.16	571210000	-1.84%

NASDAQ							
Date	Open	High	Low	Close	Adj Close	Volume	% Change
1/2/2020	9039.46	9093.43	9010.89	9092.19	9092.19	2848370000	
1/3/2020	8976.43	9065.76	8976.43	9020.77	9020.77	2567400000	-0.79%
1/6/2020	8943.5	9072.41	8943.5	9071.47	9071.47	2788120000	0.56%
1/7/2020	9076.64	9091.93	9042.55	9068.58	9068.58	2352850000	-0.03%
1/8/2020	9068.03	9168.89	9059.38	9129.24	9129.24	2464090000	0.67%
1/9/2020	9202.27	9215.95	9158.5	9203.43	9203.43	2534700000	0.81%
1/10/2020	9232.95	9235.2	9164.66	9178.86	9178.86	2378990000	-0.27%
1/13/2020	9213.72	9274.49	9193.06	9273.93	9273.93	2530270000	1.04%
1/14/2020	9270.61	9298.33	9226.49	9251.33	9251.33	2542170000	-0.24%
1/15/2020	9253.76	9298.82	9231.14	9258.7	9258.7	2435650000	0.08%
1/16/2020	9313.45	9357.92	9301.32	9357.13	9357.13	2301400000	1.06%
1/17/2020	9392.37	9393.48	9346.81	9388.94	9388.94	2522670000	0.34%
1/21/2020	9361.07	9397.58	9350.2	9370.81	9370.81	2684540000	-0.19%
1/22/2020	9413.61	9439.29	9375.13	9383.77	9383.77	2449390000	0.14%
1/23/2020	9377.72	9409.2	9334.13	9402.48	9402.48	2460050000	0.20%
1/24/2020	9446.21	9451.43	9273.23	9314.91	9314.91	2611710000	-0.93%
1/27/2020	9092.46	9185.45	9088.04	9139.31	9139.31	2583330000	-1.89%
1/28/2020	9201.82	9288.87	9182.33	9269.68	9269.68	2157830000	1.43%
1/29/2020	9318.26	9329.12	9249.04	9275.16	9275.16	2223480000	0.06%
1/30/2020	9211.15	9303	9185.18	9298.93	9298.93	2333500000	0.26%
1/31/2020	9324.33	9324.8	9123.22	9150.94	9150.94	2685840000	-1.59%
2/3/2020	9190.72	9299.85	9188.55	9273.4	9273.4	2420510000	1.34%
2/4/2020	9398.39	9485.38	9374.05	9467.97	9467.97	2445420000	2.10%
2/5/2020	9574.1	9574.94	9454.93	9508.68	9508.68	2462470000	0.43%
2/6/2020	9540.98	9575.66	9505.68	9572.15	9572.15	2267300000	0.67%
2/7/2020	9526.64	9570.09	9496.53	9520.51	9520.51	2238670000	-0.54%
2/10/2020	9493.63	9628.66	9493.63	9628.39	9628.39	2179310000	1.13%
2/11/2020	9680.89	9714.74	9617.21	9638.94	9638.94	2423670000	0.11%
2/12/2020	9688.6	9728.77	9666.69	9725.96	9725.96	2355000000	0.90%
2/13/2020	9657.04	9748.32	9650.02	9711.97	9711.97	2239270000	-0.14%
2/14/2020	9728.9	9746.36	9693.05	9731.18	9731.18	2222240000	0.20%
2/18/2020	9679.04	9747.68	9675.8	9732.74	9732.74	2273460000	0.02%
2/19/2020	9782.81	9838.37	9777.1	9817.18	9817.18	2462530000	0.87%
2/20/2020	9799.2	9820.86	9636.94	9750.97	9750.97	2735610000	-0.67%
2/21/2020	9708.01	9715.95	9542.33	9576.59	9576.59	2743010000	-1.79%
2/24/2020	9188.44	9322.88	9166.01	9221.28	9221.28	3177000000	-3.71%
2/25/2020	9301.2	9315.26	8940.49	8965.61	8965.61	3583400000	-2.77%
2/26/2020	9011.55	9148.32	8927.8	8980.78	8980.78	3567830000	0.17%
2/27/2020	8744.03	8904.11	8562.05	8566.48	8566.48	390750000	-4.61%
2/28/2020	8269.74	8591.82	8264.16	8567.37	8567.37	5301170000	0.01%
3/2/2020	8667.14	8952.81	8543.35	8952.17	8952.17	4232760000	4.49%
3/3/2020	8965.1	9070.32	8602.89	8684.09	8684.09	4336700000	-2.99%
3/4/2020	8834.1	9019.96	8757.66	9018.09	9018.09	3602870000	3.85%
3/5/2020	8790.09	8921.08	8677.39	8738.59	8738.59	3748090000	-3.10%
3/6/2020	8469.02	8612.36	8375.13	8575.62	8575.62	4279850000	-1.86%
3/9/2020	7957.93	8243.31	7943.16	7950.68	7950.68	4530350000	-7.29%
3/10/2020	8219.76	8347.4	7930.43	8344.25	8344.25	4431930000	4.95%
3/11/2020	8136.25	8181.36	7850.95	7952.05	7952.05	4273890000	-4.70%
3/12/2020	7398.58	7712.33	7194.67	7201.8	7201.8	5066530000	-9.43%
3/13/2020	7610.39	7875.93	7219.09	7874.88	7874.88	4685890000	9.35%
3/16/2020	7392.73	7422.2	6882.86	6904.59	6904.59	4594360000	-12.32%
3/17/2020	7072	7406.23	6828.91	7334.78	7334.78	4900000000	6.23%
3/18/2020	6902.32	7182.83	6686.36	6989.84	6989.84	4890820000	-4.70%
3/19/2020	6996.45	7341.38	6858.38	7150.58	7150.58	4762170000	2.30%
3/20/2020	7248.07	7354.44	6854.67	6879.52	6879.52	5239940000	-3.79%
3/23/2020	6847.28	6984.94	6631.42	6860.67	6860.67	4330610000	-0.27%
3/24/2020	7196.15	7418.37	7169.86	7417.86	7417.86	4417380000	8.12%
3/25/2020	7421.36	7671.21	7276.4	7384.3	7384.3	4666440000	-0.45%
3/26/2020	7462.21	7809.83	7462.21	7797.54	7797.54	3999850000	5.60%
3/27/2020	7554.25	7716.24	7491.14	7502.38	7502.38	3977010000	-3.79%
3/30/2020	7583.46	7784.35	7539.97	7774.15	7774.15	3846900000	3.62%
3/31/2020	7740.06	7880.31	7642.86	7700.1	7700.1	4059700000	-0.95%

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of CONSUMERS)	
ENERGY COMPANY for authority to increase its)	
rates for the generation and distribution of)	Case No. U-18322
electricity and for other relief.)	
_____)	

At the March 29, 2018 meeting of the Michigan Public Service Commission in Lansing,
Michigan.

PRESENT: Hon. Sally A. Talberg, Chairman
Hon. Norman J. Saari, Commissioner
Hon. Rachael A. Eubanks, Commissioner

ORDER

I. HISTORY OF PROCEEDINGS

On March 31, 2017, Consumers Energy Company (Consumers) filed an application seeking authority to increase rates for the generation and distribution of electricity and requesting other regulatory approvals. The rate increase sought in this proceeding is based on the company's projections for relevant items of investment, expenses, and revenues for a test year covering the period from October 1, 2017 to September 30, 2018. In its application, Consumers averred that, without rate relief, the company will experience a jurisdictional electric revenue shortfall of \$173 million on an annual basis. Consumers' current base rates were approved in an order issued on February 28, 2017 in Case No. U-17990 (February 28 order).

Consumers explained that the largest portion of its requested relief is related to investments in system reliability, environmental compliance, and enhanced technology, adding that the need for additional revenues has been offset, in part, by working capital related reductions driven by accrued taxes, pension and other post-employment benefits (OPEB), and fuel stock.

As part of its application, Consumers requested rate recovery for the costs of an expanded demand response (DR) program. Consumers requested \$10.6 million for the program under traditional ratemaking, and it proposed an alternative under which the Commission could approve regulatory asset treatment for all DR costs, with a 12-year amortization of the regulatory asset.

Consumers proposed that the rates established in this case include an authorized rate of return on common equity (ROE) of 10.5%, and reflect an overall rate of return on total rate base of 6.16%. Consumers stated that the requested returns reasonably balance the interests of customers and investors.

Consumers stated that in addition to the cost-of-service study (COSS) and rate design attached to its application, the company proposed to separate capacity charges from non-capacity charges in its power supply charges included in base rates in accordance with Section 6w of 2016 PA 341, MCL 460.6w. Consumers requested that the Commission approve capacity charges for full-service and retail open access customers to go into effect June 1, 2018.

Consumers also proposed a number of revisions to its electric rules, regulations, and tariffs, generally described in paragraph 14 of its application. In paragraph 15 of its application, Consumers requested approval of various forms of accounting authority.

According to Consumers, the net impact of all matters to be considered in this proceeding supports the company's request for rate relief of \$173 million. Consumers maintained that, absent

rate relief in this amount, the company will experience revenues so low as to deprive it of a reasonable return on its investments in violation of the federal and state constitutions.

Administrative Law Judge Sharon L. Feldman (ALJ) held a prehearing conference on May 9, 2017. At the prehearing conference, the ALJ granted petitions to intervene filed by the Michigan Department of the Attorney General (Attorney General), the Association of Businesses Advocating Tariff Equity (ABATE), Gerdau Macsteel, Inc. (Gerdau), the Michigan State Utility Workers Council, Utility Workers Union of America, AFL-CIO, The Kroger Company, Michigan Environmental Council (MEC), Environmental Law & Policy Center (ELPC), Natural Resources Defense Council (NRDC), Sierra Club (SC), Hemlock Semiconductor Operations LLC (Hemlock), Constellation NewEnergy, Inc. (CNE), Energy Michigan, Michigan Cable Telecommunications Association, the Midland Cogeneration Venture Limited Partnership, and the Residential Customer Group (RCG). The Commission Staff (Staff) also participated. Subsequent to the prehearing, the ALJ granted late petitions to intervene filed by Wal-Mart Stores East, LP, and Sam's East, Inc. (together, Wal-Mart) and Midwest Cogeneration Association (MCA).

On May 11, 2017, the Commission issued an order (May 11 order) addressing the requirements of MCL 460.6w. In response to the May 11 order, ABATE filed a motion for summary disposition, and the RCG filed a motion requesting that Consumers amend its application or, alternatively, that the application be dismissed. Subsequently, the Commission issued an order on rehearing that clarified the May 11 order and rendered the motions moot. The ALJ entered a protective order on May 12, 2017. On July 24, 2017, the ALJ granted MEC/SC's motion to unseal certain exhibits related to retirement scenarios for Consumers' "Medium 4 units."¹

¹ The Medium 4 units are D.E. Karn Units 1 and 2 and J.C. Campbell Units 1 and 2.

On August 10, 2017, Consumers filed testimony and exhibits supporting self-implementation of a \$130 million annual revenue increase on and after October 1, 2017. On August 18, 2017, the ALJ conducted a hearing on the company's proposed self-implementation. Absent action by the Commission, on October 1, 2017, Consumers self-implemented a rate increase designed to produce additional annual retail electric revenues of \$130 million above levels established by the February 28 order.

The evidentiary phase of the proceedings began on September 26, 2017, and continued through October 4, 2017. The ALJ denied, in part, the RCG's request to file certain testimony and exhibits out of time, and ABATE's motion to strike portions of Consumers' rebuttal testimony on capacity costs. The ALJ also granted the Staff's motion to strike a portion of Consumer's rebuttal testimony on ROE. Timely briefs and reply briefs were filed.

On January 8, 2018, the ALJ issued her Proposal for Decision (PFD). Consumers, the Staff, the Attorney General, ABATE/Gerdau, ELPC, Hemlock, and the RCG filed exceptions to the PFD on January 29, 2018. Replies to exceptions were filed by Consumers, the Staff, the Attorney General, ABATE/Gerdau, MCA, MEC/NRDC/SC, and the RCG on February 12, 2018. The record consists of 2,846 pages of transcript² and 448 exhibits received into evidence.³

On December 27, 2017, the Commission issued an order in Case No. U-18494 (December 27 order), directing all rate-regulated utilities to implement regulatory accounting to address the

² Consumers filed a motion on October 13, 2017, requesting that portions of volumes 9 and 10 of the transcript be corrected. No party objected and the ALJ recommended approval of the corrections. No exceptions were filed on this issue and, therefore, the Commission adopts the ALJ's recommendation.

³ The ALJ provided a detailed review of the record (PFD, pp. 6-71) and positions of the parties (PFD, *passim*), which will only be repeated as necessary to discuss an issue in contention. The Commission addresses the issues in roughly the same sequence in which they were addressed in the PFD.

financial effects of the Tax Cuts and Jobs Act of 2017 (TCJA). In addition, the Commission requested comments from regulated utilities on “the extent of the impacts of the new law, and how any resulting benefit should flow back to ratepayers.” December 27 order, p. 2. Utilities, including Consumers, were ordered to file initial comments, and interested parties were asked to file reply comments. On February 22, 2018, the Commission issued an order (February 22 order) addressing various aspects of the TCJA going forward.

On January 8, 2018, the RCG filed a motion to reopen the record, for rehearing, or for taking of judicial notice, and a motion for immediate consideration. In its filing, the RCG requested a ruling from the ALJ or the Commission that Consumers be required to update its case to reflect the effect of the TCJA on the rate increase requested in this proceeding. On January 15, 2018, the RCG filed a revised motion to reopen the record. Consumers, the Staff, and MEC/NRDC/SC filed responses to the RCG’s revised motion, and the ALJ conducted a hearing on the motion on January 18, 2018. At the close of the hearing, the ALJ issued an oral PFD in which she denied the RCG’s requests.

II. LEGAL STANDARDS

Consumers takes exception to what it characterizes as the ALJ’s incomplete recitation of the company’s arguments regarding the legal standards to be applied in rate cases, specifically with respect to the use of projected test years and the application of the used and useful principle.⁴ Contrary to the ALJ’s description of its arguments concerning projected test years, Consumers contends that it never claimed that historical information could never be used in establishing rates

⁴ The “used and useful” doctrine posits that “an item may be included in a rate base only when it is ‘used and useful’ in providing service. In other words, current rate payers should bear only legitimate costs of providing service to them.” *Tennessee Gas Pipeline Co v Fed Energy Regulatory Comm*, 196 US App DC 187, 202; 606 F2d 1094 (1979).

for the test period, noting that the company relied on historical information in developing some of its projections. Consumers further asserts that its argument was in response to suggestions by ABATE/Gerdau and the RCG that the Commission should set the company's rates based on an historical test year, rather than on a projection. Consumers maintains that, although 2016 PA 341 amended MCL 460.6a, the company's right to have its rates established on the basis of a projected test period was not altered.

Similarly, with respect to the used and useful principle, Consumers asserts that its objection was based on the Staff's claim that expenditures must be used and useful during the test year before they may be included in base rates. The company posits that such a requirement is contrary to MCL 460.6a(1) and that the Commission frequently reviews and approves costs before they are incurred. Consumers concludes that, "[t]he legal standard for ratemaking is whether the rates being set are just and reasonable." Consumers' exceptions, p. 4, citing MCL 460.557(4).

The Commission finds that the ALJ provided a thorough and correct analysis of the legal standards for setting just and reasonable rates on pages 74-86 of the PFD. The ALJ presented a detailed overview of Commission orders that clearly affirm that, while the company may rely on forecasted revenues and costs in developing its test year projection, if certain items within this projection are not adequately supported, other parties may use alternative means, including historical data, to arrive at a reasonable result. In addition, the ALJ noted that "no party seriously advocates for the use of a purely historical test year in this case[;]" thus, Consumers objection is to a degree disingenuous. PFD, p. 76.

With respect to the used and useful standard, the ALJ agreed with Consumers that "the Commission is not limited by law to allowing recovery only of used and useful expenditures[;]"

however, “it is clear the Commission has not abandoned the used-and-useful principle[.]” noting that:

[T]he Commission has only rarely deviated from general adherence to [the] principle that investments must be used and useful before they may be recovered. In rate case after rate case, the Commission has explained rate base as “the capital invested in used and useful plant . . .” Moreover, the Commission has articulated an expectation that projected expenditures used to project test-year rate base are for investments that will be used and useful in the test year.

* * *

While individual capital expense projections can be evaluated on rate case records, the Commission should expect that Consumers Energy will expressly identify in its filing any projected investment it is including in its test year projected rate base that will not be used and useful during the test year. It should also be noted that the rate case projections of future rate base are not the determinant of actual rate base. If a utility does not make a capital investment it projected, it may not include the projection in its rate base as if the expenditure had been made. Similarly, if the Commission subsequently determines an investment was unreasonable or imprudent, or is not used and useful or subject to a specific exemption from that standard, that investment will not be considered part of rate base.

PFD, pp. 80-81.

Again, the Commission agrees with the ALJ’s comprehensive examination of the used and useful doctrine, and the limited exceptions thereto, as have long been applied by this Commission. Moreover, the Commission disagrees with Consumers’ contention that items included in the approved, projected rate base are not, as a rule, required to be found used and useful during the test period. As the ALJ discussed, the Commission addressed this issue squarely in the January 31, 2017 order in Case No. U-18014, pp. 28-29, where it deferred cost recovery for a computer application, after finding that the item would not likely be deployed during the test year.

The Commission does not dispute that there is no legal requirement that items be used and useful to be included in rate base; however, the used and useful standard has been employed by this Commission, and by many others, to protect ratepayers from unreasonable or excessive facilities while allowing investors a return on the capital which they have reasonably devoted to

public use. Moreover, application of the used and useful doctrine does not violate Section 6a(1), which provides that the company may base its case on projected revenues and costs. As noted above, the Commission is not bound to accept the company's projections absent sufficient evidence to show that the projection, including the in-service date, is reasonable, prudent, and accurate.

III. TEST YEAR

Consumers proposed using the 12-month period ending September 30, 2018, as the test year for establishing representative levels of revenues, expenses, rate base, and capital structure for use in setting rates. ABATE/Gerdau did not propose a different test period but did recommend that the Commission consider the advantages of test year projections in determining an appropriate ROE.

In response, Consumers contended that a projected test year is required under MCL 460.6a, and the company provided an overview of the benefits of a projected test period. The Staff did not object to the future test period but noted that the Commission is not bound by the test year chosen by the company. In its reply brief, the RCG recommended that rates be set consistent with an historical test year.

The ALJ found that the RCG's recommendation, first raised in its reply brief, was presented so late in the proceeding that no party had an opportunity to respond. Moreover, although the RCG asserted that there was sufficient information in the record to set rates based on an historical period, it failed to cite any testimony or exhibits to support its claim. The ALJ concluded that because the RCG's proposal was unsupported and untimely, and because no other party requested the use of a different test year, the Commission should adopt the company's proposed test year. PFD, pp. 73-74. There were no exceptions. The Commission agrees with the ALJ and adopts October 1, 2017 through September 30, 2018 as the test period for setting rates.

IV. RATE BASE

A utility's rate base consists of the capital invested in used and useful plant, plus the utility's working capital requirements, less accumulated depreciation. Consumers projected a jurisdictional electric rate base of \$10,289,206,000, which was revised to \$10,258,460,000 in the company's initial brief. The Staff calculated a rate base of \$10,206,705,000, adjusted to \$10,131,927,000 in its brief, and the Attorney General advocated a downward adjustment of \$127,200,000 to the company's rate base. After making modifications, discussed in more detail below, the ALJ recommended a jurisdictional rate base of \$10,203,659,000.

As a preface to her discussion of rate base, the ALJ pointed out that, "there are many examples where Consumers Energy has spent substantially less than it projected it would spend in prior rate cases. Overall, it appears that for the projected test year used in Case No. U-17990, the company spent approximately 2% below the level of capital expenditures used in setting rates in that case." PFD, p. 82. The ALJ continued, noting "Consumers Energy's overarching view is that the capital expense projections provide an allowance for capital spending that the company is free to reprioritize to address 'emergent' issues or for other reasons. Indeed, the company's view seems to be that it will not make capital expenditures in excess of the total projected amounts included in current rates." *Id.*

Consumers takes exception, contending that the ALJ misperceived the company's position, adding that this error appeared to have "shaped [the ALJ's] perception" of the company's capital expense projections in this case. Consumers' exceptions, p. 4. Consumers reiterates that because rates are set prospectively, the company cannot foresee every eventuality. Thus, there are times when approved funding must be reallocated to other rate base items. In addition, Consumers

argues that there are a number of factors that could explain the difference between projected and actual rate base including changes in depreciation, costs of removal, and customer deposits.

The Commission agrees with Consumers that, as a general proposition, there are a number of factors that might explain a disparity between actual and projected rate base. In the instant case, however, Consumers did not point to any changes in depreciation, costs of removal, customer deposits, or the like, that might have caused a \$177 million deviation between what was projected in the company's previous case and actual rate base. Thus, the ALJ appropriately focused on the difference between projected (and approved) capital expenditures and actual capital expenditures. The Commission therefore finds that Consumers' exception should be rejected.

A. Net Utility Plant

Consumers initially projected a net plant amount of \$9.632 billion, on a total company basis, which it revised to \$9.601 billion in its initial brief. The Staff calculated a total company net plant amount of \$9.51 billion, which it revised to \$9.54 billion in its reply brief. The Attorney General recommended a reduction to net plant of \$122.8 million. Disputed issues include contingency costs, several items in electric distribution, meter estimation expense, generation capital expense, residential DR, and information technology (IT) capital expense. These issues are addressed *ad seriatim*.

1. Contingency Costs

Consumers requested contingency costs totaling \$23.5 million for various capital expense items. The Staff and the Attorney General opposed Consumers' request because the Commission has consistently rejected the inclusion of contingency on grounds that these costs are not appropriately included in rates. The ALJ agreed with the Staff and the Attorney General, noting that Consumers did not raise any new issues or arguments in this proceeding that would merit

reconsideration of the Commission's previous determination that contingency costs should be disallowed.

Consumers takes exception, maintaining that, "[e]ven though the Commission recently rejected the recovery of contingency costs in Case No. U-17990, the Commission should reconsider that position in this case and approve the Company's request for recovery because fairly estimated contingency costs should be reasonably expected to be incurred by the Company." Consumers' exceptions, p. 7. Consumers further contends that the Commission's history with respect to disallowance of contingency expense has been uneven, pointing to Case Nos. U-16191 and U-16794, wherein, according to Consumers, the Commission approved rates that included contingency expense. Consumers reiterates that contingency costs are no different than any other projected cost and points out that no party took issue with the appropriateness of the company's method for projecting contingency. The Staff, the Attorney General, the RCG, and MEC/NRDC/SC replied, repeating the arguments they made previously.

The Commission agrees with the ALJ that Consumers' projected contingency costs should be disallowed. As the Commission has found repeatedly, although allowing for contingency may be appropriate in project planning, the inclusion of these costs in customer rates is unjust and unreasonable. *See*, February 28 order, pp. 11-12; November 19, 2015 order in Case No. U-17735, pp. 7-11; December 11, 2015 order in Case No. U-17767, pp. 19-20; December 9, 2016 order in Case No. U-17999, pp. 4-6; and January 31, 2017 order in Case No. U-18014, pp. 12-13. With respect to Consumers' claim that the Commission's approach to contingency has been uneven, a review of the orders in Case Nos. U-16191 and U-16794 demonstrates that there was no explicit approval of contingency costs in those orders, thus indicating that the issue of contingency costs was not contested in those cases.

2. Electric Distribution Capital Expenditures

For the test year, Consumers requested recovery of \$762.9 million in electric distribution capital expenditures, as set forth in Exhibit A-19. According to Consumers, these projections are the investment levels necessary for new business, reliability, grid modernization, capacity, demand failures, to relocate electric distribution infrastructure, and for other electric operations.

Although the Attorney General took issue with Consumers' amount for new business, largely based on increased loading rates for indirect and overhead costs, the ALJ found that he failed to respond to the company's rebuttal in his initial brief. Thus, the ALJ adopted the amount proposed by Consumers for new business. However, because of the historical variability in loading rates, and their significant cost, the ALJ recommended that the Commission require Consumers to provide more information and support for this cost element in future rate cases. There were no exceptions to the ALJ's recommendation. The Commission agrees with the PFD and adopts the ALJ's findings and conclusions with respect to this issue. The remaining contested issues are discussed below.

a. Reliability

Consumers projected test year capital expenditures for reliability of \$121.6 million. Exhibits A-19 and A-22. The Staff recommended an adjustment of \$14.6 million on grounds that the company's projection was significantly above 2015 historical spending and 2016 preliminary levels. The Staff further contended that Consumers failed to provide sufficient detail about specific projects and pointed out that the company's five-year distribution plan, required in the

February 28 order, has not been submitted.⁵ Accordingly, the Staff recommended that reliability capital expenditures be reduced to preliminary 2016 levels adjusted for inflation.

The Attorney General similarly recommended a reduction of \$12.5 million, observing that Consumers' 2017 projections were consistent with 2016 spending levels, but that 2018 projections were not.

In response to claims that its projections were unsupported, Consumers cited testimony and a discovery response that detailed the company's method for selecting reliability projects and the timing for selection of projects for 2018. Consumers argued that it is prudent to undertake project selection near the time that construction is set to begin so that more timely information can be used. Consumers added that it is planning to invest more in these projects to improve service reliability and customer satisfaction. Consumers also criticized the Staff's assumption used for 2016 expenditures, contending that the preliminary amount was actually higher than the Staff's amount.

The ALJ agreed with the Staff and the Attorney General that Consumers' projected spending for 2018 was substantially higher than 2015 and 2016, and that the company's projections were not supported. The ALJ pointed out that while Consumers provided information about its process for selecting projects, the actual projects to be undertaken will not be determined until late 2017 or 2018. With respect to 2016 preliminary spending on reliability, the ALJ noted a discrepancy between Exhibits A-34 (preliminary actual amounts) and A-36 (preliminary projected amounts) and questioned whether the amounts in these exhibits were more reliable than the amounts from

⁵ In the February 28 order, pp. 18-19, the Commission directed Consumers to consult with the Staff and file a comprehensive distribution capital investment and operations plan covering the next five years. The plan was to be submitted on January 31, 2018, but the due date has been extended to March 1, 2018.

Exhibit A-22 that the Staff and the Attorney General used. The ALJ therefore recommended that the Commission adopt the Staff's proposed adjustment.

Consumers takes exception, arguing that the ALJ's recommendation to use projected 2016 amounts, rather than actual amounts, was inconsistent with the use of historical information. Consumers reiterates that its projections were in fact supported and repeats that it is reasonable to select projects shortly before construction to avoid the use of stale data, which could result in increased costs. Finally, Consumers again emphasizes the need to increase its investment in reliability programs to identify problems that cause customer outages.

The Attorney General also takes exception, asserting that the Commission should adopt his recommended disallowance of \$42.7 million, rather than the Staff's proposed \$14.6 million adjustment, as was recommended in the PFD.⁶

In reply, the Staff asserts that the ALJ's findings were well-reasoned and based on substantial evidence that the company has consistently underspent on reliability and other rate base items.

The Commission finds the PFD well-reasoned and adopts its findings and conclusions on this issue. In cases where the company demonstrates a consistent pattern of underspending, the Commission finds it most reasonable to limit approved amounts to historical levels, until such time as the company demonstrates a true commitment to these programs.

b. Grid Modernization

The grid modernization program includes expenditures for communications, substation automation, and distribution management systems to improve grid reliability, power quality, and service to customers. Consumers projected a test year capital expense of \$39 million for this item.

The Staff took issue with the company's projection, again based on significant underspending

⁶ The Attorney General's exception appears to be an error.

on this program, compared to approved amounts, in the company's last two rate cases. In addition, the Staff raised concerns about how grid modernization funds were reallocated after Consumers' previous rate cases. Finally, the Staff pointed out that Consumers' failure to spend in this category may have led to decreases in several reliability indices and that the company failed to provide a benefit-cost analysis of the various grid modernization programs. The Staff therefore recommended that the test year grid modernization expense be held to the 2016 level adjusted for inflation.

In response, Consumers argued that funds that were approved for grid modernization were in fact allocated to other rate base items and that, contrary to the Staff's claim, the company did provide an analysis of the various customer benefits of grid modernization. Consumers contended that it is impossible to predict necessary levels of spending and that underspending in one area is offset by overspending in another area.

The ALJ found the Staff's recommendation reasonable, noting that "[t]he company's projected 2018 spending level is twice the 2016 level and three times the 2015 level[.]" adding that "[t]he company's chronic underspending in this category is also a substantial reason to be cautious." PFD, p. 114. The ALJ reiterated that the Commission will be reviewing the company's five-year distribution plan and will have an opportunity to evaluate the company's planned investments.

Consumers takes exception, arguing that the ALJ's recommendation is based on the company's purported failure to provide a benefit-cost analysis and scope of work for the proposed grid modernization projects. Consumers maintains that the ALJ's finding was erroneous and that the company did provide ample evidence, including a program benefit analysis that demonstrated the immediate and long-term benefits of grid modernization. Moreover, Consumers maintains

that, in the February 28 order, the Commission determined that a benefit-cost analysis presented in the company's next rate case would be duplicative of information in the five-year distribution plan.

The Staff replies that the ALJ's recommendation is reasonable and supported by the record.

The Commission finds the PFD well-reasoned and supported by the record. As the Staff and the ALJ pointed out, Consumers' consistent underspending on its grid modernization program is a significant cause for concern, and one that the Commission has addressed before. As noted in several previous rate case orders, until the Commission sees a clear commitment to grid modernization, the Commission agrees that it is reasonable to approve a capital expense amount based on historical spending rather than the company's projection.

c. Demand Failures Program

Consumers' demand failures program includes capital costs for outage restoration, and the repair or replacement of equipment including pole-top rehabilitation and replacement of conventional light fixtures with light emitting diode (LED) technology. Consumers proposed capital expenditures of \$133.1 million in 2017 and \$134 million in 2018 for this program.

The Staff recommended a reduction of \$13.6 million to the demand failures program, noting that Consumers' projection was \$27 million over the five-year average of spending in this category. The Staff also objected to the lack of detail in the individual projects, contending that there was insufficient information on the scope of work and benefits related to some of the projects. The Attorney General also proposed a reduction of \$26.8 million for the demand failures program, based on the actual 2016 expense level.

Consumers responded that it was impossible to provide a detailed scope of work for customer outages and other emergent issues, and that the Staff failed to include spending for certain specific

programs.

The ALJ agreed with the Staff's recommendation for the demand failures program, explaining:

The company did not present any projects to support the 2018 projections. While some projects are identified in Exhibit A-97, that response also states that projected expenditures are based on historical experience, and does not refute Staff's analysis. Since Staff identified \$72 million of the 2018 projection that is without support, Staff's recommended reduction of \$13.6 million reflects the difficulty of projecting expenditures in this category while providing a measure of protection for ratepayers. . . . Staff's analysis provides a reasonable allowance based on historical expenditures with room for the additional programs identified by Mr. Bordine.

PFD, p. 119.

Consumers takes exception, contending that the company's projection was based on a five-year average of spending, with additional incremental expenditures for projects that are planned. Consumers argues that the Staff's recommendation, adopted in the PFD, uses 2016 actual spending updated for inflation. This amount, however, does not take into account new or expanded programs such as LED streetlights, distribution and transformer metering, and the replacement of low-voltage distribution (LVD) transformers. In response, the Staff asserts that the ALJ's findings and recommendations were reasonable and supported by the record.

The Commission finds the PFD well-reasoned and adopts its findings and conclusions. As the Staff and the ALJ pointed out, Consumers' projection is \$27 million over the five-year average spending in this category, and for 2018, there is \$72 million without support. The Commission agrees that \$121 million is sufficient to cover historical expenses with room for additional projects or programs that the company may undertake.

d. Electric Operations-Other

Electric Operations-Other includes capital expenditures for computers and equipment, capital tools, system control projects, National Electric Reliability Council (NERC) cyber security compliance and National Electrical Safety Code (NESC) working space compliance requirements and substation fall protection. Consumers projected a test year spending amount of \$8.62 million for this category.

The Staff recommended a reduction of \$7.5 million on grounds that Consumers provided support for only one expense category, and for that category (NERC/NESC expense), the Staff had concerns about the accuracy of the projection in light of historical spending. The Attorney General, on similar grounds, recommended a disallowance of \$5.8 million.

The ALJ found that Consumers failed to support its projections in this category and failed to address previous years' underspending. Accordingly, the ALJ recommended that the Commission adopt the Staff's proposed reduction for electric operations-other.

Consumers takes exception and points to Exhibits A-32, A-33, A-35, and A-98 as support for its projection. The Staff replies that the ALJ's determination was reasonable and supported by the record.

The Commission finds that Consumers' exception should be rejected. As the ALJ pointed out, Exhibit A-103 "confirm[s] that the company made no expenditures through July 2017 toward its projected \$1.7 million expenditure for NERC/NESC compliance," and "the company is \$3.2 million behind in its projected spending for the electric-other category over that same time frame, including significant deviations from projected spending in multiple line items." PFD, p. 122. Accordingly, the Commission adopts the Staff's recommendation to approve 2016 amounts adjusted for inflation for electric operations-other expense.

3. 2016 Meter-Estimation Related Expense

Based on the Commission's decisions in Case No. U-18002, the Staff recommended that \$156,516 in software for Consumers' meter estimation process and \$234,611 in new meter reading hardware costs be disallowed. According to the Staff, these investments were made to address a problem that resulted from the company's imprudence with respect to bill estimation procedures. In addition, the costs included additional meter readers that appear unnecessary in light of the company's deployment of advanced metering infrastructure (AMI).

The ALJ found that, in a revised discovery request, Consumers indicated that the expenses at issue had been paid for by the company's gas division, and were therefore not included in the rate request in this case. The ALJ therefore rejected the Staff's proposed adjustment.

The Staff takes exception, arguing that "[t]he ALJ was partly correct," observing: "the ALJ mistakenly believed the Company's revision applied to both the \$234,611 for new meter-reading hardware costs *and* the \$156,526 [sic] in software/systems development. In fact, the revision in Exhibit A-99 only applied to the \$234,611 that was charged to gas accounts." Staff's exceptions, p. 2. Accordingly, the Staff recommends that the Commission reverse the PFD with respect to \$156,516 for meter reading software.

In response, Consumers contends that at the time these expenditures were made, AMI was not fully deployed; thus, there was still a need to estimate some meter reads, and estimation software improvements were therefore necessary. In addition, the company points out that some customers have opted out of AMI, and for those customers, meter reads will still, on occasion, need to be estimated.

The Commission agrees with the Staff and finds that \$156,516 for meter estimation software should be disallowed. A review of the order in Case No. U-18002 demonstrates that Consumers

failed to address meter estimation problems for a number of years, despite numerous customer complaints. The company's previous bill estimation algorithm was set in 2009 and, despite apparent inaccuracies, remained in place until an upgrade in 2016. The Commission agrees with the Staff that ratepayers should not be required to pay the cost of an expensive upgrade necessitated by the company's imprudence.

4. Generation Capital Expense

The Staff and the company agreed to adjustments to capital expense for Resource Conservation and Recovery Act (RCRA) compliance at several of the company's units, which the ALJ adopted. In replies to exceptions, the Staff noted an error in the discussion in the PFD but observed that the amount calculated for rate base in the PFD was correct. The Attorney General raised additional issues concerning generation capital expenditures and RCRA compliance. The ALJ found that one of the Attorney General's proposed disallowances was duplicative of the Staff's recommendation and the other was adequately addressed by the company's rebuttal. There were no exceptions filed with respect to the ALJ's recommendations concerning capital expense for RCRA compliance. The Commission finds the PFD well-reasoned and supported by the record on these issues. The only remaining issue in this category concerns the evaluation of various retirement scenarios and proposed capital expenditures for Consumers' Medium 4 units.

In the February 28 order, the Commission directed Consumers to undertake a comprehensive analysis of various retirement scenarios for the Medium 4 units. In this case, the ALJ found: "The disputes between the parties involve whether the company's analysis complied with the Commission's directives in [the February 28 order], whether costs identified as avoidable in the event of an early retirement should be excluded from this rate case, and what additional analysis the company should perform." PFD, p. 134.

Consumers provided a preliminary analysis of the early retirement of the Medium 4 units, stating that the analysis is not conclusive and no retirement decisions have been made. Both the Staff and MEC/NRDC/SC recommended that the Commission exclude some or all projected avoidable capital expenses for the Medium 4 until Consumers makes a decision as to whether to retire the units. The Staff identified \$1,613,000 in avoidable capital costs for Karn Units 1 and 2 that should be disallowed. The Staff further recommended, in addition to the company's proposed retirement analysis factors, that Consumers evaluate the internal rate of return (IRR), near-term revenue requirements, conditions of existing equipment, execution risks, and any other factors the Commission finds important. In its brief, the Staff recommended that Consumers file its new retirement study in this docket by April 20, 2018. The Staff noted that the timing was critical because "a decision to pursue a 2021 retirement would have to be approved no later than March 2018 in order for the majority of the 2019 capital costs identified as avoidable to be avoided." Staff's initial brief p. 54.

MEC/NRDC/SC recommended that the Commission disallow all avoidable expenses for the Medium 4 on grounds that Consumers failed to show that continued investment in these units was reasonable and prudent. MEC/NRDC/SC criticized Consumers' presentation, contending that the company presented essentially the same analysis that it did in its previous rate case, resulting in the same conclusion, i.e., that more analysis is required before a retirement decision is made. MEC/NRDC/SC provided their own analysis demonstrating that early retirement showed economic benefits for one or more of the units. With respect to the company's next retirement analysis, MEC/NRDC/SC made several recommendations concerning specific additional evaluations that Consumers should undertake.

Consumers responded that because the company has not yet decided to retire any of the Medium 4 units, it is reasonable to assume that all four units will operate until 2031. Consumers contended that until a decision is made and evaluated as part of the company's integrated resource plan (IRP), it is essential to continue to invest in these units. Thus, any reduction in capital spending would be inappropriate. Consumers also objected to any additional analysis for the Medium 4 retirement scenarios, contending that it should not be required to do more than what is necessary for its IRP.

The ALJ found that there was no dispute that the analysis presented in this case was insufficient to make a decision about retirement of any or all of the Medium 4 units. The ALJ further determined that, despite the Commission's directive in the February 28 order for the company to submit a detailed benefit-cost analysis in accordance with the Staff's and intervenors' recommendations, Consumers failed to provide the comprehensive evaluation that the Commission ordered.

The ALJ agreed with the Staff's recommended exclusion of \$1.6 million in avoidable costs associated with the Karn units, finding persuasive the Staff's argument that it would be more reasonable to err on the side of caution and assume that these expenses may be delayed or foregone. The ALJ noted, however: "Rather than assume, as Staff and MEC/NRDC/SC urge, that the units will retire in 2021, this PFD merely recommends that the Commission defer including uncertain capital expenses in rates, without prejudice to a future review, should the company indeed make the capital investment." PFD, pp. 154-155. Finally, the ALJ recommended that Consumers include a standalone analysis of various retirement scenarios for the Medium 4 units as part of its IRP filing in June 2018.

Consumers takes exception to numerous aspects of the ALJ's assessment. First, Consumers contends that both the company and the Staff agreed that the company's analysis complied with the requirements of the February 28 order, repeating the language in the order and the parts of the company's analysis that were in conformance. Consumers adds that the ALJ, in discussing the record in the previous case, added some requirements that were not in the February 28 order.

Next, Consumers objects to certain aspects of the additional retirement analysis to be included in the company's upcoming IRP. At this point, Consumers indicates that it is feasible to include analyses of: (1) capacity replacement costs; (2) impact of recovery of undepreciated book value; (3) customer rate impact analysis; (4) non-economic variables such as portfolio balance, employment, and community impact; (5) effect on contractual fuel obligations; (6) near-term revenue requirements; (7) conditions of existing equipment; and (8) execution risk, all of which were proposed by the Staff. However, Consumers disputes that an IRR analysis would be appropriate, contending, "[i]nternal rates of return are traditionally used to evaluate the economics of acquiring a single new asset or engaging in a single project before it is part of the company's portfolio. The Company is not aware of any case in which they are used to evaluate the economics of removing an existing asset from operation." Consumers' exceptions, p. 27.

Finally, Consumers takes exception to the ALJ's recommended disallowance of potentially avoidable costs for Karn Units 1 and 2. Consumers reiterates that, because no retirement decision has been made, it is essential to continue investing in the Medium 4. Consumers adds that early retirement of the Medium 4 units could increase outage rates and power supply cost recovery (PSCR) costs and could increase costs to be borne by the remaining units at Campbell and Karn.

In reply, the Staff points out that Consumers provided no analytical support for its claim that outage rates and PSCR costs would increase if capital costs for Karn Units 1 and 2 are deferred,

and any increased costs for the remaining units should be addressed in the company's next rate case. With respect to an IRR analysis of the Medium 4, the Staff points out that in Consumers' last rate case, the company indicated that IRR was one factor that it needed to consider in evaluating retirement of the units. Given the company's opposition now, the Staff recommends that "the Commission require the Company to consider the internal rate of return in its IRP analysis for the Medium Four units: if it proves impossible to incorporate this metric into the IRP analysis, the Company must explain in the IRP why this is the case." Staff's replies to exceptions, pp. 13-14.

In their replies to exceptions, MEC/NRDC/SC assert that the ALJ properly found that Consumers' analysis did not comply with the February 28 order; it was merely an update to the preliminary analysis presented in the previous rate case. More importantly, the new analysis presented here was insufficient to make a firm decision on retirement dates for the Medium 4. Thus, capital and major maintenance expenses continue to be incurred, despite indications that early retirement of one or more of the units may be more economical than keeping these units operating until 2031. MEC/NRDC/SC further contend that Consumers should be required to submit its retirement study in this docket by April 20, 2018. In exceptions, the Staff concurs.

The Commission finds that Consumers' exceptions should be rejected. First, the Commission agrees that, at best, Consumers' retirement analysis presented in this case was little more than an update of the same analysis that the Commission found lacking in the February 28 order. In addition, the Commission agrees with the Staff and MEC/NRDC/SC, that it is reasonable to err on the side of caution and defer \$1.6 million in test year avoidable costs for the Karn units. As the ALJ pointed out, the deferral does not foreclose future recovery if any amounts are prudently spent. Finally, the Commission agrees with the ALJ that the company should include a standalone

analysis of various retirement scenarios for the Medium 4 units in its IRP. The analysis shall consider the eight factors listed above as enumerated by the company. In addition, per the Staff's suggestion, Consumers shall include an IRR analysis or provide justification for why such analysis could not be performed. Finally, as recommended by MEC/NRDC/SC:

[I]n order to avoid another round of claims by the Company that its evaluation of the Medium 4 Units is "preliminary" or incomplete, the Commission should require the unit disposition analysis to include an evaluation and discussion of any other factors that Consumers believes are relevant to selection of a prudent retirement date for each of the Medium 4 Units. Finally, the Commission should direct Consumers to include a documented justification of its assumptions around whether planned capital and major maintenance projects for each of the Medium 4 Units are avoidable or unavoidable in each retirement scenario that is evaluated.

MEC/NRDC/SC replies to exceptions, p. 15.

While the Commission recognizes the Staff's and MEC/NRDC/SC's concerns about the timing of the retirement analysis, the Commission notes that the onus is on the company to timely complete its disposition evaluation and make prudent decisions supported by that analysis. Thus, the Commission agrees with the ALJ that the retirement assessment of the Medium 4 units should be submitted as a standalone analysis in the company's IRP in June 2018.

5. Residential Demand Response

Consumers projected \$6.2 million for air conditioning (AC) load control switches for the test year and \$2 million for 2017. The Staff recommended that this amount be reduced by \$8.1 million, the amount that was approved in the February 28 order. The Staff argued that the Commission directed that the \$4.9 million AC switch funding approved in that order, combined with prior approved amounts, was expected to result in 42 megawatts (MWs) of DR savings. However, the Staff posited that Consumers was not going to reach this level until May 2018, and the company's enrollment projections were unrealistic. The Attorney General similarly argued,

with respect to DR operations and maintenance (O&M) expense, that Consumers' enrollment projections were overly optimistic.

In response, Consumers asserted that the \$4.9 million approved in the February 28 order would only cover the cost of 18,476 switches. Consumers contended that, in order to reach its 2021 goal of 344 MWs of DR associated with AC switches, it requires an additional \$5.9 million in funding for the program.

Noting that the \$4.9 million funding for AC switches approved in the February 28 order was expected to be cumulative to the \$5.2 million funding approved, but not spent, previously, the ALJ found that, in the instant case, "Consumers Energy is clearly asking that the ratepayers replace the initial funding[.]" PFD, p. 163. After a review of the February 28 order, the ALJ concluded that:

[I]t would be inconsistent with that order to fund an expansion of the program provided for in that case. The Commission concluded that the 42 MW demand reduction for the test year in that case was "reasonable and achievable," and it was not achieved. As noted above, Consumers Energy now projects it will achieve that level by May 2018. The Commission also clearly expressed a concern to avoid funding levels of demand reduction that would not materialize in the test year. Recognizing [that] Consumers Energy projects expansion of its program beyond the 42 MW previously funded, the company has not provided a solid evidentiary basis to conclude that it will attain even the 42 MW of demand reduction in the test year it now projects will be attained by May 2018.

PFD, p. 164.

In light of the above, the ALJ found that it was most reasonable to adopt the Staff's proposed \$8.1 million disallowance.

Consumers takes exception, arguing that the combined capital expense for DR approved in Case No. U-17735 and the February 28 order is \$10.078 million for 42 MWs of DR savings. Consumers contends that the reduction of \$8.1 million from the amount proposed reduces the amount approved in the previous rate cases to only \$5.5 million, half of what was previously approved. Consumers recognizes that its AC switch program is lagging behind expectations;

nevertheless, the company urges the Commission to reverse the PFD and fully fund its request “to encourage the continued successful implementation of this important program.” Consumers’ exceptions, p. 33.

In reply, the Staff describes Consumers’ argument as “sophistry,” noting “[t]he disallowance does not impact amounts previously approved for the AC Peak Cycling Program because the Company presumably spent those amounts already, just not on demand response programs.” Staff’s replies to exceptions, p. 16.

The Commission finds the PFD well-reasoned and adopts its recommendation to limit the funding for AC switches to the amount approved in the February 28 order. The Commission further notes that, while it is axiomatic that once rates are approved the company will decide how funding is utilized, in the case of DR, there are additional implications. One of the fundamental purposes of DR is to employ these programs at times when power supply costs are high. Thus, on a hot summer day, Consumers can use its AC switch technology to offset potentially expensive market purchases. Demand response may also be used to avoid potential capacity purchases. Given the Commission’s prior approvals, Consumers is expected to have at least 42 MWs of ratepayer-funded AC switch DR available by May 2018, to use as a substitute for more costly market energy. To the extent this program is not implemented in a manner that achieves this level of participation or an equivalent benefit to ratepayers through alternative program approaches that deliver similar results, any questions related to individual capacity purchases and/or energy market purchases that could have been avoided by a fully operational DR program can be addressed in a PSCR proceeding, as applicable.

The Commission has been supportive of Consumers’ efforts to expand its DR portfolio, but after increasing funding levels in the past two rate cases, it is clear that results need to be

demonstrated first before additional funding can be authorized. The Commission expects that the new regulatory framework set forth in Case No. U-18369 for review, approval, and reconciliation of DR programs, will mitigate some of these issues going forward.

6. Information Technology

The Staff and the Attorney General proposed adjustments to the company's IT capital expense projection. The ALJ rejected the Attorney General's recommendations based on the company's rebuttal testimony. There were no exceptions, and the Commission agrees with the ALJ's recommendation.

The Staff proposed reductions of \$576,000 and \$327,000, respectively, for "fleet handhelds" and mobile security. The Staff determined that Consumers had not yet determined what brand or model of fleet handheld it planned to buy and was also in the process of evaluating a solution for mobile security concerns. With the limited information the company provided, the Staff stated it was unable to determine the reasonableness of the cost of these items or the likelihood that the items would be purchased in the test year.

Consumers countered that although the exact model of the device was not yet determined, the projected cost of the fleet handhelds was in fact based on a commonly used handheld computer. For mobile security, Consumers described the planning process that the company uses for developing solutions to cyber security issues, noting that a decision will be made later in the planning process.

The ALJ found that the Staff's reduction should be adopted. While noting the Staff's general support for the type of investment the company proposed, she nevertheless agreed with the Staff that Consumers failed to provide sufficient support for its cost estimates or to demonstrate that the expenditures would be incurred in the test period.

Consumers takes exception, reiterating that “[w]hile both the Fleet Handhelds and Mobile Security Projects were in the planning phases, there was enough evidence to support cost recovery for both projects on the record.” Consumers’ exceptions, p. 33.

The Commission disagrees, and finds that the PFD appropriately found that the IT costs for fleet handhelds and mobile security were not sufficiently supported to allow either the costs or the deployment dates to be determined. As the ALJ pointed out, there appears to be conceptual support for these projects, and reasonable and prudent costs may be recovered in the future.

B. Depreciation and Working Capital

After corrections were made to Consumers’ property model, discussed in the PFD, pp. 172-173, there were no disputes over depreciation reserve, and the differences in accumulated depreciation and amortization relate to differences in proposed plant additions.

Consumers recommended an increase of \$24 million in the cash balance component of working capital, in light of the exclusion of temporary cash investments from working capital in Case No. U-17735. The Attorney General objected to this increase on grounds that Consumers failed to provide any operational reason for the increase, further noting that DTE Electric Company (DTE Electric) had a working capital cash balance of only 0.30%, compared to 2% proposed by Consumers. In addition, the Attorney General recommended a decrease in working capital to reflect the fact that Consumers is issuing significant amounts of long-term debt, resulting in higher accrued interest.

In rebuttal, Consumers cited numerous reasons for the proposed increase in cash balances and claimed that there is no historical correlation between long-term debt and accrued interest.

Noting that the Attorney General failed to address the company's response in his initial brief, the ALJ recommended that the company's proposal to increase its cash balance to \$44 million should be approved. There were no exceptions filed.

The Commission finds the PFD well-reasoned and adopts its findings and conclusions with some qualification. The Commission agrees with Consumers on the importance of maintaining adequate liquidity to improve operating flexibility, which then allows the company to make more timely and efficient financial decisions that benefit customers. The company provided a number of examples including the need to purchase gas when prices are low, or to allow the company to make expenditures if there is a delay accessing capital markets due to market conditions. See 9 Tr 1382-1383. It is also appropriate for Consumers to have a variety of methods available to address its liquidity needs in order to best respond to a range of market conditions. However, in order to best benefit customers, the appropriate method (e.g., working capital, revolving credit facilities, commercial paper) should be the lowest cost alternative available at that time. What remains unclear from this record is why an increase in working capital was the most cost-effective means to increase liquidity in this case.

Because working capital is funded through traditional debt and equity, at the weighted average cost of capital, it is typically higher cost than short-term debt. And, the record demonstrates that it is indeed the case in this proceeding. Nevertheless, the company has selected to increase the amount of working capital, and not short-term debt. In fact, Consumers has reduced the amount of short-term debt utilized consistently over its last three rate cases (from \$217 million in Case No. U-17735, to \$164.6 million in Case No. U-17990, and \$160.7 million in the instant case). Again, while there may be some justification for this, no justification is available in this record.

In addition, the analysis of which alternative to use is in turn dependent on the company achieving the most competitive cost possible for each option. The Commission observes that Consumers' short-term debt cost rates have been steadily increasing from 1.73% in Case No. U-17735 (filed December 2014), to 2.47% in U-17990 (filed March 2016), to 3.55% in the instant case (filed March 2017). This amounts to a 182 basis point increase in short-term debt costs in a little over two years. Consumers acknowledges there is a lockstep relationship between its commercial paper rates and the London Interbank Offer Rate (LIBOR) in Exhibit A-9, Schedule D-3, page 2, footnote (b), when it notes, "[f]orecasted LIBOR assumed to closely approximate commercial paper rate." The Commission understands short-term debt rates have increased as the Federal Reserve has increased its Fed Funds Rate. The Commission also understands that economic forecasts exist projecting that the Federal Reserve will continue to increase its Fed Funds Rate during the test year. However, a 100 basis point increase over the course of a year is noteworthy and should be more robustly supported.

Again, because no party addressed this issue in brief or filed an exception to the PFD, the Commission adopts the ALJ's findings regarding the increase in working capital balances. However, the Commission has limited information on whether increasing working capital balances to boost liquidity is the most prudent option. Accordingly, as part of its next rate case, the company shall provide a detailed analysis supporting its liquidity approach.

C. Rate Base Summary

Based on the above determinations, the Commission adopts a rate base amount of \$10,245,141,000 on a total company basis and \$10,202,174,000 on a jurisdictional basis.

V. CAPITAL STRUCTURE AND COST RATES

As discussed below, the parties reached agreement on several balances and cost rates for components of Consumers' proposed capital structure. Remaining areas of dispute concern the appropriate debt to equity ratio for Consumers' capital structure and the rate of return on common equity.

A. Capital Structure

Consumers initially proposed a common equity balance of \$6.648 billion, which constituted 52.91% of its permanent capital structure. However, upon consideration of the Commission's desire to see a "rebalancing" of its capital structure, Consumers accelerated its efforts to reduce its equity ratio by reducing its planned equity infusions in 2018 by \$100 million. Accordingly, Consumers proposed a revised common equity balance of \$6.579 billion, which constituted 52.64% of its permanent capital structure. The Staff adopted Consumers' revised common equity balance, agreeing that this puts Consumers on track to achieve a common equity ratio of about 50% by the end of the five-year period contemplated in the February 28 order.

ABATE/Gerdau recommended reducing the utility's initial common equity balance by \$102 million and increasing the long-term debt balance by the same amount, resulting in a common equity balance of 52.1%. The Attorney General recommended that the capital structure be adjusted to 50% equity and 50% debt based on the capital structures of a peer group of electric utilities. MEC/NRDC/SC agreed with both the Attorney General and ABATE/Gerdau that the Commission should reject the company's proposal and instead exercise its regulatory authority to rebalance the capital structure. In rebuttal, Consumers challenged the relevance of the Attorney General's proxy group and further argued that ABATE/Gerdau failed to provide details or analysis to support its conclusion that the company would maintain its credit ratings with a lower equity

ratio.

The ALJ recommended that the Commission adopt Consumers' and the Staff's agreed-to debt and equity balances, finding that the utility's revised capital structure comports with the Commission's expectations set forth in the February 28 order. The ALJ pointed out that in its rebuttal testimony, Consumers provided a plan to return to a balanced capital structure over a five-year period and took some steps toward doing so in this case. The ALJ further recommended that the Commission require additional analysis of the company's plans to reduce its capital structure in its next rate case, or in its upcoming IRP proceeding, to ensure that Consumers is not making decisions that might increase its overall cost of capital. PFD, p. 186. The ALJ explained that given Consumers' focus on rating agencies' views of purchase power agreements (PPAs), securitization as debt, and the company's plans to increase reliance on generation, it is reasonable for the Commission to expect a thorough analysis in Consumers' next electric rate case. *Id.*

Consumers takes exception, contending that the ALJ's proposal is not supported by any record evidence, was not proposed by any party, and provides insufficient clarity and direction regarding what the analysis should entail. The utility further states that, if the Commission adopts the ALJ's recommendation, the utility's next electric rate case would be the appropriate forum to present this information, rather than an IRP proceeding. Consumers disagrees with the ALJ's concern that the utility's commitment to capital structure rebalancing may have been contingent on successful early termination of the Entergy Nuclear Palisades (Palisades) PPA. Consumers points out that it did not tie its equity ratio to the termination of the Palisades PPA, adding that expiring PPAs may not be replaced entirely by company-owned generating assets, but could come from existing assets, DR, or energy efficiency. Consumers also points out that financing of new generating resources would come equally from debt and equity. Consumers further asserts that its plan to reduce its

portfolio of PPAs will enhance its credit metrics, strengthen its credit rating, and benefit customers.

The Attorney General takes exception and requests that the Commission adopt a 50/50 capital structure. He reiterates that this is consistent with the level of common equity of the peer group used to evaluate the cost of common equity, noting that the difference between the peer group average and what Consumers proposes for its equity ratio creates an “unreasonable disconnect and is also more costly to customers.” Attorney General’s exceptions, p. 4. Further, the Attorney General asks the Commission to consider financial transactions between Consumers and its parent company, pointing out that the parent company is using debt capital to make its equity infusions into Consumers.

Both the Attorney General and ABATE/Gerdau disagree with the conclusion that Consumers’ revised capital structure satisfies the requirements of the February 28 order, reiterating that the company failed to present a thorough analysis or strategy for returning to a balanced capital structure within a five-year timeframe. Therefore, the Attorney General and ABATE/Gerdau urge the Commission to adopt a lower equity ratio for Consumers than the one the ALJ proposed.

Consumers replies that the Commission should reject the Attorney General’s and ABATE/Gerdau’s proposals to reduce its common equity balance. Consumers reiterates that it made a downward revision to its planned equity infusions, accelerating its plan to meet the Commission’s expectations. Consumers states that the record in this case demonstrates it has developed a clear plan to return to a more balanced equity ratio within five years.

In reply, MEC/NRDC/SC maintain that the ALJ’s recommendation for further analysis in future proceedings is both warranted and reasonable. They argue that Consumers did not provide a strategy to balance the capital structure as directed in the February 28 order, and the company

provided little detail as to why maintaining an equity-heavy capital structure for the foreseeable future was reasonable. MEC/NRDC/SC therefore urge the Commission to reject Consumers' proposed capital structure and request that the Commission adopt the Attorney General's or ABATE/Gerdau's recommendations. The RCG similarly argues that Consumers' debt-to-equity ratio is unnecessary and that the Commission should require Consumers to increase the use of long-term and short-term debt and rebalance its capital structure.

The Commission finds the PFD well-reasoned and adopts the ALJ's recommendations on this issue. Specifically, the Commission finds that Consumers is on track to rebalance its capital structure over the five-year timeframe the Commission set out in the February 28 order. The Commission also agrees with the ALJ's recommendation that further analysis of the company's plans to adjust its capital structure is necessary. While the Commission agrees with the company that the IRP proceeding is not the appropriate forum to present such an assessment, the Commission notes that the outcome of the IRP, particularly with respect to if, or when, the company will be undertaking significant capital investments, could inform this analysis. The Commission therefore adopts a common equity balance of \$6.579 billion, or 52.64% of the company's permanent capital structure.

B. Cost of Equity

The criteria for establishing a fair rate of return for public utilities is rooted in the language of the landmark United States Supreme Court cases *Bluefield Waterworks & Improvement Co v Public Serv Comm of West Virginia*, 262 US 679; 43 S Ct 675; 67 L Ed 1176 (1923), and *Federal Power Comm v Hope Natural Gas Co*, 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944). The Supreme Court has made clear that, in establishing a fair rate of return, consideration should be given to both investors and customers. The rate of return should not be so high as to place an

unnecessary burden on ratepayers, yet should be high enough to ensure investor confidence in the financial soundness of the enterprise. Nevertheless, the determination of what is fair or reasonable, “is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use.” *Meridian Twp v City of East Lansing*, 342 Mich 734, 749; 71 NW2d 234 (1955). With these principles in mind, the Commission turns to the factors that form the basis for determining the appropriate rate of return for Consumers.

Consumers used a proxy approach to calculate its proposed ROE, selecting a sample group of 13 companies. To this sample group, Consumers applied the Capital Asset Pricing Model (CAPM) and Empirical CAPM (ECAPM), a Risk Premium (RP) approach, the Discounted Cash Flow (DCF) model, and a Comparable Earnings (CE) analysis, employing forecasted ROEs for the proxy companies to determine an appropriate ROE for the company. Consumers noted that because U.S. Treasury rates are currently artificially low, the company used both a normalized risk-free rate as well as a second, “Low Interest Rate” method, that utilized an average projected yield on 30-year U.S. Treasury Bonds for the test year but a higher average equity risk premium of 10.03% in its CAPM and ECAPM analysis. Similarly, Consumers employed two RP analyses, a normalized RP and low interest rate RP, applying the average risk premium of 8.01% for the period of federal intervention between 2011-2016 to the low interest rate RP analysis. The results of all of the company’s quantitative analyses are set forth in Exhibit A-9, Schedule D-5.

In refining its ROE recommendation, Consumers considered certain qualitative factors, including the company’s good reputation, investors’ view of Michigan’s positive regulatory environment, uncertainty in the markets, and the company’s need to attract capital in light of its plans to make significant investments in the next decade. After weighing the quantitative results

from the various models and the qualitative factors described above, Consumers recommended an ROE of 10.50%, the midpoint of its recommended range of 10.00% to 11.00%.

The Staff recommended an ROE of 9.80%, within its calculated range of 9.00% to 10.00%, based on a proxy group of 11 publicly traded utility companies, to which it applied the DCF and CAPM. The Staff also applied an RP approach. Exhibit S-4.

The Attorney General recommended an ROE of 9.75%. Exhibit AG-24. The Attorney General also employed the DCF and CAPM methods, an RP approach, and he considered current circumstances in the capital markets, the improving Michigan economy, and potential changes in Consumers' risk profile resulting from changes occurring in its electric business. Although the average result of the various models was an ROE of 8.99%, the Attorney General adjusted this to a recommended range of 9.50% to 9.75% to account for the unique risks and circumstances that Consumers faces and as a step towards transitioning the company to a true cost of capital. In his review of ROEs authorized by other utility commissions, the Attorney General noted that the average ROE for 2016, and the first quarter of 2017, was 9.59%. Exhibit AG-29.

ABATE/Gerdau applied constant growth and multi-stage DCF analyses, as well as the CAPM approach to its proxy group of 11 companies, nine of which were included in Consumers' proxy group, to arrive at an ROE recommendation of 8.60%, within their range of 7.40% to 9.70%. ABATE/Gerdau pointed out that betas for electric utilities have decreased by 21% since 2007 and that electric utility ROEs have been decreasing for over a decade. ABATE/Gerdau claimed that the risk-free cost of capital has declined at a faster pace than authorized ROEs, which provided electric utilities with a risk premium "cushion," that is unnecessary in a declining risk environment. ABATE/Gerdau's initial brief, p. 10. ABATE/Gerdau criticized several of Consumers' assumptions and analytical approaches, claiming they were flawed. ABATE/Gerdau

also took issue with Consumers' inclusion of flotation costs, an item that the Commission has historically excluded, because these costs do not represent actual expenses. With respect to the Attorney General's and the Staff's recommended ROEs, ABATE/Gerdau argued that both made unreasonable adjustments to their otherwise sound analyses.

Wal-Mart argued that Consumers' recommended ROE of 10.50% was excessive because Michigan's regulatory framework contains mechanisms that significantly reduce the risk born by utilities, including the use of a projected test year, self-implementation of all or a part of a requested rate change, 365-day rate cases, and restrictions on retail choice. Thus, according to Wal-Mart, the Commission should take a conservative approach when determining a specific ROE. Wal-Mart further argued that the inclusion of construction work in progress (CWIP) in rate base should be reflected in the ROE. Finally, Wal-Mart contended that average ROEs approved by other state commissions has declined each year from 9.92% in 2014 to 9.68% in 2017, noting that Consumers' proposed ROE is excessive by comparison.

In response, Consumers posited that the Staff's, ABATE's, and the Attorney General's recommendations were based on quantitative analyses that failed to consider numerous issues and "an indiscriminate comparison to other recently-authorized ROEs." Consumers reply brief, pp. 92-93. Consumers argued that its presentation was far more complete and reliable because it incorporated additional quantitative analyses and qualitative factors that the other parties failed to consider. Consumers reiterated the importance of the company's ability to attract capital in light of its relatively large capital spending program, and the importance to analysts and investors of consistent and supportive ROEs. Consumers further argued that the Staff and others failed to consider current and prospective economic conditions in their ROE recommendations, noting that there are significant problems with the "mechanical" application of the various models. *Id.*, p. 83.

The company also argued that the Staff and ABATE/Gerdau did not appropriately apply their quantitative models by failing to ensure that the shortcomings of the various models are corrected to account for current market conditions. Consumers also explained that Wal-Mart's arguments about reduced regulatory lag arising from new Michigan energy legislation and inclusion of CWIP in rate base are misplaced.

The ALJ recommended that the Commission adopt the Staff's ROE recommendation of 9.80%, based on her conclusion that the Staff's analysis is both objective and consistent with the analytic framework the Commission has relied on in past cases and reasonably reflects economic conditions expected in the test year. PFD, p. 219. The ALJ found the Staff's proxy group to be reasonable, while questioning Consumers' inclusion of a company that is largely a gas utility, and another one that has been engaged in merger activity since 2016, in its proxy group. The ALJ also found that Consumers failed to establish why some of its selection criteria for its proxy group was material, pointing out that requiring a 60% dividend payout ratio seemed at odds with its testimony that companies planning significant capital investment would have a lower dividend payout ratio than those not planning significant capital investment. PFD, pp. 220-221. The ALJ further found that Consumers failed to justify its proposed change from the Commission's past decisions that found that flotation costs are not recoverable.

The ALJ did not find Consumers' use of estimates of projected dividend growth in its DCF analysis persuasive. Likewise, the ALJ rejected Consumers' recommendation that the Commission give the DCF analysis little weight. The ALJ further found that Consumers failed to justify its inputs for its CAPM and RP analyses. Regarding the company's CE approach, the ALJ recommended excluding one company with an ROE of 18.56%, noting that this ROE is over 170% of the average CE ROE for the company's proxy group. Excluding this outlier, the average ROE

for the proxy group is reduced from 10.75% to 10.10%. PFD, p. 227. Finally, the ALJ questioned the objectivity of Consumers' ROE witness, because he concluded that the 30-basis-point reduction in ROE that the Staff recommended would "not assure confidence in the financial soundness of the utility." PFD, p. 229. In summary, the ALJ found that the Staff's analysis is objectively reasonable, consistent with the requirements of *Bluefield* and *Hope*, and that it should be adopted.

In exceptions, Consumers argues that the PFD's proposed ROE of 9.80% does not satisfy the standards under *Bluefield* and *Hope*. Consumers asserts that the ALJ failed to consider the impact of her recommended ROE on the utility's ability to maintain credit and attract capital, in light of Consumers' plans for significant capital investment. Consumers further argues that no evidence was provided showing that a lower ROE would allow the company to maintain its existing favorable credit ratings. Consumers also disagrees with the ALJ's criticism of its proxy group, noting that removing the two utilities at issue from the group has a limited impact on the company's ROE analysis.

Consumers further claims it is reasonable to include flotation costs when determining the utility's ROE because there is conceptual and intellectual support that Consumers is incurring those costs. Even without the inclusion of those costs, Consumers asserts that this would not support a reduction to its existing 10.10% ROE. Consumers stands by its consideration of the impact of rising interest rates and other market conditions in its quantitative ROE analyses.

Consumers also contends that it proposed reasonable adjustments to three of the quantitative models the utility relied upon. By failing to recognize such adjustments, Consumers argues that the ALJ failed to appropriately apply the risk compensation requirements for determining an appropriate ROE. The utility also disagrees with the ALJ's conclusion that dividend growth

estimates should not be used in its DCF analysis. Consumers asserts that the DCF model was meant to measure the income stream represented and therefore projections of earnings growth as inputs are not appropriate. And, Consumers points out that the PFD mischaracterizes its position on the use of the DCF model. *Id.*, p. 69.

Last, Consumers reiterates that the Commission should not give significant weight to ROE determinations resulting from evidentiary records that are not a part of this case. Although Consumers requests that the Commission authorize an ROE of 10.50%, the company further urges the Commission to not authorize an ROE lower than 10.10%.

ABATE/Gerdau take exception to the ALJ's recommended 9.80% ROE because, according to ABATE/Gerdau, the Staff's analysis actually demonstrated that Consumers' ROE should be set at 8.27%. ABATE/Gerdau contends that the reason the Staff gave in recommending an ROE that was 153 basis points above that demonstrated in its analysis was "professional judgment." ABATE/Gerdau reiterates that Consumers' low risk and reduced regulatory lag must be considered. In place of the Staff's analysis, ABATE/Gerdau argues that its analysis is fair and reasonable and should be adopted instead.

Consumers replies that ABATE/Gerdau's recommended ROE is too low and further argues that an ROE below 10.10% would not be just and reasonable and would send the wrong message to investors.

The Staff and the Attorney General reply that Consumers cannot point to any evidence to show that it would lose its favorable credit rating if the Commission adopted a lower ROE than what Consumers requested. The Staff further disagrees with the company's claim that the Federal Reserve's decision to maintain low long-term interest rates for several years is anomalous. The Staff and the Attorney General argue that the ALJ's decision to disregard Consumers' suggestion

that the proxy group have a dividend payout ratio of 60% or more was well-reasoned and should be accepted. The Staff and the Attorney General also defend the ALJ's reliance on data about other authorized ROEs. The Staff criticizes Consumers for failing to adjust its proxy group to limit it to only highly regarded regulatory environments and capital-attractive regulatory environments, given the utility's assertion that including a disproportionate number of utilities from poorly-regarded regulatory environments in the comparison pool will reduce the average ROE below levels that would be attractive to investor capital. Similarly, the Attorney General argues that Consumers' claim that the ROE data from other jurisdictions contained a disproportionate amount of information from utilities from poorly regulated regulatory environments was a vague assertion that the Commission should reject as unhelpful to its ROE determination. The Attorney General urged the Commission to adopt the PFD's well-reasoned recommendation of a 9.80% ROE in this case.

MEC/NRDC/SC reply that the ALJ's recommendation that the Commission set the ROE at 9.80% is reasonable, supported by the record, and should be adopted.

The Commission finds that an ROE of 10.00% will best achieve the goals of providing appropriate compensation for risk, ensuring the financial soundness of the business, and maintaining a strong ability to attract capital. The Commission notes that the ALJ based her recommendation to adopt the Staff's ROE on her finding that "Staff's analysis is objective and consistent with the analytic framework relied on by the Commission in past cases", and, "[it] reasonably reflects economic conditions expected in the test year[.]" PFD, p. 219. The Commission agrees with the ALJ as to the first part; however, it differs in its view regarding what economic conditions are "reasonably expected." The Commission agrees in part with Consumers

that factors such as volatility and uncertainty, are currently particularly significant and movements are more extreme in comparison to more stable historical periods:

Greater volatility, or large swings up or down, in value in the financial markets increases overall investor risk. During times of extreme fluctuations in investments, there is greater uncertainty and risk among the investment community. As the relative amount of risk in an investment increases, an investor will require a higher return on that investment to compensate for the risk level. The volatility in the financial markets should be taken into consideration in developing the appropriate ROE for the company. Interest rates have been volatile given the new [presidential] administration's focus on infrastructure spending and uncertainty regarding the Federal Reserve's decision of when, and by how much, to raise interest rates . . . It is uncertain how the U.S. economy will react to the predicted near-term interest rate hikes.

10 Tr 1756-1757.

That said, the Commission disagrees that the 10.50% ROE requested by the company is appropriate. In setting the ROE at 10.00%, the Commission believes there is an opportunity for the company to earn a fair return during this period of atypical market conditions. This decision also reinforces the Commission's belief that customers do not benefit from a lower ROE if it means the utility has difficulty accessing capital at attractive terms and in a timely manner. The fact that other utilities have been able to access capital despite lower ROEs, as argued by many intervenors, is also a relevant consideration. It is also important to consider how extreme market reactions to singular events, as have occurred in the recent past, may impact how easily capital will be able to be accessed during the future test period should an unforeseen market shock occur. The Commission will continue to monitor a variety of market factors in future rate cases to gauge whether volatility and uncertainty continue to be prevalent issues that merit more consideration in setting the ROE.

Finally, the Commission appreciates the amount of time and effort the parties put into developing their positions on ROE, providing the Commission with thoughtful analyses upon which to make the most informed decision possible. On the other hand, making a technically

correct and holistic decision becomes difficult when too many methodologies are included in the record, especially if they contain concepts that are novel or untested. Accordingly, the Commission agrees with the ALJ that in future rate cases the company should focus more on objective arguments rather than making sensational statements to bolster its position. The Commission also asks other parties to consider the degree of financial adjustment they are requesting the Commission to undertake in one proceeding, because it is not realistic to make a significant change in ROE absent a radical change in underlying economic conditions. In the future, narrowing the arguments and recommended ROE ranges would greatly assist the Commission in charting a reasonable and steady path on this important issue that impacts the company, its customers, and its shareholders.

C. Other Cost Rates and Balances

In its brief, Consumers proposed a long-term debt cost rate of 4.68%, and the Staff agreed. Consumers proposed a short-term debt balance of \$161 million at a cost rate of 3.55%. The company's debt balance is composed of both the average short-term debt-revolver/commercial paper balance of \$60 million, and the average short-term debt-renewable liability balance of \$101 million. Consumers and the Staff agreed to a 4.50% cost rate for preferred stock, and the cost rates for long-term debt, preferred stock, and common equity components of JDITC should correspond to the cost rates established for long-term debt, preferred stock, and common equity, and the cost rates for other components should be zero. Noting the lack of dispute, the ALJ recommended that the Commission adopt these balances and cost rates. There were no exceptions filed.

The Commission adopts the agreed-to balances and cost rates. Nevertheless, consistent with the discussion on working capital, the Commission notes that in the February 22 order, pp. 65-66 it stated:

The Commission notes that one upward driver appears to be the cost of revolving bank facility and letter of credit arrangements that are used as liquidity support. Similar to the overall capital structure, the Commission understands the importance of liquidity and short-term debt when undertaking infrastructure investment cycles. The Commission also notes the benefit they can provide to help keep capital costs low, as they delay or reduce the need for long-term debt or equity. However, ready availability of such facilities comes at a cost, including any banking arrangements that include commitment fees that are charged, whether they are currently being drawn upon or not. Accordingly, in the next rate case, Consumers shall demonstrate how the amount used and timing of short-term debt plays into the company's overall capital plan to ensure they are providing optimal benefit to ratepayers.

The Commission reiterates that in its next rate case, Consumers shall provide a complete analysis of, and justification for, the company's different levels of working capital and short-term debt used to ensure sufficient liquidity.

D. Overall Rate of Return

The Commission adopts a 47.36%/52.64% debt to equity capital structure, a long-term debt cost rate of 4.68%, an ROE of 10.00%, and an overall weighted cost of capital of 5.89%, as shown on the following table:

Description	Amount (000)	Ratio	Cost Rate	Weighted Cost
Long-Term Debt	\$5,880,452	36.55%	4.68%	1.71%
Preferred Stock	\$ 37,315	0.23%	4.50%	0.01%
Common Equity	\$6,578,683	40.89%	10.00%	4.09%
Short-Term Debt	\$ 160,700	1.00%	3.55%	0.04%
Deferred FIT ⁷	\$3,339,901	20.76%	0.00%	0.00%
JDITC Debt	\$ 43,266	0.27%	4.68%	0.01%
JDITC Preferred Stock	\$ 307	0.00%	4.50%	0.00%
JDITC Equity	\$ 48,310	0.30%	10.00%	0.03%
Total	\$16,088,933	100.00%		5.89%

VI. ADJUSTED NET OPERATING INCOME

Net operating income (NOI) is calculated by subtracting the company's operating expenses including depreciation, taxes, and allowance for funds used during construction (AFUDC), from the company's operating revenue. Adjusted NOI includes the ratemaking adjustments to the recorded NOI test year for projections and disallowances. On pages 230-269 of her PFD, the ALJ

⁷ The Commission notes that deferred federal income tax (FIT) will be addressed as part of the proceedings directed in the February 22 order.

provided a thorough analysis of the issues and arguments in adjusted NOI which will not be extensively repeated here.

Several issues that were previously contested were not raised in exceptions. After review of the record and arguments of the parties, the Commission finds the ALJ's recommendations on these issues well-reasoned and supported by the record. Accordingly, the Commission adopts the ALJ's findings and conclusions with respect to the following: (1) fuel purchased and interchange power expense; (2) smart energy expense; (3) avoidable expenses for the Medium 4 units; (4) residential demand response expense; (5) IT expense; (6) Pension Benefit Guarantee Corporation premiums and actuarial fees; (7) uncollectibles expense; (8) customer experience expense; (9) air conditioner switch O&M; (10) commercial and industrial (C&I) customer program expenses; and (11) interconnection queue. The remaining contested issues are addressed *ad seriatim*.

A. Sales and Revenue Forecast

1. Residential Sales Forecast

For the test year, Consumers projected total jurisdictional electric sales of 37,133 gigawatt-hours (GWhs). Consumers stated that its total sales forecast of \$4.214 billion, of which nearly \$2 billion is residential sales, is based, in part, on its plans to reduce residential energy waste through its energy efficiency programs.

The Attorney General argued that Consumers' projection understates residential sales because the actual historical sales decrease does not reflect a reduction of 1% per year. Rather, he asserted that Consumers' historical data shows an average decline of only 0.3% per customer, noting that Consumers plans to continue the same energy efficiency programs for the test year. Because the historical data for the past five years only reflects an average 0.3% decline, the Attorney General

contended that either the programs are not achieving their goals, or other factors are offsetting any reduction. The Attorney General therefore recommended applying the five-year average 0.3% usage decline to support a residential sales volume of 12,485,015 megawatt-hours (MWhs), thus increasing operating income by \$17.3 million.

Consumers countered that the Attorney General ignores the complex calculations and numerous factors in its projections and that the Attorney General failed to consider the increased spending on energy efficiency programs approved in Case No. U-17771.

The ALJ determined that Consumers did not support the 1.5% adjustment to its residential sales forecast. The ALJ stated, “clearly the company’s past efforts to reduce per capita consumption by 1% annually have not resulted in equivalent or corresponding annual decreases in actual per capita consumption.” PFD, p. 233. The ALJ explained that there are other factors likely affecting consumption, which Consumers failed to consider. Therefore, the ALJ found that the Attorney General’s residential sales forecast was more reasonable, and she recommended its adoption.

Consumers takes exception, stating that its “electric deliveries forecast should be approved by the Commission because it is reasonably based on a comprehensive modeling process which evaluates weather, the economy, and population projections[.]” Consumers’ exceptions, pp. 76-77. Consumers also argues that the records in its last three rate cases demonstrate the accuracy of the company’s forecasting and that its forecast has been regularly approved by the Commission. Thus, Consumers states that a departure from its forecasting methodology “would represent a radical shift from Commission precedent.” *Id.*, p. 81. Further, Consumers contends that because the same methodology is used for all three customer classes, the Attorney General’s residential class proposal would lead to inconsistent forecasting across the different classes. Additionally,

Consumers contends that the Attorney General's recommended historical average sales approach does not reflect the variation of customers each month and fails to give sufficient credit to the energy efficiency efforts, including the increased spending on these measures as approved in Case No. U-17771.

The Commission finds that the Attorney General's residential sales adjustment should be rejected. As Consumers pointed out, the company's energy waste reduction (EWR) plan, which was approved on July 31 and August 23, 2017 in Case No. U-17771, contains additional spending and more aggressive EWR programs for residential customers. Thus, the Attorney General's assertion that Consumers intends to continue its previous EWR program is incorrect.

The Commission disagrees that Consumers failed to justify its forecasting methods and results. As quoted by the ALJ, and reiterated by Consumers in its exceptions, the company's testimony reflects a detailed description of Consumers' multistep procedures in developing its forecast. As the record reflects, Consumers' methodology considers numerous factors, including 15-year weather cycles, economics, and population data. The Attorney General's approach, on the other hand, does not account for all of these factors. Most importantly, the Commission agrees that Consumers' forecasting methodology has proven to be reasonably accurate and reliable in several recent rate cases:

In Case No. U-17735, the Company projected total electric deliveries for 2014 and 2015 in the amounts of 37,557 GWh and 37,680 GWh, respectively, and residential electric deliveries for 2014 and 2015 in the amounts of 12,674 GWh and 12,437 GWh, respectively. See Case No. U-17735, Exhibit A-10 (HWM-3), page 1. In Case No. U-17990, the Company provided actuals for total electric deliveries for 2014 and 2015 in the amount of 37,596 GWh and 37,281 GWh, respectively, and actuals for 2014 and 2015 residential electric deliveries in the amounts of 12,594 GWh and 12,496 GWh, respectively. See Case No. U-17990, Exhibit A-10 (EMB-3), page 1. Furthermore, in Case No. U-17990, the Company projected total electric deliveries for 2016 in the amount of 37,982 GWh and residential electric deliveries for 2016 in the amount of 12,394 GWh. See Case No. U-17990, Exhibit A-10 (EMB-3), page 1. In this proceeding, the Company provided actual

2016 total electric deliveries in the amount of 37,912 GWh and actual residential electric deliveries for 2016 in the amount of 12,790 GWh. Exhibit A-10 (EMB-3), page 1.

Consumers' exceptions, pp. 78-79. The Commission finds that Consumers' sales forecast is reasonable, supported by record evidence, consistent with previously-approved forecasting methods, and is therefore adopted.

Notwithstanding the above, the Commission directs Consumers to provide additional information regarding its methodology and calculations in its next rate case. While Consumers' forecast was supported, the Commission finds more clarification on these calculations would be beneficial going forward. Specifically, Consumers shall present further evidence to support justification of its modeling results, its energy efficiency projection, and regression results in its next rate case. In addition, although the Commission has consistently found that Consumers' evaluation, measurement, and verification methods for determining energy efficiency reductions are accurate, the Attorney General's point about apparent offsets to decreases in energy use by residential customers is well-taken. Thus, the Commission looks to the Staff to engage with stakeholders on the topic of EWR, and sales forecasting through the EWR collaborative, or other forums in the future. The topic of offsets to EWR savings is ripe for further analysis and discussions given the reliance on EWR as a resource and the importance of load forecasting accuracy to planning, reliability, and rate setting.

2. Residential Income Assistance and Residential Senior Citizen Customers

The Staff proposed utilizing the 2016 average monthly customer count for the Residential Senior Citizen (RSC) program, and Consumers adopted this projection in rebuttal. The Staff also proposed reducing the projected number of customers in the Residential Income Assistance (RIA) program, indicating that the number of enrolled customers has steadily declined. The company

disputed the Staff's RIA adjustment, arguing that the number of customers enrolled in RIA fluctuates and that the company's estimate was understated and supported by the enrollment data as seen through the first seven months in 2017.

The ALJ noted that the Staff's proposed RSC adjustment was undisputed. Although she acknowledged that reliance on partial year data "may not be fully representative of what is likely to happen," the ALJ rejected the Staff's proposed RIA adjustment, finding that Consumers' projected test year count is still less than the 2017 average, and is therefore, reasonable for ratemaking purposes. PFD, pp. 235-236. Thus, the ALJ recommended that the Commission adopt Consumers' RIA customer projection.

The Staff takes exception, arguing that Consumers' projection, based on the first seven months of 2017, is incomplete data which does not reflect the month-to-month changes in enrollment that occur in a full year. Therefore, the Staff asserts that its projection of 47,990 is more reasonable given that it is based on the complete 2016 year. The Staff also notes that the ALJ admitted that the seven-month average may not fully represent the changes in enrollment through a full year. Therefore, the Staff recommends that the Commission adopt its proposed RIA program customer count of 47,990.

In reply, Consumers argues that the Staff under-projected the RIA customer count because the Staff failed to consider the most recent historical enrollment. Contrary to the Staff's contention, Consumers states that it is "not seeking to use the 2017 seven-month average approach to set the projected RIA provision customer participation level in this case." Consumers' replies to exceptions, p. 8. Rather, Consumers asserts that the seven-month average was presented to demonstrate that its projected enrollment was conservative and that the Staff's projection was understated.

The Staff's proposed RSC adjustment is undisputed and, therefore, the Commission finds that a RSC monthly customer count of 368,481 is reasonable and should be adopted. With regard to RIA, the Commission finds that the Staff's projection is reasonable and well-supported. The record reflects that the enrollments vary each month. The ALJ also acknowledged that the partial year data "may not be fully representative of what is likely to happen over the course of the year[.]" PFD, p. 236. Because the Staff's proposal is based upon a full year of data which more fully reflects the month-to-month changes, the Commission adopts the Staff's proposed participation level of 47,990 in the RIA customer program.

B. Operations and Maintenance Expense

Consumers originally requested an O&M expense amount of \$627.6 million on a total company basis. This request was reduced to \$613.9 million in briefing. The Staff initially recommended total company O&M expenses of \$538.3 million; however, this was also revised to \$589.25 million in its initial brief. The Attorney General similarly recommended a reduction, resulting in a total O&M expense amount of \$550.9 million.

1. Projected Expense Savings

The Staff initially recommended a 2% overall reduction in O&M expenses to reflect cost-reduction measures that Consumers reported to its board of directors. Although this recommendation was withdrawn in its brief, the Staff recommended that Consumers quantify and provide additional information in its next rate case regarding its cost-saving measures. Consumers responded that it "is willing to commit that it will work with Staff to share information regarding the various company-level initiatives Consumers Energy is working on in order to promote O&M cost savings and what metrics the Company plans to monitor in order to assess O&M savings." Consumers' reply brief, p. 124.

The ALJ found that “it is reasonable for the utility to keep Staff informed on its progress, as Consumers Energy offered in its reply brief[.]” PFD, p. 239. The ALJ further concluded that providing a report in the next rate case, which summarizes the cost-cutting initiatives, was not onerous. *Id.*

Consumers takes exception to the ALJ’s finding that the company should provide a report in its next rate case. Specifically, Consumers argues that the Staff’s proposal was a recommendation to quantify savings, whereas the PFD indicated a summary of measures would be appropriate. Further, Consumers states that the ALJ’s recommendation is not “sufficiently well defined” and that it is not clear what initiatives should be discussed or quantified. Consumers’ exceptions, p. 87. Therefore, Consumers requests that it be allowed to pursue a more informal initiative with the Staff to collaborate and determine “what information is desired . . . and to better define the expectations between the parties going forward.” *Id.*

The Staff replies that Consumers provided information to investors that it expected to achieve a 2% savings in O&M costs. In response to Consumers’ objection that the ALJ’s recommendation was unclear Staff indicated that it:

is merely asking for a report in [Consumers’] next rate case explaining the cost-cutting initiatives and accounting for the savings. To clarify the initiatives which are expected to achieve 2% O&M savings through the projected test period. The report would not be useful after the fact. In a fully projected test year, the Commission should require [Consumers], if telling investors that 2% O&M savings are achievable, to likewise incorporate those savings into a rate case. That did not happen in this case which could allow investors to realize these 2% savings through increased earnings and could mean that ratepayers pay 2% more than what was needed for service.

Staff’s replies to exceptions, pp. 33-34.

The Commission finds the ALJ’s recommendation to be reasonable and adopts her position on this issue. As the record reflects, Consumers projected a 2% O&M cost reduction to its investors.

See Exhibits S-8.4 and S-11. When asked to reconcile the 2% savings projection with its O&M projection in this case, Consumers indicated that its operating plan did not support the 2% savings projection, but if the savings were achieved, it would pass the savings on to customers in a future rate case. Consumers presented conflicting information to its investors and to the Commission. While there is insufficient information on the record to support an O&M reduction at this time, the Commission finds these contradictory positions troubling.

Thus, the Commission finds that providing additional information regarding cost-savings measures, as well as a quantification of any savings resulting from Consumers' initiatives focused on O&M cost reductions, is reasonable and will help ensure that the savings are passed along to customers. Although Consumers contends that the Staff's proposal is not well defined, this was, in part, due to the lack of information that Consumers provided. Specifically, Consumers indicated that there are many initiatives being conducted in 2018; however, it provided no details regarding those initiatives or how the 2% savings were calculated. Therefore, Consumers shall provide information regarding its cost-savings measures and the actual savings, or lack thereof, resulting from its efforts in its next rate case. Consumers shall also work with the Staff to determine if additional information is needed.

2. Electric Operations and Maintenance Expense

The remaining contested issue under electric O&M expense involves vegetation management and line clearance. Consumers projected that it would spend \$66.5 million in the test year on its line-clearance program and explained that this amount, adjusted for inflation, was derived from a March 2014 third-party consultant report and equates to a seven-year clearing cycle. The company stated that \$59.9 million of that amount will be spent on its LVD system. In arguing the reasonableness of its projection, Consumers presented a cost comparison between Consumers'

vegetation management spending and that of other utilities, which showed that Consumers' spending is below the average for participating utilities, per mile and per customer.

The Staff objected to Consumers' requested \$66.5 million citing concerns of historical underspending in this area and doubt as to Consumers' ability to increase its line-clearing efforts. The Staff argued that the expense amount approved in the February 28 order, adjusted for inflation, plus \$1 million to address problem trees outside the right-of-way, totaling \$51.8 million, is appropriate.

The Attorney General also recommended a reduction for the same reasons cited by the Staff. He proposed a total line-clearing allowance of \$50.8 million, which he explained is the highest amount spent by the company in recent years.

In rebuttal, Consumers maintained that any underspending on line clearing in the past was the result of overspending in other areas because of emerging priorities. For example, the company stated that in the 12-months ending July 2017, the company spent \$13 million more than was approved for electric O&M. In the storm category specifically, the company spent \$20 million over the Commission-approved amount. Thus, according to Consumers, any underspending was reasonable and prudent in light of other priorities.

The ALJ concurred with the Staff and the Attorney General and was not convinced that Consumers could spend the amount it projected within the test year. "While the company relies on a third-party report, that report was obtained in 2014, and the company's expenditures since then have been only \$37 million in 2015 and \$50.8 million in 2016, with 2017 expenditures projected to be \$48.1 million." PFD, p. 244. The ALJ was not persuaded that Consumers is committed to increased line clearance spending in the future, and thus recommended that the Commission approve the Staff's O&M amount for vegetation management.

Consumers takes exception to the ALJ's recommendation to reduce the projected vegetation management expense to \$51.8 million. The company reiterates its arguments that its overall spending for combined services restoration and line-clearing has exceeded the approved rate case amounts by an average of \$8 million annually since 2013, and that it must reallocate spending to meet emergent priorities. Consumers' exceptions, pp. 87-90.

The RCG filed a reply echoing its previous arguments that Consumers has habitually over-projected its line-clearing expenses and that it has done so again. The RCG also contests Consumers' attempt to add service restoration expenses to its line-clearing expenses because, as the RCG explains, the relationship between the two expenses is inverse; if line-clearing expenses decrease, service restoration expenses increase. The RCG argues that if Consumers actually spent the amount approved for line-clearance, its service restoration expenses would decrease. The RCG therefore requests that the Commission adopt a "more disciplined approach" to ensure that the amounts approved for line-clearing are actually spent. RCG's replies to exceptions, pp. 4-5.

The Commission finds the Staff's proposed vegetation management amount of \$51.8 million to be the most reasonable. The Commission observes that Consumers has a history of underspending in this category. See, e.g., February 28 order, pp. 82-86, and November 19, 2015 order in Case No. U-17735, p. 58. In previous rate cases, the Commission has determined that once Consumers shows that it consistently spends the approved amount for vegetation management, the Commission will consider an increase in this area. While 2016 was the first year that Consumers spent all of the approved amount for vegetation management, one year does not demonstrate the consistency the Commission requires. As the Commission noted above, Consumers has failed to demonstrate a commitment to fulfilling its spending projections in this

area. Therefore, the Commission finds the recommendation set forth in the PFD duly supported and well-reasoned, and adopts the ALJ's recommendation as to vegetation management.

3. Generation Operations and Maintenance

Consumers projected a test year expense of \$153,259,000 in fossil and hydro generation O&M expense. The Staff and the Attorney General recommended a downward adjustment to the environmental operating expense. The Attorney General also argued for an adjustment to the residential DR program. MEC/NRDC/SC disagreed with the inclusion of O&M costs for the Medium 4 units that they contended are avoidable under an early retirement scenario. As noted above, the Commission adopts the PFD on issues concerning the residential DR program and O&M costs for the Medium 4 units.

Consumers proposed an environmental operating expense amount of \$15.5 million. According to the Staff, a \$4.7 million, or 30% reduction, to Consumers' projection is appropriate, given the company's chronic history of underspending in this category. The Staff provided historical spending data to support its recommended adjustment. During 2013-2016, the company spent only 58.7% of its total projections in this category with an average of 65.9% as the projected versus actual spending. The Staff pointed out the unreasonableness of imposing costs on customers for O&M expenses that the company routinely spends in other areas that may or may not have been deemed reasonable and prudent.

The Attorney General argued a \$3 million reduction was appropriate. He maintained that the company failed to justify its \$7.2 million increase in projections over 2016 spending levels. While the company claimed the increase is, in part, related to compliance with air quality regulations, the Attorney General noted that the compliance measures taken by the company were completed in

2015 and early 2016, prior to this test year. According to the Attorney General's projections, the company was on track to spend \$11.5 million in 2017, not \$14.6 million as it estimated.

Therefore, the Attorney General asserted that the environmental operating expense should be reduced to \$12.3 million.

In response, Consumers stated that from 2013 through 2016, it had spent 97.8% of its total O&M projected expenses. The company explained that budget reallocations from one O&M category to another are necessary to provide reliable service to customers. Consumers maintained that, as of July 2017, it was on track to spend 84% or more of the 2017 projection of \$14.6 million.

The Staff contended that it is improper for the Commission to consider Consumers' "look at the total" argument because such an approach deprives the Commission of the ability to meaningfully review spending by the utility and negatively impacts transparency. Consumers disagreed, arguing that considering overall O&M spending allowed the company flexibility to make reasonable and prudent decisions in response to emergent priorities.

The ALJ found the Staff's arguments persuasive and recommended the Commission adopt the Staff's proposal to reduce the environmental operations expense by \$4.7 million. The ALJ was not convinced that Consumers' having spent 84% of the projected amount for 2017 justified the amount projected for the test year. The ALJ also noted that the use of O&M funds for decommissioning expenses for the Zeeland and Jackson generating plants, which the company argued resulted in costs \$5 million above projections, does not indicate that the environmental operations expense should be \$5 million over the Staff's stated projections. PFD, p. 249.

Additionally:

Exhibit A-112 showing total O&M expense for energy resources from 2013 through 2016 in comparison to rate case amounts shows actual spending for all generation categories below projected levels for each of the years, but on average, only a little over 2% below. This is not persuasive evidence that Consumers

Energy should have a greater environmental expense allowance than recommended by Staff.

PFD, pp. 249-250.

Consumers takes exception to the ALJ's recommendation. The company reiterates its previous arguments and clarifies that it did not suggest that the environmental operating expense should increase by \$5 million because 2016 base O&M was \$5 million over the projection. Rather, Consumers states that the base O&M increase is an example of the company's reasonable budget reallocation. Consumers provides further explanation as to its previous underspending, asserting that much of the underspending between 2013 and 2016 "was the result of the company spending \$9.7 million less than projected in 2015[.]" but claims that 2015 was an "anomaly." Consumers exceptions, p. 91. Consumers also explains that 2017 is the first year of full operation for the Air Quality Control Systems at the Campbell Plant, which increases environmental operating expenses. Additionally, although the company disagrees that annualizing actual spending amounts is a proper means of projecting future costs, Consumers states that year-to-date spending in 2017 indicates a forecast of \$12 million in 2017, or 84% of the projected \$14.6 million. Thus, the Staff's recommended 30% reduction adopted by the ALJ is too severe to meet the company's environmental operations expense.

In reply, the Staff reasserts that Consumers has consistently over projected its environmental operations expense, that the Commission should not accept Consumers' "look at the total" argument, and that it is proper for the Commission to consider historical spending in this category. As to Consumers' assertion that it has spent \$6.97 million as of July 2017 and is on track to spend \$12 million in 2017, Staff cites its initial brief asking the Commission to "keep the \$6.97 million in perspective" noting that while the company may be on target for 2017, the company's over-projections have occurred over four years. Staff's replies to exceptions, p. 31.

The Commission finds the PFD well-reasoned and adopts the ALJ's findings and conclusions as to the environmental operations expense. Consumers has failed to spend the approved amount in this category for several years, and the Commission has properly considered historical underspending in previous rate cases. See, February 28 order, pp. 90-91. Also, the Commission is not persuaded to adopt the "look at the total" argument put forth by the company. Reallocation may be common practice and necessary to ensure reliability and to address emerging priorities, but reallocation does not eliminate the need to justify and determine planned spending in each individual category within O&M. If the company requires additional funds for other areas of O&M, it may justify the increases in those categories, not this one. Thus, the Commission finds that the Staff's \$4.7 million reduction to environmental operations to be reasonable based on the company's history of underspending in this category.

4. Employee Benefit Expense

As noted above, Pension Benefit Guarantee Corporation premiums and actuarial fees are no longer in issue. Consumers applied a lower discount rate of 4.30% (2017), 4.29% (2018), and 4.49% (2017 and 2018) to its projected pension plan and OPEB expenses, to reflect market conditions.

The Attorney General claimed that Consumers has established a pattern of increasing its discount rates when not in the middle of a rate case cycle, thereby lowering the present value of future benefit obligations and pension expense to be recorded, and then doing the reverse in conjunction with a rate case filing. The Attorney General also argued that Consumers' use of the lower discount rates in this case was not justified. According to him, despite discovery requests inquiring as to how its discount rates were derived, Consumers did not provide the source information in order to substantiate the lower discount rates, claiming that the information was

proprietary and therefore unavailable. Without information from Consumers, the Attorney General performed his own analysis of the trend in the 10-year, 20-year, and 30-year US Treasury bond rates at or around the time used by Consumers' actuary. The Attorney General argued that his analysis showed an upward trend versus a downward trend and, consistent with these results, he recommended that the discount rates remain unchanged, thus calculating a total disallowance of \$16 million.

Consumers disagreed with the Attorney General, arguing that the recommended reductions of \$9 million to pension and \$7 million to OPEB expenses were unreasonable. In countering the Attorney General's assertions, Consumers argued that US Treasury bond rates are not appropriate for setting discount rates for pension and OPEB plans and that, according to Accounting Standards Codification Topic 715, corporate bond rates are to be used. Consumers also disputed the Attorney General's claim that the company's discount rates vary in between rate cases by stating that it may update its projections if it files a rate case mid-year but that any changes are supported by its actuary. Lastly, Consumers argues that the proprietary nature of Aon Hewitt's AA Above Median Yield Curve corporate bonds and analysis does not necessitate a finding that discount rates are unsupported, declaring that its actuaries operate under strict guidelines and conduct their work in accordance with accepted principles and practices. Consumers reiterated that this proprietary information was not in its possession, and thus could not be provided to the Attorney General, but stated that its external auditors did review all assumptions, including discount rates.

The ALJ found that Consumers did not support the use of the lower discount rates. The ALJ reasoned that, by failing to provide the yield curve relied upon to select the discount rates, as required by the Michigan Rules of Evidence, Consumers precluded the parties from testing its claim that the lower discount rates were warranted. The ALJ further questioned why Consumers

used the discount rates chosen by its actuary, in light of the company's testimony that "Consumers[,] . . . not the actuaries, chooses the discount rate." PFD, pp. 256, quoting 10 Tr 1933.

In exceptions, Consumers argues that because the Attorney General did not brief this issue, he abandoned his arguments. Consumers adds that because no other party supported the ALJ's recommendation, the company's pension plan and OPEB expense amounts should be approved. Consumers next argues that it did not fail to support the chosen discount rate because the company does not decide the specific discount rates that are utilized. Consumers explains that the ALJ misconstrued testimony of one of its witnesses and clarifies that, while it does choose some assumptions, "[o]ther assumptions, like the discount rate, are determined by a set methodology and the Company does not have discretion in deviating from the methodology." Consumers' exceptions, p. 97. Consumers further declares that "[t]he assumptions used by the Company to develop its Pension Plan and OPEB expenses were based on the most recent full actuarial re-measurement at the time of filing[.]" and therefore were consistent with the requirements in the February 28 order, pp. 96-97. Consumers' exceptions, p. 98. Consumers also reiterates its argument that the information requested from the Attorney General is proprietary information to its actuary, and to suggest that discount rates determined by its actuary are inappropriate without review is a meritless assertion.⁸ Consumers reiterated:

While Aon Hewitt's process and bonds used to develop the discount rate are considered proprietary, the Company did take measures to test that the discount rates were reasonable. Consumers Energy's external auditors have reviewed the assumptions used to develop the rates. 10 TR 1978. As indicated in Exhibit AG-47, while not provided a listing of the corporate bonds included in the corporate bond basket to develop the discount rate, Aon Hewitt provided the Company's external auditors the corporate bond spot rates from the Aon Hewitt AA Above

⁸ Consumers did indicate that it is working with its actuary to find a reasonable way to provide the source information to parties in future cases.

Median Yield Curve. On a national basis, the Company's external auditors then review the Aon Hewitt AA Above Median Yield Curve methodology (on a change/update basis) to assess its reasonableness. Further, Exhibit A-47 (AJD-8) indicates that the Company's external auditors independently create their own set of yield curves to further validate the results. This process is a reasonable method to verify as to whether the discount rates developed by Aon Hewitt are reasonable.

Consumers' exceptions, p. 99. Given this, and renewing its argument that looking at US Treasury bonds is not relevant in this setting, Consumers asserts that the ALJ's recommendation on this issue should be rejected.

In replies to exceptions, the RCG contends that Consumers was well aware that changes to a discount rate needed to be explained and substantiated. The RCG also states that Consumers misinterpreted case law with regard to the company's argument on briefing and abandonment of an issue and points out that the Attorney General's evidence to support his position is in the record whereas Consumers' evidence is not. The RCG therefore argues that the ALJ properly found that the discount rates should remain unchanged, based on the only credible evidence offered and admitted in this case.

The Commission agrees with the ALJ and finds that Consumers' discount rates were not justified based on the record in this proceeding. Pursuant to Mich Admin Code, R 792.10427(2) (Rule 427(2)) and MRE 703, evidence relied upon, including evidence from an expert, must be in the record. See also, Rule 427(1) and the January 31, 2017 order in Case No. U-18014, pp. 88-89. While the Commission acknowledges the proprietary nature of actuarial reports, safeguards are available to allow such evidence to be admitted in contested case proceedings, when confidential or proprietary information is used by a party to support its position. The Commission also suggests that there may be other ways to work with the actuary to provide appropriate support without disclosing confidential or proprietary information or methods used by the third-party. Thus, given the inability of the other parties to verify or test the reasonableness of the actual

discount rates applied to Consumers' pension plan and OPEB expense projections in this case, the Commission adopts the ALJ's recommendation on this issue and finds that \$9 million in pension and \$7 million in OPEB expenses should be disallowed.

5. Incentive Compensation

Consumers projected a total employee incentive compensation plan (EICP) expense of \$3,379,025 for annual, short-term incentives related to operational and financial performance metrics for non-officers and officers, except proxy officers, for the test year.⁹

The Staff argued that an additional \$2,201,875 of the remaining EICP expense, tied to financial performance measures, should be disallowed, leaving only EICP expense tied to non-financial measures, in the amount of \$1,177,150. The Staff discussed Consumers' financial metrics and asserted that the Commission has consistently found incentive compensation tied to financial performance is incurred for the benefit of shareholders; thus, these amounts should not be paid by ratepayers.

The Attorney General argued that the focus of Consumers' projected EICP expense does not chiefly translate into benefits for customers. In looking at Consumers' 2017 EICP Performance Measures in Exhibit A-44, the Attorney General claimed that certain design flaws within the employee performance measures merely tend to reward mediocrity and reduce any actual customer benefits. The Attorney General also raised issues pertaining to duplication in many of the measures, asserting that duplication makes it easier to achieve the targeted level, and that some measures are outside Consumers' control or are already addressed by the implementation of AMI

⁹ Consumers originally projected its total incentive compensation expense to be \$14,757,257 but later withdrew \$11,378,232 for projected long-term incentive restricted stock plan costs and executive retirement benefits.

meters, for which customers are already paying millions of dollars. The Attorney General further argued that exhibits to substantiate cost savings were not provided, most cost savings were for the entire company, and purported financial benefits were highly inflated and frequently stale. Therefore, the Attorney General recommended that Consumers' projected EICP expense be disallowed in its entirety.¹⁰

ABATE/Gerdau agreed with the Staff and claimed that \$2,201,875 of EICP expense should be disallowed. ABATE/Gerdau similarly argued that incentive compensation related to targeting financial goals benefits shareholders, not ratepayers, and stated that their recommendation parallels prior Commission treatment of such expenses.

In rebuttal, Consumers referenced the July 31, 2017 order in Case No. U-18124 (July 31 order) and argued that it again provided evidence to justify EICP expense tied to non-financial metrics. Consumers also maintained that its EICP is reasonable and motivates its employees to provide the best performance for the benefit of customers, specifically addressing financial measures and the benefits of a financially healthy utility. Consumers further asserted that a lack of quantifiable benefits from financial measures should not preclude rate recovery of such costs and that excluding the same inappropriately intrudes on management decisions regarding how to structure incentive compensation. Consumers contended that its incentive payments are intended to make employee compensation competitive with the market, not above the market, and that if thresholds for incentives are set too high, it would decrease employee motivation and resulting customer benefits. Consumers also clarified that shareholders cover the costs for any incentive payments above an award percentage of 100%.

¹⁰ As an alternative, the Attorney General asserted that, if the Commission finds that Consumers justified recovery of some of its projected EICP expense, the amount of incentive pay that is recoverable through rates should be no more than \$1,177,150.

The ALJ recommended that the Commission adhere to the decisions it made in Consumers' last two rate cases, and only include projected incentive compensation expense associated with operational measures.

In exceptions, Consumers chiefly argues that its EICP expense of \$3,379,025 is reasonable and supported by evidence in the record. In the alternative, should the Commission disagree, Consumers also suggests an alternative EICP expense amount of \$2,278,088, to account for full recovery of costs related to operational measures, along with 50% of costs associated with financial measures, to acknowledge that both shareholders and customers benefit from such measures. Consumers reiterates that when employees do not receive incentive compensation, they are paid below market rates. In light of this, along with its assertion that customer benefits outweigh costs, Consumers argues that it has satisfied previous criteria set forth by the Commission to allow recovery of all of its projected EICP expense.

Consumers also disputes the ALJ's rationale discussing potential adverse impacts regarding financial motivation, asserting that these concerns are speculative and do not support the partial recommended disallowance of EICP expense. Consumers further disagrees with the ALJ's finding that it has not provided any new evidence or persuasive argument to allow recovery of costs associated with its financial measures, highlighting the evidence in the record that it did provide.

In reply, ABATE/Gerdau argue that Consumers' exceptions provide no reason for the Commission to deviate from its current practice of only allowing recovery of incentive compensation costs that are tied to operational measures, a focus ABATE/Gerdau claim Consumers should have concentrated on in its exceptions, rather than stressing the ALJ's use of the word "potential" in her analysis about financial motivation. ABATE/Gerdau reiterate their argument that financial goals chiefly benefit shareholders and thus maintain that costs associated

with incentives to achieve these goals should be disallowed in their entirety. ABATE/Gerdau also contend that Consumers' alternative proposal is arbitrary and unsubstantiated by the evidence in this case.

In its replies to exceptions, the Staff continues to support its recommended \$2,201,875 disallowance, based on its evidence and briefs.

The RCG replies that financial incentive bonuses have "perverse counter-productive incentives and results" which are not for the benefit of the public or Consumers' ratepayers. RCG's replies to exceptions, p. 7. The RCG therefore contends that recovery of such financial incentive bonuses should be disallowed.

The Commission agrees with the ALJ and finds that only the EICP expense that is strictly tied to operational measures (\$1,177,150) should be allowed in this case, because Consumers has specifically quantified how those measures provide appreciable benefits to ratepayers. See Exhibit A-44. Financial measures, however, predominantly benefit shareholders. The Commission further finds that Consumers' alternative proposal, to include 50% of EICP expense related to financial measures in rates, is not well taken. Essentially, this alternative presumes a correlation, without any specific quantification, that half of the benefits realized from achieving financial measures is commensurate with half of the incentive compensation costs to be paid by ratepayers. The Commission therefore finds that \$2,201,875 of Consumers' EICP expense linked to financial measures should be disallowed.

6. Injuries and Damages Expense

Consumers used a five-year average to project an injuries and damages expense of \$4.4 million for the test year. The RCG claimed that Consumers' request is excessive, because ratepayers already cover the company's insurance costs, and that this expense should be

Consumers' responsibility. The RCG asserted that passing this expense along to ratepayers absolves Consumers of almost all electrical injuries and damages related to the company's negligence and business decisions and further fails to encourage accountability and transparency. The RCG additionally argued that this pass-through is contrary to Commission precedent, citing the March 10, 2010 order in Case No. U-15001-R, and contending that the company provided no rationale for overturning that precedent. The RCG therefore contended that Consumers' injuries and damages expense should be disallowed or, in the alternative, that the Commission should adopt an approach to allow prior review of Consumers' legal obligations to determine if such expenses should be recovered through rates.

The ALJ agreed with Consumers, highlighting the benefits of using a five-year average and noting that no specific concern was raised about any particular liability payment in the historical data in this case. The ALJ further disagreed that this expense projection sets up an adverse safety incentive and pointed to evidence provided by Consumers that it has an excellent safety record.

In exceptions, the RCG argues that the ALJ's recommendation fails to provide any means for the Commission to require Consumers to sustain its burden of proof as to the reasonableness and prudence of costs associated with lawsuit damages. The RCG asserts that this recommendation requires ratepayers to indemnify Consumers for damages resulting from the company's own negligence and also bear the risk for actions in which they had no part. The RCG also disputes the appropriateness of establishing a regulatory asset that can be amortized over a period of years, which RCG asserts becomes "a 'blank check' from ratepayers to [Consumers'] management to assume management risks and responsibilities." RCG's exceptions, p. 33.

In replies to exceptions, Consumers argues that it did not request, and the ALJ did not recommend, regulatory asset treatment for lawsuit damages. Rather, it projected this expense

using a five-year average, which the ALJ found to be appropriate. Consumers also contends that this rate case presented the opportunity for a more in-depth review of injuries and damages, but despite this opportunity, RCG did not present any evidence challenging either the reasonableness of this expense or the methodology employed to calculate the expense. Consumers therefore claims that the Commission should adopt the ALJ's recommendation.

The Commission agrees with the ALJ and finds Consumers' projected injuries and damages expense to be reasonable. Although RCG raised concerns, its concerns were merely generic in nature versus raising any specific issue(s) after auditing this expense.

7. Customer Payment Program Expense

Consumers projected its customer payment program expense to be \$7.3 million. Consumers explained that its decision to waive the \$6.25 fee it had been charging for credit card payments resulted in an 85% increase in payment card transactions. This, along with the additional payment channels that are now available for customers, are the reasons for the substantial increase.

The Attorney General disagreed with this projection, arguing that Consumers benefits from customers' ability to pay their bills with credit cards, a benefit he asserts likely offsets the fee for such types of transactions. Specifically, the Attorney General contended that allowing recovery of credit card transaction fees, without adjustment to Consumers' uncollectible expense, (i.e., shifting the risk of uncollectibles to the credit card company), results in a financial windfall to Consumers that should not be allowed. The Attorney General therefore recommended that Consumers' customer payment programs expense should be reduced by \$5,182,000, equal to Consumers' actual expense of \$2,117,000 for 2016.

Consumers responded that its customers have been able to pay their bills with credit cards for many years, albeit with the \$6.25 fee, and to correlate credit card payments with uncollectible

expense would assume that non-paying customers were either not paying by credit card due to the \$6.25 fee, or as a result of inconvenience, neither of which Consumers believes was a direct cause for non-payment in the past. Consumers also asserted that the Attorney General's assumption that this risk-shifting is primarily attributable to credit card payments by low-income customers, who are twice as likely to default on their electric bill, is unsubstantiated by any data.

The ALJ did not find Consumers' projection to be substantiated and agreed with the Attorney General that Consumers' customer payment programs expense should be set at actual historical levels. The ALJ explained that Consumers failed to provide justification for a six-fold increase in costs, to be spread across all customers, as opposed to those who actually cause the costs. The ALJ also recommended that Consumers be given an opportunity to further explain and support its position in its next rate case.

In exceptions, Consumers states that the ALJ's recommendation neither addressed nor contested that credit card transactions have increased, a fact that Consumers indicates was not disputed by any party to this proceeding. Consumers then argues that the ALJ's decision is inconsistent with past Commission orders, citing the February 28 order, pp. 86-87, and the July 31 order, p. 70. Consumers claims that, after consideration of this very issue in those cases, the Commission rejected the Attorney General's same arguments and permitted Consumers to recover credit card payment fee costs. Consumers further avers that its Customer Payment Program is beneficial for customers; the elimination of this credit card fee aligns with practices of most other businesses, including DTE Gas Company; and such costs are reasonable and prudent. Consumers thus asserts that the ALJ's recommendation should be rejected.

The Commission disagrees with the ALJ and finds Consumers' projected customer payment programs expense to be reasonable. The Commission finds that because the expense amount was

not disputed; all customers benefit from the additional payment channels that Consumers now provides, including the elimination of the \$6.25 transaction fee; and the Attorney General did not provide compelling evidence to support his contention that recovery of credit card transaction fees should result in an adjustment to Consumers' uncollectible expense.

E. Adjusted Net Operating Income Summary

In summary, the Commission finds that Consumers' jurisdictional projected NOI for the 2017-2018 test year is \$561,655,000.

VII. OTHER REVENUE AND ACCOUNTING ISSUES

A. Tax Cuts and Jobs Act of 2017

In the February 22 order, the Commission addressed comments on the appropriate method to return the benefits of the TCJA to ratepayers. The Commission agreed with the Staff's recommended approach, which provides a comprehensive plan for all regulated utilities, including Consumers, to address the impacts of the TCJA. That plan includes the filing of three contested cases to address the effect of the new FIT in rates (1) going forward (Credit A), (2) looking backward to January 1, 2018 (Credit B), and (3) with respect to deferred tax balances, bonus depreciation, and all other impacts (Calculation C). The first two case-types will be expedited.

In exceptions, ABATE/Gerdau assert that, in light of the enactment of the TCJA, the revenue deficiency calculated in the PFD is now inaccurate. ABATE/Gerdau "maintain[] that it is not just and reasonable to approve revenue relief or rate increases in this case based on tax expense assumptions which have become inaccurate by operation of law." ABATE/Gerdau's exceptions, p. 13. ABATE/Gerdau contend that any rate increase should be deferred to a separate contested case where the effects of the TCJA can be taken into account. The RCG and Hemlock similarly

urge the Commission to immediately recognize the new federal income tax rates, in order to protect ratepayers. The RCG contends that “the correct federal income tax rate, and the resulting correct federal tax expense and tax revenue conversion factor, can readily be calculated and adopted in this case, without delay.” RCG’s exceptions, p. 5. According to Hemlock, “[i]f the Commission finds that Consumers’ projected revenue deficiency based on the record in this proceeding is less than \$116 million, then no increase in Consumers’ rates is warranted above the levels set in MPSC Case No. U-17990[.]” Hemlock’s exceptions, p. 11.

Consumers replies that the calculation of the rate impact of the TCJA is more complex than ABATE/Gerdau, the RCG, and Hemlock seem to believe. Consumers adds: “The record in this case is closed, and there is insufficient time remaining before the statutory deadline for a final order to reasonably reopen the record. And, because the determination of the rate impacts of the TCJA requires more information than merely knowing the new tax rate, the issue is not conducive to resolution via the mechanism of official notice.” Consumers’ replies to exceptions, p. 27.

The Commission finds that these exceptions should be rejected. The Commission has recently approved a series of proceedings to timely and comprehensively address: (1) adjustment of rates going forward to reflect the reduction in FIT rates; (2) reconciliation of the regulatory liability established from January 1, 2018, until rates are reset; and (3) modification of deferred tax balances, bonus depreciation, and all other effects of the TCJA. Accordingly, and consistent with the February 22 order, Consumers shall file its Credit A application in Case No. U-20102 by April 30, 2018.

B. Regulatory Asset for Demand Response

Consumers proposed creating a regulatory asset for demand response expenditures citing accounting benefits, extended investment recovery to relieve rate shock, and reduced future capacity needs and costs.

The Staff, ABATE/Gerdau, and the RCG opposed Consumers' request. The Staff and ABATE/Gerdau argued that a regulatory asset is an extraordinary measure and that Consumers has not supported this approach. The Staff recommended that the Commission defer consideration of the company's proposal to Case No. U-18369. Similarly, RCG argued that the consideration of a regulatory asset for DR costs should be deferred for further review.

In light of the process for DR expense recovery set forth in Case No. U-18369, the ALJ recommended that the Commission deny Consumers' request for a regulatory asset. The ALJ determined that Consumers' proposal is temporary and its proposed amortization is problematic.

In exceptions, Consumers argues that approval of a DR regulatory asset will not conflict with the process in Case No. U-18369. Rather, Consumers states that the creation of a regulatory asset provides a customer benefit that would "smooth out the longer-term capital costs with the short-term O&M costs, which provides a customer benefit over the average life of the DR assets." Consumers' exceptions, p. 112.

The RCG also takes exception, reiterating that the Commission should defer consideration of a regulatory asset. The RCG argues that it would be imprudent to create a regulatory asset at this time because technological developments may make this approach obsolete.

Consumers replies to the RCG's exceptions, pointing out that the ALJ did not recommend regulatory asset treatment for DR expenses. In reply to Consumers, the Staff states, contrary to Consumers' exception, that the ALJ did not determine that there would be a conflict between

creating a regulatory asset and the proceedings in Case No. U-18369, rather, the ALJ merely chose not to recommend a new process when the Commission has already established one. Staff's replies to exceptions, p. 17.

The Commission finds the PFD well-reasoned and agrees that the appropriate forum to address Consumers' request is in Case No. U-18369. As discussed in the PFD, the Commission adopted a three-phase approach in its September 15, 2017 order in Case No. U-18369. Consumers failed to adequately support its request for regulatory asset approval, as the record reflects questions regarding the life of the assets and amortization period. Given the adoption of the procedures already set forth to address this issue, the Commission finds that the creation of a regulatory asset would be a temporary measure which does not bridge the gap and is unnecessary and unwarranted. Therefore, the Commission adopts the ALJ's recommendation and rejects Consumers' request for a regulatory asset.

C. Other Demand Response Program Issues

1. Residential Demand Response Program Parameters

The Staff proposed that Consumers offer shadow billing or a trial period before customers enroll in a 12-month DR program. In addition, the Staff recommended that Consumers implement additional marketing and educational programs to increase customer participation in these programs. MEC/NRDC agreed with the Staff's recommendation stating that shadow billing would increase customer knowledge regarding time-of-use (TOU) programs, likely result in increased cost savings, and provide benefits in terms of demand reduction.

Consumers responded that it does not currently have the capability for shadow billing and that MCL 460.1095 requires participants in a DR program to remain in the program for at least one year. Consumers also argued that if the Commission finds that a trial period is permissible under

the statute the period should be a minimum of six months, including the summer months.

Consumers also indicated that it is willing to increase its marketing efforts but cannot do so at this time absent additional funding.

The ALJ found the Staff's recommendations to be reasonable. The ALJ reasoned that the customer protection provision in MCL 460.1095 must be balanced with the one-year commitment requirement. Moreover, she stated that the one-year requirement is contractual in nature and that there is nothing in the statute that indicates customers cannot withdraw from the program, even if there is a penalty. The ALJ contended that allowing a three-month trial period, wherein the customer could withdraw, provides customer protection as contemplated by the statute. In addition, she found that further exploration of shadow billing "to be reasonable, and consistent with Staff's interest in the educational materials available to customers." PFD, p. 279.

The ALJ noted that Consumers does not have a very comprehensive set of explanatory materials for the existing demand response program. She further noted that Consumers has projected significant O&M spending, as well as increased enrollment in the programs. Therefore, the ALJ recommended that the company develop marketing and educational materials that include existing and new programs.

Consumers takes exception to the ALJ's recommendation. Specifically, Consumers contends that, given the plain language of MCL 460.1095, it is unclear how the statute provides for a trial period. Further, Consumers argues that even if the statute were to allow a trial period, the three-month timeframe is simply too short to permit customers to fully understand the impact of the TOU rate.

Consumers reiterates that it does not have shadow billing capability. More specifically, it indicates that the information available on its WebPortal only "provides an estimated monthly cost

for a shadowed rate, but only for the rate displayed” and “cannot perform the task that Staff recommends.” Consumers’ exceptions, p. 115. Consumers also contends that the Staff’s recommendation was made for the first time in its brief and “is not based on record evidence that the Commission can rely on in its final order.” *Id.* Finally, Consumers disputes the ALJ’s conclusion that it did not appropriately respond to the Staff’s recommendation to *increase* its DR marketing and educational efforts and that an explanation of current efforts was not required.

In reply, Staff states that it did present testimony regarding shadow billing and evidence regarding using the WebPortal for the shadow billing. Staff replies to exceptions, p. 18. The Staff further states that even if shadow billing is not entirely accurate, the estimates would assist customers in reviewing rates and determining which rate best suits their needs.

The Commission first notes that testimony regarding the investigation of shadow billing and use of the WebPortal is in the record and is therefore properly before the Commission. In addition, the ALJ’s recommendation that the Commission read the one-year requirement in conjunction with the consumer protection provision of MCL 460.1195 is well taken. When reading a statute, “the statute must be read as a whole. Individual words and phrases, while important, should be read in the context of the entire legislative scheme.” *Michigan Prop, LLC v. Meridian Twp*, 491 Mich 518, 528; 817 NW2d 548 (2012) (internal citations omitted.) The first step is to review the statutory language at issue. MCL 460.1095 states:

The programs may provide incentives for customer participation and shall include customer protection provisions as required by the commission. To participate in a program, a customer shall agree to remain in the program for at least 1 year.

This language indicates that a customer must *agree* to remain in the program for at least one year. An agreement to remain in the program does not necessarily indicate that a customer cannot choose to withdraw early from the program. As the ALJ stated:

At heart, the one-year provision contemplated here is essentially a contractual provision, leaving it to the Commission to specify the consequences for early termination. The statutory one-year commitment requirement does not mean that no matter what, under all circumstances, because the customer “agreed” to remain in the program, there are no alternatives. Note that Consumers Energy’s form contract for its commercial and industrial demand response program in Exhibit A-68 has a force majeure clause in section 12, and also makes clear in section 8 that participants are not penalized for failing to shed load when requested, although future incentive payments will be reduced. Legal remedies for breach of contract rarely require specific performance.

PFD, p. 280.

The statute also states that the programs “shall” include customer protections. The ALJ’s examples of customer protection provisions, specifically the recommendation to allow customers to withdraw from the program within the first three months of the first year without penalty, are reasonable. The Commission finds this provides a balance to the contractual requirement to agree to remain in the program for one year yet allows the customer to be protected. The Commission finds that this provision complies with the plain language of the statute. The Commission further agrees with the ALJ that “the appropriate customer protections can be refined over time through the process provided for in Case No. U-18369.” PFD, p. 280.

Consumers argues that three months is insufficient time for customers to understand the impacts of the rate. The Commission disagrees. The need for customer protections is substantial. Therefore, the Commission finds that a three-month, penalty-free, withdrawal period is reasonable, and it can be balanced, for example, with a penalty that the customer forfeits any rate-related benefits received if the customer withdraws after the three-month trial period.

The Commission finds that shadow billing would further customer understanding of the benefits of DR programs. Although Consumers stated that it cannot presently offer shadow billing, the Commission finds that it is reasonable for Consumers to continue investigating

furthering its shadow billing capabilities. Even if the shadow billing is not fully accurate, it would nevertheless provide customers additional information.

Regarding marketing efforts for DR and TOU rates, the Commission finds that, like shadow billing, this is something Consumers should continue to investigate and potentially present in the next rate case. The Commission emphasizes that benefits associated with customer participation in TOU and related rate designs were built into the company's business case for AMI; thus, the Commission expects appropriate steps by the utility to ensure savings materialize to confirm the large capital investment is, in fact, prudent. See, e.g., June 30, 2015 order in Case No. U-17688, pp. 31-32. If there are incremental programmatic costs associated with such marketing, those costs should be reflected along with any revised estimates of customer benefits/savings in the updated advanced metering business case, as discussed in the next section.

D. Advanced Metering Infrastructure and Smart Energy

1. Advanced Metering Business Case

Consumers presented its business case update, indicating that the installation of AMI would be completed within the test year. As a result, Consumers requested to be relieved of the requirement to file another business case and benefit-cost analysis.

The Staff and the Attorney General opposed Consumers' request. The Staff recommended that Consumers be required to make a standalone report but conceded that the company should be relieved of the obligation to address the business case in its five-year distribution plan. The Attorney General argued that "[t]he point has not been reached yet where the cumulative benefits accruing to customers have exceeded the cumulative revenue requirement billed to customers." 12 Tr 2572.

The ALJ recommended that the Commission require Consumers to file its final AMI business case in its next rate case. The ALJ stated, “[i]f the program has reached an equilibrium, the Commission should expect to see a report which is very similar to the report presented in this case.” PFD, p. 284.

In exceptions, Consumers states that future updates to its AMI business case are unnecessary, pointing out that the November 19, 2015 order in Case No. U-17735 only required a benefit-cost analysis while the AMI program was in the implementation phase. Consumers’ exceptions, p. 117. Consumers further argues that the completion of meter installation and targeted system enhancements concluded the implementation phase and “Continuing to explicitly demonstrate AMI cost reductions in the next rate case will likely cause confusion instead of offering clarity.” Id., p. 118.

The Staff also takes exception to the ALJ’s recommendation. The Staff argues that the installation of smart meters does not mean that the program is fully implemented. Further, the Staff recommends that Consumers be required to support its business case “until it can prove that the cumulative benefits being realized exceeded the cumulative costs of the program.” Staff’s exceptions, p. 3. Similarly, the Attorney General objects to the ALJ’s recommendation, stating that Consumers should file benefit-cost analyses in support of the AMI program for the foreseeable future.

Consumers replies to the Staff’s and the Attorney General’s exceptions, stating that “updates to the business case alone do not reflect the entirety of the benefits of AMI.” Consumers’ replies to exceptions, p. 3. Consumers reiterates that the implementation phase is complete, and the Commission should not require a continual update to its AMI business case.

In replies to exceptions, the Staff argues that the implementation phase is not equivalent to the installation phase and that Consumers should be required to continue updating its business case. The Attorney General reiterates that the Commission should reject the ALJ's recommendation and require benefit-cost analyses for the foreseeable future. And, the RCG contends that Consumers' arguments to eliminate the AMI business case are unconvincing.

The Commission declines to adopt the ALJ's recommendation on this issue. Contrary to Consumers' argument, the Commission finds that merely completing the installation of meters and system enhancements does not conclude the implementation phase. In addition, the Commission believes that further updates regarding the AMI program are not only reasonable, but also will not cause confusion. The ongoing benefits of the program have not been well-documented and, therefore, the Commission finds it necessary for Consumers to continue to update its AMI business case for the foreseeable future.

2. Electric Consumption by AMI Meters

The RCG requested that the Commission investigate whether smart meters cause increased energy consumption and increased costs for customers, and that as a result, the opt-out tariff should be revised. The RCG also requested elimination of opt-out charges for customers who agree to self-read their meter and participate in a budget plan.

Consumers presented evidence demonstrating that the electrical burden of the meters was minimal and that any consumption is not registered on the customer side of the meter.

The ALJ agreed with Consumers that the company provided sufficient evidence to show "that the meters are not registering consumption attributable to the operation of the meter, i.e. 'on the customer side.' This PFD also finds [Consumers' witness] testimony persuasive that the line-side electric burden is not of the magnitude [RCG] has estimated." PFD, p. 286. However, the ALJ

recommended that Consumers should be required to identify any difference in the energy consumption between AMI meters and non-transmitting or analog meters when seeking to revise the opt-out charge in accordance with the February 28 order.

Consumers takes exception to the ALJ's recommendation that the company identify the disparity, if any, in energy consumption between AMI and analog meters. Consumers argues that the minimal energy required to operate the AMI meters would not impact the opt-out charge and "is not a vital part of the analysis to revise the AMI opt-out charge." Consumers' exceptions, p. 144.

In exceptions, the RCG reiterates that it provided evidence demonstrating that the AMI meters – as installed on a home – significantly impact electric consumption and costs to customers. RCG renews its request that the Commission investigate the energy usage of smart meters, specifically in "a non-scientific laboratory setting" such as at a residential home where the meter is installed and operating. The RCG added that opt-out fees should be eliminated for customers who self-read their meters. RCG's exceptions, p. 6.

In reply, Consumers restates that an investigation is unnecessary and that the record supports the ALJ's determination.

The Commission adopts the ALJ's findings and conclusions. Consumers presented credible testimony and evidence showing that the electricity consumed by an AMI meter, in general, is not as extensive as estimated by the RCG and that, in any event, the consumption is not registered on the customer side. However, the Commission adopts the ALJ's recommendation that Consumers identify any difference in the energy consumption between the transmitting AMI meters and non-transmitting or analog meters in the company's review of the opt-out charges.

3. Other Advanced Metering Issues

The RCG requested that the Commission investigate the health and safety of AMI meters and argued that the opt-out tariff should be eliminated because of the Commission's lack of jurisdiction, its duty to set just and reasonable rates, and other legal and constitutional restrictions.

The ALJ found that the RCG did not present any new evidence to warrant a renewed investigation on the health and safety of the AMI meters and that the RCG is free to present new information to the Staff at any time. PFD, p. 286.

The RCG takes exception, arguing that the ALJ erred in rejecting its requested investigation into the health, safety, and privacy issues regarding AMI meters. The RCG also reiterates that the required installation of AMI meters constitutes a violation of customer's due process and fourth amendment rights under the Constitution and that the Commission lacks legislative authority to require AMI meter installation. Finally, the RCG appeals the ALJ's August 28, 2017 decision to strike testimony and exhibits.

In reply, Consumers argues that the RCG's health, safety, and privacy claims and allegations of constitutional and legislative violations have been litigated by the parties, decided by the Commission, and have been affirmed by the Court of Appeals.

Regarding the RCG's appeal of the ALJ's decision to strike testimony and exhibits, Consumers replies that the testimony was filed five days after intervenor direct testimony was due to be filed and notes that the ALJ found that, "RCG has not shown good cause for the late filing." Consumers' replies to exceptions, p. 56, quoting 5 Tr 166.

The Commission adopts the ALJ's findings and conclusions. The Commission agrees that there is no credible information in this record to warrant revisiting any alleged health, safety, or privacy issues associated with AMI meters. With regards to the RCG's jurisdictional and

constitutional arguments, the Commission does not find it necessary to repeat the conclusions of the many orders and cases wherein the RCG's claims have been thoroughly considered. *Pennwalt Corp v Public Serv Comm*, 166 Mich App 1, 9; 420 NW2d 156 (1988); *Detroit Edison Co v Stenman*, 311 Mich App 367, 382; 875 NW2d 767 (2015); *In re Application of Detroit Edison Co to Implement Opt-Out Program*, unpublished opinion per curium of the Court of Appeals, issued February 19, 2015 (Docket Nos. 316728, 316781); *Attorney General v Public Service Comm*, unpublished opinion per curiam of the Court of Appeals, issued April 30, 2015 (Docket No. 317456); *In re Consumers Energy Co*, ____ Mich App ____; ____ NW2d ____ (2017) (Docket No. 330675, 330745, and 330797); November 19, 2015 order in Case No. U-17735, pp. 114-132; December 11, 2015 order in Case No. U-17767, pp. 91-110; January 31, 2017 order in Case No. U-18014, p. 129; and February 28 order, p. 156.

Finally, the Commission affirms the ALJ's decision to strike the RCG's testimony and exhibits. The Commission agrees with the ALJ that the RCG failed to show good cause for its untimely filing.

E. Deferred Accounting for Local Taxes

The RCG again raised various arguments with respect to accounting approvals necessary for deferred income tax accounting treatment for local income taxes that were granted in the February 28 order. The RCG claimed that deferred accounting is unnecessary because the difference between cash accounting and deferred accounting for city taxes is not sufficiently material to warrant deferred accounting. In addition, the RCG contends that deferred accounting for local taxes is prohibited retroactive ratemaking.

In response, Consumers pointed out that the company is not proposing any changes to the deferred accounting method approved in its previous rate case, and the Commission has already addressed the RCG's retroactive ratemaking claim.

The ALJ agreed, finding, "this matter was resolved by the Commission in the last rate case, and the RCG has presented no new evidence to justify reconsidering the authorized accounting treatment for this expense." PFD, p. 268.

The Commission agrees with Consumers, finding that, because the company did not request any changes to its accounting for deferred taxes, there is nothing new to address in this proceeding. Moreover, as Consumers pointed out, the RCG's retroactive ratemaking argument has been addressed repeatedly by the Commission, and was recently rejected by the Court of Appeals. See, e.g., *In re Application of DTE Elec Co*, unpublished opinion per curium of the Court of Appeals, issued February 13, 2018 (Docket Nos. 331599, 331868, and 332159), p. 8.

VIII. REVENUE DEFICIENCY SUMMARY

In accordance with the foregoing findings, Consumers' jurisdictional revenue deficiency for the test year is computed as follows:

Rate Base	\$ 10,202,174,000
Required Rate of Return	5.89%
Income Required	\$600,711,000
Adjusted Net Operating Income	\$561,655,000
Income Deficiency (Excess)	\$39,056,000
Revenue Multiplier	1.6377
Revenue Deficiency	\$ 63,960,000
FERC Docket No. ER16-188 Revenue Req't ¹¹	\$1,800,000
Total Revenue Deficiency	\$ 65,760,000

IX. COST OF SERVICE

A. Capacity Costs

Several parties provided testimony addressing the identification, allocation, and collection of capacity costs pursuant to MCL 460.6w. The ALJ found that, on November 21, 2017, in Case No. U-18239 (November 21 order), the Commission resolved the capacity issues presented in this case, including the method for establishing a capacity charge and the amount. The ALJ also noted that, per the November 21 order, the "final tariffs could not be determined for June 1, 2018 until this pending rate case was resolved," and "the Commission directed Consumers Energy to file

¹¹ See, Consumers' initial brief, Appendix A; PFD, pp. 171-172.

revised tariffs in that docket, Case No. U-18239, within 30 days of the Commission's order in this case." PFD, p. 289. Therefore, the ALJ concluded, the tariffs filed by Consumers in this rate case do not need to reflect the capacity charge because the Commission will separately address the capacity charge in Case No. U-18239.

Consumers takes exception, explaining that Attachment A to the November 21 order was an example tariff demonstrating the Commission's methodology for determining the capacity charge as applied to Consumers' proposed rate design. According to the company, the November 21 order requires that the costs and rate design in this case be applied to the capacity charge set in Case No. U-18239 and that, within 30 days, Consumers must file tariff sheets in the instant case.

The Staff agrees, arguing that "The updated capacity charge, including the application of the methodology approved by the Commission in U-18239 to the costs and rate design in the instant case, should be approved by the Commission. The calculation of capacity and non capacity rates are not severable." Staff's exceptions, p. 9.

CNE replies that the Staff misinterpreted the November 21 order, further contending that "[t]he Staff's exception in this proceeding amounts to an impermissible collateral attack on the Commission's November 21 Order," is unlawful, and violates the November 21 order. CNE's replies to exceptions, pp. 3-4.

CNE notes that, pursuant to MCL 460.6w(3), the Commission must establish the SRM charge by December 1 of each year. CNE asserts that the Commission recognized that Consumers' rate case would not be concluded by December 1, 2017, therefore, according to CNE, in the November 21 order, the Commission evaluated the methodology and set Consumers' SRM charge at \$300.59 per megawatt-day, stating that the charge would be applied effective June 1, 2018. CNE states that, "after the conclusion of this general rate case, Consumers must file tariff sheets recovering its

approved revenue requirement and rate design taking into account that the SRM capacity charge for both AES customers and bundled service customers effective June 1, 2018 is the SRM capacity charge of \$300.59 per megawatt-day.” *Id.*, p. 7. CNE claims that if the Commission adjusts the SRM charge that is effective for June 1, 2018, it will violate the December 1 mandate of MCL 460.6w(3).

The Commission agrees with Consumers and the Staff that the methodology approved in the November 21 order for calculating the capacity costs and capacity charge is to be applied to the updated costs and rate design in this case. The Commission explained on page 69 of the November 21 order:

Attachment A to this order reflects the application of the decisions made herein to Consumers’ proposed rate design. Attachment A is merely illustrative, because Consumers’ pending rate case, Case No. U-18322, will have been completed prior to June 1, 2018, and new costs and a new rate design will apply to the capacity charge. Attachment A should provide guidance for the utility when the applicable rate design and tariff sheets are required to be filed.

And, in ordering paragraph B of the November 21 order, the Commission stated that:

Beginning June 1, 2018, Consumers Energy Company shall implement a state reliability mechanism capacity charge of \$109,714 per megawatt-year, or \$300.59 per megawatt-day, for full service customers, using Consumers Energy Company’s proposed year-round rate design as modified by this order, illustrated in Attachment A to this order. Within 30 days of the issuance of the final order in Case No. U-18322, Consumers Energy Company shall file tariff sheets substantially similar to those contained in Attachment A.

The November 21 order clearly states that the new costs and rate design will apply to the capacity charge.

The Commission disagrees that modifying the capacity charge violates MCL 460.6w(3).

Section 6w(3) of Act 341 states that a capacity charge must be established by December 1 of each year. Consumers’ capacity charge was established on November 21, 2017, prior to the December 1 deadline. Section 6w(3) of Act 341 also states that no new capacity charge is required to be paid

prior to June 1, 2018. However, nothing in Section 6w(3) states that the new costs and rate design in a subsequent rate case may not apply to the capacity charge, and Section 6w(5) in fact requires the Commission to “review or amend the capacity charge in all subsequent rate cases, power supply cost recovery cases, or separate proceedings established for that purpose.” Therefore, the Commission has applied the SRM methodology approved in the November 21 order to the costs and rate design in the instant case. The capacity charge for full-service customers shall go into effect when rates approved by this order are effective and, for choice customers who require capacity service from the company, the capacity charge shall become effective June 1, 2018.

B. Allocation of Residential Discounts

Consistent with the June 7, 2012 order in Case No. U-16794, Consumers first proposed allocating RIA and RSC costs on a total cost-of-service basis. ABATE/Gerdau argued that the costs should be allocated on a total distribution basis because it is more consistent with the method in which the charges are applied. In response, Consumers agreed that the discounts are applied on a per-customer basis and recommended allocation of the costs on a total distribution basis.

The Staff opposed the recommended change, stating that:

Simply because the RIA and RSC discounts are applied to the residential customer charge does not mean the discounts are related to distribution customer related costs. . . . Total cost of service represents an equitable allocation to all customers derived from the two premises underlying the issue: that such discounts are required by law to be allocated to all customers, and the commonality between all Consumers['] customers is that they are served by the Company. Total cost of service is the allocative representation of a customer's existence as a regulated utility customer.

11 Tr 2241.

The ALJ determined that, in light of the Staff's response, ABATE/Gerdau did not provide adequate justification for revising the allocation of residential discounts.

ABATE/Gerdau excepts, arguing that the Staff recommended rejection of its proposal because ABATE/Gerdau had supported total cost-of-service allocation in a previous rate case, Case No. U-16794. However, ABATE/Gerdau asserts that once the Staff reviewed ABATE's testimony and briefing in the previous case, the Staff acknowledged that the issue in this case can be distinguished. Therefore, ABATE/Gerdau contends that, because the ALJ's determination was based upon a misunderstanding, the Commission should reject the ALJ's recommendation.

In reply, the Staff reiterates that the residential discounts are required by law, and because no particular customer caused the cost, the costs should not be allocated on a total distribution basis. Additionally, the Staff states that "the application of the discounts happens to occur on the same basis as residential customers charges, but the method of discounts is not expressly required by law, only the discount[']s existence." Staff's replies to exceptions, p. 46.

In its replies to exceptions, MEC/NRDC agrees with the Staff that "residential discounts are not necessarily related to customer-related distribution costs, and the costs are to be allocated to total cost of service. MCL 460.11(2)." MEC/NRDC's replies to exceptions, p. 38.

The Commission agrees with the ALJ that ABATE/Gerdau failed to provide sufficient rationale for revising the residential discount allocation. As the Staff explained, although the RIA and RSC discounts are applied to the residential customer charge, they are not distribution-customer-related costs. MCL 460.11(2) states, "Upon filing of a rate increase request, a utility shall include proposed eligible low-income customer and eligible senior citizen customer rates and a method to allocate the revenue shortfall attributed to the implementation of those rates upon all customer classes." Thus, as required by law, these discounts must be allocated to all customers, and total cost of service represents an equitable allocation to all customers.

C. Demand Line Loss

Consumers used an updated line loss study in its COSS. According to ABATE/Gerdau, Consumers incorrectly applied the energy loss factors to the meter-level 4 coincident peak (CP) and 12CP demands. ABATE/Gerdau claimed that energy loss factors reflect average usage throughout the year and that the company “should have used the peak or demand loss factors to recognize [that] the losses are higher during peak usage periods.” 12 Tr 2658. In ABATE/Gerdau’s opinion, demand line loss factors should be used to restate the 4CP and 12CP demand allocators from the meter to the generator. Similarly, MEC/NRDC/SC averred that Consumers failed to use the demand loss factors appropriately in the COSS.

In response, Consumers argued that ABATE/Gerdau and MEC/NRDC/SC erroneously applied the demand loss factors to the class peak. Consumers stated that demand loss factors are based on the company’s monthly system peak and they differ from the annual peak of each class. In addition, Consumers noted that the 4CP 75/25 allocators in Exhibit AB-2 are different than those used in Exhibit AB-4. Using Exhibit AB-4 and the COSS with the updated loss factors, the company calculated that ABATE/Gerdau’s proposal would shift \$2.2 million of costs to the Primary class from all of the other classes. Therefore, ABATE/Gerdau’s proposal to use demand loss factors to restate the demands from the meter to the generator impacts the way production costs are allocated in the COSS and also changes the allocation of distribution costs.

MEC/NRDC/SC requested that, in future line loss studies, Consumers be required to present an appropriate determination of the losses for calculating each of the cost allocators used in the COSS. MEC/NRDC/SC explained that “because line losses as a percentage of load vary with load, each of these cost allocators should reflect different line loss factors that are consistent with the definition of the allocator.” 9 Tr 1580. In MEC/NRDC/SC’s opinion, if the line loss study

generates an intermediate work product consisting of hourly deliveries and losses to each component of Consumers' system, the results will be more accurate and transparent.

MEC/NRDC/SC asserted that, because Consumers did not object to revisions to the 12CP allocator using demand loss factors, the Commission should require the company to update its COSS to apply the demand loss factors to the 12CP allocator data. In addition, MEC/NRDC/SC recommended that Consumers apply the demand loss factors in the line loss study for peak load allocators in all future cases, including PSCR cases.

Consumers disagreed with MEC/NRDC/SC's proposal, asserting that the hourly data is only available for the transmission and high voltage distribution (HVD) system components and not for each system component. Even if hourly delivery and loss data were available, the company explained that the LVD secondary system is not modeled and, therefore, it cannot calculate the hourly losses in that system. Consumers stated that it already has a Commission-approved system for calculating LVD system losses but that it would consider improvements to its current method of applying line loss factors in the development of allocators in a future rate case, provided any changes are consistent with cost causation principles and their application is reasonable.

The company also opposed revising the 12CP or 4CP allocator in this case. Although Consumers is amenable to considering the proposed change in allocator, the company needs to perform more analyses to determine whether MEC/NRDC/SC's proposed allocator is the most appropriate.

Regarding Consumers' request for additional time to evaluate MEC/NRDC/SC's proposal, the ALJ found the company's proposal reasonable, considering the limited data available to adjust the monthly peaks. Therefore, the ALJ recommended that Consumers be required to provide an

analysis of the proposed refinement and a calculation of demand loss factors for peak allocators, or an explanation why it is unable to do so, in its next rate case.

In exceptions, Consumers reiterates that it cannot provide hourly delivery and loss data, for each component of the transmission and distribution systems because this data is only available for the transmission and HVD system components. The company further contends that it is not convinced that the method proposed by MEC/NRDC/SC for determining line losses is better than the methodology that the company currently uses.

In reply, MEC/NRDC/SC reiterates that an accurate calculation and application of loss factors results in more accurate rates reflecting the actual cost of service. MEC/NRDC/SC also states that inaccurate loss factors may have a significant negative impact on cost allocation. MEC/NRDC/SC argues that AMI metering offers an opportunity to update and improve loss factor calculations. Finally, MEC/NRDC/SC contends that the ALJ's recommendation is limited in scope and not unreasonably burdensome on Consumers.

The Staff replies that the ALJ based her recommendation on the company's briefing, in which Consumers requested additional time to perform an analysis of MEC/NRDC/SC's proposal. The Staff contends that the ALJ's recommendation was based upon the record and the parties' positions and, therefore, Consumers' exception should be rejected.

The Commission notes that Consumers did not oppose evaluating improvements to its current method of applying line loss factors in the development of allocators in a future rate case, as long as the allocators are consistent with cost causation principles and their application is reasonable. For the purposes of this case, the Commission adopts the company's updated line-loss study in its COSS. However, the Commission finds that there is value in conducting additional analyses of the demand loss factors for peak allocators. Therefore, the Commission directs Consumers, in its

next rate case, to present a line-loss study that considers demand line loss factors restating the 4CP and 12CP demand allocators from the meter to the generator.

D. Interruptible Credits

ABATE/Gerdau disputed Consumers' allocation of credits provided to interruptible customers under the company's residential and C&I demand response programs. According to ABATE/Gerdau, the company improperly included interruptible customers in the 4CP 75/25 allocation because Consumers does not plan capacity resources to serve interruptible load. ABATE/Gerdau argued that interruptible credits should be allocated to customer classes based on firm loads and requested that the Commission approve the 4CP 75/25 firm demand allocation factors as shown in Exhibit AB-3.

Consumers responded that ABATE/Gerdau's proposed allocation does not change significantly how interruptible credits are allocated between the major classes. Because Consumers methodology is reasonable, and it produces nearly the same results as the method recommended by ABATE/Gerdau, there is no need to create a new allocator.

The ALJ agreed with the company that ABATE/Gerdau's and Consumers' methodologies produce very similar results, and therefore, it is unnecessary to create an additional allocator.

In exceptions, ABATE/Gerdau states that the ALJ notably did not find that its proposed allocation method was incorrect. Instead, ABATE/Gerdau asserts, the ALJ concluded that because Consumers' and ABATE/Gerdau's methodologies produced similar results, there was no reason to deviate from the company's method. However, ABATE/Gerdau argues that Consumers' method is incorrect and "the fact that an incorrect method produced similar results, materiality aside, does not justify a conceptually incorrect method to persist." ABATE/Gerdau's exceptions, p. 4.

ABATE/Gerdau reaffirms its proposal and requests that the Commission adopt its interruptible credit allocation method.

Consumers reiterates that its allocation is reasonable and produces results very similar to ABATE/Gerdau's proposed allocation. However, the company argues that its proposed allocation is simpler and does not require the creation of a new allocator. Consumers' replies to exceptions, p. 44.

The Commission adopts the ALJ's recommendation. The Commission finds Consumers' methodology reasonable and that the results are very similar to those produced by ABATE/Gerdau's proposed methodology. ABATE/Gerdau did not provide adequate justification for modifying or creating a new allocator.

E. Intersystem Sales Allocator

Regarding Midcontinent Independent System Operator, Inc., (MISO) energy sales revenue, Consumers proposed an allocation based on energy, rather than capacity, asserting that this change is consistent with the type of transaction. Consumers explained that the company sells energy when there is a surplus of generation, which is less expensive to produce than the market price for power. The company claimed that "[e]nergy sales to MISO, either for economic or reliability purposes are an output of the PROMOD IV production cost model simulation. The nature of those credits is strictly energy-related and they include no revenues for the sale of capacity." 6 Tr 534. Consumers noted that PROMOD IV documentation explains the outputs as a process by which companies purchase and sell energy on an economic basis as a means to reduce production costs for the buyer and provide a profit to the seller.

ABATE/Gerdau supported Consumers' proposal, asserting that, because there is no firm commitment to sell a fixed amount of power over a specific time period, it is not a capacity sale.

The Staff disagreed, responding that revenues should be allocated on a 4CP 75/25 basis, like the underlying production costs. The Staff argued that when Consumers produces less energy than its customers use, the cost to purchase energy from the market is appropriately included in rates as an energy cost. Accordingly, the Staff stated, the revenue from the market sale of energy produced in excess of the company's use should be considered an offset to the cost of capacity used to produce that energy, which is required by MCL 460.6w(3)(b). In addition, the Staff contended that the revenue from market sales of energy should be considered an offset to the cost of capacity because it is made possible by capital expenditures over and above the capital expenditures for a combustion turbine, which "enables the production of energy at a cost low enough to make money in the market. Therefore, revenue from such sales should be used to offset the higher capital expenditures required to enable them." 11 Tr 2419.

The ALJ noted that the November 21 order resolved the allocation issue consistent with the Staff's recommendation. Nonetheless, she found the Staff's position persuasive: energy that is produced in excess of the company's use and is available for sale "is attributable to the existence of the underlying capacity, and the costs and benefits should be allocated accordingly." PFD, p. 296.

In exceptions, Consumers reiterates that "[i]ntersystem sales credits are strictly energy related and include no revenues for the sale of capacity. As a result, the proper allocation for these credits is 100% on energy sales." Consumers' exceptions, p. 121 (citations omitted).

ABATE/Gerdau also disagree that the November 21 order resolved this issue, and that there is no evidence in this case that intersystem sales are anything other than energy sales, not capacity sales. According to ABATE/Gerdau, this differs from prior cases where intersystem sales were primarily capacity sales.

Additionally, contrary to the Staff's position, ABATE/Gerdau state that Section 6w does not necessarily resolve this issue. ABATE/Gerdau assert that the "infirmity in Staff's position is that market energy sales are not capacity-related costs, and there is nothing in the law that mandates how these revenues should be allocated to customer classes. The law only requires that market energy sales be used to offset capacity costs." ABATE/Gerdau's exceptions, p. 6. Therefore, ABATE/Gerdau argue, intersystem sales should be allocated to customer classes in the same way that all other production energy costs are allocated.

In replies to exceptions, the Staff asserts that the ALJ considered Consumers' and ABATE/Gerdau's arguments and rejected them. The Staff responds to Consumers' exception that the November 21 order states that energy sales in the market, less fuel costs, are used to "separate out the energy costs from the overall production costs to arrive at a capacity-only cost." Staff's replies to exceptions, p. 35, quoting the November 21 order, p. 67. Therefore, the Staff contends that the Commission has already determined that intersystem sales offset capacity costs and that they should be allocated on the same basis. Moreover, "[w]ithout allocating these revenues on the same basis as the costs they are meant to offset, the offset cannot be properly applied." Staff's replies to exceptions, p. 36.

The Commission finds the ALJ's findings and conclusions persuasive. The November 21 order resolved the allocation issue consistent with the Staff's recommendation. And, as noted by the Staff and the ALJ, pursuant to Section 6w(3)(b), any revenues from the market sale of energy produced in excess of Consumers' use should be considered an offset to the cost of capacity used to produce that energy.

F. Distribution System Cost Allocations

MEC/NRDC/SC noted that, pursuant to MCL 460.11, the Commission must ensure that electric rates are equal to the cost of providing service to each customer class. Accordingly, MEC/NRDC/SC stated that basing the allocation of distribution system costs strictly on class peaks is illogical because substantial portions of the distribution system are unrelated to demand. Therefore, in a future rate case, MEC/NRDC/SC requested that Consumers be required to conduct an investigation of distribution system cost allocations.

With the installation of AMI meters, MEC/NRDC/SC asserted that more detailed information will be available to test the assumptions in the COSS. And, MEC/NRDC/SC noted that Consumers will shortly file a five-year distribution plan, which might be an ideal forum to conduct an investigation into distribution system allocation costs.

The Staff agreed that a study of distribution system cost allocations was appropriate, but disagreed that the company's five-year distribution plan is the proper forum to consider cost allocation issues. The Staff asserted that a rate case is the only proceeding in which distribution system costs may be allocated and is, therefore, the appropriate forum for evaluation. If the Commission finds that the distribution costs may be allocated in a forum other than a rate case, the Staff recommended that the Commission open a separate case.

Consumers objected to MEC/NRDC/SC's and the Staff's proposals, stating that the NARUC Manual supports the company's method of allocating distribution costs based on customer class peaks. Consumers noted that according to the NARUC Manual, because "load diversity at distribution substations and primary feeders is usually high," the "customer-class peaks are normally used for the allocation of these facilities." Consumers' reply brief, p. 179, quoting Exhibit S-17, p. 108. However, the company is open to evaluating and considering improvements

to cost allocations and suggested that the Staff and MEC/NRDC/SC submit alternative COSS proposals in Consumers' next rate case.

Although the ALJ agreed with the Staff that it is inappropriate to determine distribution system cost allocations outside of a rate case, she opined that the cost allocations could be evaluated by interested parties in a forum other than a rate case due to the time and effort needed to undertake the analysis. The ALJ stated that "[b]y providing for some exploration of alternative allocation methods outside the context of a rate case, even if no general consensus is reached, the Commission should expect a better, more well-considered record in the subsequent rate case in which alternatives are presented to the Commission." PFD, p. 300. Therefore, the ALJ recommended that the Commission create a collaborative to identify and evaluate alternative methods for distribution system cost allocation, but in a proceeding separate from the review of Consumers' distribution system planning.

Consumers takes exception, reiterating that its proposed allocation of distribution costs is an appropriate and acceptable allocation method and that, in its next rate case, the company will continue to evaluate its COSS, and the parties will have an opportunity to review the COSS, perform discovery, and make counter-proposals. Thus, the company argues that a separate collaborative is unnecessary and an imprudent use of the parties' and the Commission's time and resources.

In reply, the Staff states that although Consumers is correct that the NARUC Manual provides for the company's allocation method, the Staff claims:

The company fails to note several critical facts:

1. the reason for using these allocation methods is the nature of cost-causation and load diversity,
2. there are exceptions to its use,
3. care must be taken in the load included, and
4. portions of the system should be allocated differently.

Staff's replies to exceptions, pp. 36-37, quoting Exhibit S-17, p 108. Even if the NARUC Manual supports the company's current allocation method, the Staff contends that, in its next rate case, Consumers should be required to prove that its method is the most appropriate and that it properly reflects cost causation.

In replies to exceptions, MEC/NRDC/SC assert that Consumers' reliance on the NARUC Manual is misplaced because the manual is not authoritative and, rather than endorsing Consumers' method of using coincident peak time by rate class, it "justifies the use of customer-class coincident peak." MEC/NRDC/SC's replies to exceptions, pp. 29-30. In addition, MEC/NRDC/SC restate that a rate case "presents significant limitations on the exchange of information needed to properly evaluate distribution system cost causation" and, therefore, MEC/NRDC/SC support the ALJ's recommendation to establish a collaborative proceeding to identify and evaluate alternative methods for distribution system cost allocation. *Id.*, p. 32.

The Commission agrees with Consumers that, at this time, a collaborative is unnecessary. However, the Commission finds persuasive MEC/NRDC/SC's and the Staff's recommendation that the allocation of distribution system costs should properly reflect the manner in which costs are caused. Therefore, the Commission directs the company to justify its current methodology in its next rate case. This approach should not foreclose the parties from discussing these issues before or during the next rate case. Regarding the company's distribution plan, Consumers, the Staff, and stakeholders should examine potential uses for data that may be relevant to informing future rate design and cost allocation decisions and whether that data could be made available with enhanced monitoring and controls on the system (e.g., advanced distribution management system, AML, distribution supervisory control and data acquisition, etc.), as well as the associated costs and benefits, to the extent there is incremental cost.

X. RATE DESIGN AND OTHER TARIFF ISSUES¹²

A. Uncontested Rate Design Issues

There were no exceptions filed regarding Rate GPD,¹³ Rate GPD transmission costs, Rate GPD voltage levels, Rate GPD/GP crossing-point adjustment, Energy-Intensive Primary Rate, and Rate GSG-2 power supply revenues. Therefore, the Commission adopts the ALJ's findings and conclusions on these issues.

B. Residential Rate Design

Regarding the capacity charges to be approved under Section 6w of Act 341, the Staff suggested a rate design that collects capacity charges in a manner that reflects how the costs are assigned. Thus, for rates with demand charges, the Staff proposed on-peak billing demand for summer months. For other rates, the Staff asserted that the capacity charges should be collected through summer on-peak usage. The Staff also recommended eliminating the "inverted block" residential rate design and replacing it with higher rates for summer on-peak usage and lower rates for all other hours.

MEC/NRDC similarly recommended "that the Commission shift as much of the production plant cost, allocated based on 4CP, out of Rate RS winter rates and into summer rates." MEC/NRDC's initial brief, p. 75. MEC/NRDC argued that by allocating capacity and energy costs to billing determinants that may be controlled by the customer and by accurately predicting

¹² Minor tariff changes that were not disputed by the parties, and not addressed in the PFD or exceptions, are approved.

¹³ The Commission notes that the ALJ's finding that "the summer-only demand charges [under Rate GPD] . . . has been resolved by the Commission's decision in Case No. U-18239" was incomplete. Case No. U-18239 did not directly address the rate differential increase that was raised here.

the customer's contribution to the statistics on which cost allocation is based, it sends price signals to customers, encouraging reduction of the company's costs. MEC/NRDC explained that:

More specifically, the costs allocated to a customer class based on a statistic used in the cost of service study should be allocated to billing determinants within a class based on a regression that predicts the individual customer's contribution to the cost allocation statistic given the customer's billing determinants. Because that regression will provide the most accurate prediction of the customer's contribution to allocated costs based on the billing determinants, it will provide the most accurate allocation of costs to each customer within the class.

9 Tr 1592. In MEC/NRDC's opinion, this method will reduce errors in the allocation of costs to each customer and will minimize intra-class cross subsidies.

Consumers opposed the Staff's and MEC/NRDC's proposed changes, arguing that the company bills such rates based on interval meter data and these rates are a part of Consumers' complex billing system. According to the company, the system capacity for time-based rates was designed and tested for no more than 420,000 accounts annually. If Consumers were to move 1.5 million residential customers to complex billing, the company claimed that it would exceed the system capacity and would require extensive infrastructure and application architecture changes, along with significant testing of various systems.

Responding to the recommendation to align rate design to reflect cost responsibility, Consumers argued that the company provides capacity service year-round—not just during summer months—and therefore it is appropriate to collect capacity costs from customers year round. Consumers contended that the Staff's proposal is a dramatic change and it could cause unnecessary hardship for customers in summer months, disrupt industrial customer planning, and affect the company's ability to recover rates. Although the company did not dispute that the Staff's rate design might provide better price signals, Consumers suggested that it be offered on an optional basis or phased-in over a number of years.

In addition to disagreeing with MEC/NRDC's regression analysis, the company asserted that MEC/NRDC confused rate design with the establishment of cost responsibility. Consumers opined that MEC/NRDC's analysis would be more helpful if the costs of peaking units were allocated in the summer months. And, the company stated, MEC/NRDC failed to consider the impact on low-income and fixed-income customers.

The ALJ found that the November 21 order resolved the rate design for the capacity charge in this case. However, in light of the information provided by the Staff and MEC/NRDC, the ALJ acknowledged the importance of rate design for the capacity charge and recommended that "Consumers Energy be directed to present a plan in its next rate case for attaining the capability to implement time-of-use rates such as summer on-peak rates for residential customers, including the necessary educational materials and customer service training, with information on the applicable costs and timeframes for implementation." PFD, pp. 303-304.

Consumers argues that the ALJ's recommendation "was not requested by any of the parties, is wholly imbalanced in that it does not require Staff or Intervenors to address impacts on ratepayers or the Company, is inconsistent with the U-18239 Order, is inconsistent with the record evidence presented by Consumers Energy in this matter, and should not be required by the Commission." Consumers' exceptions, p. 125.

In exceptions, the Staff argues that the "ALJ erred in conflating Staff's recommendation on non-capacity residential rate design with its proposal related to capacity charges." Staff's exceptions, p. 7. The Staff asserts that the November 21 order did not resolve the Staff's non-capacity proposal and it requests that the Commission address the issue in this case. In addition, the Staff reiterates its support for elimination of the inverted block rate, stating that removal of the

rate will match rates with cost causation, send beneficial price signals, and will prevent intraclass subsidization.

The Attorney General takes exception, asserting that the ALJ failed to consider his arguments in making her recommendation, arguing that the Staff's approach is a "radical departure[] from the status quo," and that it will be "too financially burdensome on residential and small business customers." Attorney General's exceptions, pp. 7, 9. He contends that the Staff incorrectly assumes that capacity costs are only incurred during the summer months and should only be billed during those months. However, the Attorney General argues, full-service customers pay for capacity year-round and, therefore, a year-round capacity charge is more appropriate.

In addition, he states that the "Staff failed to adequately explain the reason of billing energy costs at different rates during on-peak and off-peak periods, and the ALJ did not adequately address this issue in the PFD." *Id.*, p. 11. According to the Attorney General, energy-related costs are mostly the result of fuel and O&M costs that are directly related to the volume of energy generated. Therefore, he argues that a flat, uniform rate is the best method to recover the costs. The Attorney General contends that there is no cost basis for a tiered structure for energy-related costs, particularly the rate proposed by the Staff.

In reply, Consumers reiterates that the ALJ's recommendation was in error, contrary to the record in this case and should therefore be rejected.

Regarding the Attorney General's recommendation to replace the current tiered structure with a flat, uniform rate, Consumers claims that the Attorney General introduced this proposal for the first time in his reply brief. Consumers asserts that the parties were given no opportunity to address or respond to the proposal prior to the close of the record or during briefing, and therefore, the Commission should reject the request.

In replies to exceptions, the Staff disputes the company's claim that, if it is required to more broadly offer residential rates for energy that differ between summer on-peak and other hours, Consumers will have to employ a rate design for capacity charges different from the one recently approved in the November 21 order. The Staff argues that the company "is taking advantage of a mistake by the ALJ, which Staff addressed in its Exceptions, conflating Staff's capacity and non-capacity rate design proposals." Staff's replies to exceptions, p. 38. In addition, the Staff notes that, in Case No. U-18239, the Commission specifically recognized the potential value of a time-varying rate design and stated that the proper forum for such changes is a rate case.

Regarding Consumers' argument that its system is not designed for 1.5 million customers on time-based rates, the Staff notes that the ALJ recommended that the company file a plan for this very reason. And, in response to Consumers' claim that TOU rates are unnecessary because the company offers the rate on an optional basis, the Staff asserts that TOU rates "better match the rates paid [sic] by customers for energy use with the costs caused by that usage[.]" Staff's replies to exceptions, p. 39. According to the Staff, with the company's AMI metering, Consumers is able to charge the differential directly to the kilowatt-hour, rather than using a proxy for the usage. The Staff argues that this sends an appropriate price signal for customer usage in each time period, which results in more economically efficient outcomes.

In response to the Attorney General's allegation that there is no cost basis for a tiered structure, the Staff asserts that the record does not support his claim. The Staff contends that its evidence demonstrates that "[e]nergy has different costs at different times," and the rate design the Staff proposes "send[s] the appropriate price signal for usage in each time period, . . . more closely aligning the rates charged with the costs caused by that usage." *Id.*, p. 47, quoting 11 Tr 2426.

In replies to exceptions, MEC/NRDC state that the ALJ's recommendation is based on record evidence and that Consumers' and the Attorney General's exceptions should be rejected.

MEC/NRDC reiterate that on-peak summer billing more accurately reflects cost causation, the current residential RS rate design inappropriately forces RIA customers to subsidize other rate RS customers, and none of the challenges cited by Consumers and the Attorney General justify retaining the current rate design.

While the Commission's November 21 order left open the possibility to consider the Staff's proposed change to the capacity charge rate design in this rate case, the Commission agrees with the ALJ's recommendation to retain the rate design for capacity charges. However, for non-capacity charges, beginning at the conclusion of the company's next rate case, the Commission adopts the Staff's proposal to eliminate the inverted block residential rate design and replace it with a summer on-peak and all-other-hours rate. This represents a gradual move to cost-of-service-based rates for residential customers, and it improves price signals for all residential customers while still making available specific TOU rates on a voluntary basis. As the Staff observed, this rate design "send[s] the appropriate price signal for usage in each time period, leading to more economically efficient outcomes, and more closely aligning the rates charged with the costs caused by that usage." 11 Tr 2426.

While some parties referred to the Staff's seasonal rate structure as "TOU rates," the Commission observes important differences between the on-peak summer rates approved here and DR program-related TOU rates. As discussed above, the Commission's primary objective in eliminating the inverted block rate design, and replacing it with summer on-peak and off-peak rates, is to adjust the rate design to one that more accurately reflects cost-causation. Prior to the deployment of AMI, total monthly usage was the only available proxy for assessing customers for

on-peak usage. Now, with the interval data made available by advanced metering systems, the company can far more accurately bill customers in accordance with cost-causation principles. While customers may make some adjustments to shift energy usage from on-peak to off-peak hours, the primary purpose is not to further DR efforts. As noted, customers who want to do more may enroll in a voluntary program.¹⁴

In accordance with the findings and conclusions discussed above, Consumers shall, in its next general rate case, eliminate the inverted block rate and replace it with a summer, on-peak, non-capacity rate for residential customers. Consumers shall also include a proposal for allowing customers who opt out of AMI to retain the existing rate structure.

C. Rate GSG-2

1. Rate GSG-2 Rate Design

Consumers proposed an adjustment to the rate design for Rate GSG-2, its standby rate for large customers with their own generation. After completing the study required by the February 28 order, the company found that Rate GSG-2 customers are paying more than their total allocated embedded cost of service. However, Consumers explained that this overpayment is due to the use of the 4CP allocation, which may not correspond with the times the customer is using capacity. In addition, the company stated that Rate “GSG-2 capacity customers are paying about half of the Company’s embedded capacity costs on a dollar per kilowatt (kW) basis compared to what comparable customers served at the same voltage levels are responsible for.” 10 Tr 2004. In Consumers’ opinion, the cost of capacity should reflect the company’s embedded cost of service that is allocated to comparable customers in the approved COSS, and therefore, the company’s

¹⁴ Consumers offers “Peak Rewards Time of Use” and “Critical Peak Time of Use” residential TOU programs that are specifically designed to facilitate DR for participating customers.

proposed amended rate design should be approved. The company also stated that the proposed capacity charge for Rate GSG-2 customers will continue to indicate the number of on-peak days the customer takes standby service during the month.

ABATE/Gerdau objected to the company's proposed adjustment, arguing that Consumers already recovers its embedded cost of service and that the company's proposal would more than double the power supply demand charge. ABATE/Gerdau also contended that the tariff does not reflect the different characteristics of backup and maintenance power, there is no cost basis for adding 10% to locational marginal price (LMP) energy price for summer on-peak use, and the proration language is unclear. ABATE/Gerdau recommended that the Commission require Consumers to review the New York standby rate design and conduct further analysis of the distribution system. MCA agreed.

The Staff explained that a customer's use of the distribution system is currently measured by the non-coincident peak demand for rate design purposes. The Staff stated that class peak at a given level of the system, on the other hand, is used to allocate costs to each class. The Staff recommended that, "for now, distribution charges for GSG-2 customers continue to be charged in the manner that they historically have been, but [the Staff] reserves the right to recommend changes in the future, potentially including the recommendations in the [standby rate working group] SRWG Report." 11 Tr 2369.

Regarding recommendation 3 from the supplemental SRWG report, the Staff claimed that, because it does not have the projected metered demand for standby customers, it is unable to design rates on that basis. Therefore, the Staff recommended that Consumers be required to provide actual and projected peak metered demand billing determinants for Rate GSG-2 customers, including any ratchet that would be applied. However, if the company chooses to rely

on contracted demand, the Staff requested that Consumers be required to provide “justification for deviating from the standardized framework.” *Id.*, p. 2368.

The Staff agreed with ABATE/Gerdau that Consumers is currently recovering its cost of service, and therefore, Consumers’ proposed Rate GSG-2 charges should be rejected. According to MEC/NRDC, Consumers incorrectly compared the cost of service for Rate GSG-2 customers and other customers served at the same voltage level. MEC/NRDC asserted that the Commission set forth the proper assessment in the February 28 order, which is a comparison “between the costs a standby customer causes and the revenue a standby customer generates.” 9 Tr 1615. Therefore, MEC/NRDC recommended setting the capacity charges for Rate GSG-2 at no more than the product of the forced outage rate for the customer multiplied by the average cost of capacity for that customer. Finally, MEC/NRDC asserted that, under the Public Utility Regulatory Policies Act (PURPA), the tariff must be nondiscriminatory. MCA agreed.

MCA claimed that Consumers’ rates are already excessive, the tariff lacks transparency, and the distribution charge component of the rate design needs further evaluation. MCA recommended that Consumers eliminate complicated formulas, “state the same energy charges for standby power that it charges the same customer for its full-time supplemental power,” and amend its Rate GSG-2 tariff to prorate its delivery demand charges based on a customer’s use of the company’s delivery system. 6 Tr 193-194. MCA asserted that Consumers’ proposed revision to Rate GSG-2 will approximately double standby users’ capacity demand charges, which will further discourage cogeneration projects in Consumers’ service territory. In addition, MCA argued that “cogeneration systems’ 5% outage rate warrants no more than a 5% allocation of non-dedicated utility resource costs to the GSG-2 customer class and Consumers’ rates for the GSG-2 class should reflect that allocation.” *Id.*, p. 197.

In reply, Consumers stated that:

[S]tandby customers only pay for this capacity on a prorated basis, based on the number of on-peak days the standby customer actually uses the capacity. This prorated approach essentially enables the standby customer to only pay for capacity on the days they use it. This is not an option offered to full requirement GPD customers who are charged for capacity based on their monthly highest demand established during the on-peak hours, regardless of how many days they actually use capacity.

10 Tr 2026. If the company's rate design is rejected, Consumers asserted that a subsidy will be created for standby customers. And, according to the company, the tariff permits the customer to receive service during scheduled maintenance outages, which avoids an additional payment of 10% of LMP during the summer billing months.

Consumers disputed that, under the company's proposal, Rate GSG-2 customers pay more than their fair share. The company claimed that prorating delivery demand charges would be unreasonable because the cost of the existing distribution facilities serving customers does not vary based on the amount of time the customer uses the system. The Staff agreed.

Responding to MEC/NRDC's claim that, under PURPA, the tariff must be nondiscriminatory, Consumers argued that Rate GSG-2 is not exclusively available to PURPA qualifying facilities, but to other facilities as well, and therefore, the tariff language permitting the company to refuse a PPA is appropriate.

Consumers contended that MCA failed to provide evidence that the company's proposed GSG-2 rate is not cost based and that the company did not offer any cost-based alternatives. The company advocated for an LMP energy price because "when a GSG-2 customer uses supplemental power, [it] holds all non-standby customers harmless for the cost of energy that standby customers take on a supplemental or standby basis." 10 Tr 2028. Consumers claimed that the LMP reflects the actual market price of energy and avoids any subsidization by full-service customers.

The ALJ recommended that Consumers' proposed adjustment to Rate GSG-2 should be denied because:

[T]he revenues from this rate are already above the fully-allocated cost. Consumers Energy has not justified its assertion that rates for Rate GSG-2 and for comparable full-service customers should be the same on a dollar-per-kW basis, or that its new proposed power supply demand charges are compatible with its LMP-based energy charges, including the 10% adder for summer use.

PFD, p. 317. The ALJ also stated that, regarding the distinction between backup power and maintenance power, Consumers' tariff requires customers to provide notice of a scheduled maintenance outage 6-10 months in advance in order to avoid the 10% adder in summer months. The ALJ noted that this requirement differs significantly from DTE Electric's tariff, and Consumers failed to reconcile the advanced notice requirement with the proposed rate change. The ALJ recommended that the advanced notice requirement be examined in the company's next rate case.

Regarding future rate design and tariff provisions for Rate GSG-2, the ALJ proposed that Consumers be required to provide a review and analysis of the recommendations in the supplemental SRWG report, "including an explanation of how it considered the recommendations in its recommended rate design and tariff for Rate GSG-2, i.e., whether it rejected the recommendation or incorporated it in some way, and why." *Id.*, p. 319.

Finally, the ALJ recommended that the Commission direct Consumers to provide, in its next rate case, the information requested by the Staff regarding determinants. The ALJ determined that specific additional analysis of distribution system charges for standby customers is unnecessary because she already recommended that the Commission require further analysis of cost allocation methods for distribution system components.

In exceptions, Consumers claims that, in making her recommendation, the ALJ failed to consider that the current rate design causes full-requirements customers to subsidize Rate GSG-2 customers and it does not reflect the intermittent use of capacity by standby customers.

Additionally, the company contends that the ALJ “does not indicate what factors and information are missing in the Company’s analysis that cause the Company’s supporting evidence, including testimony and exhibits, to purportedly fail.” Consumers’ exceptions, p. 132.

Responding to MCA’s claim that the company’s standby rates are higher than those of other utilities, Consumers asserts that MCA’s comparison included out-of-state utilities that have incentives and subsidies that are not permitted in Michigan. In fact, Consumers states, MCA’s analysis shows that the company’s rates are comparable to utilities in Michigan’s jurisdiction. The company contends that “MCA offered no evidence that suggests the Company’s proposed GSG-2 Rate is not cost-based, that the standby rates of other utilities are cost-based, or any cost-based alternatives to collect the costs placed on the system for standby service.” *Id.*, p. 131.

Consumers also disputes that it should be required to provide a review and analysis of the SRWG report. The company initially notes that no party requested this relief. Then, Consumers argues that most of the recommendations in the report have already been addressed in this case. The company asserts that its proposal to use the embedded cost of capacity will improve the transparency of the rate on the tariff, complying with item 1 of the SRWG report. Regarding item 2 of the SRWG report, the company states that the Staff acknowledged that a cost-of-service-based standardized framework for the standby service tariff may not be possible and that there may be good reasons for inconsistencies in tariffs. Consumers contends that it “already has a distinction between and interaction between supplemental and standby service,” and therefore, item 3 of the SRWG report has been addressed. *Id.*, p. 133. For item 4 of the SRWG report, the company

asserts that it has requested review of this capacity charge and, because the proposed charge is prorated based on the number of days the customer uses capacity, the charge is consistent with the Staff's recommendation. Consumers argues that its proposal to prorate Rate GSG-2 is consistent with item 5 of the SRWG report because the company's seasonal on-peak capacity charge encourages customers to schedule maintenance during non-peak periods. The company claims that its proposal addresses item 6 of the SRWG report because the customer is billed for standby energy use at LMP, which is an ideal form of a TOU rate. Finally, because Consumers has agreed to allow solar standby customers to use the General Primary TOU rate on a pilot basis, the company states that item 7 of the SRWG report has been fulfilled. Consumers concludes that the Staff "made no specific proposals that improve the Company's GSG-2 Standby rate with respect to Staff's own recommendations in the supplemental workgroup report. Thus, based on the foregoing, the recommendation of the PFD is without merit and should be rejected by the Commission." *Id.*, p. 135.

ABATE/Gerdau again request that Consumers be required to clarify the proration language in Rate GSG-2. In reply, Consumers states that this issue was addressed and resolved in the February 28 order.

The Staff disputes Consumers' argument that it is more appropriate to charge Rate GSG-2 customers based on the embedded costs allocated to other customers. Although Consumers claimed that Rate GSG-2 customers did not use power during the four coincident peaks in 2013 and 2014, according to the Staff, this assertion "could just as easily apply to any other customer; indeed this argument impugns the 4 CP method that the Company has supported." Staff's replies to exceptions, p. 40 (note omitted). In the Staff's opinion, Consumers disregarded the ALJ's extensive evaluation of the parties' arguments and evidence, including the company's study

showing that Rate GSG-2 customers are charged rates higher than the cost to serve them. The Staff contends that Consumers must decide that 4CP is appropriate, in which case the study showing that Rate GSG-2 customers are overpaying is valid, or that 4CP is invalid, in which case it needs to be changed – the company cannot not have it both ways. *Id.*, p. 41.

In their replies to exceptions, ABATE/Gerdau reiterate that the evidence in this case sufficiently demonstrates that Rate GSG-2 customers are paying more than their total allocated embedded cost of service.

MEC/NRDC reply that Consumers' proposed rate is not based on the cost of service and that "The Commission is obligated to ensure rates reflect cost of service. MCL 460.11(1). For this reason, and for the reasons fully discussed by the ALJ, MEC/NRDC request that the Commission reject Consumers' exception." MEC/NRDC's replies to exceptions, p. 50 (note omitted). MEC/NRDC also agree with the ALJ that the company should be required to analyze the SRWG report, including the recommendation that the rate reflect the cost of service.

On page 2 of its replies to exceptions, MCA states that Consumers rejected the results of its COSS "and its own 4-CP methodology and data and asks the Commission to apply a new and different methodology – one in which it 'cherry picks' years to favor its conclusions." MCA disputes that Consumers' proposal aligns Rate GSG-2 with the embedded costs to serve full-service customers. Rather, MCA argues, the company is arbitrarily allocating to Rate GSG-2 customers 50% of its embedded costs for power supply capacity. As a result, MCA asserts that a standby customer will pay 10 times the rate of a full-service customer for peak power supply capacity.

The Commission finds that Consumers' proposed adjustment to the rate design for Rate GSG-2 should be rejected. The record evidence demonstrates that the company is already recovering its

embedded cost of service and that the proposed adjustment would more than double the power supply demand charge. And, as argued by ABATE/Gerdau and the Staff, the tariff does not reflect the different characteristics of backup and maintenance power, there is no cost basis for adding 10% to LMP energy price for summer on-peak use, and the proration language is unclear.

In the company's next rate case, the Commission directs Consumers to provide actual and projected peak metered demand billing determinants for Rate GSG-2 customers, including any ratchet that would be applied. In addition, if the company chooses to rely on contracted demand, Consumers shall provide justification for its departure from the standardized framework.

2. Solar Self-Generation

The Staff recommended that the Commission consider items 6 and 7 regarding solar generation in the June 2017 SRWG report issued in this case. The Staff averred that, because customers with self-service solar generation need access to power every day, Consumers should allow customers with self-service solar generation to take service under the Rate GSG-2 tariff or under the General Primary TOU rate.

Consumers consented to the Staff's proposal that solar customers retain eligibility to take service under TOU rates, but under the condition that it function as a pilot program for a minimum of five years. Consumers explained that the pilot would "provide the Company with the time and data necessary to make a determination as to whether this is an appropriate rate design for standby service based on their actual experience." 9 Tr 1507.

ELPC proposed that customers with self-service solar generation be permitted to take service under the Rate GSG-2 tariff or under the tariff to which they would be otherwise assigned. ELPC disputed the value of the five-year pilot program proposed by Consumers.

The ALJ recommended that the Commission approve the pilot program suggested by Consumers and supported by the Staff, “with the proviso that Consumers Energy present an evaluation of the ongoing pilot in each of its subsequent rate cases, so that the parties can consider whether to recommend additional changes in the eligibility of standby customers for other rate schedules. The parties should also be encouraged to continue discussing this issue.” PFD, pp. 319-320.

ELPC takes exception, requesting that the Commission “order that customers with solar ‘behind-the-meter’ generation of any size be allowed to take service under the GPTU rate or as Supplementary Service.” ELPC’s exceptions, p. 1. ELPC contends that Consumers did not present any evidence showing that, if solar customers were allowed to choose supplementary service, it would result in cross-subsidies. In fact, ELPC argues, if solar customers are allowed to choose supplementary service, Consumers may more quickly receive useful data to evaluate the appropriate rate design for standby service and may be able to identify the rates that most appropriately reflect the cost to serve solar self-generators.

In reply to ELPC, Consumers argues that “the very reason for the five-year pilot is to allow time to gather information regarding the impact of the rate design and evaluate whether the rate is appropriate so that no cross subsidies are created.” Consumers’ replies to exceptions, p. 50. And, Consumers disputes ELPC’s assertion that the company will obtain a greater amount of information in a shorter period by allowing solar customers to take supplementary service on all rates; rather, Consumers asserts that it will not be able to receive the necessary information to plan system needs or the amount of standby service the company will be required to provide.

Additionally, Consumers requests that the Commission reject ELPC’s exception and adopt the ALJ’s recommendation because it reflects the agreement between the company and the Staff.

According to Consumers, the “record demonstrates that the Company agreed to Staff’s proposal to open the General Primary Time-of-Use (‘GPTU’) Rate to solar standby service for a pilot period.” *Id.*, p. 49. The company notes that the ALJ adopted the parties’ agreement, with the condition that Consumers provide an evaluation of the ongoing pilot in each subsequent rate case. Consumers does not believe that an evaluation is necessary in every future rate case, but agrees to a review “at some time during the term of the pilot program.” *Id.*

The Commission adopts the ALJ’s recommendation. The Commission finds persuasive Consumers’ and the Staff’s proposal that solar customers should retain eligibility to take service under TOU rates, but that it function as a pilot program for a minimum of five years. As stated by the company, a five-year pilot program will allow Consumers time to gather information regarding the impact of the rate design, evaluate the relevance of the rate, and ensure that there are no resulting cross subsidies. In addition, Consumers shall provide an evaluation of the pilot in each subsequent rate case, so that the parties may review the program and consider whether to recommend additional changes in the eligibility of standby customers for other rate schedules.

D. Customer-Specific Delivery Charge

For customers with at least 100 MWs of demand who are served on the company’s Primary Rate, Consumers requested that it be permitted to design a maximum demand charge that it claims reflects the cost of service. Consumers explained that for customers served on the Primary Rate, the company’s delivery charges, which are based on allocated distribution costs for the class, will collect a disproportionate amount of revenue from these customers because of the large electric load. The company proposed that:

the rate reflect an annual revenue requirement based on the original cost of the facilities, levelized over the asset life of the facilities in place to serve the customer. The delivery rate would also include Operation and Maintenance overheads at a level consistent with the costs other customers pay in that rate class. If the

Company makes additional investment to serve new load at the site, or if additional investment is required based on the customer's revised energy needs or requested changes, or Company overheads change, the rate could be revised in future rate cases.

10 Tr 2011-2012.

Although Hemlock acknowledged that the delivery charge was designed specifically for Hemlock, it requested that the charge be further reduced to remove a portion of the allocated overheads. 11 Tr 2097. Consumers agreed and provided Exhibit A-105 in response.

In Hemlock's opinion, based upon the charges set in the February 28 order, Hemlock pays distribution charges that are significantly out of line with the distribution costs incurred by Consumers to serve Hemlock. Hemlock argued that the customer-specific delivery charge should be "made available to customers whose distribution service from Consumers cannot be accurately priced at Consumers' GPD distribution rate even with a substation ownership credit." 11 Tr 2113. According to Hemlock, the proposed rate is cost-based, it complies with the February 28 order, it is specifically designed for large customers for whom Consumers has dedicated distribution facilities, and it appropriately compensates the company for its delivery service to Hemlock.

The Staff recommended that the Commission reject Consumers' proposed charge because the company failed to follow the directive in the February 28 order requiring the company to analyze issues related to a joint-ownership substation credit for Rate GPD. The Staff also noted that the language in Consumers' proposed tariff indicates that the rate is not for large customers, but is only available to customers whose load exceeds 100 MWs at any single site. According to the Staff, rates should be designed to recover costs for similarly-served customers. Because Hemlock is served by a company-owned substation at the distribution level, just like other customers on Rate GPD, Hemlock should be allocated similar distribution costs as those other customers on

Rate GPD. The Staff opined that the proposed delivery charge is not designed in a way that appropriately distinguishes Hemlock from its similarly-served peers.

The Staff argued that, even if Consumers is currently overrecovering from Hemlock, the overrecovery may not continue in the future. The Staff explained:

For example, a customer may be paying over their customer-specific cost of service because the assets used to serve the customer are fully depreciated, their service lines require little-to-no maintenance, or the customer pays their bill in full with no need for account services. But if [a] utility invests in infrastructure to serve that same, specific customer by upgrading distribution equipment, installing new metering, or performing vegetation management, then suddenly the customer will be paying less than their specific cost of service.

Staff's reply brief, pp. 21-22. In addition, the Staff asserted that at any given time, Consumers may be overrecovering from some customers and underrecovering from others. However, as the Staff explained above, in the long-run of rate design, the company will recover all costs to serve. Therefore, the Staff averred, a customer-specific delivery charge is unnecessary.

ABATE/Gerdau initially argued that Consumers' proposed delivery charge is discriminatory because it fails to explain why the charge is limited to "very large" customers. Accordingly, ABATE/Gerdau proposed that Consumers provide the delivery charge to any customer served from dedicated facilities. ABATE/Gerdau also alleged that the delivery charge lacks transparency because it is unclear how Consumers will calculate the levelized carrying charge rate associated with the dedicated facilities and what corresponding dedicated facilities and revenues relate to the proposed charge. ABATE/Gerdau's brief, pp. 34-35.

ABATE/Gerdau recommended that Hemlock's load should be removed from the Rate GPD class before allocating any of Consumers' 138 kilovolt (kV)-related costs to the Rate GPD class. Consumers agreed to adopt this recommendation.

Consumers disputed the Staff's claim that it did not comply with the February 28 order, stating that it explored some of the concerns raised by Hemlock and took measures to address several of the concerns. The company agreed with the Staff that, generally, a large load is not a sufficient distinguishing factor for a separate delivery charge. However, Consumers asserted that the charge is for "extraordinarily large" customers, and because Hemlock has a unique connection with the company, it justifies a customer-specific delivery charge.

In reply to ABATE/Gerdau, Consumers argued that there are many customers served from dedicated facilities and that it is not possible to offer a customer-specific delivery charge to a large number of customers. Additionally, Consumers contended that the charge applies equally to all customers meeting the size requirement and, therefore, it is not discriminatory. Consumers claimed that the cost detail for the delivery charge was provided in its COSS and explained that the charge would be based on the levelized cost of the company's investment in facilities directly serving the customer, plus the customer's share of O&M overheads. Consumers' reply brief, pp. 194-195.

The ALJ found persuasive the Staff's and ABATE/Gerdau's arguments and recommended rejecting Consumers' customer-specific delivery charge. According to the ALJ, the basis for the company's charge is not transparent and the proposed tariff language is especially open-ended. Also, the ALJ noted that Consumers failed to provide assurance that, if costs change, the rate would correspondingly change. In the ALJ's opinion, the burden would be on the Staff and other parties to monitor the relationship between Consumers and Hemlock to ensure that the charge is appropriate.

In exceptions, Consumers disputes the Staff's claim that the company failed to evaluate the issues regarding the joint-ownership substation credit for Rate GPD and that the company's charge

disregards “the nuance of dissecting the substation ownership credit.” Consumers’ exceptions, p. 137. Citing its testimony explaining the delivery charge, Consumers avers that the company followed the Commission’s directives and designed a charge that addresses the concerns of extraordinarily large customers. *Id.*, pp. 137-138.

In response to ABATE/Gerdau’s request that the charge apply to all Rate GPD customers that are served from dedicated distribution facilities, Consumers reiterates that a customer-specific charge for such a large number of customers would be impractical. Consumers also disagrees that the delivery charge is discriminatory because it applies to all customers who qualify for the rate.

In exceptions, ABATE/Gerdau state that, although it initially had concerns about Consumers’ proposal, as the proceedings concluded, ABATE/Gerdau was satisfied with the company’s explanation of the delivery charge calculation. ABATE/Gerdau assert that they “support[] the proposed customer-specific delivery charge, because ABATE is satisfied that the Company will implement it in a non-discriminatory, fully-transparent, cost-based, and revenue-neutral fashion. The most important facet of this support is that the customer-specific delivery charge be consistent with cost of service principles.” ABATE/Gerdau’s exceptions, p. 7.

ABATE/Gerdau dispute the Staff’s claim that any overrecovery from Hemlock will be offset by a future underrecovery when Consumers must invest in Hemlock’s dedicated facilities. According to ABATE/Gerdau, Hemlock provides most of the funding for its dedicated facilities, and, therefore, it is unreasonable to assume that, in the future, the funding responsibility will be transferred to the company and other ratepayers.

ABATE/Gerdau also note that, in its originally filed COSS, Consumers did not remove the Hemlock loads and the ALJ adopted this revenue allocation. Therefore, ABATE/Gerdau request

that the Commission reject the ALJ's recommendation and adopt a class revenue allocation that uses the appropriate COSS.

Hemlock takes exception, stating that, as Consumers' largest customer, the company's distribution charges must be adjusted to establish cost based delivery rates for Hemlock. According to Hemlock, the Staff "failed to analyze the impact of Consumers' existing distribution rates on HSC or the relationship of the costs recovered under those rates to Consumers' cost to provide service to HSC." Hemlock's exceptions, p. 6. Rather, Hemlock argues, the company's existing delivery charges overrecover Consumers' costs to provide delivery service to Hemlock.

Hemlock asserts that, according to the Staff:

[I]f Consumers' delivery rates plus the facilities agreement compensation from HSC over-recovers Consumers' costs to provide delivery service, then it is the facilities agreements that should be modified, not Consumers' delivery rates. . . . [The Staff] however, could not explain how HSC's facilities agreements with Consumers were not compliant, how HSC's facilities agreements with Consumers should have been any different, or how or whether the facilities agreements could now be modified.

Id. Hemlock contends that the Staff conceded that Consumers' delivery rates plus facilities agreements compensation should equal Consumers' cost to provide delivery service, and that unrecovered delivery costs, including those in facilities agreements, should be recovered in tariffed delivery rates.

In addition, Hemlock claims that the ALJ erred in determining that the customer-specific delivery charge is not transparent or flexible. Hemlock asserts that Consumers provided cost detail in the COSS and explained the delivery charge in testimony. And, Hemlock states that "[i]f Consumers' investment in facilities directly serving HSC change over time, so too, will the customer-specific delivery charge." *Id.*, p. 8. Regarding the ALJ's conclusion that the delivery

charge is arbitrary, Hemlock argues that the rate would apply to any Rate GPD customer with more than 100 MWs of demand at a single site served with dedicated distribution facilities.

Regarding ABATE/Gerdau's recommendation that Hemlock's load should be removed from Rate GPD before allocating any of Consumers' 138 kV-related costs to the Rate GPD class, Hemlock agrees, asserting that none of the company's 138 kV system is used to serve Hemlock. Therefore, Hemlock contends that its "load should not be utilized for purposes of allocating these delivery costs to the Primary class." *Id.* Hemlock requests that ABATE/Gerdau's proposed adjustment be incorporated in the final COSS supporting final rates in this case.

In its replies to exceptions, the Staff asserts that Consumers' decision to remove Hemlock's load from factors used to allocate transmission costs and include these costs in the customer-specific delivery charge does not fully address ABATE/Gerdau's concerns that the delivery charge is discriminatory and vague.

Regarding ABATE/Gerdau's claim that because Hemlock has invested to provide most of its own delivery facilities and that, accordingly, there is no reason to assume that the company and ratepayers will be responsible for Hemlock's facilities, the Staff argues that this is a truly unsupported factual claim. The Staff states that, "using ABATE's logic, there is also no reason to suppose that HSC would *not* put that responsibility on Consumers and, hence, all other ratepayers." Staff's replies to exceptions, p. 43. The Staff contends that Hemlock purchased premium upgrades to substations and some of its standard equipment, and as a result, Consumers' overrecovery is, in part, Hemlock's responsibility. In the Staff's opinion, "[t]ailoring rates for a single customer because of that customer's own investment choices is bad ratemaking." *Id.*, p. 45. As a result, the Staff encouraged the parties to settle this issue through their facilities agreement.

The Commission adopts the ALJ's recommendation. Although the Commission acknowledges the company's effort to comply with the February 28 order, the Commission agrees that the resulting customer-specific delivery charge is insufficiently transparent and not applicable to other customers. Therefore, to comply with the February 28 order, the Commission directs Consumers design a delivery charge addressing Hemlock's concerns, but that may also be provided to any customer served from dedicated facilities. In addition, the delivery charge must demonstrate Consumers' calculation of the levelized carrying charge rate associated with the dedicated facilities and the corresponding dedicated facilities and revenues related to the proposed charge.

Because the Commission declines to adopt the customer-specific deliver charge, the Commission finds that it is unnecessary to address ABATE/Gerdau's recommendation that Hemlock's load should be removed from the Rate GPD class before allocating any of Consumers' 138 kV-related costs to the Rate GPD class.

E. Commercial and Industrial Customer Rate Design

Although MEC/NRDC/SC support the use of DR programs, MEC/NRDC/SC requested that the costs of the DR program be collected only from program participants, "either as an explicit charge or an offset to any rate benefits that are provided to program participants for their participation." 9 Tr 1606. MEC/NRDC/SC argued that, if Consumers charges program costs to participating customers, the program will be self-funded in a way that reflects participation. According to MEC/NRDC/SC, if there is less participation in the program than the company expects, Consumers will not benefit from excess cost recovery; if there is greater than expected participation, the company will not experience a shortfall and, as a result, will be forced to limit the program. MEC/NRDC/SC contended that the total benefit of the DR program to Consumers

and its customers is the difference between the avoided capacity costs and the costs of marketing and operating the program.

Consumers agreed with MEC/NRDC/SC that the net benefit to all customers is the difference between the avoided capacity costs and the costs of marketing and operating the DR program. However, the company disagrees with MEC/NRDC/SC that the credit to customers participating in the program is greater than the cost of marketing and operating the program. Consumers explained that the company's capacity credit is based on the market value of a MW of power purchased in the MISO market for a particular planning year. Conversely, Consumers stated, the market value of a MW of capacity purchased in the MISO market is exactly the same, regardless of the source, including DR. Consumers averred that it uses market prices as a reference points when constructing its portfolio and fulfills its capacity obligation with resources of different types at or below the competitive market price. 9 Tr 1546. Therefore, Consumers argued that DR program participants are compensated for the market price of the avoided capacity.

Contrary to MEC/NRDC/SC's interpretation, the Staff stated that the benefits of DR, specifically avoided capacity costs, are realized by all customers and cannot be assigned to one customer type. The Staff asserted that Consumers provides all customers with capacity, "regardless of whether those resources are supply-side or demand-side." 11 Tr 2243. Additionally, the Staff argued that, because DR customers are both a utility customer and a capacity resource, rates must be designed accordingly. The Staff contended that DR customers should receive both the benefits of their resource as a customer and the benefits of providing a capacity resource. If, as MEC/NRDC/SC proposed, "rates are designed to include all of the net benefits of DR, then it both ignores the practical use of DR as a capacity resource for all customers and it distorts the DR customer's compensation for the value of their resource." *Id.*

The ALJ determined that “the parties are miscommunicating on this issue.” PFD, p. 329. She noted that both Consumers and MEC/NRDC/SC agree that the net benefit to customers is the difference between the avoided costs and the costs of marketing and operating the DR program. Therefore, the ALJ asserted, the program participants should receive a credit based on the avoided costs less the costs of operating the program. The ALJ recommended that the Commission direct Consumers to ensure that the credits to program participants not exceed the net benefits to customers, after considering enrollment and operating expenses. In addition, the ALJ recommended that Consumers be required to demonstrate in its next rate case that ratepayers benefitted from the program, less enrollment and operating costs.

Consumers disagrees, asserting that the ALJ’s recommendation for a benefit-cost analysis is unreasonable and that she mistakenly found that the benefits of the program should be limited to when an actual DR event occurs. The company argues that, “[t]his fails to recognize how the program is structured and the importance of customer participation.” Consumers’ exceptions, p. 141.

In exceptions, the Staff also asserts that the ALJ misunderstood its position. According to the Staff,

The ALJ correctly found that the benefits of the demand response program should include offsets for program costs; however . . . Staff’s position is that credits should be paid to demand response program participants so long as there is a net benefit to customers, meaning only if the program is beneficial to all customers. Importantly, the credits paid to demand response program participants should not be calculated using only the overall net benefit to all customers.

Staff’s exceptions, p. 6. The Staff reiterates that the net-benefits analysis should not determine the credit paid to DR customers; rather, the credit paid to DR customers should inform the net-benefits analysis. *Id.*, p. 7. Therefore, the Staff states, the Commission should reject the ALJ’s

recommendation that the DR credit be based on the benefits accrued to all customers, offset by enrollment and program costs.

In reply to Consumers, MEC/NRDC/SC argue that a benefit-cost analysis is reasonable “because ensuring and demonstrating the cost-effectiveness of capacity resource investments, including in demand response, is inherent in just and reasonable rates.” MEC/NRDC/SC’s replies to exceptions, p. 53. Regarding the Staff’s exception, MEC/NRDC/SC states that the Staff’s position seems inconsistent with the PFD, which, according to MEC/NRDC/SC, did not recommend restructuring the program incentive payments. MEC/NRDC/SC asserts that the ALJ actually recommended that, “however the incentive payments are calculated, they should not exceed the net benefits to customers, considering enrollment and other costs. Staff appears to concur.” *Id.*, p. 54 (note omitted).

The Commission finds persuasive the Staff’s position on this issue. The Commission agrees that the benefits of DR, specifically avoided capacity costs, are realized by all customers and cannot be credited to a single customer class. In addition, DR customers should receive both the benefits of their resource as a customer and the benefits of providing a capacity resource. Credits should be paid to DR program participants provided that there is a net benefit to all customers. However, the Commission finds that the credits paid to DR program participants should not be calculated using only the overall net benefit to all customers.

The Commission declines to adopt the ALJ’s recommended benefit-cost analysis because the rates, participation, and the benefits and costs of Consumers’ DR program will be evaluated pursuant to the three-phase approach adopted in the September 15, 2017 order in Case No. U-18369.

F. Advanced Metering Opt-Out Charges

1. Consumers Energy Company's Request to Revise Tariff Language

Consumers requested a revision to the following AMI tariff language: "Customers electing a non-transmitting meter will pay the following charges per premises" Exhibit A-11, page 7. The company stated that the current language is too vague and that it is impractical to apply one opt-out charge to a single premises because this provision could be applied to an apartment complex or any location with a bank of meters. Consumers explained that the current language could permit a single customer to opt-out, thus affecting multiple other customers at a location who may want AMI meters. In addition, the company asserted that a customer with multiple accounts may wish to retain their legacy meters and, therefore, each meter, regardless of proximity, should be assessed an opt-out charge to contribute to the cost of maintaining the opt-out program.

The Staff both supports and opposes Consumers' request. The Staff "agrees that it is reasonable to apply the up-front charge by billing meter, because the costs included in that charge are specific to the installation of the legacy meter." 11 Tr 2350. However, the monthly charge is based on the meter reading and testing costs, which are linked to the number of customers, rather than the number of meters. As a result, the Staff recommended that the monthly charge continue to be applied by premises.

The ALJ recommended that the Commission approve the Staff's proposal to modify the tariff so that it is clear that the up-front charge is to be applied by meter. She stated that this modification seems to satisfy Consumers' request that multi-unit dwellings be excluded. However, she stated that any other revision, including the monthly meter-reading charge, should

be postponed until the charges for the opt-out tariff are reconsidered and the Commission can ensure consistency between the monthly charges and monthly costs.

No exceptions were filed on this issue and, therefore, the Commission adopts the ALJ's recommendation.

2. Consumers Energy Company's Request to Delay Opt-out Tariff Charge Revisions

Pursuant to the February 28 order, Consumers was required to recalculate the AMI opt-out charges in its next rate case filed after full deployment or in a contested case filed six months following full deployment, whichever occurs sooner. The company noted that full deployment was not complete until August 2017, almost five months after this rate case was filed. Consumers requested that the filing of an updated opt-out charge be deferred until the company's next rate case. In the company's opinion, a rate case, rather than a separate contested proceeding, is the best forum to update AMI charges so that rate case test year meter reading and AMI capital and investment expenses may be used.

No party objected to Consumers' request and the ALJ deferred to the Commission's discretion.

In exceptions, Consumers reiterates its request that the Commission permit the company to defer its review of the AMI opt-out tariff to its next general rate case.

On page 9 of its replies to exceptions, the RCG objects to Consumers' request stating that "There should be a definite commitment to carrying through with this promise as stated in the Commission's previous orders which should not be delayed or buried in a future rate case which may not be filed for years."

The Commission finds Consumers' request reasonable and grants its approval. However, the Commission would like to be clear that no further requests for deferral will be granted.

THEREFORE, IT IS ORDERED that:

A. Based on this order's findings adopting an October 1, 2017 through September 30, 2018 test year, a jurisdictional rate base of \$10,202,174,000, an authorized rate of return on common equity of 10.00%, and an overall rate of return of 5.89%, Consumers Energy Company is authorized to implement rates that increase its annual electric revenues by \$65,760,000 on a jurisdictional basis over the rates approved on February 28, 2017, in Case No. U-17990.

B. Consumers Energy Company is authorized to implement the rates approved by this order on a service rendered basis for service provided on and after April 1, 2018, as summarized in Attachment A, and set forth in Attachment B. Within 30 days of the date of this order, Consumers Energy Company shall file tariff sheets substantially similar to those contained in Attachment B. When filing the tariffs consistent with those ordered, Consumers Energy Company shall also update the Contribution In Aid of Construction Allowance Schedule amounts on Tariff Sheet C-3.10, Section C1.4 to be consistent with the rates approved in this order. Due to the size of Attachment B, it is not physically attached to the original order contained in the official docket or paper copies of the order, but is electronically appended to this order, which is available on the Commission's website. Attachment C contains a calculation of the capacity charge as updated by this order.

C. On or before July 30, 2018, Consumers Energy Company shall file an application for authority to conduct a self-implementation reconciliation proceeding as required under MCL 460.6a.

D. In its next general rate case, Consumers Energy Company shall provide more evidentiary support for loading rates, indirect, and overhead costs, as set forth in the order.

E. In its next general rate case, Consumers Energy Company shall provide a detailed benefit-cost analysis regarding the company's utilization of working capital and short-term debt facilities.

F. In its integrated resource plan proceeding, Consumers Energy Company shall provide a standalone analysis evaluating various retirement scenarios for D.E. Karn Units 1 and 2 and J. H. Campbell Units 1 and 2 as set forth in the order.

G. In its next general rate case, Consumers Energy Company shall provide additional information regarding cost savings measures, as well as a quantification of any savings resulting from initiatives focused on operations and maintenance cost reductions.

H. In the event that Consumers Energy Company makes a material change to its calculation of pension or other post-employment benefits costs that might affect the revenues or costs in a pending rate case, the company shall inform the Commission Staff in a timely manner.

I. In its next general rate case, Consumers Energy Company shall submit tariffs that reflect the elimination of the 600 kilowatt-hour summer monthly block, replaced with a summer on-peak/off-peak rate as set forth in the order. The company shall also include a proposal for allowing customers who opt out of advanced metering infrastructure to retain the existing rate structure.

J. In its next general rate case, Consumers Energy Company shall provide actual and projected peak metered demand billing determinants for Rate GSG-2 customers, including any ratchet that would be applied. In addition, if the company chooses to rely on contracted demand, Consumers Energy Company shall provide justification for its departure from the standardized framework.

K. Consumers Energy Company shall establish a five-year pilot program under Rate GSG-2, and it shall present an evaluation of the ongoing pilot in each of its subsequent rate cases, so that

the parties can consider whether to recommend additional changes in the eligibility of standby customers for other rate schedules.

L. In its next general rate case, Consumers Energy Company may submit a tariff for a substation joint ownership delivery charge that may be provided to any customer served from dedicated facilities. If proposed, the delivery charge must include a calculation of the levelized carrying charge rate associated with the dedicated facilities and the corresponding dedicated facilities and revenues related to the proposed charge.

M. By April 30, 2018, Consumers Energy Company shall file a Credit A application in Case No. U-20102, as provided in the February 22, 2018 order in Case No. U-18494.

N. Consumers Energy Company's accounting requests are addressed as set forth in the order.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, under MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General - Public Service Division at pungpl@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION



Sally A. Talberg, Chairman



Norman J. Saari, Commissioner



Rachael A. Eubanks, Commissioner

By its action of March 29, 2018.



Kavita Kale, Executive Secretary

MICHIGAN PUBLIC SERVICE COMMISSION

Schedule F-2

Case No.: U-18322
ATTACHMENT A
Page 1 of 3

Consumers Energy Company

Summary of Present and Proposed Revenues by Rate Schedule

Total Revenues

Line No.	Description	(a) Sales MWh	(b) Present Revenue \$000	(c) Proposed Revenue \$000	(d) Difference Revenue \$000	(e) Percent %
Bundled Service						
Residential Class						
1	Residential Service RS	12,053,207	\$ 1,885,890	\$ 1,930,027	\$ 44,337	2.4
2	Residential Time-of-Day RT	55,778	7,508	7,772	263	3.5
3	Residential Electric Vehicle REV	10,001	1,448	1,481	33	2.3
4	Res. Dynamic Price RSDP	-	-	-	-	NA
5	Res. Dynamic Price Rebate RSDPR	-	-	-	-	NA
6	Total Residential Class	12,118,986	1,894,646	1,939,279	44,634	2.4
Secondary Class						
7	Secondary Energy-only GS	3,802,549	539,921	547,333	7,412	1.4
8	Sec. Energy Dynamic Price GSDP	-	-	-	-	NA
9	Secondary Demand GSD	3,551,171	461,254	490,112	28,857	6.3
10	Secondary Energy-only GS TOU	-	-	-	-	NA
11	Total Secondary Class	7,153,720	1,001,175	1,037,444	36,269	3.6
Primary Class						
12	Primary Energy-only GP	1,356,398	156,743	160,610	3,867	2.5
13	Primary Demand GPD	11,497,488	968,432	950,368	(18,064)	(1.9)
	Standard Service	10,376,360	846,995	832,983	(14,013)	(1.7)
	Education GEI	346,427	37,822	37,588	(234)	(0.6)
	Interruptible GI	774,700	83,614	79,797	(3,817)	(4.6)
14	Primary Energy Intensive Rate EIP	255,121	16,719	16,401	(318)	(1.9)
15	Primary Time of Use Pilot GPTU	303,937	29,609	29,107	(502)	(1.7)
16	Total Primary Class	13,412,943	1,171,503	1,156,486	(15,017)	(1.3)
Lighting & Unmetered Class						
17	Metered Lighting Service GML	18,204	2,024	2,155	131	6.5
18	Unmetered Lighting Service GUL	123,389	29,750	31,529	1,779	6.0
19	Unmetered Exp. Lighting GU-XL	14	2	1,418	1,416	NA
20	Unmetered Service GU	85,150	7,729	7,982	253	3.3
21	Total Lighting & Unmetered Class	226,757	39,504	43,084	3,580	9.1
Self-generation Class						
22	Small Self-generation GSG-1	27,481	-	-	-	NA
23	Large Self-generation GSG-2	33,144	5,047	1,917	(3,130)	NA
24	Total Self-Generation Class	60,624	5,047	1,917	(3,130)	NA
25	Total Bundled Service	32,973,030	\$ 4,111,875	\$ 4,178,210	\$ 66,335	1.6
ROA Service						
Residential Class						
26	Residential Service RS	-	\$ -	\$ -	\$ -	NA
27	Residential Time-of-Day RT	-	-	-	-	NA
28	Total Residential Class	-	-	-	-	NA
Secondary Class						
29	Secondary Energy-only GS	23,636	1,015	1,027	11	1.1
30	Secondary Demand GSD	213,651	6,998	8,082	1,083	15.5
	Standard Service	146,896	4,777	5,522	745	15.6
	Education GEI	66,756	2,222	2,560	338	15.2
31	Total Secondary Class	237,287	8,014	9,108	1,094	13.7
Primary Class						
32	Primary Energy-only GP	67,215	1,315	1,173	(142)	(10.8)
33	Primary Demand GPD	3,855,694	24,325	21,471	(2,854)	(11.7)
	Standard Service	3,613,285	20,980	18,568	(2,412)	(11.5)
	Voltage Level 1	1,177,791	2,316	2,163	(153)	(6.6)
	Voltage Level 2	1,412,217	5,771	5,293	(478)	(8.3)
	Voltage Level 3	1,023,277	12,893	11,113	(1,780)	(13.8)
	Education GEI	242,408	3,345	2,903	(442)	(13.2)
	Voltage Level 1	2,995	17	16	(1)	(5.8)
	Voltage Level 2	78,484	396	357	(39)	(9.9)
	Voltage Level 3	160,930	2,932	2,530	(402)	(13.7)
34	Total Primary Class	3,922,909	25,640	22,644	(2,996)	(11.7)
35	Total ROA Service	4,160,196	\$ 33,654	\$ 31,752	\$ (1,902)	(5.7)
36	Total Bundled and ROA Service	37,133,226	\$ 4,145,529	\$ 4,209,962	\$ 64,433	1.6

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: UI-18322
ATTACHMENT A
Page 2 of 3

Consumers Energy Company

Summary of Present and Proposed Revenues by Rate Schedule

Power Supply Revenues

Line		(a)	(b)	(c)	(d)	(e)
No.	Description	Sales	Present Revenue	Proposed Revenue	Difference Revenue	Difference Percent
		MWh	\$000	\$000	\$000	%
Bundled Service						
Residential Class						
1	Residential Service RS	12,053,207	\$ 1,203,479	\$ 1,210,980	\$ 7,500	0.6
2	Residential Time-of-Day RT	55,778	4,732	4,823	92	1.9
3	Residential Electric Vehicle REV	10,001	909	911	2	0.3
4	Res. Dynamic Price RSDP	-	-	-	-	NA
5	Res. Dynamic Price Rebate RSDPR	-	-	-	-	NA
6	Total Residential Class	12,118,986	1,209,120	1,216,714	7,594	0.6
Secondary Class						
7	Secondary Energy-only GS	3,602,549	341,944	347,753	5,809	1.7
8	Sec. Energy Dynamic Price GSDP	-	-	-	-	NA
9	Secondary Demand GSD	3,551,171	335,092	345,939	10,847	3.2
10	Sec. Demand Dynamic Price GSDDP	-	-	-	-	NA
11	Total Secondary Class	7,153,720	677,037	693,692	16,655	2.5
Primary Class						
12	Primary Energy-only GP	1,356,398	129,128	135,846	6,719	5.2
13	Primary Demand GPD	11,497,488	884,469	878,590	(5,879)	(0.7)
	Standard Service	10,376,360	778,691	774,908	(3,784)	(0.5)
	Education GEI	346,427	32,581	33,028	446	1.4
	Interruptible GI	774,700	73,197	70,655	(2,542)	(3.5)
14	Primary Energy Intensive Rate EIP	255,121	14,653	14,512	(141)	(1.0)
15	Primary Time of Use Pilot GPTU	303,937	25,478	25,542	64	0.3
16	Total Primary Class	13,412,943	1,053,728	1,054,490	763	0.1
Lighting & Unmetered Class						
17	Metered Lighting Service GML	18,204	982	948	(34)	(3.4)
18	Unmetered Lighting Service GUL	123,403	6,485	5,619	(867)	(13.4)
19	Unmetered Exp. Lighting GU-XL	14	1	273	272	36,754.0
20	Unmetered Service GU	85,150	6,443	6,524	81	1.3
21	Total Lighting & Unmetered Class	226,771	13,911	13,364	(547)	(3.9)
Self-generation Class						
22	Small Self-generation GSG-1	-	-	-	-	NA
23	Large Self-generation GSG-2	33,144	2,982	-	(2,982)	(100.0)
24	Total Self-Generation Class	33,144	2,982	-	(2,982)	(100.0)
25	Total Bundled Service	32,945,563	\$ 2,956,777	\$ 2,978,260	\$ 21,484	0.7
ROA Service						
Residential Class						
26	Residential Service RS	-	\$ -	\$ -	\$ -	NA
27	Residential Time-of-Day RT	-	-	-	-	NA
28	Total Residential Class	-	-	-	-	NA
Secondary Class						
29	Secondary Energy-only GS	23,636	-	-	-	NA
30	Secondary Demand GSD	213,651	-	-	-	NA
	Standard Service	146,896	-	-	-	NA
	Education GEI	66,756	-	-	-	NA
31	Total Secondary Class	237,287	-	-	-	NA
Primary Class						
32	Primary Energy-only GP	67,215	-	-	-	NA
33	Primary Demand GPD	3,855,694	-	-	-	NA
	Standard Service	3,613,285	-	-	-	NA
	Voltage Level 1	1,177,791	-	-	-	NA
	Voltage Level 2	1,412,217	-	-	-	NA
	Voltage Level 3	1,023,277	-	-	-	NA
	Education GEI	242,408	-	-	-	NA
	Voltage Level 1	2,995	-	-	-	NA
	Voltage Level 2	78,484	-	-	-	NA
	Voltage Level 3	160,930	-	-	-	NA
34	Total Primary Class	3,922,909	-	-	-	NA
35	Total ROA Service	4,160,196	\$ -	\$ -	\$ -	NA
36	Total Bundled and ROA Service	37,105,759	\$ 2,956,777	\$ 2,978,260	\$ 21,484	0.7

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-18322
ATTACHMENT A
Page 3 of 3

Consumers Energy Company

Summary of Present and Proposed Revenues by Rate Schedule

Delivery Revenues

Line No.	Description	(a) Sales MWh	(b) Present Revenue \$000	(c) Proposed Revenue \$000	(d) Difference Revenue \$000	(e) Difference Percent %
Bundled Service						
Residential Class						
1	Residential Service RS	12,053,207	\$ 682,210	\$ 719,047	\$ 36,837	5.4
2	Residential Time-of-Day RT	55,778	2,777	2,948	172	6.2
3	Residential Electric Vehicle REV	10,001	539	570	31	5.7
4	Res. Dynamic Price RSDP	-	-	-	-	NA
5	Res. Dynamic Price Rebate RSDPR	-	-	-	-	NA
6	Total Residential Class	12,118,986	\$ 685,526	722,565	37,039	5.4
Secondary Class						
7	Secondary Energy-only GS	3,602,549	197,977	199,580	1,603	0.8
8	Sec. Energy Dynamic Price GSDP	-	-	-	-	NA
9	Secondary Demand GSD	3,551,171	126,162	144,172	18,011	14.3
10	Sec. Demand Dynamic Price GSDDP	-	-	-	-	NA
11	Total Secondary Class	7,153,720	324,139	343,752	19,614	6.1
Primary Class						
12	Primary Energy-only GP	1,356,398	27,615	24,764	(2,852)	(10.3)
13	Primary Demand GPD	11,497,488	83,963	71,778	(12,185)	(14.5)
	Standard Service	10,376,360	68,304	58,075	(10,229)	(15.0)
	Education GEI	346,427	5,241	4,560	(681)	(13.0)
	Interruptible GI	774,700	10,418	9,143	(1,275)	(12.2)
14	Primary Energy Intensive Rate EIP	255,121	2,066	1,889	(177)	(8.6)
15	Primary Time of Use Pilot GPTU	303,937	4,131	3,565	(566)	(13.7)
16	Total Primary Class	13,412,943	117,775	101,996	(15,780)	(13.4)
Lighting & Unmetered Class						
17	Metered Lighting Service GML	18,204	1,042	1,206	165	15.8
18	Unmetered Lighting Service GUL	123,389	23,264	25,910	2,646	11.4
19	Unmetered Exp. Lighting GULXL	14	1	1,145	1,144	85,771.0
20	Unmetered Service GU	85,150	1,286	1,458	173	13.4
21	Total Lighting & Unmetered Class	226,757	25,593	29,720	4,127	16.1
Self-generation Class						
22	Small Self-generation GSG-1	-	-	-	-	NA
23	Large Self-generation GSG-2	33,144	2,065	1,917	(148)	(7.2)
24	Total Self-Generation Class	33,144	2,065	1,917	(148)	(7.2)
25	Total Bundled Service	32,945,549	\$ 1,155,099	\$ 1,199,950	\$ 44,851	3.9
ROA Service						
Residential Class						
26	Residential Service RS	-	\$ -	\$ -	\$ -	NA
27	Residential Time-of-Day RT	-	-	-	-	NA
28	Total Residential Class	-	-	-	-	NA
Secondary Class						
29	Secondary Energy-only GS	23,836	1,015	1,027	11	1.1
30	Secondary Demand GSD	213,651	6,998	8,082	1,083	15.5
	Standard Service	146,896	4,777	5,522	745	15.6
	Education GEI	66,756	2,222	2,560	338	15.2
31	Total Secondary Class	237,287	8,014	9,108	1,094	13.7
Primary Class						
32	Primary Energy-only GP	67,215	1,315	1,173	(142)	(10.8)
33	Primary Demand GPD	3,855,694	24,325	21,471	(2,854)	(11.7)
	Standard Service	3,613,285	20,980	18,568	(2,412)	(11.5)
	Voltage Level 1	1,177,791	2,316	2,163	(153)	(6.6)
	Voltage Level 2	1,412,217	5,771	5,293	(478)	(8.3)
	Voltage Level 3	1,023,277	12,893	11,113	(1,780)	(13.8)
	Education GEI	242,408	3,345	2,903	(442)	(13.2)
	Voltage Level 1	2,995	17	16	(1)	(5.8)
	Voltage Level 2	78,484	396	357	(39)	(9.9)
	Voltage Level 3	160,930	2,932	2,530	(402)	(13.7)
34	Total Primary Class	3,922,909	25,640	22,644	(2,996)	(11.7)
35	Total ROA Service	4,160,196	\$ 33,654	\$ 31,752	\$ (1,902)	(5.7)
36	Total Bundled and ROA Service	37,105,745	\$ 1,188,753	\$ 1,231,702	\$ 42,949	3.6

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. A-5.00

INDEX

(Continued From Sheet No. A-4.00)

**SECTION D
RATE SCHEDULES (Contd)**

	<u>Sheet No.</u>
RESIDENTIAL SERVICE SECONDARY RATE RS	D-9.00
RESIDENTIAL DYNAMIC PRICING PROGRAM	D-13.00
EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM	D-13.10
RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT	D-14.00
GENERAL SERVICE SECONDARY RATE GS	D-18.00
GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU	D-21.10
GENERAL SERVICE SECONDARY DEMAND RATE GSD	D-22.00
GENERAL SERVICE PRIMARY RATE GP	D-27.00
LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD	D-31.00
GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU	D-36.10
ENERGY INTENSIVE PRIMARY RATE EIP	D-37.00
EXPERIMENTAL ADVANCED RENEWABLE PROGRAM AR	D-40.01
EXPERIMENTAL ADVANCED RENEWABLE PROGRAM - ANAEROBIC DIGESTION PROGRAM (AD Program)	D-40.02
GENERAL SERVICE SELF GENERATION RATE GSG-2	D-42.00
GENERAL SERVICE METERED LIGHTING RATE GML	D-46.00
GENERAL SERVICE UNMETERED LIGHTING RATE GUI	D-50.00
GENERAL SERVICE UNMETERED RATE GU	D-54.10
POLE ATTACHMENT AND CONDUIT USE RATE PA	D-57.10

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. C-3.10

(Continued From Sheet No. C-3.00)

C1. CHARACTERISTICS OF SERVICE (Contd)**C1.4 Extraordinary Facility Requirements and Charges (Contd)**

Contribution In Aid of Construction Allowance Schedule							
Schedule	Customer Voltage Level(CVL)	With a Full Service Contract, by Contract Duration					Without Full Service Contract
		1 Year	2 Year	3 Year	4 Year	5 Year	
General Service Primary Rate GP	1	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh
	2	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh
	3	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh
Large General Service Primary Demand Rate GPD	1	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh
	2	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh
	3	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh
General Service Primary Time-of-Use Rate GPTU	1	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh
	2	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh
	3	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh
Energy Intensive Primary Rate EIP	1	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh
	2	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh
	3	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh	\$X.XX /kWh

The Company reserves the right to make special contractual arrangements as to the provision of necessary Service Facilities, duration of contract, minimum bills, require upfront deposit and other service conditions, including, but not limited to, when the customer's load requirements are of a short-term duration, temporary or a transient nature, or if in the opinion of the Company, the customer does not have acceptable credit history or represents an unacceptable credit risk or other reasons within the sound discretion of the Company.

C1.5 Invalidity of Oral Agreements or Representations

When a written contract is required, no employee or agent of the Company is authorized to modify or supplement the Rules and Regulations and Rate Schedules of the Electric Rate Book by oral agreement or representation, and no such oral agreement or representation shall be binding upon the Company.

(Continued on Sheet No. C-4.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. C-4.00

(Continued From Sheet No. C-3.00)

C1. CHARACTERISTICS OF SERVICE (Contd)

C1.6 General Provisions of Service

A. Service Requirements

The customer is required, at no expense to the Company: (a) to provide space for Company facilities on the customer's premises to meet the customer's needs for service, and (b) to allow the Company to trim, cut down, remove, or otherwise prevent future growth of trees and brush on the customer's premises that, in the Company's discretion, interfere or threaten to interfere with or be hazardous to the construction, operation and maintenance of the Company's facilities. Company facilities shall be utilized in accordance with the provisions of this Electric Rate Book.

The Company shall install service connections from its distribution lines to a suitable point of attachment on the customer's premises designated by the Company. Where the customer requests a point of attachment other than that specified by the Company, the additional cost resulting therefrom shall be borne by the customer.

Service Facilities shall be installed subject to the provisions and charges specified in Rule C4.5, Mobile Home Park - Individually Served or Rule C6., Distribution Systems, Line Extensions and Service Connections.

When relocation or modification of Company facilities is requested or made necessary by the customer, for reasons other than anticipated increases in energy use, all costs for the relocation or modification may be charged to the party responsible for changes. Relocation or modification necessary to accommodate load additions or changes in service characteristics are governed by Rule C6., Distribution Systems, Line Extensions and Service Connections.

Modification to existing residential, commercial or industrial overhead distribution and service lines involving conversion of such facilities to underground shall be done if requested by the customer(s) being directly served by those facilities. Prior to any work by the Company, the customer(s) shall fulfill all customer requirements, including, but not limited to, payment of estimated charges, submission of easement or permits or other documents showing that legal requirements are satisfied. The requesting customer(s) shall pay the depreciated cost of the existing overhead facilities plus the cost of removal less the salvage value thereof, and make a contribution in aid of construction equal to the estimated difference in cost between new underground and new overhead facilities including, but not limited to, the costs of breaking and repairing streets, walks, parking lots, and driveways, and of repairing lawns and replacing grass, shrubs and flowers.

Should it become necessary for any cause beyond the Company's control to change the location of the point of attachment of service connections, the entire cost of any necessary changes in the customer's wiring shall be borne by the customer.

All service entrances shall comply with the National Electrical Code and/or local electrical codes, whichever governs. Any poles, wires or other equipment required beyond the customer's meter shall be furnished, installed and maintained by the customer. The customer is responsible for obtaining all permits and inspections of customer's wiring or equipment required by applicable law. Service shall be denied for failure to obtain such permits or inspections.

All residential customers shall install three-wire service entrance connections of not less than 100 Ampere capacity, except as required with premanufactured mobile homes.

(Continued on Sheet No. C-5.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. C-21.00

(Continued From Sheet No. C-20.00)

C4. APPLICATION OF RATES (Contd)

C4.3 Application of Residential Usage and Non-Residential Usage (Contd)

A. Residential Usage and Rate Application (Contd)

(2) Private Family Dwellings

Private family dwellings, where individual household usage is separately metered and consumed, shall be billed on a Residential Service Rate. All newly constructed private family dwellings shall have separately metered households. A private family dwelling shall include:

- (a) a single-family home
- (b) a farm home
- (c) a seasonal dwelling
- (d) a duplex
- (e) a separately metered mobile home
- (f) a separately metered household within a condominium
- (g) a separately metered household within an apartment complex
- (h) a separately metered household within a cooperative complex

(3) Homes or Dormitories for Groups Other Than Private Family Dwellings

Tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons where residential usage is metered and consumed shall be classified as residential and billed on a Residential Service Rate. The landlord and his/her immediate family are not included in the six-person limitation.

(4) Multifamily Dwellings

(a) General

A "multifamily dwelling" shall be considered any duplex, apartment building, mobile home park, condominium, cooperative or other grouping of households. All newly constructed multifamily dwellings shall have separately metered households. The requirement for separately metered households may be waived at the request of the developer in cases where newly constructed or rehabilitated duplexes, apartment buildings and other multifamily dwellings are owned by a nonprofit corporation or "flow-through entity," which have a long-term regulatory agreement with the Michigan State Housing Development Authority, the United States Department of Housing and Urban Development or the United States Department of Agriculture to provide affordable housing for qualifying low-income residents. Separately metered households shall be required in the event the property is no longer subject to such regulatory agreement; the owner must notify Consumers Energy and all costs associated with conversion from a single metered facility to separately metered multifamily dwellings shall be the responsibility of the property owner. Any spaces within the development used for commercial purposes shall be separately metered by Consumers Energy.

(b) Common Area Usage in Multifamily Dwellings Containing Separately Metered Households

Common area usage, excluding mobile home parks, shall be metered and billed as follows:

- (i) Dwellings containing less than five households shall be separately metered and billed on a Residential Service Rate. When the landlord lives in one of the units, the common area usage may be metered and billed through the landlord's meter.
- (ii) Dwellings containing five or more households shall be separately metered and billed on the appropriate General Service Rate.

Common area usage in mobile home parks shall be separately metered and billed on the appropriate General Service Rate.

(Continued on Sheet No. C-22.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. C-23.00

(Continued From Sheet No. C-22.00)

C4. APPLICATION OF RATES (Contd)

C4.3 Application of Residential Usage and Non-Residential Usage (Contd)

C. Combined Residential and Non-Residential Usage and Rate Application

When the electricity supplied to a customer is used for both residential and Non-Residential purposes, the wiring may be so arranged that the residential and Non-Residential usage are metered separately. Each type of usage shall be billed on the appropriate Rate Schedule. If the usage is not separately metered, the *Company* shall *determine* the appropriate Rate *Schedule for billing based on the customer's usage*.

D. Rate Application for Seasonal Condominium Campgrounds

When the electricity supplied to a customer is used for Seasonal Condominium Campgrounds, the usage shall be considered Non-Residential and shall be billed on the *Company's* appropriate General Service Rate. To be considered a Seasonal Condominium Campground, the following conditions must exist:

- (1) The property must, in total or in part, be owned by a single legal entity, such as an Association, who must have primary operational responsibility for the property.
- (2) The legal entity with ownership and operating responsibility must be subject to licensing provisions under Act 368 of 1978 of the State of Michigan, specifically that required for operation of a campground or its equivalent.
- (3) All components of the property must be subject to limitations of occupancy of six months or less.
- (4) No individual owning such property in part or in total may claim such property as their Principal Residence.
- (5) Units allowed within the park are restricted to those classified by law as a Camping Trailer, Travel Trailer, Camping Cabin, or Park Model Recreational Unit by Act 206 of 1893 and 368 of 1978.

In the absence of any of these conditions, the *Company* shall classify the customer as residential or Non-Residential, based on the criteria in other portions of this Rule. The customer shall then be required to take service consistent with the requirements of that classification and bear any expenses to be incurred in meeting such requirements, or be subject to shutoff of service by the *Company*.

Customers that meet the above conditions may be served by individual meters or by a single metering installation, but must adhere to the following conditions in cases where individual metering by the *Company* is not applicable.

- (1) The customer's facilities may not be constructed so as to cross public streets, alleys, or rights-of-way.
- (2) The customer's facilities for each unit shall not exceed 50 amps. Should the customer desire service above 50 amps for any unit, they shall request service from the *Company* and pay all costs incurred by the *Company* in supplying such service.
- (3) If the customer uses meters or similar measuring devices on his/her side of the *Company's* point of attachment to his/her facilities, then the customer is required to take service under the resale provision included in one of the *Company's* General Service Rate Schedules, GS, GP, or GPD, and is subject to Rule C4.4, Resale.
- (4) The customer must, at his/her own expense, have the electrical facilities initially installed and periodically inspected, every five years at a minimum, by a licensed electrical contractor. In the event that it is determined that the installation is unsafe, the customer shall modify the system at his/her own expense using a licensed electrical contractor.

(Continued on Sheet No. C-24.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. C-24.00

(Continued From Sheet No. C-23.00)

C4. APPLICATION OF RATES (Contd)**C4.3 Application of Residential Usage and Non-Residential Usage (Contd)****D. Rate Application for Seasonal Condominium Campgrounds (Contd)**

- (5) The customer must notify individuals and/or co-owners utilizing the customer's property that the customer's facilities may not be able to be located by Miss Dig.
- (6) The customer must notify individuals and co-owners utilizing the customer's property that requests and concerns regarding electric service will be addressed between the single legal entity and ownership and primary operating authority, not with individuals.
- (7) The customer shall be responsible for ensuring that the electrical facilities are adequate to meet the needs of the units placed within the Seasonal Condominium Campground in their entirety and shall pay the Company for any charges incurred for modifications necessary to accommodate load according to other portions of this Electric Rate Book.

C4.4 Resale

This provision is closed to resale for general unmetred service, unmetred or metered lighting service and new or expanded service for resale for residential use.

No customer shall resell electric service to others except when the customer is served under a Company rate expressly made available for resale purposes, and then only as permitted under such rate and under this rule.

Where, in the Company's opinion, the temporary or transient nature of the proposed ultimate use, physical limitation upon extensions, or other circumstances, make it impractical for the Company to extend or render service directly to the ultimate user, the Company may allow a customer to resell electric service to others.

For the purposes of this tariff, the provision of electric vehicle charging service for which there is no direct per kWh charge shall not be considered resale of service.

A resale customer is required to take service under the resale provision of one of the following rates for which they qualify: General Service Secondary Rate GS, General Service Secondary Demand Rate GSD, General Service Primary Rate GP, or *Large* General Service Primary Demand Rate GPD. Resale Service is provided pursuant to a service contract providing for such resale privilege. Service to each ultimate user shall be separately metered.

- A. If the resale customer elects to take service under a Company Full Service resale rate, the ultimate user shall be served and charged for such service under standard Rate RS for residential use or under the appropriate standard General Service Rate applicable in the Company's Electric Rate Book available for similar service under like conditions. Reselling customers are not required to offer or administer any additional service provisions or nonstandard rates contained in the Electric Rate Book, such as the Income Assistance Service Provision, Residential Service Time-of-Day Secondary Rate RT or the Educational Institution Service Provision.
- B. If the resale customer elects to take service under a Company Retail Open Access Service rate, the ultimate user shall be served and charged for such service under Rate ROA-R for residential use or under Rate ROA-S or ROA-P applicable in the Company's Electric Rate Book available for similar service under like conditions.
- C. If the ultimate user is a campground lot or boat harbor slip, the resale customer has the option to charge a maximum of the following all inclusive rate per kWh in place of billing the ultimate customer on the appropriate standard Company tariff rate:

\$0.152852	per kWh for all kWh during the months of June-September
\$0.148934	per kWh for all kWh during the months of October-May

The Company shall be under no obligation to furnish or maintain meters or other facilities for the resale of service by the reselling customer to the ultimate user.

The service contract shall provide that the reselling customer's billings to the ultimate user shall be audited each year by February's month end, for the previous calendar year. The audit shall be conducted either by the Company, if the Company elects to conduct such audit, or by an independent auditing firm approved by the Company. The reselling customer shall be assessed a reasonable fee for an audit conducted by the Company. If the audit is conducted by an independent auditing firm, the customer shall submit a copy of the results of such audit to the Company in a form approved by the Company.

(Continued on Sheet No. C-25.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. C-32.20

(Continued From Sheet No. C-32.10)

C5. CUSTOMER RESPONSIBILITIES (Contd)**C5.4 Shutoff Protection Plan for Residential Customers (Contd)****C. Customer Protection (Contd)**

The estimated annual bill for the SPP Customer and the delinquent balance due may be recalculated periodically by the Company. The Company may also recalculate the estimated annual bill and the delinquent balance due upon the transfer of a balance owed on another account in compliance with the Consumer Standards and Billing Practices for Electric and Gas Residential Service.

D. Default

Should a SPP Customer fail to make payment by the due date, a shutoff notice specific to this SPP shall be issued but shall comply with the requirements of Part 8 of Rule B2., Consumer Standards and Billing Practices for Electric and Gas Residential Service. If the SPP Customer makes payment before the date provided for shutoff of service, the customer shall not be considered to be in default but shall remain in the SPP. If the SPP Customer makes payment after this date, the SPP Customer shall be in default and shall be removed from the SPP. The customer shall be subject to shutoff, provided the 24-hour notice was made by the Company.

E. Participation in Other Shutoff Protection Plans

Customers eligible to participate under the Winter Protection Plan, Rules R 460.148 and R 460.149, will be required to waive their rights to participate under the Winter Protection Plan in order to participate in the Plan. Upon enrollment, the Company shall send written confirmation of the enrollment terms and include notice of this provision.

C5.5 Non-Transmitting Meter Provision

Customers served on Residential Service Secondary Rates RS and General Service Secondary Rates GS have the option to choose a non-transmitting meter. In order for a customer to be eligible to participate in the Non-Transmitting Meter Provision, the customer must have a meter that is accessible to Company employees and the customer shall have zero instances of unauthorized use, theft, fraud and/or threats of violence toward Company employees.

Customers electing a non-transmitting meter will pay the following charges per premises *or billing meter*:

Up Front Charge:	\$ 69.39	a one-time charge per <i>billing meter</i> per request if the notice is given before the transmitting meter is installed
	OR	
	\$123.91	a one-time charge per <i>billing meter</i> per request if the notice is given after the transmitting meter is installed
Monthly Charge:	\$ 9.72	per month at each premises

All standard charges and provisions of the customer's applicable tariff shall apply.

(Continued on Sheet No. C-32.30)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. C-32,30

(Continued From Sheet No. C-32.20)

C5. CUSTOMER RESPONSIBILITIES (Contd)**C5.6 Customer-Selected Due Date Program**

Notwithstanding other provisions in this tariff book, the Company, at its discretion, may provide its electric service customers and combination electric and gas service customers the option to select the day of the month on which their bill is due, regardless of the meter read date. Participating customers must have an electric AMI transmitting technology meter.

Participation in the Customer-Selected Due Date Program is available to customers, as determined by the Company, when technically feasible based on the customer's selected rate and billing options. Customers not eligible to participate include, but not limited to, customers billed on a calendar-month basis, customers participating in Retail Open Access and customers participating in the Net Metering Program.

The Customer-Selected Due Date Program is only available for the following rate categories: Residential (RS), Residential Service Time-of-Day Secondary (RT), Plug-In Electric Vehicle Charging (PEV), General Service Secondary (GS), General Service Secondary Demand (GSD), General Service Primary (GP) and General Service Metered Lighting (GML).

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS**C6.1 Overhead Extension Policy**

Applications for electric service which require the construction of an overhead distribution system shall be granted under the following conditions:

A. Residential Customers

The Company shall construct single-phase distribution line extensions at its own cost a distance of 600 feet, for each residential dwelling.

The length of the distribution line extension shall be measured from the nearest point of connection to the Company's facilities from which the extension can be made to the point from which the service line to the customer shall be run.

Distribution line extensions in excess of the above *600 feet* shall require a deposit for the estimated cost of such excess footage. The required deposit for such excess footage shall be \$3.50 per lineal foot less 25%.

(Continued on Sheet No. C-33.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. C-33.00

(Continued From Sheet No. C-32.30)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)

C6.1 Overhead Extension Policy (Contd)

A. Residential Customers (Contd)

The Company shall make a one-time refund, five years from the completion date of the extension or upon completion of the customer's construction, whichever the customer chooses, of \$1,000 for each additional residential customer and/or *three times* the estimated *annual* revenue for each additional General Service customer who connects directly to the line for which a deposit was required. Refund allowances shall first be credited against the 25% reduction before a refund is made to the customer based on the customer's cash deposit. Directly connected customers are those who do not require the construction of more than 300 feet of Primary and/or Secondary distribution line. Refunds shall not include any amount of contribution in aid of construction for underground service made under the provisions of Rule C6.2, Underground Policy. Total refund shall not exceed the amount of the original deposit.

B. General Service Customers

The Company shall construct single-phase and three-phase distribution line extensions, at its own cost when the cost of such extension does not exceed three times the estimated annual revenue from the customer(s) to be immediately served.

Extensions *with costs* in excess of *three times the estimated annual revenue* shall require a deposit from the customer.

(1) Original Customers

At the end of the first complete 12-month period beginning *three* months following the date the line extension is completed, the Company shall refund to the depositor three times the amount that actual revenue exceeds the original revenue estimate. If the actual revenue exceeds the estimated revenue, the actual revenue then becomes the base upon which future refund calculations are to be made during the remainder of the five year refund period.

(2) Additional Connected Customers

The Company shall refund \$1,000 for each residential customer and/or *three times* the estimated *annual* revenue for each General Service customer who connects directly to the line for which a deposit was required. Directly connected customers are those who do not require the construction of more than 300 feet of Primary and/or Secondary distribution line. Refunds shall not be made until the original customer(s) or equivalent is actually connected to the extension. Refunds shall not include any amount of contribution in aid of construction for underground service made under the provisions of Rule C6.2, Underground Policy.

C. General

- (1) Refundable deposits made with the Company under this rule shall be subject to refund without interest, for a five -year period which begins *three* months after the line extension is completed. The Company shall have no further obligation to refund any remaining portion of line extension deposits.
- (2) Each extension shall be a separate, distinct unit and any further extension therefrom shall have no effect upon the agreements under which existing extensions were constructed.
- (3) Refunds cannot exceed the refundable portion of the deposit.
- (4) Estimated construction costs shall exclude services and meters.
- (5) The applicant shall furnish, without cost to the Company, all necessary rights-of-way and tree trimming permits, in a form satisfactory to the Company. If the applicant is unable to secure rights-of-way and permits, in a form satisfactory to the Company, the Company *may* extend its distribution system along an alternate route selected by the Company, and *may* require the applicant to pay all additional costs incurred.

(Continued on Sheet No. C-34.00)

M.P.S.C. No. 13 – Electric
Consumers Energy Company

Sheet No. C-38.00

(Continued From Sheet No. C-37.00)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)

C6.2 Underground Policy (Contd)

C. Installations of Underground Distribution Facilities - General Service

(1) Installation of Underground Distribution Systems

The Company shall construct single-phase and three-phase distribution line extensions *at its own cost*, when the cost of such extension, *less contributions made under other sections of this rule*, does not exceed three times the estimated annual revenue from the customer(s) to be immediately served. Extensions with costs in excess of *three times the estimated annual revenue* shall require a *deposit* from the customer.

(2) Installation of Underground Service Connections

The developer or customer shall be required to make a contribution in aid of construction, to cover the additional cost resulting from the installation of an underground service connection. The required contribution shall be:

- (a) For apartment houses and condominiums, a rate of \$6.50 per trench foot.
- (b) For all other General Service customers a rate of \$6.50 per trench foot.

(Continued on Sheet No. C-39.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. C-39.00

(Continued From Sheet No. C-38.00)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)

C6.2 Underground Policy (Contd)

D. Underground Extension Policy

Applications for electric service which require the construction of an underground distribution system shall be granted under the following conditions:

(1) (a) Residential in Subdivisions

The Company shall construct single-phase underground direct burial distribution line extensions, at its own cost, when the cost of such extension, less contributions made under other sections of this rule, does not exceed a total of three times the estimated annual revenue to be received from the customer(s) to be immediately served.

Underground distribution line extensions *with costs in excess of three times the estimated annual revenue* shall require a deposit from the customer.

(b) Residential Outside of Subdivisions

Single-phase underground direct burial distribution line extensions shall be based on the free footage allowances and charges of Rule C6.1 A., Overhead Extension Policy. Any deposit required shall be in addition to the nonrefundable contribution to cover the estimated difference in cost between overhead and direct burial underground facilities specified in Rule C6.2, B(2)(b), Underground Policy.

(c) General Service

Single-phase and three-phase underground direct burial distribution line extensions shall be based on *three times the estimated annual revenue* and charges of Rule C6.1 B., Overhead Extension Policy.

The Company shall refund deposits to residential and General Service applicant(s) on the same basis as provided in its Rule C6.1, Overhead Extension Policy.

(2) General

(a) This rule is subject to all provisions of Rule C6.1 C., Overhead Extension Policy - General.

(b) Where the customer is eligible for an overhead distribution line extension but the Company elects to provide an underground distribution line extension, the extension shall be governed by Rule C6.1, Overhead Extension Policy, as though the extension were overhead with deposits and contributions based on an equivalent overhead line extension.

(Continued on Sheet No. C-40.00)

M.P.S.C. No. 13- Electric
Consumers Energy Company

Sheet No. C-42.00

(Continued From Sheet No. C-41.00)

C8. POWER SUPPLY COST RECOVERY (PSCR) CLAUSE (Contd)**A. Applicability of Clause (Contd)**

"Power Supply Costs" means those elements of the costs of fuel and purchased and net interchanged power as determined by the Commission to be included in the calculation of the Power Supply Cost Recovery Factor. The Commission determined in its Order in Case No. U-10335 dated May 10, 1994 that the fossil plant emissions permit fees over or under the amount included in base rates charged the Company are an element of fuel costs for the purpose of the clause.

B. Billing

- (1) The Power Supply Cost Recovery Factor shall consist of an adjustment factor of 1.0805 applied to projected average booked cost of fuel burned for electric generation and purchased and net interchange power incurred above or below a cost base of \$0.05570 per kWh (excluding line losses). Average booked costs of fuel burned and purchased and net interchange power shall be equal to the booked costs in that period divided by that period's net system kWh requirements. The average booked costs so determined shall be truncated to the full \$0.00001 cost per Kilowatt-hour. Net system kWh requirements shall be the sum of the net kWh generation and net kWh purchased and interchange power.

- (2) Each month the Company shall include in its rates a Power Supply Cost Recovery Factor up to the maximum authorized by the Commission as shown on Sheet No. D-4.00.

Should the Company apply lesser factors than those shown on Sheet No. D-4.00, or if the factors are later revised pursuant to Commission Orders or Michigan Compiled Laws, Annotated, 460.6 et seq., the Company shall notify the Commission if necessary and file a revised Sheet No. D-4.00.

C. General Conditions

- (1) The power supply and cost review shall be conducted not less than once a year for the purpose of evaluating the Power Supply Cost Recovery Plan filed by the Company and to authorize appropriate Power Supply Cost Recovery Factors. Contemporaneously with its Power Supply Cost Recovery Plan, the Company shall file a 5-year forecast of the power supply requirements of its customers, its anticipated sources of supply and projections of Power Supply Costs.
- (2) Not more than 45 days following the last day of each billing month in which a Power Supply Cost Recovery Factor has been applied to customers' bills, the Company shall file with the Commission a detailed statement for that month of the revenues recorded pursuant to the Power Supply Cost Recovery Factor and the allowance for cost of power included in the base rates established in the latest Commission order for the Company, and the cost of power supply.
- (3) All revenues collected pursuant to the Power Supply Cost Recovery Factors and the allowance for power included in the base rates are subject to annual reconciliation proceedings.

(Continued on Sheet No. C-43.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. C-50.00

(Continued From Sheet No. C-49.00)

C11. NET METERING PROGRAM (Contd)**D. Customer Eligibility (Contd)**

- (1) A Category 1 Net Metering customer has one or more Eligible Electric Generators with an aggregate nameplate capacity of 20 kW or less that use equipment certified by a nationally recognized testing laboratory to IEEE 1547.1 testing standards and is in compliance with UL 1741 scope 1.1 A located on the customer's premises and metered at a single point of contact.
- (2) A Category 2 Net Metering customer has one or more Eligible Electric Generators with an aggregate nameplate capacity greater than 20 kW but not more than 150 kW located on the customer's premises and metered at a single point of contact.
- (3) A Category 3 Net Metering customer has one or more methane digesters with an aggregate nameplate capacity greater than 150 kW but not more than 550 kW located on the customer's premises and metered at a single point of contact.

E. Customer Billing and Net Excess Generation Credit**(1) Category 1 Customers****(a) Full Service Customers**

- (i) The customer will be billed at the Full Retail Rate, plus surcharges, Securitization and Securitization Tax Charges, Power Plant Securitization Charges and Power Supply Cost Recovery (PSCR) Factor on Net Customer Consumption for the billing month.
- (ii) The customer will be credited at the Full Retail Rate on Net Excess Generation for the billing month. The credit shall appear on the bill for the following billing period and shall be used to offset total utility charges on that bill. Any excess credit not used to offset total utility charges will be carried forward to subsequent billing periods. Net Excess Generation Credit is non-transferrable. In months when the customer has zero Net Customer Consumption or Net Excess Generation, all applicable surcharges will be billed on the metered inflow supplied by the Company to the customer.

(b) Retail Open Access Customers

- (i) The customer will be billed for the distribution components, including applicable surcharges, Securitization and Securitization Tax Charges and Power Plant Securitization Charges, if applicable, as stated on the customer's Retail Open Access Rate Schedule on Net Customer Consumption for the billing month.
- (ii) The Retail Open Access customer will be credited for distribution components as stated on the ROA customer's otherwise applicable Company Full Service Rate Schedule on Net Excess Generation for the billing month. The credit shall appear on the bill for the following billing period and shall be used to offset utility distribution charges on that bill. Any excess credit not used to offset utility distribution charges will be carried forward to subsequent billing periods. Net Excess Generation Credit is non-transferrable. In months when the customer has zero Net Customer Consumption or Net Excess Generation, all applicable surcharges will be billed on the metered inflow delivered by the Company to the customer.

(2) Category 2 Customers**(a) Full Service Customers**

- (i) The customer will be billed for power supply energy components, including Power Supply Cost Recovery (PSCR) Factor, on Net Customer Consumption. The customer will be billed for distribution components, surcharges, Securitization and Securitization Tax Charges and Power Plant Securitization Charges on metered inflow supplied by the Company to the customer. General Service Secondary Demand Rate GSD and Large General Service Primary Demand Rate GPD customers will be billed for demand based capacity charges as stated on the applicable Rate Schedule.

(Continued on Sheet No. C-50.10)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. C-50.10

(Continued From Sheet No. C-50.00)

C11. NET METERING PROGRAM (Contd)

E. Customer Billing and Net Excess Generation Credit (Contd)

(2) Category 2 Customers (Contd)

(a) Full Service Customers (Contd)

- (i) The customer will be credited for power supply energy components on Net Excess Generation. The credit shall appear on the bill for the following billing period and shall be used to offset total power supply charges on that bill. Net Excess Generation Credit exceeding total power supply charges shall be carried forward and applied to power supply charges in subsequent billing periods. Net Excess Generation Credit is non-transferrable.

(b) Retail Open Access Customers

- (i) The customer will be billed for the distribution components, including applicable surcharges, Securitization and Securitization Tax Charges and Power Plant Securitization Charges, if applicable, as stated on the ROA customer's otherwise applicable Company Full Service Rate Schedule on metered inflow supplied by the Company to the customer. The customer will be billed for demand based capacity charges in accordance with the ROA customer's otherwise applicable Company Full Service Rate Schedule.

- (ii) Retail Open Access customers will not receive distribution credit on Net Excess Generation.

(3) Category 3 Customers

(a) Full Service Customers on General Service Secondary Rate GS or General Service Primary Rate GP

- (i) The customer will be billed for power supply energy components, including Power Supply Cost Recovery (PSCR) Factor, on Net Customer Consumption. The customer will be billed for surcharges, Securitization and Securitization Tax Charges and Power Plant Securitization Charges on the metered inflow supplied by the Company to the customer. The customer will be billed for distribution components on Imputed Customer Usage.

- (ii) The customer will be credited for power supply energy components on Net Excess Generation. The credit shall appear on the bill for the following billing period and shall be used to offset total power supply charges on that bill. Net Excess Generation Credit exceeding total power supply charges will be carried forward and applied to power supply charges in subsequent billing periods. Net Excess Generation Credit is non-transferrable.

(b) Full Service Customers on General Service Secondary Demand Rate GSD or *Large* General Service Primary Demand Rate GPD

- (i) The customer will be billed for power supply components, including Power Supply Cost Recovery (PSCR) Factor, on Net Customer Consumption. The customer will be billed for surcharges, Securitization and Securitization Tax Charges and Power Plant Securitization Charges on the metered inflow supplied by the Company to the customer. The customer will be billed for distribution components on Imputed Customer Usage. General Service Secondary Demand Rate GSD and *Large* General Service Primary Demand Rate GPD customers will be billed for demand based capacity charges as stated on the applicable Rate Schedule.

- (ii) The customer will be credited for power supply energy components on Net Excess Generation. The credit shall appear on the bill for the following billing period and shall be used to offset total power supply charges on that bill. Net Excess Generation Credit exceeding total power supply charges will be carried forward and applied to power supply charges in subsequent billing periods. Net Excess Generation Credit is non-transferrable.

(Continued on Sheet No. C-50.20)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. C-53.00

SECTION C - PART III
COMPANY RULES AND REGULATIONS
(NON-RESIDENTIAL CUSTOMERS)**INTENT OF SECTION C - PART III**

These Company Rules and Regulations for Non-Residential customers are not to supersede but are in addition to Rule B1., Technical Standards for Electric Service; and Rule B4., Billing Practices Applicable to Non-Residential Electric and Gas Customers.

C13. CUSTOMER DEPOSITS

The Company may require a cash deposit from the transferor or transferee upon receipt of a bulk transfer notice. The Company shall pay interest on such deposits in accordance with Rule B4., Billing Practices Applicable to Non-Residential Electric and Gas Customers.

C14. PROVISIONS GOVERNING THE APPLICATION OF ON-PEAK AND OFF-PEAK RATES

- A. Energy consumed under *Large* General Service Primary Demand Rate GPD shall be subject to the on-peak and off-peak charges as set forth in the Rate Schedule and as defined in the Schedule of On-Peak and Off-Peak Hours.

Demands created under General Service Secondary Demand Rate GSD and *Large* General Service Primary Demand Rate GPD shall be subject to the on-peak and off-peak charges as set forth in these Rate Schedules and as defined in the Schedule of On-Peak and Off-Peak Hours.

- B. Schedule of On-Peak and Off-Peak Hours

Except where otherwise provided, the following schedule shall apply Monday through Friday (except holidays designated by the Company). Weekends and holidays are off-peak.

- (1) On-Peak Hours: 11:00 AM to 7:00 PM
(2) Off-Peak Hours: 7:00 PM to 11:00 AM

(Continued on Sheet No. C-54.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-6.00

RATE CATEGORIES AND PROVISIONS

<u>Description</u>	<u>Full Service</u>	<u>Retail Open Access</u>
RESIDENTIAL SERVICE SECONDARY RATE RS		
Residential	1000	2000
<u>Provisions</u>		
Residential With Income Assistance (RIA) *	Applicable	Applicable
Residential With Senior Citizen (RSC) *	Applicable	Applicable
Peak Power Savers – <i>Air Conditioner Peak Cycling Program</i>	1005	Not Applicable
Residential With Self-Generation (SG) ***	1700	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
Non-Transmitting Meter Provision	Applicable	Applicable
RESIDENTIAL SERVICE DYNAMIC PROGRAM		
<i>Peak Power Savers – Critical Peak Time-Of-Use (RDP)</i>	1007	Not Applicable
<i>Peak Power Savers – Peak Rewards Time-Of-Use (RDPR)</i>	1008	Not Applicable
<u>Provisions</u>		
Residential Dynamic Pricing With Income Assistance (RIA) *	Applicable	Applicable
Residential Dynamic Pricing With Senior Citizen (RSC) *	Applicable	Applicable
Residential Dynamic Pricing With Self-Generation (SG) ***	1700	Not Applicable
Green Generation Program	Applicable	Not Applicable
RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT		
Residential Time-of-Day	1010	2010
<u>Provisions</u>		
Residential Time-of-Day With Income Assistance (RIA) *	Applicable	Applicable
Residential Time-of-Day With Senior Citizen (RSC) *	Applicable	Applicable
Residential Time-of-Day With Self-Generation (SG) ***	1705	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM		
Residential Electric Vehicle Service (REV-1)	1020	Not Applicable
Residential Electric Vehicle Service (REV-1) With Self-Generation (SG) ***	1710	Not Applicable
Residential Electric Vehicle Service (REV-2)	1030	Not Applicable
Green Generation Program	Applicable	Not Applicable

* Provisions shall not be taken in conjunction with each other.

*** Provisions shall not be taken in conjunction with the-Net Metering Program.

(Continued on Sheet No. D-6.10)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-6.10

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-6.00)

<u>Description</u>	<u>Full Service</u>	<u>Retail Open Access</u>
GENERAL SERVICE SECONDARY RATE GS		
Commercial	1100	2100
Commercial - Temporary Construction Service	1999	Not Applicable
<u>Provisions</u>		
Commercial Billboards/Outdoor Advertising Signs - Dusk to Dawn	Applicable	Not Applicable
Commercial Billboards/Outdoor Advertising Signs - Fixed Hours of Operation	Applicable	Not Applicable
Commercial Miscellaneous	Applicable	Not Applicable
Commercial Resale	Applicable	Applicable
Commercial With Educational Institution (GEI)	Applicable	Applicable
Commercial With Self-Generation (SG) *	1715	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
Non-Transmitting Meter Provision	Applicable	Applicable
GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU		
Commercial	1121	Not Applicable
<u>Provisions</u>		
Commercial With Educational Institution (GEI)	Applicable	Applicable
Commercial With Self-Generation (SG) *	1716	Not Applicable
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE SECONDARY DEMAND RATE GSD		
Commercial	1120	2120
Commercial (100 kW Billing Demand Guarantee)	1140	2140
<u>Provisions</u>		
Commercial Resale	Applicable	Applicable
Commercial With Educational Institution (GEI)	Applicable	Applicable
Commercial With Self-Generation (SG) *	1725	Not Applicable
Commercial (100 kW Billing Demand Guarantee) With Self-Generation (SG) *	1735	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable

*Provisions shall not be taken in conjunction with the Net Metering Program.

(Continued on Sheet No. D-7.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-7.00

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-6.10)

Description	Full Service	Retail Open Access
GENERAL SERVICE PRIMARY RATE GP		
Commercial (Customer Voltage Level 1, 2 or 3)	1200	2200
Industrial (Customer Voltage Level 1, 2 or 3)	1210	2210
<u>Provisions</u>		
Commercial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Educational Institution (GEI)	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) ***	1745	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) ***	1750	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD		
Commercial (Customer Voltage Level 1, 2 or 3)	1220	2220
Industrial (Customer Voltage Level 1, 2 or 3)	1230	2230
<u>Provisions</u>		
Commercial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Applicable
Industrial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Aggregate Peak Demand (GAP) ***	Applicable	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Aggregate Peak Demand (GAP) ***	Applicable	Not Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Educational Institution (GEI) ***	Applicable	Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Educational Institution (GEI) ***	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Interruptible (GI)	Applicable	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Interruptible (GI)	Applicable	Not Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) ***	1755	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) ***	1760	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU		
Commercial (Customer Voltage Level 1, 2, or 3)	1280	Not Applicable
Industrial (Customer Voltage Level 1, 2, or 3)	1285	Not Applicable
<u>Provisions</u>		
Commercial with Education Institution (GEI)	Applicable	Applicable
Industrial with Education Institution (GEI)	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) ***	1765	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) ***	1770	Not Applicable
Net Metering Program	Applicable	Not Applicable
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE ENERGY INTENSIVE PRIMARY RATE EIP		
Industrial (Customer Voltage Level 1, 2, or 3)	1250	Not Applicable
<u>Provisions</u>		
Commercial (Customer Voltage Level 1, 2, or 3) With Self-Generation (SG) ***	1775	Not Applicable
Industrial (Customer Voltage Level 1, 2, or 3) With Self-Generation (SG) ***	1780	Not Applicable
Green Generation Program	Applicable	Applicable

* Provisions shall not be taken in conjunction with the GEI provision or the Net Metering Program.

*** Provisions shall not be taken in conjunction with the Net Metering Program.

(Continued on Sheet No. D-7.10)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-7.10

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-7.00)

Description	Full Service	Retail Open Access
EXPERIMENTAL ADVANCED RENEWABLE PROGRAM AR		
Residential	1015	2015
Commercial - Secondary Delivery, Rate GS	1105	2105
Industrial - Secondary Delivery, Rate GS	1115	2115
Commercial - Secondary Delivery, Rate GSD	1125	2125
Industrial - Secondary Delivery, Rate GSD	1135	2135
Commercial - Primary Delivery, Rate GP	1205	2205
Industrial - Primary Delivery, Rate GP	1215	2215
Commercial - Primary Delivery, Rate GPD	1225	2225
Industrial - Primary Delivery, Rate GPD	1235	2235
PILOT SOLAR PROGRAM		
Residential	1800	Not Applicable
Commercial	1825	Not Applicable
Industrial	1850	Not Applicable
GENERAL SERVICE SELF GENERATION RATE GSG-2		
Commercial - Primary Service	1320	Not Applicable
Commercial (Customer Voltage Level 1, 2, or 3) - Primary Service 100 kW or less	1325	Not Applicable
Industrial - Primary Service	1340	Not Applicable
Industrial (Customer Voltage Level 1, 2, or 3) - Primary Service 100 kW or less	1345	Not Applicable
Industrial (Customer Voltage Level 1, 2, or 3) - Primary Service greater than 100 kW	1350	Not Applicable
<u>Provisions</u>		
Green Generation	Applicable	Not Applicable

(Continued on Sheet No. D-8.00)

M.P.S.C. No. 13 - Electric
 Consumers Energy Company

Sheet No. D-9.00

RESIDENTIAL SERVICE SECONDARY RATE RS

Availability:

Subject to any restrictions, this rate is available to any customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, without the specific consent of the Company.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; or (iv) any other Non-Residential usage.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company will schedule meter readings on a monthly basis and attempt to obtain an actual meter reading for all tourist and/or occasional residence customers at intervals of not more than six months.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service customers.

Energy Charge:

<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
\$0.061776	\$0.032749	\$0.094525	per kWh for the first 600 kWh per month during the billing months of June - September
\$0.083153	\$0.044082	\$0.127235	per kWh for all kWh over 600 kWh per month during the billing months of June - September
\$0.061776	\$0.032749	\$0.094525	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

System Access Charge:	\$7.00	per customer per month
Distribution Charge:	\$0.050297	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-10.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-11.00

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-10.00)

Monthly Rate: (Contd)**Senior Citizen Service Provision (RSC):**

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

Senior Citizen Credit: \$(3.50) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge: \$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Peak Power Savers - Air Conditioner Peak Cycling Program:

A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary Peak Power Savers - *Air Conditioner Peak Cycling* Program for load management of eligible electric central air conditioning, central heat pump, or other qualifying electric equipment. Customer eligibility to participate in this program is determined solely by the Company. The customer must be located within an area in which Advanced Metering Infrastructure (AMI) is deployed and have a fully operational AMI meter for purposes of this program. The Company will accept a customer's central air conditioning, central heat pump, and other qualifying electric equipment under this program only if it has the capability to be controlled by the Company. Load Management of a customer's swimming pool pump is permitted under this program only if the customer is allowing Load Management of their air conditioner or heat pump unit. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

(Continued on Sheet No. D-11.10)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-11.10

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-11.00)

Monthly Rate: (Contd)**Peak Power Savers - *Air Conditioner Peak Cycling Program*: (Contd)**

The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service.

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load Management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Peak Power Savers - *Air Conditioner Peak Cycling Credit* may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers - *Air Conditioner Peak Cycling Program*.

The monthly credit for the Peak Power Savers - *Air Conditioner Peak Cycling Program* shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Power Savers - <i>Air Conditioner Peak Cycling Credit</i> :	\$ (7.84)	per customer per month during the billing months of June-September
--	-----------	--

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C 11., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C 11., Net Metering Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Non-Transmitting Meter Provision:

A customer who chooses a non-transmitting meter is subject to the provisions contained in Rule C5.5, Non-Transmitting Meter Provision.

(Continued on Sheet No. D-11.20)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-13.00

RESIDENTIAL DYNAMIC PRICING PROGRAM

Availability:

The Residential Dynamic Pricing Program is voluntary and available to Full Service residential customers who have, or are selected to have, the required metering equipment and infrastructure installed. Customer eligibility to participate in this program is determined solely by the Company. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense. At the sole discretion of the Company, customers may be allowed to furnish, install and maintain the equipment at the customer's expense. Equipment and installations must conform to the Company's specifications. By enrolling in the program, the customer agrees to provide an email address, to participate in surveys and understands that the metering data will be used for evaluation purposes.

The customer's enrollment shall be terminated if the program ceases or for any reasons as provided for in Rule C1.3, Use of Service.

Deployment of the Residential Dynamic Pricing Program is at the sole discretion of the Company and is dependent upon installation of advanced metering infrastructure and supporting critical systems.

Customers participating in the Residential Dynamic Pricing Program shall not participate in any other Demand Response Program or Net Metering.

The program is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; or (iv) any other Non-Residential usage.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this program only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this program shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Rate Options:

Customers are able to manage electric costs by either reducing load during high cost pricing periods or shifting load from high cost pricing periods to lower cost pricing periods. Upon enrollment of the customer in the Residential Dynamic Pricing Pilot, the customer shall take service under one of the following rate options:

Option 1 –Peak Power Savers - Critical Peak Time of Use (RDP) – During a critical peak event, customers on Rate RDP will be charged the Critical Peak Event charge for all kWh consumed during the critical peak event.

Option 2 –Peak Power Savers - Peak Rewards Time of Use (RDPR) – During a critical peak event, customers on Rate RDPR will be credited the Critical Peak Rebate for incremental energy reductions.

The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-13.01

RESIDENTIAL DYNAMIC PRICING PROGRAM

(Continued From Sheet No. D-13.00)

Monthly Rate:**Option 1 —Peak Power Savers - Critical Peak Time of Use Rate (RDP):****Power Supply Charges:**

These charges are applicable to Full Service customers.

Energy Charge:

	<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
Off-Peak – Summer	\$0.041976	\$0.017318	\$0.059294	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak – Summer	\$0.058503	\$0.024136	\$0.082639	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak – Summer	\$0.073248	\$0.030219	\$0.103467	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak – Winter	\$0.057435	\$0.030448	\$0.087883	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak – Winter	\$0.066212	\$0.035101	\$0.101313	per kWh for all On-Peak kWh during the billing months of October-May
Critical Peak Event	\$0.614634	\$0.335366	\$0.950000	per kWh during a critical peak event between June 1 and September 30

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	\$7.00	per customer per month
Distribution Charge:	\$0.050297	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

Option 2 —Peak Power Savers - Peak Rewards Time-of-Use Rate RDPR:**Power Supply Charges:**

These charges are applicable to Full Service Customers.

Energy Charge:

	<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
Off-Peak-Summer	\$0.050762	\$0.026802	\$0.077564	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak-Summer	\$0.070748	\$0.037354	\$0.108102	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak-Summer	\$0.088580	\$0.046769	\$0.135349	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak-Winter	\$0.057435	\$0.030448	\$0.087883	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak -Winter	\$0.066212	\$0.035101	\$0.101313	per kWh for all On-Peak kWh during the billing months of October-May
Critical Peak Reward	\$(0.614634)	\$(0.335366)	\$(0.950000)	per kWh during a critical peak event between June 1 and September 30

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-13.02)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-13.02

RESIDENTIAL DYNAMIC PRICING PROGRAM

(Continued From Sheet No. D-13.01)

Monthly Rate: (Contd)

Option 2 ~~Peak Power Savers~~ - Peak Rewards Time-of-Use Rate RDPR: (Contd)**Delivery Charges:** These charges are applicable to Full Service Customers.

System Access Charge	\$7.00	per customer per month
Distribution Charge:	\$0.050297	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2, Consumer Standards and Billing Practices for Electric and Gas Residential Customers, R 460.102, Definitions. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Income Assistance Credit:	\$(7.00)	per customer per month
---------------------------	----------	------------------------

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

Senior Citizen Credit:	\$(3.50)	per customer per month
------------------------	----------	------------------------

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

(Continued on Sheet No. D-13.03)

M.P.S.C. No. 13 – Electric
Consumers Energy Company

Sheet No. D-13.10

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM

Availability:

The Experimental Residential Plug-In Electric Vehicle Charging Program is a voluntary pilot available to Full Service residential customers. Upon enrollment of the customer in the program, the customer may take service under one of the following options as applicable:

Option 1 - Residential Home and Plug-in Electric Vehicle Time-of-Day Rate (REV-1) – Level 1 or Level 2 Charging of an electric vehicle combined with household electric usage such as space conditioning, cooking, water heating, refrigeration, clothes drying, incineration or lighting based upon on-peak, mid-peak and off-peak periods and through a single meter.

Option 2 - Residential Plug-In Electric Vehicle Only Time-of-Day Rate (REV-2) – Level 2 Charging of the electric vehicle based upon on-peak, mid-peak and off-peak periods through a separate meter. Electric usage for the household will be billed under the RS or RT Rate Schedule.

“Level 1 Charging” is defined as voltage connection of 120 volts and a maximum load of 12 amperes or 1.4 kVA.

“Level 2 Charging” is defined as voltage connection of either 240 volts or 208 volts and a maximum load of 32 amperes or 7.7 kVA at 240 volts or 6.7 kVA at 208 volts.

“Electric Vehicle Supply Equipment (EVSE)” is defined as the conductors, including the ungrounded, grounded and equipment grounding conductors, the electric vehicle connectors, attachment plugs, and all other fittings, devices, power outlets, or apparatus installed specifically for the purpose of delivering energy from the premise wiring to the electric vehicle.

Vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this rate. Low-speed electric vehicles including golf carts are not eligible to take service under this rate even if licensed to operate on public streets. The customer may be required to provide proof of registration of the electric vehicle to qualify for program.

The total connected load of the home including the electric vehicle charging shall not exceed 10 kW, without the specific consent of the Company.

Customers shall not back-feed or transmit stored energy from the electric vehicle’s battery to the Company’s distribution system.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service.

Monthly Rate:

Option 1 – REV-1:

Power Supply Charges:

These charges are applicable to Full Service customers.

Energy Charge:

	<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
Off-Peak – Summer	\$0.054896	\$0.029061	\$0.083957	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak – Summer	\$0.076510	\$0.040502	\$0.117012	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak – Summer	\$0.095794	\$0.050711	\$0.146505	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak – Winter	\$0.054896	\$0.029061	\$0.083957	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak – Winter	\$0.063285	\$0.033502	\$0.096787	per kWh for all On-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-13.20)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-13.20

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM

(Continued From Sheet No. D-13.10)

Monthly Rate (Contd)**Option 1 – REV – 1 (Contd)****Delivery Charges:** These charges are applicable to Full Service and Retail Open Access customers.

System Access Charge: \$7.00 per customer per month

Distribution Charge: \$0.050297 per kWh for all kWh for a Full Service customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

General Terms:

These rates are subject to all general terms and conditions shown on Sheet No. D-1.00.

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge:

\$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstance.

(Continued on Sheet No. D-13.25)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-13.25

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM
(Continued From Sheet No. D-13.20)

Monthly Rate (Contd)

Option 2 - REV-2:

Power Supply Charges: These charges are applicable to Full Service customers.

Energy Charge:

	<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
Off-Peak – Summer	\$0.054896	\$0.029061	\$0.083957	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak – Summer	\$0.076510	\$0.040502	\$0.117012	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak – Summer	\$0.095794	\$0.050711	\$0.146505	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak – Winter	\$0.054896	\$0.029061	\$0.083957	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak – Winter	\$0.063285	\$0.033502	\$0.096787	per kWh for all On-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers

Distribution Charge: \$0.050297 for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10. The REP Surcharge shown on Sheet No. D-2.10 shall not apply.

General Terms:

These rates are subject to all general terms and conditions shown on Sheet No. D-1.00.

(Continued on Sheet No. D-13.30)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-14.00

RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT**Availability:**

Subject to any restrictions, this rate is available to any residential customer desiring electric service who chooses to have their electric consumption metered based upon on-peak and off-peak periods. In addition, this rate is available to customers desiring electric service for electric vehicle battery charging where such service is in addition to all other household requirements. Battery charging service is limited to four-wheel vehicles licensed for operation on public streets and highways. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, without the specific consent of the Company.

Service under this rate is limited to 10,000 customers.

This rate is not available for resale purposes or for any Non-Residential usage.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
On-Peak-Summer	\$0.081273	\$0.031800	\$0.113073	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak-Summer	\$0.056314	\$0.022034	\$0.078348	per kWh for all Off-Peak kWh during the billing months of June-September
On-Peak-Winter	\$0.065553	\$0.025649	\$0.091202	per kWh for all On-Peak kWh during the billing months of October-May
Off-Peak -Winter	\$0.058255	\$0.022794	\$0.081049	per kWh for all Off-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

System Access Charge:	\$7.00	per customer per month
Distribution Charge:	\$0.050297	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2, Consumer Standards and Billing Practices for Electric and Gas Residential Customers, R460.102, Definitions. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Income Assistance Credit:	\$(7.00)	per customer per month
---------------------------	----------	------------------------

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

(Continued on Sheet No. D-15.00)

M.P.S.C. No. 13 - Electric
 Consumers Energy Company

Sheet No. D-18.00

GENERAL SERVICE SECONDARY RATE GS

Availability:

Subject to any restrictions, this rate is available to any general use customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Secondary Voltage service for any of the following: (i) standard secondary service, (ii) public potable water pumping and/or waste water system(s), or (iii) resale purposes. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers. Unmetered Billboard Service is not available to Retail Open Access service.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service customers.

Energy Charge:

<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
\$0.064823	\$0.031976	\$0.096799	per kWh for all kWh during the billing months of June-September
\$0.062199	\$0.030682	\$0.092881	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

System Access Charge:	\$20.00	per customer per month
Distribution Charge:	\$0.042598	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

Billboard Service Provision:

Monthly kWh shall be determined by multiplying the total connected load in kW (including the lamps, ballasts, transformers, amplifiers, and control devices) times 730 hours. The kWh for cyclical devices shall be adjusted for the average number of hours used.

 (Continued on Sheet No. D-19.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-19.00

GENERAL SERVICE SECONDARY RATE GS
(Continued From Sheet No. D-18.00)**Monthly Rate: (Contd)****Resale Service Provision:**

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Education Institution Credit: \$(0.000708) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

(Continued on Sheet No. D-19.10)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-21.10

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU**Availability**

Subject to any restrictions, General Service Secondary Time-of-Use Rate GSTU is available to any Full Service Customer taking service at the Company's Secondary Voltage level with advanced metering infrastructure and supporting critical systems.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers.

This rate shall not be taken in conjunction with any other Demand Response Program or Net Metering.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate**Power Supply Charges: These charges are applicable to Full Service Customers.****Energy Charge:**

	<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
Off-Peak-Summer	\$0.059790	\$0.029494	\$0.089284	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak-Summer	\$0.090451	\$0.044618	\$0.135069	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak-Summer	\$0.113249	\$0.055864	\$0.169113	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak-Winter	\$0.051063	\$0.025189	\$0.076252	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak -Winter	\$0.057461	\$0.028345	\$0.085806	per kWh for all On-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	\$20.00	per customer per month
Distribution Charge:	\$0.042598	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10

(Continued on Sheet No. D-21.20)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-21.20

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU
(Continued From Sheet No. D-21.10)**Monthly Rate (Contd)****Schedule of Hours**

The following schedule shall apply Monday through Friday (except holidays designated by the Company). Weekends and holidays are off-peak. Holidays designated by the Company include: New Year's Day – January 1, Memorial Day – Last Monday in May, Independence Day – July 4, Labor Day – First Monday in September, Thanksgiving Day – Fourth Thursday in November and Christmas Day – December 25. Whenever January 1, July 4, or December 25 falls on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

Summer Billing Months of June through September:

- (1) Off-Peak Hours 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
- (2) Mid-Peak Hours 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
- (3) On-Peak Hours 2:00 PM to 6:00 PM

Winter Billing Months of January through May and October through December:

- (1) Off-Peak Hours 11:00 PM to 7:00 AM
- (2) On-Peak Hours 7:00 AM to 11:00 PM

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Education Institution Credit:	\$(0.00070\$)	per kWh for all kWh
-------------------------------	---------------	---------------------

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Self-Generation Provision (SG)

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C 1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

(Continued on Sheet No. D-21.30)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-22.00

GENERAL SERVICE SECONDARY DEMAND RATE GSD**Availability:**

Subject to any restrictions, this rate is available to any customer desiring Secondary Voltage service, either for general use or resale purposes, where the Peak Demand is 5 kW or more. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service, (iii) resale for lighting service, or (iv) new or expanded service for resale to residential customers.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the demand and energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:**Power Supply Charges: These charges are applicable to Full Service Customers.**

Capacity Charge:	\$12.17	per kW for all kW of Peak Demand during the billing months of June-September
	\$10.17	per kW for all kW of Peak Demand during the billing months of October-May

Energy Charge:

Non-Capacity

\$0.066606	per kWh for all kWh during the billing months of June September
\$0.061437	per kWh for all kWh during the billing months of October-May.

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge:	\$30.00	per customer per month
Capacity Charge:	\$1.15	per kW for all kW of Peak Demand
Distribution Charge:	\$0.035114	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10

(Continued on Sheet No. D-23.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-24.00

GENERAL SERVICE SECONDARY DEMAND RATE GSD
(Continued From Sheet No. D-23.00)**Monthly Rate: (Contd)****Educational Institution Service Provision (GEI):**

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Education Institution Credit: \$(0.000619) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Self-Generation Provision (SG):

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge: \$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less

(Continued on Sheet No. D-24.10)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-27.00

GENERAL SERVICE PRIMARY RATE GP

Availability:

Subject to any restrictions, this rate is available to any customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Primary Voltage service for general use or for public potable water pumping and/or waste water system(s).

This rate is available to existing Full Service Customers with an electric generating facility interconnected at a primary voltage level utilizing General Service Primary Rate GP for standby service on or before June 7, 2012. The amount of retail usage shall be determined on an hourly basis. Customers with a generating installation are required to have an Interval Data Meter.

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for lighting service, except for temporary service for lighting installations.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the energy measurements thus made.

Monthly Rate:**Power Supply Charges: These charges are applicable to Full Service customers.**Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
\$0.059560	\$0.041426	\$0.100986	per kWh for all kWh during the billing months of June-September
\$0.057461	\$0.040061	\$0.097522	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
\$0.053860	\$0.035726	\$0.089586	per kWh for all kWh during the billing months of June-September
\$0.051761	\$0.034361	\$0.086122	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
\$0.051860	\$0.033726	\$0.085586	per kWh for all kWh during the billing months of June-September
\$0.049761	\$0.032361	\$0.082122	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-27.10)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-27.10

GENERAL SERVICE PRIMARY RATE GP
(Continued From Sheet No. D-27.00)**Monthly Rate (Contd)****Delivery Charges:** These charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge: \$100.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)

Distribution Charge: \$0.017201 per kWh for all kWh

Charges for Customer Voltage Level 2 (CVL2)

Distribution Charge: \$0.010745 per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL1)

Distribution Charge: \$0.007861 per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

- (a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.
- (b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

- (c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access customers.

Substation Ownership Credit: \$(0.000393) per kWh for all kWh

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kWh.

(Continued on Sheet No. D-28.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-28.00

GENERAL SERVICE PRIMARY RATE GP
(Continued From Sheet No. D-27.10)**Monthly Rate (Contd)****Educational Institution Service Provision (GEI)**

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities. The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access Customers.

Educational Institution Credit: \$(0.000530) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge: \$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

(Continued on Sheet No. D-29.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-31.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD**Availability**

Subject to any restrictions, this rate is available to any customer desiring Primary Voltage service, either for general use or resale purposes, where the On-Peak Billing Demand is 25 kW or more. This rate is also available to any political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, for Primary Voltage service for potable water pumping and/or waste water system(s).

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is also not available for lighting service, for resale for lighting service, or for new or expanded service for resale to residential customers.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Monthly Rate:**Power Supply Charges: These charges are applicable to Full Service customers.**Charges for Customer Voltage Level 3 (CVL3)Demand Charges:

Capacity	Non-Capacity	Transmission	Total	per kW of On-Peak Billing Demand during the billing months of June-September
\$12.52	\$7.86	\$1.86	\$22.24	
Capacity	Non-Capacity	Transmission	Total	per kW of On-Peak Billing Demand during the billing months of October-May
\$11.52	\$7.86	\$1.86	\$21.24	

Energy Charges:Non-Capacity

\$0.053889	per kWh for all On-Peak kWh during the billing months of June-September
\$0.038016	per kWh for all Off-Peak kWh during the billing months of June-September
\$0.043953	per kWh for all On-Peak kWh during the billing months of October-May
\$0.039917	per kWh for all Off-Peak kWh during the billing months of October-May

Charges for Customer Voltage Level 2 (CVL2)Demand Charges:

Capacity	Non-Capacity	Transmission	Total	per kW of On-Peak Billing Demand during the billing months of June-September
\$11.52	\$7.86	\$1.86	\$21.24	
Capacity	Non-Capacity	Transmission	Total	per kW of On-Peak Billing Demand during the billing months of October-May
\$10.52	\$7.86	\$1.86	\$20.24	

Energy Charges:Non-Capacity

\$0.048189	per kWh for all On-Peak kWh during the billing months of June-September
\$0.032316	per kWh for all Off-Peak kWh during the billing months of June-September
\$0.038253	per kWh for all On-Peak kWh during the billing months of October-May
\$0.034217	per kWh for all Off-Peak kWh during the billing months of October-May

(Continued on Sheet No. D-31.10)

ATTACHMENT B

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-31.10

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-31.00)

Monthly Rate: (Contd)

Power Supply Charges: These charges are applicable to Full Service customers. (Contd)Charges for Customer Voltage Level 1 (CVL1)Demand Charges:

<i>Capacity</i>	<i>Non-Capacity</i>	<i>Transmission</i>	<i>Total</i>	
\$10.52	\$7.86	\$1.86	\$20.24	per kW of On-Peak Billing Demand during the billing months of June-September

<i>Capacity</i>	<i>Non-Capacity</i>	<i>Transmission</i>	<i>Total</i>	
\$9.52	\$7.86	\$1.86	\$19.24	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charges:*Non-Capacity*

\$0.046189	per kWh for all On-Peak kWh during the billing months of June-September
\$0.030316	per kWh for all Off-Peak kWh during the billing months of June-September

\$0.036253	per kWh for all On-Peak kWh during the billing months of October-May
\$0.032217	per kWh for all Off-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge: \$ 200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)

Capacity Charge: \$ 4.21 per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL2)

Capacity Charge: \$ 1.90 per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL1)

Capacity Charge: \$ 1.06 per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

- If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.
- If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

Adjustment for Power Factor shall not be applied when the On-Peak Billing Demand is based on 60% of the highest On-Peak Billing Demand created during the preceding bill months of June through September or on a Minimum On-Peak Billing Demand.

- A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

(Continued on Sheet No. D-32.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-32.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-31.10)

Monthly Rate: (Contd)**Maximum Demand:**

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

On-Peak Billing Demand:

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the billing month, but never less than 60% of the highest on-peak billing demand of the preceding billing months of June through September, nor less than 25 kW.

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 Volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit:	\$(0.65)	per kW of Maximum Demand
------------------------------	----------	--------------------------

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit:	\$(0.38)	per kW of Maximum Demand
------------------------------	----------	--------------------------

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Aggregate Peak Demand Service Provision (GAP):

This provision is available to any customer with 7 accounts or more who desire to aggregate their On-Peak Billing Demands for power supply billing purposes. To be eligible, each account must have a minimum average On-Peak Billing Demand of 250 kW and be located within the same billing district. The customer's aggregated accounts shall be billed under the same rate schedule and service provisions. The aggregate maximum capacity of all customers served under this provision shall be limited to 200,000 kW.

This provision commences with service rendered on and after June 20, 2008 and remains in effect until terminated by a Commission Order.

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Interval Data Meters are required for service under this provision.

The aggregated accounts shall be summarized for each interval time period registered and a comparison shall be performed to determine the on-peak time at which the summarized value of the aggregated accounts reached a maximum for the billing month. The individual aggregated accounts shall be billed for their corresponding On-Peak Billing Demand occurring at that point in time.

(Continued on Sheet No. D-33.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-33.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-32.00)

Monthly Rate: (Contd)

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

Educational Institution Credit: \$(0.000296) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

(Continued on Sheet No. D-34.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-34.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-33.00)

Monthly Rate: (Contd)**Self-Generation Provision (SG):**

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge: \$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Interruptible Service Provision (GI):

This provision is available to any customer account willing to contract for at least 500 kW of On-Peak Billing Demand as interruptible. The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed 75,000 kW. *Customers shall have no more than 50% of their annual On-Peak Billing Demand contracted as interruptible when contracting for more than 50,000 kW of interruptible load.* The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 300,000 kW.

Consumers Energy may require the Customer to monitor and provide real-time, Internet-enabled power monitoring. If such monitoring is required, Consumers Energy will provide the metering or monitoring devices necessary, which shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

(Continued on Sheet No. D-34.10)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-34.10

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-34.00)

Monthly Rate: (Contd)**Interruptible Service Provision (GI): (Contd)**

For billing purposes, the monthly interruptible On-Peak Billing Demand shall be billed first and discounted under this interruptible service provision. The actual On-Peak Billing Demand for the interruptible load supplied shall be credited by the amount specified under the Power Supply Charges - Interruptible Credit listed below. Subsequently all firm service used during the billing period in excess of the contracted interruptible shall be billed at the appropriate firm rate. All contracts under this provision shall be negotiated on an annual basis. *The Customer must notify the Company by December 31st of each year of their desire to renew the GI provision and the amount of interruptible kW for the following year.* Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity.

The minimum On-Peak Billing Demand that shall be billed for the interruptible portion of a customer's bill is the contracted interruptible amount. At the Company's discretion, the customer may reduce the contracted amount one time within the annual contract period.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements as determined by the Company.

Conditions of Interruption

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide notice in advance of probable interruption, and if possible, a second notice of positive interruption. *The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision.* The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of \$50.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Interruptible Credit:	\$(7.00)	per kW of On-Peak Billing Demand during the billing months of June-September
	\$(6.00)	per kW of On-Peak Billing Demand during the billing months of October-May

(Continued on Sheet No. D-35.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-35.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-34.10)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., Net Metering Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, and applicable any non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

For customers with monthly demands of 300 kW or more, all service under this rate shall require a written contract with a minimum term of one year.

For customers with monthly demands of less than 300 kW, service under this rate shall not require a written contract except for: (i) service under the Resale Service Provision, (ii) service under the Green Generation Program, (iii) service under the Educational Institution Service Provision, (iv) service under the Aggregate Peak Demand Service Provision, (v) service under the Interruptible Service Provision, or (vi) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

A new contract will not be required for existing customers who increase their demand requirements after initiating service, unless new or additional facilities are required or service provisions deem it necessary.

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-36.10

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

Availability:

Subject to any restrictions, this General Service Primary Time-Of-Use (GPTU) Rate is available to any Full Service Customer taking service at the Company's Primary Voltage level.

This rate is not available for Standby service with generators that exceed 550kW, nor available for lighting service, except for temporary service for lighting installations.

Nature of Service:

Service under the rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a normal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling, and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Schedule of Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

Summer:

Off-Peak Hours:	12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM
Low-Peak Hours:	6:00 AM to 12:00 PM and 7:00 PM to 11:00 PM
Mid-Peak Hours:	12:00 PM to 2:00 PM and 5:00 PM to 7:00 PM
High-Peak Hours:	2:00 PM to 5:00 PM

Winter:

Off-Peak Hours:	12:00 AM to 2:00 PM and 9:00 PM to 12:00 AM
Mid-Peak Hours:	2:00 PM to 4:00 PM and 7:00 PM to 9:00 PM
High-Peak Hours:	4:00 PM to 7:00 PM

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4 or December 25 fall on a Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-36.20

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-36.10)

Monthly Rate:

Power Supply Charges:Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

	<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
Off-Peak-Summer	\$0.055686	\$0.019871	\$0.075557	per kWh during the calendar months of June-September
Low-Peak-Summer	\$0.073172	\$0.024306	\$0.097478	per kWh during the calendar months of June-September
Mid-Peak-Summer	\$0.087538	\$0.027950	\$0.115488	per kWh during the calendar months of June-September
High-Peak-Summer	\$0.093628	\$0.029495	\$0.123123	per kWh during the calendar months of June-September
Off-Peak - Winter	\$0.055049	\$0.019709	\$0.074758	per kWh during the calendar months of October-May
Mid-Peak - Winter	\$0.061891	\$0.021444	\$0.083335	per kWh during the calendar months of October-May
High-Peak - Winter	\$0.064759	\$0.022171	\$0.086930	per kWh during the calendar months of October-May

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

	<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
Off-Peak-Summer	\$0.049986	\$0.014171	\$0.064157	per kWh during the calendar months of June-September
Low-Peak-Summer	\$0.067472	\$0.018606	\$0.086078	per kWh during the calendar months of June-September
Mid-Peak-Summer	\$0.081838	\$0.022250	\$0.104088	per kWh during the calendar months of June-September
High-Peak-Summer	\$0.087928	\$0.023795	\$0.111723	per kWh during the calendar months of June-September
Off-Peak - Winter	\$0.049349	\$0.014009	\$0.063358	per kWh during the calendar months of October-May
Mid-Peak - Winter	\$0.056191	\$0.015744	\$0.071935	per kWh during the calendar months of October-May
High-Peak - Winter	\$0.059059	\$0.016471	\$0.075530	per kWh during the calendar months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

	<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
Off-Peak-Summer	\$0.047986	\$0.012171	\$0.060157	per kWh during the calendar months of June-September
Low-Peak-Summer	\$0.065472	\$0.016606	\$0.082078	per kWh during the calendar months of June-September
Mid-Peak-Summer	\$0.079838	\$0.020250	\$0.100088	per kWh during the calendar months of June-September
High-Peak-Summer	\$0.085928	\$0.021795	\$0.107723	per kWh during the calendar months of June-September
Off-Peak - Winter	\$0.047349	\$0.012009	\$0.059358	per kWh during the calendar months of October-May
Mid-Peak - Winter	\$0.054191	\$0.013744	\$0.067935	per kWh during the calendar months of October-May
High-Peak - Winter	\$0.057059	\$0.014471	\$0.071530	per kWh during the calendar months of October-May

Delivery Charges:

System Access Charge:	\$200.00	per customer per month
<u>Charges for Customer Voltage Level 3 (CVL3)</u>		
Capacity Charge:	\$4.21	per kW of Maximum Demand
<u>Charges for Customer Voltage Level 2 (CVL2)</u>		
Capacity Charge:	\$1.90	per kW of Maximum Demand
<u>Charges for Customer Voltage Level 1 (CVL1)</u>		
Capacity Charge:	\$1.06	per kW of Maximum Demand

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(Continued on Sheet No. D-36.30)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-36.30

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-36.20)

Monthly Rate (Contd)**Adjustment for Power Factor (Contd)**

- (a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.
- (b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

- (c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: \$(0.65) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: \$(0.38) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Educational Institution Credit: \$(0.000296) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

(Continued on Sheet No. D-36.40)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-37.00

ENERGY INTENSIVE PRIMARY RATE EIP

Availability

Subject to any restrictions, the Energy Intensive Primary Rate EIP is available to any Full Service electric metal melting customer taking service at the Company's Primary Voltage levels, where the electric load on this rate is utilized for industrial metal melting processes such as electric arc or induction furnaces or to any Full Service electric industrial customer who qualified as energy intensive as defined herein. *For metal melting customers, only electric load that directly supports the process of melting metal using electricity as the main melting source qualifies as load to be served under this rate. Ancillary equipment required for the metal melting process is not intended to be served on this rate.*

Existing metal melting customers taking service under the Company's former Metal Melting Primary Pilot as of November 30, 2015 are eligible for service on Rate EIP. An additional 200 MW of Maximum Demand capacity will be available on a first-come, first-served basis to Full Service customers with new electric metal melting or energy intensive industrial load not previously served by the Company. To qualify as energy intensive load, the customer must demonstrate viable options to site the production outside of the state and the customer's incremental load must exceed 2 MW at a single site with an annual load factor that exceeds 70% or the customer's incremental load must exceed 15 MW with a minimum of 75% of their total consumption occurring during Off-Peak Hours. New electric metal melting load must be separately metered. The customer must provide a special circuit or circuits in order for the Company to install separate metering.

Nature of Service

Service under the rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

For purposes of this rate, the appropriate measure of market price is the Real-Time LMP for the Company's retail aggregating node CONS.CETR established by the Midcontinent Independent System Operator Inc. (MISO).

Critical Peak Event Determination

The Company shall call a Critical Peak Event to signal either the market price has exceeded an Economic Trigger Price or a system integrity event is enacted.

A System Integrity Event is enacted when MISO declares that a Maximum Generation Emergency Event has occurred and MISO has instructed the Company to implement Load Management Measures using Load Modifying Resources and Load Management Measures - Stage 1. A System Integrity Event shall occur at any time for any duration. A Critical Peak Event caused by a System Integrity Event shall be billed at the greater of 150% of the High Peak Energy Charge or the average market price during the duration of the event.

The Summer Economic Trigger Price is the greater of 150% of the High Peak Energy Charge, Customer Voltage Level 1 or the average market price during the hours of 3:00 PM to 5:00 PM for the period of June 1 through September 30 of the previous year. The Summer Economic Trigger Price will be set on January 30 of each year by the Company.

The Winter Economic Trigger Price is the greater of 150% of the High Peak Energy Charge, Customer Voltage Level 1 or the average market price during the hours of 5:00 PM to 7:00 PM for the period of October 1 through May 31 of the previous year. The Winter Economic Trigger Price will be set on July 31 of each year by the Company.

Energy Intensive Primary Rate customers will be notified after the Summer and Winter Economic Trigger Prices are set. The Company shall endeavor to provide notice in advance of a probable System Integrity Event.

(Continued on Sheet No. D-37.10)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-37.10

ENERGY INTENSIVE PRIMARY RATE EIP
(Continued from Sheet No. D-37.00)**Schedule of Hours:**

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

Summer:	
Off-Peak Hours:	12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM
Low-Peak Hours:	6:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
Mid-Peak Hours:	2:00 PM to 3:00 PM and 5:00 PM to 6:00 PM
High-Peak Hours:	3:00 PM to 5:00 PM
Critical Peak Hours:	3:00 PM to 5:00 PM during a Critical Peak Event
Winter:	
Off-Peak Hours:	12:00 AM to 4:00 PM and 8:00 PM to 12:00 AM
Mid-Peak Hours:	4:00 PM to 5:00 PM and 7:00 PM to 8:00 PM
High-Peak Hours:	5:00 PM to 7:00 PM
Critical Peak Hours:	5:00 PM to 7:00 PM during a Critical Peak Event

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4, or December 25 fall on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

Monthly Rate:**Power Supply Charges:**Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

	<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
Off-Peak-Summer	\$0.038946	\$0.007688	\$0.046634	per kWh during the calendar months of June-September
Low-Peak-Summer	\$0.050273	\$0.013375	\$0.063648	per kWh during the calendar months of June-September
Mid-Peak-Summer	\$0.059579	\$0.018047	\$0.077626	per kWh during the calendar months of June-September
High-Peak-Summer	\$0.063363	\$0.019947	\$0.083310	per kWh during the calendar months of June-September
Critical Peak-Summer				the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June - September
Off-Peak - Winter	\$0.040009	\$0.008222	\$0.048231	per kWh during the calendar months of October-May
Mid-Peak - Winter	\$0.049444	\$0.012959	\$0.062402	per kWh during the calendar months of October-May
High-Peak - Winter	\$0.059804	\$0.018160	\$0.077964	per kWh during the calendar months of October-May
Critical Peak-Winter				the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May

(Continued on Sheet No. D-37.20)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-37.20

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-37.10)

Monthly Rate (Contd):**Power Supply Charges: (Contd)**Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

	<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
Off-Peak-Summer	\$0.033246	\$0.018688	\$0.051934	per kWh during the calendar months of June-September
Low-Peak-Summer	\$0.044573	\$0.024375	\$0.068948	per kWh during the calendar months of June-September
Mid-Peak-Summer	\$0.053879	\$0.029047	\$0.082926	per kWh during the calendar months of June-September
High-Peak-Summer	\$0.057663	\$0.030947	\$0.088610	per kWh during the calendar months of June-September
Critical Peak-Summer				the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September
Off-Peak - Winter	\$0.034309	\$0.019222	\$0.053531	per kWh during the calendar months of October - May
Mid-Peak - Winter	\$0.043744	\$0.023959	\$0.067702	per kWh during the calendar months of October - May
High-Peak - Winter	\$0.054104	\$0.029160	\$0.083264	per kWh during the calendar months of October - May
Critical Peak-Winter				the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

	<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
Off-Peak-Summer	\$0.031246	\$0.015688	\$0.046934	per kWh during the calendar months of June-September
Low-Peak-Summer	\$0.042573	\$0.021375	\$0.063948	per kWh during the calendar months of June-September
Mid-Peak-Summer	\$0.051879	\$0.026047	\$0.077926	per kWh during the calendar months of June-September
High-Peak-Summer	\$0.055663	\$0.027947	\$0.083610	per kWh during the calendar months of June-September
Critical Peak-Summer				Critical Peak-Summer
Off-Peak - Winter	\$0.032309	\$0.016222	\$0.048531	per kWh during the calendar months of October - May
Mid-Peak - Winter	\$0.041744	\$0.020959	\$0.062702	per kWh during the calendar months of October - May
High-Peak - Winter	\$0.052104	\$0.026160	\$0.078264	per kWh during the calendar months of October - May
Critical Peak-Winter				the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May

Delivery Charges:

System Access Charge:	\$200.00	per customer per month
<u>Charges for Customer Voltage Level 3 (CVL3)</u>		
Capacity Charge:	\$4.21	per kW of Maximum Demand
<u>Charges for Customer Voltage Level 2 (CVL2)</u>		
Capacity Charge:	\$1.90	per kW of Maximum Demand
<u>Charges for Customer Voltage Level 1 (CVL1)</u>		
Capacity Charge:	\$1.06	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10

(Continued on Sheet No. D-37.30)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-37.30

ENERGY INTENSIVE PRIMARY RATE EIP
(Continued from Sheet No. D-37.20)**Adjustment for Power Factor:**

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

- (a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.
- (b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

- (c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access Customers.Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: \$(0.65) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: \$(0.38) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Self-Generation Provision (SG):

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

(Continued on Sheet No. D-37.40)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-43.00

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-42.00)

Nature of Service (Contd)

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage above 25,000 volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Where service is supplied at a nominal voltage less than 2,400 volts and the Company elects to measure the service at a nominal voltage equal to or greater than 2,400 volts, 3% shall be deducted for billing purposes from the energy measurements thus made.

There shall be no double billing of demand under the base rate and Rate GSG-2.

Monthly Rate**Standby Charges****Power Supply Standby Charges**

For all standby energy supplied by the Company, the customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of \$0.002/kWh. In addition capacity charges will be assessed monthly, calculated using the highest 15 minute kW demand associated with Standby Service occurring during the Company's On-Peak billing hours will be multiplied by the highest contracted capacity purchased by the Company in that month, plus allocated transmission and ancillaries. The capacity charges will be prorated based on the number of On-Peak days that Standby Service was used during the billing month.

A customer with a generator(s) nameplate rating more than 550 kW must provide written notice to the Company by December 1 if they desire standby service in the succeeding calendar months of June through September. Written notice shall be submitted on Company Form 500. If the customer fails to meet this written notice requirement, the LMP shall be increased by applying a 10% adder.

Delivery Standby ChargesSystem Access Charge:

Generator that does not meet or exceed load:	\$100.00	per generator installation per month
Generator that meets or exceeds load:	\$200.00	per generator installation per month

Charges for Customer Voltage Level 3 (CVL 3)

Capacity Charge:	\$4.21	per kW of Standby Demand
------------------	--------	--------------------------

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge:	\$1.90	per kW of Standby Demand
------------------	--------	--------------------------

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge:	\$1.06	per kW of Standby Demand
------------------	--------	--------------------------

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-44.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-44.00

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-43.00)

Monthly Rate (Contd)**Standby Charges (Contd)****Adjustment for Power Factor**

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

- (a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.
- (b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months
- (c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the billed Standby Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery ChargesCharges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: \$(0.65) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: \$(0.38) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Transmission Interconnect Credit

Where standby service is provided to a non-utility electric generator located within the Company's service territory and taking power through its transmission interconnect, where the Company has no owned infrastructure other than metering, including billing grade current transformers and potential transformers, telemetry facilities and associated wiring, the following monthly credit shall be applied to the bill:

Delivery Charges

Transmission Interconnect Credit: \$(1.06) per kW of Standby Demand

This credit shall be based on the kW after the 1% deduction has been applied to the metered kW. The credit supersedes any applicable substation ownership credit.

(Continued on Sheet No. D-45.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-46.00

GENERAL SERVICE METERED LIGHTING RATE GML**Availability**

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways, for Primary or Secondary Voltage energy-only metered lighting service where the Company has existing distribution lines available for supplying energy for such service. Luminaires which are served under the Company's unmetered lighting rates shall not be intermixed with luminaires served under this metered lighting rate. Luminaire types in addition to those served on Rate Schedule GUL, such as light-emitting diode (LED) streetlights, may receive service under this Rate Schedule.

This rate is not available for resale purposes or for Retail Open Access Service.

Nature of Service**Secondary Voltage**

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), 120/240 nominal Volt service for a minimum of ten luminaires located within a clearly defined area. Control equipment shall be furnished, owned and maintained by the Company. The customer shall furnish, install, own and maintain the rest of the equipment comprising the metered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires, protective equipment, and the supply circuits extending to the point of attachment with the Company's distribution system. The Company shall connect the customer's equipment to the Company's lines and supply the energy for its operation. All of the customer's equipment shall be subject to the Company's approval. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Dusk to Midnight Service

Dusk to midnight service shall be the same as Secondary service except:

The customer shall pay the difference between the cost of the control equipment necessary for dusk to midnight service and control equipment normally installed for Secondary service. Circuits shall be arranged approximating minimum loads of 3 kW.

Primary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), Primary Voltage service for actual kW demands of not less than 100 kW for each point of delivery and where the customer guarantees a minimum of 4,000 annual hours' use of the actual demand. The Company will determine the particular nature of the voltage in each case. The customer shall furnish, install, own and maintain all equipment comprising the metered lighting system including, but not limited to, controls, protective equipment, transformers and overhead or underground metered lighting circuits extending to the point of attachment with the Company's distribution system. The Company shall furnish, install, own and maintain the metering equipment and connect the customer's metered lighting circuit to its distribution system and supply the energy for operation of the customer's metered lighting system.

Monthly Rate**Secondary Power Supply Charge**

Energy Charge:

<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
\$0.050986	\$0.000000	\$0.050986	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-47.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-47.00

GENERAL SERVICE METERED LIGHTING RATE GML
(Continued From Sheet No. D-46.00)

Monthly Rate (Contd)

Secondary Delivery Charge

System Access Charge:	\$10.00	per customer per month
Distribution Charge:	\$0.065052	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

Primary Power Supply Charge

Energy Charge:

<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
\$0.025022	\$0.000000	\$0.025022	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Primary Delivery Charge

System Access Charge:	\$20.00	per customer per month
Distribution Charge:	\$0.049217	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

Net Metering Program

The Net Metering Program is available to any eligible customer as described in Rule C11., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.B, Net Metering Program.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., Net Metering Program.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

(Continued on Sheet No. D-48.00)

ATTACHMENT B

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-51.00

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-50.10)

Monthly Rate

The charge per luminaire per month shall be:

Nominal Rating of Lamps (One Lamp per Luminaire) (1)

<u>Type of Luminaire</u>	<u>Watts</u>	<u>Watts Including Ballast (2)</u>	<u>Lumens</u>	<u>Service Charge per Luminaire (4)</u>			<u>Fixture Charge per Luminaire (4)</u>
				<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
Mercury Vapor (3)	100	128	3,500	\$ 7.71	\$ 0.00	\$ 7.71	\$6.00
Mercury Vapor (3)	175	209	7,500	12.59	0.00	12.59	\$6.00
Mercury Vapor (3)	250	281	10,000	16.93	0.00	16.93	\$6.00
Mercury Vapor (3)	400	458	20,000	27.59	0.00	27.59	\$6.00
Mercury Vapor (3)	700	770	35,000	46.39	0.00	46.39	\$6.00
Mercury Vapor (3)	1,000	1,080	50,000	65.07	0.00	65.07	\$6.00
High-Pressure Sodium (3)	70	83	5,000	5.00	0.00	5.00	\$6.00
High-Pressure Sodium	100	117	8,500	7.05	0.00	7.05	\$6.00
High-Pressure Sodium	150	171	14,000	10.30	0.00	10.30	\$6.00
High-Pressure Sodium (3)	200	247	20,000	14.88	0.00	14.88	\$6.00
High-Pressure Sodium	250	318	24,000	19.16	0.00	19.16	\$6.00
High-Pressure Sodium	400	480	45,000	28.92	0.00	28.92	\$6.00
Fluorescent (3)	380	470	20,000	28.32	0.00	28.32	\$6.00
Incandescent (3)	202	202	2,500	12.17	0.00	12.17	\$6.00
Incandescent (3)	305	305	4,000	18.37	0.00	18.37	\$6.00
Incandescent (3)	405	405	6,000	24.40	0.00	24.40	\$6.00
Incandescent (3)	690	690	10,000	41.57	0.00	41.57	\$6.00
Metal Halide	150	170	9,750	10.24	0.00	10.24	\$6.00
Metal Halide (3)	175	210	10,500	12.65	0.00	12.65	\$6.00
Metal Halide	250	290	15,500	17.47	0.00	17.47	\$6.00
Metal Halide	400	460	24,000	27.71	0.00	27.71	\$6.00

- (1) Ratings for fluorescent lighting apply to all lamps in one luminaire.
- (2) Watts including ballast used for monthly billing of the Power Supply Cost Recovery (PSCR) Factor, Securitization and Securitization Tax Charges, Power Plant Securitization Charges and surcharges.
- (3) Rates apply to existing luminaires only and are not open to new business.
- (4) For customers who own their lighting fixtures and are assessed a Service Charge (but not a Fixture Charge), the charge per luminaire represents a 29.7% Power Supply Charge and a 70.3% Distribution Charge. For customers who do not own their lighting fixtures and are assessed both a Service Charge and a Fixture Charge, the charge per luminaire represents a 18.0% Power Supply Charge and a 82.0% Distribution Charge.

For energy conservation purposes, customers may, at their option, elect to have any or all luminaires served under this rate disconnected for a period of six months or more. The charge per luminaire per month, for each disconnected luminaire, shall be 40% of the monthly rate set forth above. However, should any such disconnected luminaire be reconnected at the customer's request after having been disconnected for less than six months, the monthly rate set forth above shall apply to the period of disconnection. An \$8.00 per luminaire disconnect/reconnect charge shall be made at the time of disconnection except that when the estimated disconnect/reconnect cost is significantly higher than \$8.00, the estimated cost per luminaire shall be charged.

For 24-hour mercury-vapor service, the charge per luminaire shall be 125% of the foregoing rates.

(Continued on Sheet No. D-52.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-54.01

GENERAL UNMETERED EXPERIMENTAL LIGHTING RATE GU-XL**Availability:**

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways for unmetered streetlighting service where the Company has existing distribution lines available for supplying energy for unmetered experimental lighting technology including light-emitting diode (LED) or for any Company-owned streetlighting system consisting of one or more luminaires. This rate is not available for resale purposes or for Retail Open Access Service. Installations under this rate shall require advanced approval by the Company and a written agreement.

Nature of Service:**Company-Owned Option**

In Company-owned systems, the Company shall select, furnish, install and own all equipment for any new unmetered experimental lighting or for any modifications to existing Company-owned equipment. The Company shall supply the energy and maintain all equipment. In areas where the Company's facilities are underground or required to be placed underground or the customer requests underground facilities, the unmetered lighting system shall be served from underground cables pursuant to the provisions contained in this Rate Schedule. In all other areas, the unmetered lighting system shall normally be served from overhead lines pursuant to the provisions contained in this Rate Schedule.

Customer-Owned Option

The capacity requirements of the customer-owned Unmetered Experimental Lighting served under this rate shall be determined by the Company based on verifiable documentation supplied by the customer. The Company shall have the right to test such capacity requirements. In the event that said tests show capacity requirements different from those indicated by the documentation supplied by the customer, the Company's test capacity value shall be used for billing purposes.

In customer-owned systems, control equipment shall be furnished and owned by the Company. The customer shall furnish, install and maintain the equipment comprising the unmetered experimental lighting system including, but not limited to, poles, the overhead wires or underground cables between the luminaires and the supply circuits extending to the point of attachment with the Company's lines. The customer's experimental lighting fixtures and equipment must be approved in advance by the Company before purchase and installation for service under this rate. The Company shall connect the customer's equipment to the Company's lines in a manner consistent with the Company's engineering standards, supply the energy and control the burning hours of the experimental lighting. Maintenance and replacement of the customer-owned equipment shall be the responsibility of the customer.

Existing unmetered installations with customer-owned fixtures on Company-owned distribution equipment must be converted to the customer-owned system described above or the Company-owned system described below to receive service under this Rate Schedule. Such installations may also be converted to a customer-owned metered system and receive service under Rate Schedule GML. Conversion costs shall be the responsibility of the customer.

Facilities Policy:**Company-Owned Option**

At the customer's request and following execution of a written agreement, the Company shall install experimental lighting and associated facilities it will make available under this rate under the following guidelines:

- A. The installation of all new, standard unmetered lights shall require a customer contribution of *\$100 per luminaire*. This policy includes the extension of up to 350 feet of distribution facilities to serve any individual light. Any extension beyond this amount shall require a contribution based on the Company's general service line extension policy. For unmetered lighting systems installed underground, the customer shall be required to contribute the estimated difference in cost between the equivalent standard overhead construction and required underground construction.
- B. The conversion of existing unmetered lights shall require a customer contribution per luminaire equal to the incremental additional cost to be incurred by the Company, less a discount of \$200 for the conversion of existing luminaires that are closed to new business if converted to the nearest equivalent fixture size available and approved by the Company.
- C. For light upgrades, such as the replacement of fixtures to a size greater or less than the next equivalent value, Company expenditures for additional facilities beyond those described above shall be calculated in accordance with the Company's general service line extension policy.

(Continued on Sheet No. D-54.02)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-54.02

GENERAL UNMETERED EXPERIMENTAL LIGHTING RATE GU-XL

(Continued From Sheet No. D-54.01)

Facilities Policy (Contd)**Company-Owned Option (Contd)**

- D. The Company will determine the type and size of all experimental lighting fixtures to be offered under this rate. The list of approved fixtures is subject to modification at the sole discretion of the Company to accommodate new product development and advances in technology. Upon customer request, the Company shall provide a list of experimental lighting available under this rate.
- E. The Company shall determine all associated equipment necessary to provide service under the Company-Owned Unmetered Experimental Lighting option.
- F. Any charges, deposits or contributions may be required in advance of commencement of construction.
- G. *At the Company's discretion, any failed lighting fixtures may be converted to an equivalent LED at no cost to the customer if the customer agrees to the conversion. The replaced fixture will then be moved to General Unmetered Experimental Lighting Rate GU-XL upon completion of the installation.*

Customer-Owned Option

If it is necessary for the Company to install distribution facilities to serve a customer-owned system, contributions and/or deposits for such additional facilities shall be calculated in accordance with the Company's general service line extension policy. Any charges, deposits or contributions may be required in advance of commencement of construction.

Monthly Rate**Power Supply Charges****Energy Charge:**

<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
\$0.059553	\$0.00000	\$0.059553	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges Customer-Owned Option

Distribution Charge: \$0.025336 per kWh for all kWh

Delivery Charges Company-Owned Option

Distribution Charge: \$0.031076 per kWh for all kWh

Fixture Charge per Luminaire: \$6.00 per month

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Determination of Monthly Kilowatt-Hours and Burning Hours per Month Based on 4,200 Burning Hours per Year:

The monthly kilowatt-hours shall be determined by multiplying the total capacity requirements in watts (including the lamps, ballasts, drivers, and control devices) times the monthly Burning Hours as defined below divided by 1,000. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made, and modifying the lighting contract with the Company accordingly.

Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
457.8	382.2	369.6	306.6	264.6	226.8	252.0	298.2	336.0	399.0	432.6	474.6	4,200

Hours of Lighting:

Unmetered Experimental Lighting shall be burning at all times when the natural general level of illumination is lower than about 3/4 footcandle, and under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. Lighting service will be supplied from dusk to dawn every night and all night on an operating schedule of approximately 4,200 hours per year.

(Continued on Sheet No. D-54.03)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. D-54.10

GENERAL SERVICE UNMETERED RATE GU

Availability:

Subject to any restrictions, this rate is available to the US Government, any political subdivision or agency of the State of Michigan, and any public or private school district for filament and/or gaseous discharge lamp installations maintained for traffic regulation or guidance, as distinguished from street illumination and police signal systems. Lighting for traffic regulation may use experimental lighting technology including light-emitting diode (LED). This rate is also available to Community Antenna Television Service Companies (CATV), Wireless Access Companies or Security Camera Companies for unmetered Power Supply Units. Where the Company's total investment to serve an individual location exceeds three times the annual revenue to be derived from such location, a contribution to the Company shall be required for the excess.

This rate is not available for resale purposes, new roadway lighting or for Retail Open Access Service.

Nature of Service:

Customer furnishes and installs all fixtures, lamps, ballasts, controls, amplifiers and other equipment, including wiring to point of connection with Company's overhead or underground system, as directed by the Company. Company furnishes and installs, where required for center suspended overhead traffic light signals, messenger cable and supporting wood poles and also makes final connections to its lines. If, in the Company's opinion, the installation of wood poles for traffic lights is not practical, the customer shall furnish, install and maintain suitable supports other than wood poles. The customer shall maintain the equipment, including lamp renewals, and the Company shall supply the energy for the operation of the equipment. Conversion and/or relocation costs of existing facilities shall be paid for by the customer except when initiated by the Company.

The capacity requirements of the lamp(s), associated ballast(s) and control equipment for each luminaire shall be determined by the Company from the specifications furnished by the manufacturers of such equipment, provided that the Company shall have the right to test such capacity requirements from time to time. In the event that said tests shall show capacity requirements different from those indicated by the manufacturers' specifications, the capacity requirements shown by said tests shall control. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Monthly Rate:**Power Supply Charges:****Energy Charge:**

<i>Non-Capacity</i>	<i>Capacity</i>	<i>Total</i>	
<i>\$0.056376</i>	<i>\$0.018011</i>	<i>\$0.074387</i>	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges:

System Access Charge:	\$2.00	per customer per month
Distribution Charge:	<i>\$0.017001</i>	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-55.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. E-11.00

(Continued From Sheet No. E-10.00)

E2. ROA CUSTOMER SECTION (Contd)**E2.5 Term, Commencement of Service, and Return to Company Full Service (Contd)****C. Return to Company Full Service – Non-Residential ROA Customers (Contd)**

For ROA Non-Residential Customers that violate the December 1 written notice requirement, the market based rate shall be adjusted as follows:

- (1) For market based rate (1) above, a 10% adder shall apply to the power supply costs for bills rendered during the June through September billing months.
- (2) For market based rate (2) above, a 10% adder shall apply to the MISO Real Time Locational Marginal Price for its CONS.CETR node for bills rendered during the June through September billing months.

D. Return to Company Full Service – Residential ROA Customers

Only the ROA Customer may initiate the return to Company Full Service by contacting the Company. The Company has no obligation to verify that the ROA Customer is eligible to terminate the service under the terms of a contract with its Retailer.

Upon completion of the ROA Customer's bill cycle for ROA service, the ROA Customer may return to Company Full Service at the beginning of the customer's next billing cycle by giving the Company written notice. A ROA Customer who so notifies the Company shall be obligated to take Company Full Service from the Company for a minimum of twelve months and pay for such service at any Company Full Service residential rate for which the customer qualifies.

Written notice is required from all ROA Customers returning to Company Full Service, except for Retailer defaults or Slamming. Once the ROA Customer provides written notice to the Company of its intent to Return to Company Full Service, in accordance with the notification requirements set forth in this rule, the ROA Customer may not rescind its notice.

Slammed Customer: In the event a ROA Customer returns to Company Full Service because the ROA Customer was Slammed by a Retailer, the Company will waive all notice and minimum term requirements. The ROA Customer who was Slammed shall be immediately reinstated to the customer's Company Full Service rate the customer was transferred from prior to being Slammed.

State Reliability Mechanism *In the event that a ROA customer is subject to the State Reliability Mechanism (SRM) pursuant to Public Act 341 of 2016, their energy allotment will continue to be counted against the 10% cap as defined in Public Act 295 of 2008.*

(Continued on Sheet No. E-12.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. E-23.00

RETAIL OPEN ACCESS RESIDENTIAL SECONDARY RATE ROA-R

(Continued From Sheet No. E-22.00)

RETAILER**Monthly Rate - Retailer:****Transmission Service:**

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

Real Power Losses:

The Retailer is responsible for replacing Real Power Losses of 7.239% on the Company's Distribution System associated with the movement of Power and for compensation for losses.

General Terms and Conditions:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Term and Form of Contract - Retailer:

All service under this rate shall require a written ROA Service Contract between the Company and a Retailer.

ROA CUSTOMER**Monthly Rate - ROA Customer:****ROA System Access Charge, Distribution Charge, General Terms, Minimum Charge and Due Date and Late Payment Charge:**

The System Access Charge, Distribution Charge, General Terms, Minimum Charge and the Due Date and Late Payment Charge shall be as provided for under the ROA Customer's otherwise applicable Company Full Service rate.

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10. Customers taking ROA service on December 6, 2013 are excluded from the Power Plant Securitization Charges. This exclusion does not apply to customers first taking ROA service after December 6, 2013 or to customers taking service on December 6, 2013 who discontinue taking ROA service any time after December 6, 2013. Customers who discontinue taking ROA service any time after December 6, 2013 and who return to ROA service shall pay the Power Plant Securitization Charges applicable to the customer's otherwise applicable Company Full Service Rate Schedule.

State Reliability Mechanism for ROA:

Beginning June 1, 2018 all ROA customers may be subject to a State Reliability Mechanism Capacity Charge. This charge shall not apply to ROA customers for any planning year in which their Alternative Electric Supplier can demonstrate to the Commission that it can meet its capacity obligations by the seventh business day of February each year starting in 2018.

If a capacity charge is required to be paid in the planning year beginning June 1, 2018, or any of the three subsequent planning years, due to the Alternative Electric Supplier not meeting its capacity obligations, then the capacity charge is applicable for each of those planning years. Any capacity charged required to be paid any time after the first initial four-year period shall be applicable for a single year. The planning year is defined as being June 1 through the following May 31 of each year. The capacity charge paid by ROA customers will be the same amount as a Full Service Customer on the otherwise applicable Rate Schedule. Non-capacity charges shall not apply.

ROA Customer Switching Service Charge:

A \$5.00 switching fee shall be charged the ROA Customer each time a ROA Customer switches (i) from one Retailer to another or (ii) from ROA to a Company Full Service rate. The ROA Customer may switch Retailers at the end of any billing month by having their new Retailer give the Company at least 30 days' written notice. The Company will notify the ROA Customer's previous Retailer and new Retailer electronically of the effective date of the switch. The ROA Customer may choose to return to Company Full Service at the end of any billing month in compliance with Rule

E2.5 D., Return to Company Full Service - Residential ROA Customers. The ROA Customer Switching Service Charge shall not be applied (i) for the initial switch to ROA Service or (ii) at the time the ROA Customer returns to Company Full Service or another Retailer because the ROA Customer was Slammed by the Retailer.

Term and Form of Contract - ROA Customer:

Service under this rate shall not require a ROA Service Contract between the Company and a ROA Customer.

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. E-26.00

RETAIL OPEN ACCESS SECONDARY RATE ROA-S

(Continued From Sheet No. E-25.00)

ROA CUSTOMER**Monthly Rate - ROA Customer:**

ROA System Access Charge, Distribution Charge, General Terms, Adjustment for Power Factor, Minimum Charge and Due Date and Late Payment Charge:

The System Access Charge, Distribution Charge, General Terms, Adjustment for Power Factor, Minimum Charge and the Due Date and Late Payment Charge shall be as provided for under the ROA Customer's otherwise applicable Company Full Service rate.

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10. Customers taking ROA service on December 6, 2013 are excluded from the Power Plant Securitization Charges. This exclusion does not apply to customers first taking ROA service after December 6, 2013 or to customers taking service on December 6, 2013 who discontinue taking ROA service any time after December 6, 2013. Customers who discontinue taking ROA service any time after December 6, 2013 and who return to ROA service will pay the Power Plant Securitization Charges applicable to the customer's otherwise applicable Company Full Service Rate Schedule.

State Reliability Mechanism for ROA:

Beginning June 1, 2018 all ROA customers may be subject to a State Reliability Mechanism Capacity Charge. This charge shall not apply to ROA customers for any planning year in which their Alternative Electric Supplier can demonstrate to the Commission that it can meet its capacity obligations by the seventh business day of February each year starting in 2018.

If a capacity charge is required to be paid in the planning year beginning June 1, 2018, or any of the three subsequent planning years, due to the Alternative Electric Supplier not meeting its capacity obligations, then the capacity charge is applicable for each of those planning years. Any capacity charged required to be paid any time after the first initial four-year period shall be applicable for a single year. The planning year is defined as being June 1 through the following May 31 of each year. The capacity charge paid by ROA customers will be the same amount as a Full Service Customer on the otherwise applicable Rate Schedule. Non-capacity charges shall not apply.

ROA Customer Switching Service Charge:

A \$5.00 switching fee shall be charged the ROA Customer each time a ROA Customer switches (i) from one Retailer to another or (ii) from ROA to a Company Full Service rate. The ROA Customer may switch Retailers at the end of any billing month by having their new Retailer give the Company at least 30 days' written notice. The Company will notify the ROA Customer's previous Retailer and new Retailer electronically of the effective date of the switch. The ROA Customer may choose to return to Company Full Service at the end of any billing month in compliance with Rule E2.5 C., Return to Company Full Service - Non-Residential ROA Customers. The ROA Customer Switching Service Charge shall not be applied (i) for the initial switch to ROA Service or (ii) at the time the ROA Customer returns to Company Full Service or another Retailer because the ROA Customer was Slammed by the Retailer.

Term and Form of Contract - ROA Customer:

All service under this rate has a minimum term of two years.

All resale service under this rate shall require a written ROA Service Contract, with a minimum term of two years, between the Company and a ROA Customer.

All service under this rate shall require a written ROA Service Contract, with a minimum term of two years, between the Company and a ROA Customer with a Maximum Demand of 300 kW or more.

For a ROA Customer with a Maximum Demand of less than 300 kW, service under this rate may, at the Company's option, require a written ROA Service Contract with a minimum term of two years.

A new ROA Service Contract will not be required for an existing ROA Customer who increases their demand requirements after initiating service unless new or additional facilities are required.

M.P.S.C. No. 13 - Electric
Consumers Energy Company

Sheet No. E-28.00

RETAIL OPEN ACCESS PRIMARY RATE ROA-P
(Continued From Sheet No. E-27.00)**RETAILER** (Contd)**Monthly Rate - Retailer: (Contd)****General Terms and Conditions:**

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Term and Form of Contract - Retailer:

All service under this rate shall require a written ROA Service Contract between the Company and a Retailer.

ROA CUSTOMER**Monthly Rate - ROA Customer:****ROA System Access Charge, Distribution Charge, General Terms, Adjustment for Power Factor, Substation Ownership Credit, Minimum Charge and Due Date and Late Payment Charge:**

The System Access Charge, Distribution Charge, General Terms, Adjustment for Power Factor, Substation Ownership Credit, Minimum Charge and the Due Date and Late Payment Charge shall be as provided for under the ROA Customer's otherwise applicable Company Full Service rate.

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10. Customers taking ROA service on December 6, 2013 are excluded from the Power Plant Securitization Charges. This exclusion does not apply to customers first taking ROA service after December 6, 2013 or to customers taking service on December 6, 2013 who discontinue taking ROA service any time after December 6, 2013. Customers who discontinue taking ROA service any time after December 6, 2013 and who return to ROA service will pay the Power Plant Securitization Charges applicable to the customer's otherwise applicable Company Full Service Rate Schedule.

State Reliability Mechanism for ROA:

Beginning June 1, 2018 all ROA customers may be subject to a State Reliability Mechanism Capacity Charge. This charge shall not apply to ROA customers for any planning year in which their Alternative Electric Supplier can demonstrate to the Commission that it can meet its capacity obligations by the seventh business day of February each year starting in 2018.

If a capacity charge is required to be paid in the planning year beginning June 1, 2018, or any of the three subsequent planning years, due to the Alternative Electric Supplier not meeting its capacity obligations, then the capacity charge is applicable for each of those planning years. Any capacity charged required to be paid any time after the first initial four-year period shall be applicable for a single year. The planning year is defined as being June 1 through the following May 31 of each year. The capacity charge paid by ROA customers will be the same amount as a Full Service Customer on the otherwise applicable Rate Schedule. Non-capacity charges shall not apply.

ROA Customer Switching Service Charge:

A \$5.00 switching fee shall be charged the ROA Customer each time a ROA Customer switches (i) from one Retailer to another or (ii) from ROA to a Company Full Service rate. The ROA Customer may switch Retailers at the end of any billing month by having their new Retailer give the Company at least 30 days' written notice. The Company will notify the ROA Customer's previous Retailer and new Retailer electronically of the effective date of the switch. The ROA Customer may choose to return to Company Full Service at the end of any billing month in compliance with Rule E2.5 C., Return to Company Full Service - Non-Residential ROA Customers. The ROA Customer Switching Service Charge shall not be applied (i) for the initial switch to ROA Service or (ii) at the time the ROA Customer returns to Company Full Service or another Retailer because the ROA Customer was Slammed by the Retailer.

Term and Form of Contract - ROA Customer:

All service under this rate has a minimum term of two years.

All resale service under this rate shall require a written ROA Service Contract, with a minimum term of two years, between the Company and a ROA Customer.

All service under this rate shall require a written ROA Service Contract, with a minimum term of two years, between the Company and a ROA Customer with a Maximum Demand of 300 kW or more.

For a ROA Customer with a Maximum Demand of less than 300 kW, service under this rate may, at the Company's option, require a written ROA Service Contract with a minimum term of two years.

A new ROA Service Contract will not be required for an existing ROA Customer who increases their demand requirements after initiating service unless new or additional facilities are required.

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-18322
ATTACHMENT C

Consumers Energy Company
Capacity Related Cost and Charge Calculation

<u>Line</u>	<u>Description</u> (a)	<u>Total</u> <u>Electric</u> (b)
1	Total Production Related Costs	\$ 2,937,208
2	<u>Non-Capacity Related Costs:</u>	
3	Fuel Expense	565,262
4	Purchased & Interchanged	454,687
5	Other O&M Expense	62,491
6	PSCR Revenue Credits	(143,507)
7	Non-PSCR Revenue Credits	(12,581)
8	Transmission Expense	429,656
9	Non-Capacity Related Costs:	<u>1,356,009</u>
10	Capacity Related Costs	<u>\$ 1,581,199</u>
11	<u>U-18239 Offsets</u>	
12	Energy Market Sales	1,022,880
13	Off-System Energy Sales	12,000
14	Ancillary Service Sales	25,128
15	Bilateral Energy Sales	-
16	Revenue	<u>1,060,009</u>
17	Related Fuel Costs	<u>408,807</u>
18	Net Revenue Less Fuel Costs	<u>651,202</u>
19	Net Capacity Cost	<u>929,997</u>
20		
21	U-18239 Capacity Charge Demand	<u>8,331,000</u>
22	Capacity Charge	<u>\$305.84</u> MW/Day

PROOF OF SERVICE

STATE OF MICHIGAN)

Case No. U-18322

County of Ingham)

Lisa Felice being duly sworn, deposes and says that on March 29, 2018 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).



Lisa Felice

Subscribed and sworn to before me
this March 29 day of March 2018



Steven J. Cook
Notary Public, Ingham County, Michigan
As acting in Eaton County
My Commission Expires: April 30, 2018

Service List for Case: U-18322

Name	Email Address
Amit T. Singh	singha9@michigan.gov
Anne Uitvlugt	anne.uitvlugt@cmsenergy.com
Bret A. Totoraitis	bret.totoraitis@cmsenergy.com
Brian W. Coyer	bwcoyer@publiclawresourcecenter.com
Bryan A. Brandenburg	bbrandenburg@clarkhill.com
Christopher M. Bzdok	chris@envlaw.com
Consumers Energy Company 1 of 2	mpsc.filings@cmsenergy.com
Consumers Energy Company 2 of 2	matorrey@cmsenergy.com
David E.S. Marvin	dmarvin@fraserlawfirm.com
Don L. Keskey	donkeskey@publiclawresourcecenter.com
Gary A. Gensch Jr.	gary.genschjr@cmsenergy.com
H. Richard Chambers	hrchambers@cmsenergy.com
Jason T. Hanselman	jhanselman@dykema.com
Jennifer U. Heston	jheston@fraserlawfirm.com
Jody Kyler Cohn	jkylercohn@bkllawfirm.com
Joel King	kingj38@michigan.gov
John A. Janiszewski	janiszewskij2@michigan.gov
John R. Canzano	jcanzano@michworkerlaw.com
John R. Liskey	john@liskeypllc.com
Kelly M. Hall	kelly.hall@cmsenergy.com
Kurt J. Boehm	kboehm@bkllawfirm.com
Laura A. Chappelle	lachappelle@varnumlaw.com
Lauren D. Donofrio	donofriol@michigan.gov
Margrethe Kearney	mkearney@elpc.org
Melissa M. Horne	mhorne@hcc-law.com
Meredith R. Beidler	beidlerm@michigan.gov
Michael C. Soules	msoules@earthjustice.org
Michael J. Pattwell	mpattwell@clarkhill.com
Michael S. Ashton	mashton@fraserlawfirm.com
Michael Torrey	matorrey@cmsenergy.com
Monica M. Stephens	stephensm11@michigan.gov
Patricia F. Sharkey	psharkey@e-lawcounsel.com
Patrick J. Rorai	prorai@michworkerlaw.com
Richard J. Aaron	raaron@dykema.com
Robert W. Beach	robert.beach@cmsenergy.com
Sean P. Gallagher	sgallagher@clarkhill.com
Shannon Fisk	sfisk@earthjustice.org
Sharon Feldman	feldmans@michigan.gov
Spencer A. Sattler	sattlers@michigan.gov
Theresa A.G. Staley	theresa.staley@cmsenergy.com
Tim Lundgren	tjlundgren@varnumlaw.com

Toni L. Newell
Tracy Jane Andrews

tlnewell@varnumlaw.com
tjandrews@envlaw.com

Witness Crowe CAPM Anaysis Excluding Dominion and National Fuel Gas

[illegible]

Witness Crowe CAPM Analysis Full Proxy Group - 200% Outlier Test

Company	Ticker	Div Yield	Proj. Growth	Cost of Equity	Risk-free rate	Risk Premium	Beta	Unadjusted Ke	Market Cap (\$MM)	Size Adjustment	Implied Cost of Equity
Dominion Energy, Inc	D	2.57%	7.95%	10.52%	1.69%	8.83%	0.8	8.75%	72,557	-0.29%	8.46%
Kinder Morgan Inc.	KMI	2.57%	7.95%	10.52%	1.69%	8.83%	1.3	13.17%	36,522	-0.29%	12.88%
National Fuel Gas Company	NFG	2.57%	7.95%	10.52%	1.69%	8.83%	0.7	7.87%	3,716	1.26%	9.13%
TC Energy Corporation	TRP	2.57%	7.95%	10.52%	1.69%	8.83%	1.05	10.96%	43,138	-0.29%	10.67%
The Williams Companies, Inc.	WMB	2.57%	7.95%	10.52%	1.69%	8.83%	1.6	15.82%	25,061	0.50%	16.32%

High End Outlier	<div>200%</div> of median	low	8.46%
		high	16.32%
		Median	10.67%
		Outlier Test	21.34%
		No Outliers	

Witness Crowe CAPM Analysis Full Proxy Group - 200% Outlier Test

Company	Ticker	Div Yield	Proj. Growth	Cost of Equity	Risk-free rate	Risk Premium	Beta	Unadjusted Ke	Market Cap (\$MM)	Size Adjustment	Implied Cost of Equity
Dominion Energy, Inc	D	2.57%	7.95%	10.52%	1.69%	8.83%	0.8	8.75%	72,557	-0.29%	
Kinder Morgan Inc.	KMI	2.57%	7.95%	10.52%	1.69%	8.83%	1.3	13.17%	36,522	-0.29%	12.88%
National Fuel Gas Company	NFG	2.57%	7.95%	10.52%	1.69%	8.83%	0.7	7.87%	3,716	1.26%	
TC Energy Corporation	TRP	2.57%	7.95%	10.52%	1.69%	8.83%	1.05	10.96%	43,138	-0.29%	10.67%
The Williams Companies, Inc.	WMB	2.57%	7.95%	10.52%	1.69%	8.83%	1.6	15.82%	25,061	0.50%	16.32%

High End Outlier	<div>200%</div> of median	low	10.67%
		high	16.32%
		Median	12.88%
		Outlier Test	25.76%
		No Outliers	

Start Date 1/2/2003
End Date 6/30/2020

Dates	VIX Index Last Price PX_LAST
1/2/2006	12.07
1/3/2006	11.14
1/4/2006	11.37
1/5/2006	11.31
1/6/2006	11
1/9/2006	11.13
1/10/2006	10.86
1/11/2006	10.94
1/12/2006	11.2
1/13/2006	11.23
1/16/2006	11.23
1/17/2006	11.91
1/18/2006	12.25
1/19/2006	11.98
1/20/2006	14.56
1/23/2006	13.93
1/24/2006	13.31
1/25/2006	12.87
1/26/2006	12.42
1/27/2006	11.97
1/30/2006	12.39
1/31/2006	12.95
2/1/2006	12.36
2/2/2006	13.23
2/3/2006	12.96
2/6/2006	13.04
2/7/2006	13.59
2/8/2006	12.83
2/9/2006	13.12
2/10/2006	12.87
2/13/2006	13.35
2/14/2006	12.25
2/15/2006	12.31
2/16/2006	11.48
2/17/2006	12.01
2/20/2006	12.01
2/21/2006	12.41
2/22/2006	11.88
2/23/2006	11.87
2/24/2006	11.46
2/27/2006	11.59
2/28/2006	12.34
3/1/2006	11.54
3/2/2006	11.72
3/3/2006	11.96
3/6/2006	12.74
3/7/2006	12.66
3/8/2006	12.32
3/9/2006	12.68
3/10/2006	11.85
3/13/2006	11.37
3/14/2006	10.74
3/15/2006	11.35
3/16/2006	11.98
3/17/2006	12.12
3/20/2006	11.79
3/21/2006	11.62
3/22/2006	11.21
3/23/2006	11.17
3/24/2006	11.19
3/27/2006	11.46
3/28/2006	11.58
3/29/2006	10.95
3/30/2006	11.57
3/31/2006	11.39
4/3/2006	11.57
4/4/2006	11.14
4/5/2006	11.13
4/6/2006	11.45
4/7/2006	12.26

4/10/2006	12.19
4/11/2006	13
4/12/2006	12.76
4/13/2006	12.38
4/14/2006	12.38
4/17/2006	12.58
4/18/2006	11.4
4/19/2006	11.32
4/20/2006	11.64
4/21/2006	11.59
4/24/2006	11.75
4/25/2006	11.75
4/26/2006	11.76
4/27/2006	11.84
4/28/2006	11.59
5/1/2006	12.54
5/2/2006	11.99
5/3/2006	11.99
5/4/2006	11.86
5/5/2006	11.62
5/8/2006	12
5/9/2006	11.99
5/10/2006	11.78
5/11/2006	12.49
5/12/2006	14.19
5/15/2006	13.57
5/16/2006	13.35
5/17/2006	16.26
5/18/2006	16.99
5/19/2006	17.18
5/22/2006	17.72
5/23/2006	18.26
5/24/2006	17.36
5/25/2006	15.5
5/26/2006	14.26
5/29/2006	14.26
5/30/2006	18.66
5/31/2006	16.44
6/1/2006	14.52
6/2/2006	14.32
6/5/2006	16.65
6/6/2006	17.34
6/7/2006	17.8
6/8/2006	18.35
6/9/2006	18.12
6/12/2006	20.96
6/13/2006	23.81
6/14/2006	21.46
6/15/2006	15.9
6/16/2006	17.25
6/19/2006	17.83
6/20/2006	16.69
6/21/2006	15.52
6/22/2006	15.88
6/23/2006	15.89
6/26/2006	15.62
6/27/2006	16.4
6/28/2006	15.79
6/29/2006	13.03
6/30/2006	13.08
7/3/2006	13.05
7/4/2006	13.05
7/5/2006	14.15
7/6/2006	13.65
7/7/2006	13.97
7/10/2006	14.02
7/11/2006	13.14
7/12/2006	14.49
7/13/2006	17.79
7/14/2006	18.05
7/17/2006	18.64
7/18/2006	17.74
7/19/2006	15.55
7/20/2006	16.21
7/21/2006	17.4
7/24/2006	14.98

7/25/2006	14.85
7/26/2006	14.62
7/27/2006	14.94
7/28/2006	14.33
7/31/2006	14.95
8/1/2006	15.05
8/2/2006	14.34
8/3/2006	14.46
8/4/2006	14.34
8/7/2006	15.23
8/8/2006	15.23
8/9/2006	15.2
8/10/2006	14.46
8/11/2006	14.3
8/14/2006	14.26
8/15/2006	13.42
8/16/2006	12.41
8/17/2006	12.24
8/18/2006	11.64
8/21/2006	12.22
8/22/2006	12.19
8/23/2006	12.4
8/24/2006	12.4
8/25/2006	12.31
8/28/2006	12.18
8/29/2006	12.28
8/30/2006	12.22
8/31/2006	12.31
9/1/2006	11.96
9/4/2006	11.96
9/5/2006	12.63
9/6/2006	13.74
9/7/2006	13.88
9/8/2006	13.16
9/11/2006	12.99
9/12/2006	11.92
9/13/2006	11.18
9/14/2006	11.55
9/15/2006	11.76
9/18/2006	11.78
9/19/2006	11.98
9/20/2006	11.39
9/21/2006	12.25
9/22/2006	12.59
9/25/2006	12.12
9/26/2006	11.53
9/27/2006	11.58
9/28/2006	11.72
9/29/2006	11.98
10/2/2006	12.57
10/3/2006	12.24
10/4/2006	11.86
10/5/2006	11.98
10/6/2006	11.56
10/9/2006	11.68
10/10/2006	11.52
10/11/2006	11.62
10/12/2006	11.09
10/13/2006	10.75
10/16/2006	11.09
10/17/2006	11.73
10/18/2006	11.34
10/19/2006	10.9
10/20/2006	10.63
10/23/2006	11.08
10/24/2006	10.78
10/25/2006	10.66
10/26/2006	10.56
10/27/2006	10.8
10/30/2006	11.2
10/31/2006	11.1
11/1/2006	11.51
11/2/2006	11.42
11/3/2006	11.16
11/6/2006	11.16
11/7/2006	11.09

11/8/2006	10.75
11/9/2006	11.01
11/10/2006	10.79
11/13/2006	10.86
11/14/2006	10.5
11/15/2006	10.31
11/16/2006	10.16
11/17/2006	10.05
11/20/2006	9.97
11/21/2006	9.9
11/22/2006	10.14
11/23/2006	10.14
11/24/2006	10.73
11/27/2006	12.3
11/28/2006	11.62
11/29/2006	10.83
11/30/2006	10.91
12/1/2006	11.66
12/4/2006	11.23
12/5/2006	11.27
12/6/2006	11.33
12/7/2006	12.67
12/8/2006	12.07
12/11/2006	10.71
12/12/2006	10.65
12/13/2006	10.18
12/14/2006	9.97
12/15/2006	10.05
12/18/2006	10.6
12/19/2006	10.3
12/20/2006	10.26
12/21/2006	10.53
12/22/2006	11.36
12/25/2006	11.36
12/26/2006	11.26
12/27/2006	10.64
12/28/2006	10.99
12/29/2006	11.56
1/1/2007	11.56
1/2/2007	11.56
1/3/2007	12.04
1/4/2007	11.51
1/5/2007	12.14
1/8/2007	12
1/9/2007	11.91
1/10/2007	11.47
1/11/2007	10.87
1/12/2007	10.15
1/15/2007	10.15
1/16/2007	10.74
1/17/2007	10.59
1/18/2007	10.85
1/19/2007	10.4
1/22/2007	10.77
1/23/2007	10.34
1/24/2007	9.89
1/25/2007	11.22
1/26/2007	11.13
1/29/2007	11.45
1/30/2007	10.96
1/31/2007	10.42
2/1/2007	10.31
2/2/2007	10.08
2/5/2007	10.55
2/6/2007	10.65
2/7/2007	10.32
2/8/2007	10.44
2/9/2007	11.1
2/12/2007	11.61
2/13/2007	10.34
2/14/2007	10.23
2/15/2007	10.22
2/16/2007	10.02
2/19/2007	10.02
2/20/2007	10.24
2/21/2007	10.2

2/22/2007	10.18
2/23/2007	10.58
2/26/2007	11.15
2/27/2007	18.31
2/28/2007	15.42
3/1/2007	15.82
3/2/2007	18.61
3/5/2007	19.63
3/6/2007	15.96
3/7/2007	15.24
3/8/2007	14.29
3/9/2007	14.09
3/12/2007	13.99
3/13/2007	18.13
3/14/2007	17.27
3/15/2007	16.43
3/16/2007	16.79
3/19/2007	14.59
3/20/2007	13.27
3/21/2007	12.19
3/22/2007	12.93
3/23/2007	12.95
3/26/2007	13.16
3/27/2007	13.48
3/28/2007	14.98
3/29/2007	15.14
3/30/2007	14.64
4/2/2007	14.53
4/3/2007	13.46
4/4/2007	13.24
4/5/2007	13.23
4/6/2007	13.23
4/9/2007	13.14
4/10/2007	12.68
4/11/2007	13.49
4/12/2007	12.71
4/13/2007	12.2
4/16/2007	11.98
4/17/2007	12.14
4/18/2007	12.42
4/19/2007	12.54
4/20/2007	12.07
4/23/2007	13.04
4/24/2007	13.12
4/25/2007	13.21
4/26/2007	12.79
4/27/2007	12.45
4/30/2007	14.22
5/1/2007	13.51
5/2/2007	13.08
5/3/2007	13.09
5/4/2007	12.91
5/7/2007	13.15
5/8/2007	13.21
5/9/2007	12.88
5/10/2007	13.6
5/11/2007	12.95
5/14/2007	13.96
5/15/2007	14.01
5/16/2007	13.5
5/17/2007	13.51
5/18/2007	12.76
5/21/2007	13.3
5/22/2007	13.06
5/23/2007	13.24
5/24/2007	14.08
5/25/2007	13.34
5/28/2007	13.34
5/29/2007	13.53
5/30/2007	12.83
5/31/2007	13.05
6/1/2007	12.78
6/4/2007	13.29
6/5/2007	13.63
6/6/2007	14.87
6/7/2007	17.06

6/8/2007	14.84
6/11/2007	14.71
6/12/2007	16.67
6/13/2007	14.73
6/14/2007	13.64
6/15/2007	13.94
6/18/2007	13.42
6/19/2007	12.85
6/20/2007	14.67
6/21/2007	14.21
6/22/2007	15.75
6/25/2007	16.65
6/26/2007	18.89
6/27/2007	15.53
6/28/2007	15.54
6/29/2007	16.23
7/2/2007	15.4
7/3/2007	14.92
7/4/2007	14.92
7/5/2007	15.48
7/6/2007	14.72
7/9/2007	15.16
7/10/2007	17.57
7/11/2007	16.64
7/12/2007	15.54
7/13/2007	15.15
7/16/2007	15.59
7/17/2007	15.63
7/18/2007	16
7/19/2007	15.23
7/20/2007	16.95
7/23/2007	16.81
7/24/2007	18.55
7/25/2007	18.1
7/26/2007	20.74
7/27/2007	24.17
7/30/2007	20.87
7/31/2007	23.52
8/1/2007	23.67
8/2/2007	21.22
8/3/2007	25.16
8/6/2007	22.94
8/7/2007	21.56
8/8/2007	21.45
8/9/2007	26.48
8/10/2007	28.3
8/13/2007	26.57
8/14/2007	27.68
8/15/2007	30.67
8/16/2007	30.83
8/17/2007	29.99
8/20/2007	26.33
8/21/2007	25.25
8/22/2007	22.89
8/23/2007	22.62
8/24/2007	20.72
8/27/2007	22.72
8/28/2007	26.3
8/29/2007	23.81
8/30/2007	25.06
8/31/2007	23.38
9/3/2007	23.38
9/4/2007	22.78
9/5/2007	24.58
9/6/2007	23.99
9/7/2007	26.23
9/10/2007	27.38
9/11/2007	25.27
9/12/2007	24.96
9/13/2007	24.76
9/14/2007	24.92
9/17/2007	26.48
9/18/2007	20.35
9/19/2007	20.03
9/20/2007	20.45
9/21/2007	19

9/24/2007	19.37
9/25/2007	18.6
9/26/2007	17.63
9/27/2007	17
9/28/2007	18
10/1/2007	17.84
10/2/2007	18.49
10/3/2007	18.8
10/4/2007	18.44
10/5/2007	16.91
10/8/2007	17.46
10/9/2007	16.12
10/10/2007	16.67
10/11/2007	18.88
10/12/2007	17.73
10/15/2007	19.25
10/16/2007	20.02
10/17/2007	18.54
10/18/2007	18.5
10/19/2007	22.96
10/22/2007	21.64
10/23/2007	20.41
10/24/2007	20.8
10/25/2007	21.17
10/26/2007	19.56
10/29/2007	19.87
10/30/2007	21.07
10/31/2007	18.53
11/1/2007	23.21
11/2/2007	23.01
11/5/2007	24.31
11/6/2007	21.39
11/7/2007	26.49
11/8/2007	26.16
11/9/2007	28.5
11/12/2007	31.09
11/13/2007	24.1
11/14/2007	25.94
11/15/2007	28.06
11/16/2007	25.49
11/19/2007	26.01
11/20/2007	24.88
11/21/2007	26.84
11/22/2007	26.84
11/23/2007	25.61
11/26/2007	28.91
11/27/2007	26.28
11/28/2007	24.11
11/29/2007	23.97
11/30/2007	22.87
12/3/2007	23.61
12/4/2007	23.79
12/5/2007	22.53
12/6/2007	20.96
12/7/2007	20.85
12/10/2007	20.74
12/11/2007	23.59
12/12/2007	22.47
12/13/2007	22.56
12/14/2007	23.27
12/17/2007	24.52
12/18/2007	22.64
12/19/2007	21.68
12/20/2007	20.58
12/21/2007	18.47
12/24/2007	18.6
12/25/2007	18.6
12/26/2007	18.66
12/27/2007	20.26
12/28/2007	20.74
12/31/2007	22.5
1/1/2008	22.5
1/2/2008	23.17
1/3/2008	22.49
1/4/2008	23.94
1/7/2008	23.79

1/8/2008	25.43
1/9/2008	24.12
1/10/2008	23.45
1/11/2008	23.68
1/14/2008	22.9
1/15/2008	23.34
1/16/2008	24.38
1/17/2008	28.46
1/18/2008	27.18
1/21/2008	27.18
1/22/2008	31.01
1/23/2008	29.02
1/24/2008	27.78
1/25/2008	29.08
1/28/2008	27.78
1/29/2008	27.32
1/30/2008	27.62
1/31/2008	26.2
2/1/2008	24.02
2/4/2008	25.99
2/5/2008	28.24
2/6/2008	28.97
2/7/2008	27.66
2/8/2008	28.01
2/11/2008	27.6
2/12/2008	26.33
2/13/2008	24.88
2/14/2008	25.54
2/15/2008	25.02
2/18/2008	25.02
2/19/2008	25.59
2/20/2008	24.4
2/21/2008	25.12
2/22/2008	24.06
2/25/2008	23.03
2/26/2008	21.9
2/27/2008	22.69
2/28/2008	23.53
2/29/2008	26.54
3/3/2008	26.28
3/4/2008	25.52
3/5/2008	24.6
3/6/2008	27.55
3/7/2008	27.49
3/10/2008	29.38
3/11/2008	26.36
3/12/2008	27.22
3/13/2008	27.29
3/14/2008	31.16
3/17/2008	32.24
3/18/2008	25.79
3/19/2008	29.84
3/20/2008	26.62
3/21/2008	26.62
3/24/2008	25.73
3/25/2008	25.72
3/26/2008	26.08
3/27/2008	25.88
3/28/2008	25.71
3/31/2008	25.61
4/1/2008	22.68
4/2/2008	23.43
4/3/2008	23.21
4/4/2008	22.45
4/7/2008	22.42
4/8/2008	22.36
4/9/2008	22.81
4/10/2008	21.98
4/11/2008	23.46
4/14/2008	23.82
4/15/2008	22.78
4/16/2008	20.53
4/17/2008	20.37
4/18/2008	20.13
4/21/2008	20.5
4/22/2008	20.87

4/23/2008	20.26
4/24/2008	20.06
4/25/2008	19.59
4/28/2008	19.64
4/29/2008	20.24
4/30/2008	20.79
5/1/2008	18.88
5/2/2008	18.18
5/5/2008	18.9
5/6/2008	18.21
5/7/2008	19.73
5/8/2008	19.4
5/9/2008	19.41
5/12/2008	17.79
5/13/2008	17.98
5/14/2008	17.66
5/15/2008	16.3
5/16/2008	16.47
5/19/2008	17.01
5/20/2008	17.58
5/21/2008	18.59
5/22/2008	18.05
5/23/2008	19.55
5/26/2008	19.55
5/27/2008	19.64
5/28/2008	19.07
5/29/2008	18.14
5/30/2008	17.83
6/2/2008	19.83
6/3/2008	20.24
6/4/2008	20.8
6/5/2008	18.63
6/6/2008	23.56
6/9/2008	23.12
6/10/2008	23.18
6/11/2008	24.12
6/12/2008	23.33
6/13/2008	21.22
6/16/2008	20.95
6/17/2008	21.13
6/18/2008	22.24
6/19/2008	21.58
6/20/2008	22.87
6/23/2008	22.64
6/24/2008	22.42
6/25/2008	21.14
6/26/2008	23.93
6/27/2008	23.44
6/30/2008	23.95
7/1/2008	23.65
7/2/2008	25.92
7/3/2008	24.78
7/4/2008	24.78
7/7/2008	25.78
7/8/2008	23.15
7/9/2008	25.23
7/10/2008	25.59
7/11/2008	27.49
7/14/2008	28.48
7/15/2008	28.54
7/16/2008	25.1
7/17/2008	25.01
7/18/2008	24.05
7/21/2008	23.05
7/22/2008	21.18
7/23/2008	21.31
7/24/2008	23.44
7/25/2008	22.91
7/28/2008	24.23
7/29/2008	22.03
7/30/2008	21.21
7/31/2008	22.94
8/1/2008	22.57
8/4/2008	23.49
8/5/2008	21.14
8/6/2008	20.23

8/7/2008	21.15
8/8/2008	20.66
8/11/2008	20.12
8/12/2008	21.17
8/13/2008	21.55
8/14/2008	20.34
8/15/2008	19.58
8/18/2008	20.98
8/19/2008	21.28
8/20/2008	20.42
8/21/2008	19.82
8/22/2008	18.81
8/25/2008	20.97
8/26/2008	20.49
8/27/2008	19.76
8/28/2008	19.43
8/29/2008	20.65
9/1/2008	20.65
9/2/2008	21.99
9/3/2008	21.43
9/4/2008	24.03
9/5/2008	23.06
9/8/2008	22.64
9/9/2008	25.47
9/10/2008	24.52
9/11/2008	24.39
9/12/2008	25.66
9/15/2008	31.7
9/16/2008	30.3
9/17/2008	36.22
9/18/2008	33.1
9/19/2008	32.07
9/22/2008	33.85
9/23/2008	35.72
9/24/2008	35.19
9/25/2008	32.82
9/26/2008	34.74
9/29/2008	46.72
9/30/2008	39.39
10/1/2008	39.81
10/2/2008	45.26
10/3/2008	45.14
10/6/2008	52.05
10/7/2008	53.68
10/8/2008	57.53
10/9/2008	63.92
10/10/2008	69.95
10/13/2008	54.99
10/14/2008	55.13
10/15/2008	69.25
10/16/2008	67.61
10/17/2008	70.33
10/20/2008	52.97
10/21/2008	53.11
10/22/2008	69.65
10/23/2008	67.8
10/24/2008	79.13
10/27/2008	80.06
10/28/2008	66.96
10/29/2008	69.96
10/30/2008	62.9
10/31/2008	59.89
11/3/2008	53.68
11/4/2008	47.73
11/5/2008	54.56
11/6/2008	63.68
11/7/2008	56.1
11/10/2008	59.98
11/11/2008	61.44
11/12/2008	66.46
11/13/2008	59.83
11/14/2008	66.31
11/17/2008	69.15
11/18/2008	67.64
11/19/2008	74.26
11/20/2008	80.86

11/21/2008	72.67
11/24/2008	64.7
11/25/2008	60.9
11/26/2008	54.92
11/27/2008	54.92
11/28/2008	55.28
12/1/2008	68.51
12/2/2008	62.98
12/3/2008	60.72
12/4/2008	63.64
12/5/2008	59.93
12/8/2008	58.49
12/9/2008	58.91
12/10/2008	55.73
12/11/2008	55.78
12/12/2008	54.28
12/15/2008	56.76
12/16/2008	52.37
12/17/2008	49.84
12/18/2008	47.34
12/19/2008	44.93
12/22/2008	44.56
12/23/2008	45.02
12/24/2008	44.21
12/25/2008	44.21
12/26/2008	43.38
12/29/2008	43.9
12/30/2008	41.63
12/31/2008	40
1/1/2009	40
1/2/2009	39.19
1/5/2009	39.08
1/6/2009	38.56
1/7/2009	43.39
1/8/2009	42.56
1/9/2009	42.82
1/12/2009	45.84
1/13/2009	43.27
1/14/2009	49.14
1/15/2009	51
1/16/2009	46.11
1/19/2009	46.11
1/20/2009	56.65
1/21/2009	46.42
1/22/2009	47.29
1/23/2009	47.27
1/26/2009	45.69
1/27/2009	42.25
1/28/2009	39.66
1/29/2009	42.63
1/30/2009	44.84
2/2/2009	45.52
2/3/2009	43.06
2/4/2009	43.85
2/5/2009	43.73
2/6/2009	43.37
2/9/2009	43.64
2/10/2009	46.67
2/11/2009	44.53
2/12/2009	41.25
2/13/2009	42.93
2/16/2009	42.93
2/17/2009	48.66
2/18/2009	48.46
2/19/2009	47.08
2/20/2009	49.3
2/23/2009	52.62
2/24/2009	45.49
2/25/2009	44.67
2/26/2009	44.66
2/27/2009	46.35
3/2/2009	52.65
3/3/2009	50.93
3/4/2009	47.56
3/5/2009	50.17
3/6/2009	49.33

3/9/2009	49.68
3/10/2009	44.37
3/11/2009	43.61
3/12/2009	41.18
3/13/2009	42.36
3/16/2009	43.74
3/17/2009	40.8
3/18/2009	40.06
3/19/2009	43.68
3/20/2009	45.89
3/23/2009	43.23
3/24/2009	42.93
3/25/2009	42.25
3/26/2009	40.36
3/27/2009	41.04
3/30/2009	45.54
3/31/2009	44.14
4/1/2009	42.28
4/2/2009	42.04
4/3/2009	39.7
4/6/2009	40.93
4/7/2009	40.39
4/8/2009	38.85
4/9/2009	36.53
4/10/2009	36.53
4/13/2009	37.81
4/14/2009	37.67
4/15/2009	36.17
4/16/2009	35.79
4/17/2009	33.94
4/20/2009	39.18
4/21/2009	37.14
4/22/2009	38.1
4/23/2009	37.15
4/24/2009	36.82
4/27/2009	38.32
4/28/2009	37.95
4/29/2009	36.08
4/30/2009	36.5
5/1/2009	35.3
5/4/2009	34.53
5/5/2009	33.36
5/6/2009	32.45
5/7/2009	33.44
5/8/2009	32.05
5/11/2009	32.87
5/12/2009	31.8
5/13/2009	33.65
5/14/2009	31.37
5/15/2009	33.12
5/18/2009	30.24
5/19/2009	28.8
5/20/2009	29.03
5/21/2009	31.35
5/22/2009	32.63
5/25/2009	32.63
5/26/2009	30.62
5/27/2009	32.36
5/28/2009	31.67
5/29/2009	28.92
6/1/2009	30.04
6/2/2009	29.63
6/3/2009	31.02
6/4/2009	30.18
6/5/2009	29.62
6/8/2009	29.77
6/9/2009	28.27
6/10/2009	28.46
6/11/2009	28.11
6/12/2009	28.15
6/15/2009	30.81
6/16/2009	32.68
6/17/2009	31.54
6/18/2009	30.03
6/19/2009	27.99
6/22/2009	31.17

6/23/2009	30.58
6/24/2009	29.05
6/25/2009	26.36
6/26/2009	25.93
6/29/2009	25.35
6/30/2009	26.35
7/1/2009	26.22
7/2/2009	27.95
7/3/2009	27.95
7/6/2009	29
7/7/2009	30.85
7/8/2009	31.3
7/9/2009	29.78
7/10/2009	29.02
7/13/2009	26.31
7/14/2009	25.02
7/15/2009	25.89
7/16/2009	25.42
7/17/2009	24.34
7/20/2009	24.4
7/21/2009	23.87
7/22/2009	23.47
7/23/2009	23.43
7/24/2009	23.09
7/27/2009	24.28
7/28/2009	25.01
7/29/2009	25.61
7/30/2009	25.4
7/31/2009	25.92
8/3/2009	25.56
8/4/2009	24.89
8/5/2009	24.9
8/6/2009	25.67
8/7/2009	24.76
8/10/2009	24.99
8/11/2009	25.99
8/12/2009	25.45
8/13/2009	24.71
8/14/2009	24.27
8/17/2009	27.89
8/18/2009	26.18
8/19/2009	26.26
8/20/2009	25.09
8/21/2009	25.01
8/24/2009	25.14
8/25/2009	24.92
8/26/2009	24.95
8/27/2009	24.68
8/28/2009	24.76
8/31/2009	26.01
9/1/2009	29.15
9/2/2009	28.9
9/3/2009	27.1
9/4/2009	25.26
9/7/2009	25.26
9/8/2009	25.62
9/9/2009	24.32
9/10/2009	23.55
9/11/2009	24.15
9/14/2009	23.86
9/15/2009	23.42
9/16/2009	23.69
9/17/2009	23.65
9/18/2009	23.92
9/21/2009	24.06
9/22/2009	23.08
9/23/2009	23.49
9/24/2009	24.95
9/25/2009	25.61
9/28/2009	24.88
9/29/2009	25.19
9/30/2009	25.61
10/1/2009	28.27
10/2/2009	28.68
10/5/2009	26.84
10/6/2009	25.7

10/7/2009	24.68
10/8/2009	24.18
10/9/2009	23.12
10/12/2009	23.01
10/13/2009	22.99
10/14/2009	22.86
10/15/2009	21.72
10/16/2009	21.43
10/19/2009	21.49
10/20/2009	20.9
10/21/2009	22.22
10/22/2009	20.69
10/23/2009	22.27
10/26/2009	24.31
10/27/2009	24.83
10/28/2009	27.91
10/29/2009	24.76
10/30/2009	30.69
11/2/2009	29.78
11/3/2009	28.81
11/4/2009	27.72
11/5/2009	25.43
11/6/2009	24.19
11/9/2009	23.15
11/10/2009	22.84
11/11/2009	23.04
11/12/2009	24.24
11/13/2009	23.36
11/16/2009	22.89
11/17/2009	22.41
11/18/2009	21.63
11/19/2009	22.63
11/20/2009	22.19
11/23/2009	21.16
11/24/2009	20.47
11/25/2009	20.48
11/26/2009	20.48
11/27/2009	24.74
11/30/2009	24.51
12/1/2009	21.92
12/2/2009	21.12
12/3/2009	22.46
12/4/2009	21.25
12/7/2009	22.1
12/8/2009	23.69
12/9/2009	22.66
12/10/2009	22.32
12/11/2009	21.59
12/14/2009	21.15
12/15/2009	21.49
12/16/2009	20.54
12/17/2009	22.51
12/18/2009	21.68
12/21/2009	20.49
12/22/2009	19.54
12/23/2009	19.71
12/24/2009	19.47
12/25/2009	19.47
12/28/2009	19.93
12/29/2009	20.01
12/30/2009	19.96
12/31/2009	21.68
1/1/2010	21.68
1/4/2010	20.04
1/5/2010	19.35
1/6/2010	19.16
1/7/2010	19.06
1/8/2010	18.13
1/11/2010	17.55
1/12/2010	18.25
1/13/2010	17.85
1/14/2010	17.63
1/15/2010	17.91
1/18/2010	17.91
1/19/2010	17.58
1/20/2010	18.68

1/21/2010	22.27
1/22/2010	27.31
1/25/2010	25.41
1/26/2010	24.55
1/27/2010	23.14
1/28/2010	23.73
1/29/2010	24.62
2/1/2010	22.59
2/2/2010	21.48
2/3/2010	21.6
2/4/2010	26.08
2/5/2010	26.11
2/8/2010	26.51
2/9/2010	26
2/10/2010	25.4
2/11/2010	23.96
2/12/2010	22.73
2/15/2010	22.73
2/16/2010	22.25
2/17/2010	21.72
2/18/2010	20.63
2/19/2010	20.02
2/22/2010	19.94
2/23/2010	21.37
2/24/2010	20.27
2/25/2010	20.1
2/26/2010	19.5
3/1/2010	19.26
3/2/2010	19.06
3/3/2010	18.83
3/4/2010	18.72
3/5/2010	17.42
3/8/2010	17.79
3/9/2010	17.92
3/10/2010	18.57
3/11/2010	18.06
3/12/2010	17.58
3/15/2010	18
3/16/2010	17.69
3/17/2010	16.91
3/18/2010	16.62
3/19/2010	16.97
3/22/2010	16.87
3/23/2010	16.35
3/24/2010	17.55
3/25/2010	18.4
3/26/2010	17.77
3/29/2010	17.59
3/30/2010	17.13
3/31/2010	17.59
4/1/2010	17.47
4/2/2010	17.47
4/5/2010	17.02
4/6/2010	16.23
4/7/2010	16.62
4/8/2010	16.48
4/9/2010	16.14
4/12/2010	15.58
4/13/2010	16.2
4/14/2010	15.59
4/15/2010	15.89
4/16/2010	18.36
4/19/2010	17.34
4/20/2010	15.73
4/21/2010	16.32
4/22/2010	16.47
4/23/2010	16.62
4/26/2010	17.47
4/27/2010	22.81
4/28/2010	21.08
4/29/2010	18.44
4/30/2010	22.05
5/3/2010	20.19
5/4/2010	23.84
5/5/2010	24.91
5/6/2010	32.8

5/7/2010	40.95
5/10/2010	28.84
5/11/2010	28.32
5/12/2010	25.52
5/13/2010	26.68
5/14/2010	31.24
5/17/2010	30.84
5/18/2010	33.55
5/19/2010	35.32
5/20/2010	45.79
5/21/2010	40.1
5/24/2010	38.32
5/25/2010	34.61
5/26/2010	35.02
5/27/2010	29.68
5/28/2010	32.07
5/31/2010	32.07
6/1/2010	35.54
6/2/2010	30.17
6/3/2010	29.46
6/4/2010	35.48
6/7/2010	36.57
6/8/2010	33.7
6/9/2010	33.73
6/10/2010	30.57
6/11/2010	28.79
6/14/2010	28.58
6/15/2010	25.87
6/16/2010	25.92
6/17/2010	25.05
6/18/2010	23.95
6/21/2010	24.88
6/22/2010	27.05
6/23/2010	26.91
6/24/2010	29.74
6/25/2010	28.53
6/28/2010	29
6/29/2010	34.13
6/30/2010	34.54
7/1/2010	32.86
7/2/2010	30.12
7/5/2010	30.12
7/6/2010	29.65
7/7/2010	26.84
7/8/2010	25.71
7/9/2010	24.98
7/12/2010	24.43
7/13/2010	24.56
7/14/2010	24.89
7/15/2010	25.14
7/16/2010	26.25
7/19/2010	25.97
7/20/2010	23.93
7/21/2010	25.64
7/22/2010	24.63
7/23/2010	23.47
7/26/2010	22.73
7/27/2010	23.19
7/28/2010	24.25
7/29/2010	24.13
7/30/2010	23.5
8/2/2010	22.01
8/3/2010	22.63
8/4/2010	22.21
8/5/2010	22.1
8/6/2010	21.74
8/9/2010	22.14
8/10/2010	22.37
8/11/2010	25.39
8/12/2010	25.73
8/13/2010	26.24
8/16/2010	26.1
8/17/2010	24.33
8/18/2010	24.59
8/19/2010	26.44
8/20/2010	25.49

8/23/2010	25.66
8/24/2010	27.46
8/25/2010	26.7
8/26/2010	27.37
8/27/2010	24.45
8/30/2010	27.21
8/31/2010	26.05
9/1/2010	23.89
9/2/2010	23.19
9/3/2010	21.31
9/6/2010	21.31
9/7/2010	23.8
9/8/2010	23.25
9/9/2010	22.81
9/10/2010	21.99
9/13/2010	21.21
9/14/2010	21.56
9/15/2010	22.1
9/16/2010	21.72
9/17/2010	22.01
9/20/2010	21.5
9/21/2010	22.35
9/22/2010	22.51
9/23/2010	23.87
9/24/2010	21.71
9/27/2010	22.54
9/28/2010	22.6
9/29/2010	23.25
9/30/2010	23.7
10/1/2010	22.5
10/4/2010	23.53
10/5/2010	21.76
10/6/2010	21.49
10/7/2010	21.56
10/8/2010	20.71
10/11/2010	18.96
10/12/2010	18.93
10/13/2010	19.07
10/14/2010	19.88
10/15/2010	19.03
10/18/2010	19.09
10/19/2010	20.63
10/20/2010	19.79
10/21/2010	19.27
10/22/2010	18.78
10/25/2010	19.85
10/26/2010	20.22
10/27/2010	20.71
10/28/2010	20.88
10/29/2010	21.2
11/1/2010	21.83
11/2/2010	21.57
11/3/2010	19.56
11/4/2010	18.52
11/5/2010	18.26
11/8/2010	18.29
11/9/2010	19.08
11/10/2010	18.47
11/11/2010	18.64
11/12/2010	20.61
11/15/2010	20.2
11/16/2010	22.58
11/17/2010	21.76
11/18/2010	18.75
11/19/2010	18.04
11/22/2010	18.37
11/23/2010	20.63
11/24/2010	19.56
11/25/2010	19.56
11/26/2010	22.22
11/29/2010	21.53
11/30/2010	23.54
12/1/2010	21.36
12/2/2010	19.39
12/3/2010	18.01
12/6/2010	18.02

12/7/2010	17.99
12/8/2010	17.74
12/9/2010	17.25
12/10/2010	17.61
12/13/2010	17.55
12/14/2010	17.61
12/15/2010	17.94
12/16/2010	17.39
12/17/2010	16.11
12/20/2010	16.41
12/21/2010	16.49
12/22/2010	15.45
12/23/2010	16.47
12/24/2010	16.47
12/27/2010	17.67
12/28/2010	17.52
12/29/2010	17.28
12/30/2010	17.52
12/31/2010	17.75
1/3/2011	17.61
1/4/2011	17.38
1/5/2011	17.02
1/6/2011	17.4
1/7/2011	17.14
1/10/2011	17.54
1/11/2011	16.89
1/12/2011	16.24
1/13/2011	16.39
1/14/2011	15.46
1/17/2011	15.46
1/18/2011	15.87
1/19/2011	17.31
1/20/2011	17.99
1/21/2011	18.47
1/24/2011	17.65
1/25/2011	17.59
1/26/2011	16.64
1/27/2011	16.15
1/28/2011	20.04
1/31/2011	19.53
2/1/2011	17.63
2/2/2011	17.3
2/3/2011	16.69
2/4/2011	15.93
2/7/2011	16.28
2/8/2011	15.81
2/9/2011	15.87
2/10/2011	16.09
2/11/2011	15.69
2/14/2011	15.95
2/15/2011	16.37
2/16/2011	16.72
2/17/2011	16.59
2/18/2011	16.43
2/21/2011	16.43
2/22/2011	20.8
2/23/2011	22.13
2/24/2011	21.32
2/25/2011	19.22
2/28/2011	18.35
3/1/2011	21.01
3/2/2011	20.7
3/3/2011	18.6
3/4/2011	19.06
3/7/2011	20.66
3/8/2011	19.82
3/9/2011	20.22
3/10/2011	21.88
3/11/2011	20.08
3/14/2011	21.13
3/15/2011	24.32
3/16/2011	29.4
3/17/2011	26.37
3/18/2011	24.44
3/21/2011	20.61
3/22/2011	20.21

3/23/2011	19.17
3/24/2011	18
3/25/2011	17.91
3/28/2011	19.44
3/29/2011	18.16
3/30/2011	17.71
3/31/2011	17.74
4/1/2011	17.4
4/4/2011	17.5
4/5/2011	17.25
4/6/2011	16.9
4/7/2011	17.11
4/8/2011	17.87
4/11/2011	16.59
4/12/2011	17.09
4/13/2011	16.92
4/14/2011	16.27
4/15/2011	15.32
4/18/2011	16.96
4/19/2011	15.83
4/20/2011	15.07
4/21/2011	14.69
4/22/2011	14.69
4/25/2011	15.77
4/26/2011	15.62
4/27/2011	15.35
4/28/2011	14.62
4/29/2011	14.75
5/2/2011	15.99
5/3/2011	16.7
5/4/2011	17.08
5/5/2011	18.2
5/6/2011	18.4
5/9/2011	17.16
5/10/2011	15.91
5/11/2011	16.95
5/12/2011	16.03
5/13/2011	17.07
5/16/2011	18.24
5/17/2011	17.55
5/18/2011	16.23
5/19/2011	15.52
5/20/2011	17.43
5/23/2011	18.27
5/24/2011	17.82
5/25/2011	17.07
5/26/2011	16.09
5/27/2011	15.98
5/30/2011	15.98
5/31/2011	15.45
6/1/2011	18.3
6/2/2011	18.09
6/3/2011	17.95
6/6/2011	18.49
6/7/2011	18.07
6/8/2011	18.79
6/9/2011	17.77
6/10/2011	18.86
6/13/2011	19.61
6/14/2011	18.26
6/15/2011	21.32
6/16/2011	22.73
6/17/2011	21.85
6/20/2011	19.99
6/21/2011	18.86
6/22/2011	18.52
6/23/2011	19.29
6/24/2011	21.1
6/27/2011	20.56
6/28/2011	19.17
6/29/2011	17.27
6/30/2011	16.52
7/1/2011	15.87
7/4/2011	15.87
7/5/2011	16.06
7/6/2011	16.34

7/7/2011	15.95
7/8/2011	15.95
7/11/2011	18.39
7/12/2011	19.87
7/13/2011	19.91
7/14/2011	20.8
7/15/2011	19.53
7/18/2011	20.95
7/19/2011	19.21
7/20/2011	19.09
7/21/2011	17.56
7/22/2011	17.52
7/25/2011	19.35
7/26/2011	20.23
7/27/2011	22.98
7/28/2011	23.74
7/29/2011	25.25
8/1/2011	23.66
8/2/2011	24.79
8/3/2011	23.38
8/4/2011	31.66
8/5/2011	32
8/8/2011	48
8/9/2011	35.06
8/10/2011	42.99
8/11/2011	39
8/12/2011	36.36
8/15/2011	31.87
8/16/2011	32.85
8/17/2011	31.58
8/18/2011	42.67
8/19/2011	43.05
8/22/2011	42.44
8/23/2011	36.27
8/24/2011	35.9
8/25/2011	39.76
8/26/2011	35.59
8/29/2011	32.28
8/30/2011	32.89
8/31/2011	31.62
9/1/2011	31.82
9/2/2011	33.92
9/5/2011	33.92
9/6/2011	37
9/7/2011	33.38
9/8/2011	34.32
9/9/2011	38.52
9/12/2011	38.59
9/13/2011	36.91
9/14/2011	34.6
9/15/2011	31.97
9/16/2011	30.98
9/19/2011	32.73
9/20/2011	32.86
9/21/2011	37.32
9/22/2011	41.35
9/23/2011	41.25
9/26/2011	39.02
9/27/2011	37.71
9/28/2011	41.08
9/29/2011	38.84
9/30/2011	42.96
10/3/2011	45.45
10/4/2011	40.82
10/5/2011	37.81
10/6/2011	36.27
10/7/2011	36.2
10/10/2011	33.02
10/11/2011	32.86
10/12/2011	31.26
10/13/2011	30.7
10/14/2011	28.24
10/17/2011	33.39
10/18/2011	31.56
10/19/2011	34.44
10/20/2011	34.78

10/21/2011	31.32
10/24/2011	29.26
10/25/2011	32.22
10/26/2011	29.86
10/27/2011	25.46
10/28/2011	24.53
10/31/2011	29.96
11/1/2011	34.77
11/2/2011	32.74
11/3/2011	30.5
11/4/2011	30.16
11/7/2011	29.85
11/8/2011	27.48
11/9/2011	36.16
11/10/2011	32.81
11/11/2011	30.04
11/14/2011	31.13
11/15/2011	31.22
11/16/2011	33.51
11/17/2011	34.51
11/18/2011	32
11/21/2011	32.91
11/22/2011	31.97
11/23/2011	33.98
11/24/2011	33.98
11/25/2011	34.47
11/28/2011	32.13
11/29/2011	30.64
11/30/2011	27.8
12/1/2011	27.41
12/2/2011	27.52
12/5/2011	27.84
12/6/2011	28.13
12/7/2011	28.67
12/8/2011	30.59
12/9/2011	26.38
12/12/2011	25.67
12/13/2011	25.41
12/14/2011	26.04
12/15/2011	25.11
12/16/2011	24.29
12/19/2011	24.92
12/20/2011	23.22
12/21/2011	21.43
12/22/2011	21.16
12/23/2011	20.73
12/26/2011	20.73
12/27/2011	21.91
12/28/2011	23.52
12/29/2011	22.65
12/30/2011	23.4
1/2/2012	23.4
1/3/2012	22.97
1/4/2012	22.22
1/5/2012	21.48
1/6/2012	20.63
1/9/2012	21.07
1/10/2012	20.69
1/11/2012	21.05
1/12/2012	20.47
1/13/2012	20.91
1/16/2012	20.91
1/17/2012	22.2
1/18/2012	20.89
1/19/2012	19.87
1/20/2012	18.28
1/23/2012	18.67
1/24/2012	18.91
1/25/2012	18.31
1/26/2012	18.57
1/27/2012	18.53
1/30/2012	19.4
1/31/2012	19.44
2/1/2012	18.55
2/2/2012	17.98
2/3/2012	17.1

2/6/2012	17.76
2/7/2012	17.65
2/8/2012	18.16
2/9/2012	18.63
2/10/2012	20.79
2/13/2012	19.04
2/14/2012	19.54
2/15/2012	21.14
2/16/2012	19.22
2/17/2012	17.78
2/20/2012	17.78
2/21/2012	18.19
2/22/2012	18.19
2/23/2012	16.8
2/24/2012	17.31
2/27/2012	18.19
2/28/2012	17.96
2/29/2012	18.43
3/1/2012	17.26
3/2/2012	17.29
3/5/2012	18.05
3/6/2012	20.87
3/7/2012	19.07
3/8/2012	17.95
3/9/2012	17.11
3/12/2012	15.64
3/13/2012	14.8
3/14/2012	15.31
3/15/2012	15.42
3/16/2012	14.47
3/19/2012	15.04
3/20/2012	15.58
3/21/2012	15.13
3/22/2012	15.57
3/23/2012	14.82
3/26/2012	14.26
3/27/2012	15.59
3/28/2012	15.47
3/29/2012	15.48
3/30/2012	15.5
4/2/2012	15.64
4/3/2012	15.66
4/4/2012	16.44
4/5/2012	16.7
4/6/2012	16.7
4/9/2012	18.81
4/10/2012	20.39
4/11/2012	20.02
4/12/2012	17.2
4/13/2012	19.55
4/16/2012	19.55
4/17/2012	18.46
4/18/2012	18.64
4/19/2012	18.36
4/20/2012	17.44
4/23/2012	18.97
4/24/2012	18.1
4/25/2012	16.82
4/26/2012	16.24
4/27/2012	16.32
4/30/2012	17.15
5/1/2012	16.6
5/2/2012	16.88
5/3/2012	17.56
5/4/2012	19.16
5/7/2012	18.94
5/8/2012	19.05
5/9/2012	20.08
5/10/2012	18.83
5/11/2012	19.89
5/14/2012	21.87
5/15/2012	21.97
5/16/2012	22.27
5/17/2012	24.49
5/18/2012	25.1
5/21/2012	22.01

5/22/2012	22.48
5/23/2012	22.33
5/24/2012	21.54
5/25/2012	21.76
5/28/2012	21.76
5/29/2012	21.03
5/30/2012	24.14
5/31/2012	24.06
6/1/2012	26.66
6/4/2012	26.12
6/5/2012	24.68
6/6/2012	22.16
6/7/2012	21.72
6/8/2012	21.23
6/11/2012	23.56
6/12/2012	22.09
6/13/2012	24.27
6/14/2012	21.68
6/15/2012	21.11
6/18/2012	18.32
6/19/2012	18.38
6/20/2012	17.24
6/21/2012	20.08
6/22/2012	18.11
6/25/2012	20.38
6/26/2012	19.72
6/27/2012	19.45
6/28/2012	19.71
6/29/2012	17.08
7/2/2012	16.8
7/3/2012	16.66
7/4/2012	16.66
7/5/2012	17.5
7/6/2012	17.1
7/9/2012	17.98
7/10/2012	18.72
7/11/2012	17.95
7/12/2012	18.33
7/13/2012	16.74
7/16/2012	17.11
7/17/2012	16.48
7/18/2012	16.16
7/19/2012	15.45
7/20/2012	16.27
7/23/2012	18.62
7/24/2012	20.47
7/25/2012	19.34
7/26/2012	17.53
7/27/2012	16.7
7/30/2012	18.03
7/31/2012	18.93
8/1/2012	18.96
8/2/2012	17.57
8/3/2012	15.64
8/6/2012	15.95
8/7/2012	15.99
8/8/2012	15.32
8/9/2012	15.28
8/10/2012	14.74
8/13/2012	13.7
8/14/2012	14.85
8/15/2012	14.63
8/16/2012	14.29
8/17/2012	13.45
8/20/2012	14.02
8/21/2012	15.02
8/22/2012	15.11
8/23/2012	15.96
8/24/2012	15.18
8/27/2012	16.35
8/28/2012	16.49
8/29/2012	17.06
8/30/2012	17.83
8/31/2012	17.47
9/3/2012	17.47
9/4/2012	17.98

9/5/2012	17.74
9/6/2012	15.6
9/7/2012	14.38
9/10/2012	16.28
9/11/2012	16.41
9/12/2012	15.8
9/13/2012	14.05
9/14/2012	14.51
9/17/2012	14.59
9/18/2012	14.18
9/19/2012	13.88
9/20/2012	14.07
9/21/2012	13.98
9/24/2012	14.15
9/25/2012	15.43
9/26/2012	16.81
9/27/2012	14.84
9/28/2012	15.73
10/1/2012	16.32
10/2/2012	15.71
10/3/2012	15.43
10/4/2012	14.55
10/5/2012	14.33
10/8/2012	15.11
10/9/2012	16.37
10/10/2012	16.29
10/11/2012	15.59
10/12/2012	16.14
10/15/2012	15.27
10/16/2012	15.22
10/17/2012	15.07
10/18/2012	15.03
10/19/2012	17.06
10/22/2012	16.62
10/23/2012	18.83
10/24/2012	18.33
10/25/2012	18.12
10/26/2012	17.81
10/29/2012	17.81
10/30/2012	17.81
10/31/2012	18.6
11/1/2012	16.69
11/2/2012	17.59
11/5/2012	18.42
11/6/2012	17.58
11/7/2012	19.08
11/8/2012	18.49
11/9/2012	18.61
11/12/2012	16.68
11/13/2012	16.65
11/14/2012	17.92
11/15/2012	17.99
11/16/2012	16.41
11/19/2012	15.24
11/20/2012	15.08
11/21/2012	15.31
11/22/2012	15.31
11/23/2012	15.14
11/26/2012	15.5
11/27/2012	15.92
11/28/2012	15.51
11/29/2012	15.06
11/30/2012	15.87
12/3/2012	16.64
12/4/2012	17.12
12/5/2012	16.46
12/6/2012	16.58
12/7/2012	15.9
12/10/2012	16.05
12/11/2012	15.57
12/12/2012	15.95
12/13/2012	16.56
12/14/2012	17
12/17/2012	16.34
12/18/2012	15.57
12/19/2012	17.36

12/20/2012	17.67
12/21/2012	17.84
12/24/2012	17.84
12/25/2012	17.84
12/26/2012	19.48
12/27/2012	19.47
12/28/2012	22.72
12/31/2012	18.02
1/1/2013	18.02
1/2/2013	14.68
1/3/2013	14.56
1/4/2013	13.83
1/7/2013	13.79
1/8/2013	13.62
1/9/2013	13.81
1/10/2013	13.49
1/11/2013	13.36
1/14/2013	13.52
1/15/2013	13.55
1/16/2013	13.42
1/17/2013	13.57
1/18/2013	12.46
1/21/2013	12.46
1/22/2013	12.43
1/23/2013	12.46
1/24/2013	12.69
1/25/2013	12.89
1/28/2013	13.57
1/29/2013	13.31
1/30/2013	14.32
1/31/2013	14.28
2/1/2013	12.9
2/4/2013	14.67
2/5/2013	13.72
2/6/2013	13.41
2/7/2013	13.5
2/8/2013	13.02
2/11/2013	12.94
2/12/2013	12.64
2/13/2013	12.98
2/14/2013	12.66
2/15/2013	12.46
2/18/2013	12.46
2/19/2013	12.31
2/20/2013	14.68
2/21/2013	15.22
2/22/2013	14.17
2/25/2013	18.99
2/26/2013	16.87
2/27/2013	14.73
2/28/2013	15.51
3/1/2013	15.36
3/4/2013	14.01
3/5/2013	13.48
3/6/2013	13.53
3/7/2013	13.06
3/8/2013	12.59
3/11/2013	11.56
3/12/2013	12.27
3/13/2013	11.83
3/14/2013	11.3
3/15/2013	11.3
3/18/2013	13.36
3/19/2013	14.39
3/20/2013	12.67
3/21/2013	13.99
3/22/2013	13.57
3/25/2013	13.74
3/26/2013	12.77
3/27/2013	13.15
3/28/2013	12.7
3/29/2013	12.7
4/1/2013	13.58
4/2/2013	12.78
4/3/2013	14.21
4/4/2013	13.89

4/5/2013	13.92
4/8/2013	13.19
4/9/2013	12.84
4/10/2013	12.36
4/11/2013	12.24
4/12/2013	12.06
4/15/2013	17.27
4/16/2013	13.96
4/17/2013	16.51
4/18/2013	17.56
4/19/2013	14.97
4/22/2013	14.39
4/23/2013	13.48
4/24/2013	13.61
4/25/2013	13.62
4/26/2013	13.61
4/29/2013	13.71
4/30/2013	13.52
5/1/2013	14.49
5/2/2013	13.59
5/3/2013	12.85
5/6/2013	12.66
5/7/2013	12.83
5/8/2013	12.66
5/9/2013	13.13
5/10/2013	12.59
5/13/2013	12.55
5/14/2013	12.77
5/15/2013	12.81
5/16/2013	13.07
5/17/2013	12.45
5/20/2013	13.02
5/21/2013	13.37
5/22/2013	13.82
5/23/2013	14.07
5/24/2013	13.99
5/27/2013	13.99
5/28/2013	14.48
5/29/2013	14.83
5/30/2013	14.53
5/31/2013	16.3
6/3/2013	16.28
6/4/2013	16.27
6/5/2013	17.5
6/6/2013	16.63
6/7/2013	15.14
6/10/2013	15.44
6/11/2013	17.07
6/12/2013	18.59
6/13/2013	16.41
6/14/2013	17.15
6/17/2013	16.8
6/18/2013	16.61
6/19/2013	16.64
6/20/2013	20.49
6/21/2013	18.9
6/24/2013	20.11
6/25/2013	18.47
6/26/2013	17.21
6/27/2013	16.86
6/28/2013	16.86
7/1/2013	16.37
7/2/2013	16.44
7/3/2013	16.2
7/4/2013	16.2
7/5/2013	14.89
7/8/2013	14.78
7/9/2013	14.35
7/10/2013	14.21
7/11/2013	14.01
7/12/2013	13.84
7/15/2013	13.79
7/16/2013	14.42
7/17/2013	13.78
7/18/2013	13.77
7/19/2013	12.54

7/22/2013	12.29
7/23/2013	12.66
7/24/2013	13.18
7/25/2013	12.97
7/26/2013	12.72
7/29/2013	13.39
7/30/2013	13.39
7/31/2013	13.45
8/1/2013	12.94
8/2/2013	11.98
8/5/2013	11.84
8/6/2013	12.72
8/7/2013	12.98
8/8/2013	12.73
8/9/2013	13.41
8/12/2013	12.81
8/13/2013	12.31
8/14/2013	13.04
8/15/2013	14.73
8/16/2013	14.37
8/19/2013	15.1
8/20/2013	14.91
8/21/2013	15.94
8/22/2013	14.76
8/23/2013	13.98
8/26/2013	14.99
8/27/2013	16.77
8/28/2013	16.49
8/29/2013	16.81
8/30/2013	17.01
9/2/2013	17.01
9/3/2013	16.61
9/4/2013	15.88
9/5/2013	15.77
9/6/2013	15.85
9/9/2013	15.63
9/10/2013	14.53
9/11/2013	13.82
9/12/2013	14.29
9/13/2013	14.16
9/16/2013	14.38
9/17/2013	14.53
9/18/2013	13.59
9/19/2013	13.16
9/20/2013	13.12
9/23/2013	14.31
9/24/2013	14.08
9/25/2013	14.01
9/26/2013	14.06
9/27/2013	15.46
9/30/2013	16.6
10/1/2013	15.54
10/2/2013	16.6
10/3/2013	17.67
10/4/2013	16.74
10/7/2013	19.41
10/8/2013	20.34
10/9/2013	19.6
10/10/2013	16.48
10/11/2013	15.72
10/14/2013	16.07
10/15/2013	18.66
10/16/2013	14.71
10/17/2013	13.48
10/18/2013	13.04
10/21/2013	13.16
10/22/2013	13.33
10/23/2013	13.42
10/24/2013	13.2
10/25/2013	13.09
10/28/2013	13.31
10/29/2013	13.41
10/30/2013	13.65
10/31/2013	13.75
11/1/2013	13.28
11/4/2013	12.93

11/5/2013	13.27
11/6/2013	12.67
11/7/2013	13.91
11/8/2013	12.9
11/11/2013	12.53
11/12/2013	12.82
11/13/2013	12.52
11/14/2013	12.37
11/15/2013	12.19
11/18/2013	13.1
11/19/2013	13.39
11/20/2013	13.4
11/21/2013	12.66
11/22/2013	12.26
11/25/2013	12.79
11/26/2013	12.81
11/27/2013	12.98
11/28/2013	12.98
11/29/2013	13.7
12/2/2013	14.23
12/3/2013	14.55
12/4/2013	14.7
12/5/2013	15.08
12/6/2013	13.79
12/9/2013	13.49
12/10/2013	13.91
12/11/2013	15.42
12/12/2013	15.54
12/13/2013	15.76
12/16/2013	16.03
12/17/2013	16.21
12/18/2013	13.8
12/19/2013	14.15
12/20/2013	13.79
12/23/2013	13.04
12/24/2013	12.48
12/25/2013	12.48
12/26/2013	12.33
12/27/2013	12.46
12/30/2013	13.56
12/31/2013	13.72
1/1/2014	13.72
1/2/2014	14.23
1/3/2014	13.76
1/6/2014	13.55
1/7/2014	12.92
1/8/2014	12.87
1/9/2014	12.89
1/10/2014	12.14
1/13/2014	13.28
1/14/2014	12.28
1/15/2014	12.28
1/16/2014	12.53
1/17/2014	12.44
1/20/2014	12.44
1/21/2014	12.87
1/22/2014	12.84
1/23/2014	13.77
1/24/2014	18.14
1/27/2014	17.42
1/28/2014	15.8
1/29/2014	17.35
1/30/2014	17.29
1/31/2014	18.41
2/3/2014	21.44
2/4/2014	19.11
2/5/2014	19.95
2/6/2014	17.23
2/7/2014	15.29
2/10/2014	15.26
2/11/2014	14.51
2/12/2014	14.3
2/13/2014	14.14
2/14/2014	13.57
2/17/2014	13.57
2/18/2014	13.87

2/19/2014	15.5
2/20/2014	14.79
2/21/2014	14.68
2/24/2014	14.23
2/25/2014	13.67
2/26/2014	14.35
2/27/2014	14.04
2/28/2014	14
3/3/2014	16
3/4/2014	14.1
3/5/2014	13.89
3/6/2014	14.21
3/7/2014	14.11
3/10/2014	14.2
3/11/2014	14.8
3/12/2014	14.47
3/13/2014	16.22
3/14/2014	17.82
3/17/2014	15.64
3/18/2014	14.52
3/19/2014	15.12
3/20/2014	14.52
3/21/2014	15
3/24/2014	15.09
3/25/2014	14.02
3/26/2014	14.93
3/27/2014	14.62
3/28/2014	14.41
3/31/2014	13.88
4/1/2014	13.1
4/2/2014	13.09
4/3/2014	13.37
4/4/2014	13.96
4/7/2014	15.57
4/8/2014	14.89
4/9/2014	13.82
4/10/2014	15.89
4/11/2014	17.03
4/14/2014	16.11
4/15/2014	15.61
4/16/2014	14.18
4/17/2014	13.36
4/18/2014	13.36
4/21/2014	13.25
4/22/2014	13.19
4/23/2014	13.27
4/24/2014	13.32
4/25/2014	14.06
4/28/2014	13.97
4/29/2014	13.71
4/30/2014	13.41
5/1/2014	13.25
5/2/2014	12.91
5/5/2014	13.29
5/6/2014	13.8
5/7/2014	13.4
5/8/2014	13.43
5/9/2014	12.92
5/12/2014	12.23
5/13/2014	12.13
5/14/2014	12.17
5/15/2014	13.17
5/16/2014	12.44
5/19/2014	12.42
5/20/2014	12.96
5/21/2014	11.91
5/22/2014	12.03
5/23/2014	11.36
5/26/2014	11.36
5/27/2014	11.51
5/28/2014	11.68
5/29/2014	11.57
5/30/2014	11.4
6/2/2014	11.58
6/3/2014	11.87
6/4/2014	12.08

6/5/2014	11.68
6/6/2014	10.73
6/9/2014	11.15
6/10/2014	10.99
6/11/2014	11.6
6/12/2014	12.56
6/13/2014	12.18
6/16/2014	12.65
6/17/2014	12.06
6/18/2014	10.61
6/19/2014	10.62
6/20/2014	10.85
6/23/2014	10.98
6/24/2014	12.13
6/25/2014	11.59
6/26/2014	11.63
6/27/2014	11.26
6/30/2014	11.57
7/1/2014	11.15
7/2/2014	10.82
7/3/2014	10.32
7/4/2014	10.32
7/7/2014	11.33
7/8/2014	11.98
7/9/2014	11.65
7/10/2014	12.59
7/11/2014	12.08
7/14/2014	11.82
7/15/2014	11.96
7/16/2014	11
7/17/2014	14.54
7/18/2014	12.06
7/21/2014	12.81
7/22/2014	12.24
7/23/2014	11.52
7/24/2014	11.84
7/25/2014	12.69
7/28/2014	12.56
7/29/2014	13.28
7/30/2014	13.33
7/31/2014	16.95
8/1/2014	17.03
8/4/2014	15.12
8/5/2014	16.87
8/6/2014	16.37
8/7/2014	16.66
8/8/2014	15.77
8/11/2014	14.23
8/12/2014	14.13
8/13/2014	12.9
8/14/2014	12.42
8/15/2014	13.15
8/18/2014	12.32
8/19/2014	12.21
8/20/2014	11.78
8/21/2014	11.76
8/22/2014	11.47
8/25/2014	11.7
8/26/2014	11.63
8/27/2014	11.78
8/28/2014	12.05
8/29/2014	11.98
9/1/2014	11.98
9/2/2014	12.25
9/3/2014	12.36
9/4/2014	12.64
9/5/2014	12.09
9/8/2014	12.66
9/9/2014	13.5
9/10/2014	12.88
9/11/2014	12.8
9/12/2014	13.31
9/15/2014	14.12
9/16/2014	12.73
9/17/2014	12.65
9/18/2014	12.03

9/19/2014	12.11
9/22/2014	13.69
9/23/2014	14.93
9/24/2014	13.27
9/25/2014	15.64
9/26/2014	14.85
9/29/2014	15.98
9/30/2014	16.31
10/1/2014	16.71
10/2/2014	16.16
10/3/2014	14.55
10/6/2014	15.46
10/7/2014	17.2
10/8/2014	15.11
10/9/2014	18.76
10/10/2014	21.24
10/13/2014	24.64
10/14/2014	22.79
10/15/2014	26.25
10/16/2014	25.2
10/17/2014	21.99
10/20/2014	18.57
10/21/2014	16.08
10/22/2014	17.87
10/23/2014	16.53
10/24/2014	16.11
10/27/2014	16.04
10/28/2014	14.39
10/29/2014	15.15
10/30/2014	14.52
10/31/2014	14.03
11/3/2014	14.73
11/4/2014	14.89
11/5/2014	14.17
11/6/2014	13.67
11/7/2014	13.12
11/10/2014	12.67
11/11/2014	12.92
11/12/2014	13.02
11/13/2014	13.79
11/14/2014	13.31
11/17/2014	13.99
11/18/2014	13.86
11/19/2014	13.96
11/20/2014	13.58
11/21/2014	12.9
11/24/2014	12.62
11/25/2014	12.25
11/26/2014	12.07
11/27/2014	12.07
11/28/2014	13.33
12/1/2014	14.29
12/2/2014	12.85
12/3/2014	12.47
12/4/2014	12.38
12/5/2014	11.82
12/8/2014	14.21
12/9/2014	14.89
12/10/2014	18.53
12/11/2014	20.08
12/12/2014	21.08
12/15/2014	20.42
12/16/2014	23.57
12/17/2014	19.44
12/18/2014	16.81
12/19/2014	16.49
12/22/2014	15.25
12/23/2014	14.8
12/24/2014	14.37
12/25/2014	14.37
12/26/2014	14.5
12/29/2014	15.06
12/30/2014	15.92
12/31/2014	19.2
1/1/2015	19.2
1/2/2015	17.79

1/5/2015	19.92
1/6/2015	21.12
1/7/2015	19.31
1/8/2015	17.01
1/9/2015	17.55
1/12/2015	19.6
1/13/2015	20.56
1/14/2015	21.48
1/15/2015	22.39
1/16/2015	20.95
1/19/2015	20.95
1/20/2015	19.89
1/21/2015	18.85
1/22/2015	16.4
1/23/2015	16.66
1/26/2015	15.52
1/27/2015	17.22
1/28/2015	20.44
1/29/2015	18.76
1/30/2015	20.97
2/2/2015	19.43
2/3/2015	17.33
2/4/2015	18.33
2/5/2015	16.85
2/6/2015	17.29
2/9/2015	18.55
2/10/2015	17.23
2/11/2015	16.96
2/12/2015	15.34
2/13/2015	14.69
2/16/2015	14.69
2/17/2015	15.8
2/18/2015	15.45
2/19/2015	15.29
2/20/2015	14.3
2/23/2015	14.56
2/24/2015	13.69
2/25/2015	13.84
2/26/2015	13.91
2/27/2015	13.34
3/2/2015	13.04
3/3/2015	13.86
3/4/2015	14.23
3/5/2015	14.04
3/6/2015	15.2
3/9/2015	15.06
3/10/2015	16.69
3/11/2015	16.87
3/12/2015	15.42
3/13/2015	16
3/16/2015	15.61
3/17/2015	15.66
3/18/2015	13.97
3/19/2015	14.07
3/20/2015	13.02
3/23/2015	13.41
3/24/2015	13.62
3/25/2015	15.44
3/26/2015	15.8
3/27/2015	15.07
3/30/2015	14.51
3/31/2015	15.29
4/1/2015	15.11
4/2/2015	14.67
4/3/2015	14.67
4/6/2015	14.74
4/7/2015	14.78
4/8/2015	13.98
4/9/2015	13.09
4/10/2015	12.58
4/13/2015	13.94
4/14/2015	13.67
4/15/2015	12.84
4/16/2015	12.6
4/17/2015	13.89
4/20/2015	13.3

4/21/2015	13.25
4/22/2015	12.71
4/23/2015	12.48
4/24/2015	12.29
4/27/2015	13.12
4/28/2015	12.41
4/29/2015	13.39
4/30/2015	14.55
5/1/2015	12.7
5/4/2015	12.85
5/5/2015	14.31
5/6/2015	15.15
5/7/2015	15.13
5/8/2015	12.86
5/11/2015	13.85
5/12/2015	13.86
5/13/2015	13.76
5/14/2015	12.74
5/15/2015	12.38
5/18/2015	12.73
5/19/2015	12.85
5/20/2015	12.88
5/21/2015	12.11
5/22/2015	12.13
5/25/2015	12.13
5/26/2015	14.06
5/27/2015	13.27
5/28/2015	13.31
5/29/2015	13.84
6/1/2015	13.97
6/2/2015	14.24
6/3/2015	13.66
6/4/2015	14.71
6/5/2015	14.21
6/8/2015	15.29
6/9/2015	14.47
6/10/2015	13.22
6/11/2015	12.85
6/12/2015	13.78
6/15/2015	15.39
6/16/2015	14.81
6/17/2015	14.5
6/18/2015	13.19
6/19/2015	13.96
6/22/2015	12.74
6/23/2015	12.11
6/24/2015	13.26
6/25/2015	14.01
6/26/2015	14.02
6/29/2015	18.85
6/30/2015	18.23
7/1/2015	16.09
7/2/2015	16.79
7/3/2015	16.79
7/6/2015	17.01
7/7/2015	16.09
7/8/2015	19.66
7/9/2015	19.97
7/10/2015	16.83
7/13/2015	13.9
7/14/2015	13.37
7/15/2015	13.23
7/16/2015	12.11
7/17/2015	11.95
7/20/2015	12.25
7/21/2015	12.22
7/22/2015	12.12
7/23/2015	12.64
7/24/2015	13.74
7/27/2015	15.6
7/28/2015	13.44
7/29/2015	12.5
7/30/2015	12.13
7/31/2015	12.12
8/3/2015	12.56
8/4/2015	13

8/5/2015	12.51
8/6/2015	13.77
8/7/2015	13.39
8/10/2015	12.23
8/11/2015	13.71
8/12/2015	13.61
8/13/2015	13.49
8/14/2015	12.83
8/17/2015	13.02
8/18/2015	13.79
8/19/2015	15.25
8/20/2015	19.14
8/21/2015	28.03
8/24/2015	40.74
8/25/2015	36.02
8/26/2015	30.32
8/27/2015	26.1
8/28/2015	26.05
8/31/2015	28.43
9/1/2015	31.4
9/2/2015	26.09
9/3/2015	25.61
9/4/2015	27.8
9/7/2015	27.8
9/8/2015	24.9
9/9/2015	26.23
9/10/2015	24.37
9/11/2015	23.2
9/14/2015	24.25
9/15/2015	22.54
9/16/2015	21.35
9/17/2015	21.14
9/18/2015	22.28
9/21/2015	20.14
9/22/2015	22.44
9/23/2015	22.13
9/24/2015	23.47
9/25/2015	23.62
9/28/2015	27.63
9/29/2015	26.83
9/30/2015	24.5
10/1/2015	22.55
10/2/2015	20.94
10/5/2015	19.54
10/6/2015	19.4
10/7/2015	18.4
10/8/2015	17.42
10/9/2015	17.08
10/12/2015	16.17
10/13/2015	17.67
10/14/2015	18.03
10/15/2015	16.05
10/16/2015	15.05
10/19/2015	14.98
10/20/2015	15.75
10/21/2015	16.7
10/22/2015	14.45
10/23/2015	14.46
10/26/2015	15.29
10/27/2015	15.43
10/28/2015	14.33
10/29/2015	14.61
10/30/2015	15.07
11/2/2015	14.15
11/3/2015	14.54
11/4/2015	15.51
11/5/2015	15.05
11/6/2015	14.33
11/9/2015	16.52
11/10/2015	15.29
11/11/2015	16.06
11/12/2015	18.37
11/13/2015	20.08
11/16/2015	18.16
11/17/2015	18.84
11/18/2015	16.85

11/19/2015	16.99
11/20/2015	15.47
11/23/2015	15.62
11/24/2015	15.93
11/25/2015	15.19
11/26/2015	15.19
11/27/2015	15.12
11/30/2015	16.13
12/1/2015	14.67
12/2/2015	15.91
12/3/2015	18.11
12/4/2015	14.81
12/7/2015	15.84
12/8/2015	17.6
12/9/2015	19.61
12/10/2015	19.34
12/11/2015	24.39
12/14/2015	22.73
12/15/2015	20.95
12/16/2015	17.86
12/17/2015	18.94
12/18/2015	20.7
12/21/2015	18.7
12/22/2015	16.6
12/23/2015	15.57
12/24/2015	15.74
12/25/2015	15.74
12/28/2015	16.91
12/29/2015	16.08
12/30/2015	17.29
12/31/2015	18.21
1/1/2016	18.21
1/4/2016	20.7
1/5/2016	19.34
1/6/2016	20.59
1/7/2016	24.99
1/8/2016	27.01
1/11/2016	24.3
1/12/2016	22.47
1/13/2016	25.22
1/14/2016	23.95
1/15/2016	27.02
1/18/2016	27.02
1/19/2016	26.05
1/20/2016	27.59
1/21/2016	26.69
1/22/2016	22.34
1/25/2016	24.15
1/26/2016	22.5
1/27/2016	23.11
1/28/2016	22.42
1/29/2016	20.2
2/1/2016	19.98
2/2/2016	21.98
2/3/2016	21.65
2/4/2016	21.84
2/5/2016	23.38
2/8/2016	26
2/9/2016	26.54
2/10/2016	26.29
2/11/2016	28.14
2/12/2016	25.4
2/15/2016	25.4
2/16/2016	24.11
2/17/2016	22.31
2/18/2016	21.64
2/19/2016	20.53
2/22/2016	19.38
2/23/2016	20.98
2/24/2016	20.72
2/25/2016	19.11
2/26/2016	19.81
2/29/2016	20.55
3/1/2016	17.7
3/2/2016	17.09
3/3/2016	16.7

3/4/2016	16.86
3/7/2016	17.35
3/8/2016	18.67
3/9/2016	18.34
3/10/2016	18.05
3/11/2016	16.5
3/14/2016	16.92
3/15/2016	16.84
3/16/2016	14.99
3/17/2016	14.44
3/18/2016	14.02
3/21/2016	13.79
3/22/2016	14.17
3/23/2016	14.94
3/24/2016	14.74
3/25/2016	14.74
3/28/2016	15.24
3/29/2016	13.82
3/30/2016	13.56
3/31/2016	13.95
4/1/2016	13.1
4/4/2016	14.12
4/5/2016	15.42
4/6/2016	14.09
4/7/2016	16.16
4/8/2016	15.36
4/11/2016	16.26
4/12/2016	14.85
4/13/2016	13.84
4/14/2016	13.72
4/15/2016	13.62
4/18/2016	13.35
4/19/2016	13.24
4/20/2016	13.28
4/21/2016	13.95
4/22/2016	13.22
4/25/2016	14.08
4/26/2016	13.96
4/27/2016	13.77
4/28/2016	15.22
4/29/2016	15.7
5/2/2016	14.68
5/3/2016	15.6
5/4/2016	16.05
5/5/2016	15.91
5/6/2016	14.72
5/9/2016	14.57
5/10/2016	13.63
5/11/2016	14.69
5/12/2016	14.41
5/13/2016	15.04
5/16/2016	14.68
5/17/2016	15.57
5/18/2016	15.95
5/19/2016	16.33
5/20/2016	15.2
5/23/2016	15.82
5/24/2016	14.42
5/25/2016	13.9
5/26/2016	13.43
5/27/2016	13.12
5/30/2016	13.12
5/31/2016	14.19
6/1/2016	14.2
6/2/2016	13.63
6/3/2016	13.47
6/6/2016	13.65
6/7/2016	14.05
6/8/2016	14.08
6/9/2016	14.64
6/10/2016	17.03
6/13/2016	20.97
6/14/2016	20.5
6/15/2016	20.14
6/16/2016	19.37
6/17/2016	19.41

6/20/2016	18.37
6/21/2016	18.48
6/22/2016	21.17
6/23/2016	17.25
6/24/2016	25.76
6/27/2016	23.85
6/28/2016	18.75
6/29/2016	16.64
6/30/2016	15.63
7/1/2016	14.77
7/4/2016	14.77
7/5/2016	15.58
7/6/2016	14.96
7/7/2016	14.76
7/8/2016	13.2
7/11/2016	13.54
7/12/2016	13.55
7/13/2016	13.04
7/14/2016	12.82
7/15/2016	12.67
7/18/2016	12.44
7/19/2016	11.97
7/20/2016	11.77
7/21/2016	12.74
7/22/2016	12.02
7/25/2016	12.87
7/26/2016	13.05
7/27/2016	12.83
7/28/2016	12.72
7/29/2016	11.87
8/1/2016	12.44
8/2/2016	13.37
8/3/2016	12.86
8/4/2016	12.42
8/5/2016	11.39
8/8/2016	11.5
8/9/2016	11.66
8/10/2016	12.05
8/11/2016	11.68
8/12/2016	11.55
8/15/2016	11.81
8/16/2016	12.64
8/17/2016	12.19
8/18/2016	11.43
8/19/2016	11.34
8/22/2016	12.27
8/23/2016	12.38
8/24/2016	13.45
8/25/2016	13.63
8/26/2016	13.65
8/29/2016	12.94
8/30/2016	13.12
8/31/2016	13.42
9/1/2016	13.48
9/2/2016	11.98
9/5/2016	11.98
9/6/2016	12.02
9/7/2016	11.94
9/8/2016	12.51
9/9/2016	17.5
9/12/2016	15.16
9/13/2016	17.85
9/14/2016	18.14
9/15/2016	16.3
9/16/2016	15.37
9/19/2016	15.53
9/20/2016	15.92
9/21/2016	13.3
9/22/2016	12.02
9/23/2016	12.29
9/26/2016	14.5
9/27/2016	13.1
9/28/2016	12.39
9/29/2016	14.02
9/30/2016	13.29
10/3/2016	13.57

10/4/2016	13.63
10/5/2016	12.99
10/6/2016	12.84
10/7/2016	13.48
10/10/2016	13.38
10/11/2016	15.36
10/12/2016	15.91
10/13/2016	16.69
10/14/2016	16.12
10/17/2016	16.21
10/18/2016	15.28
10/19/2016	14.41
10/20/2016	13.75
10/21/2016	13.34
10/24/2016	13.02
10/25/2016	13.46
10/26/2016	14.24
10/27/2016	15.36
10/28/2016	16.19
10/31/2016	17.06
11/1/2016	18.56
11/2/2016	19.32
11/3/2016	22.08
11/4/2016	22.51
11/7/2016	18.71
11/8/2016	18.74
11/9/2016	14.38
11/10/2016	14.74
11/11/2016	14.17
11/14/2016	14.48
11/15/2016	13.37
11/16/2016	13.72
11/17/2016	13.35
11/18/2016	12.85
11/21/2016	12.42
11/22/2016	12.41
11/23/2016	12.43
11/24/2016	12.43
11/25/2016	12.34
11/28/2016	13.15
11/29/2016	12.9
11/30/2016	13.33
12/1/2016	14.07
12/2/2016	14.12
12/5/2016	12.14
12/6/2016	11.79
12/7/2016	12.22
12/8/2016	12.64
12/9/2016	11.75
12/12/2016	12.64
12/13/2016	12.72
12/14/2016	13.19
12/15/2016	12.79
12/16/2016	12.2
12/19/2016	11.71
12/20/2016	11.45
12/21/2016	11.27
12/22/2016	11.43
12/23/2016	11.44
12/26/2016	11.44
12/27/2016	11.99
12/28/2016	12.95
12/29/2016	13.37
12/30/2016	14.04
1/2/2017	14.04
1/3/2017	12.85
1/4/2017	11.85
1/5/2017	11.67
1/6/2017	11.32
1/9/2017	11.56
1/10/2017	11.49
1/11/2017	11.26
1/12/2017	11.54
1/13/2017	11.23
1/16/2017	11.23
1/17/2017	11.87

1/18/2017	12.48
1/19/2017	12.78
1/20/2017	11.54
1/23/2017	11.77
1/24/2017	11.07
1/25/2017	10.81
1/26/2017	10.63
1/27/2017	10.58
1/30/2017	11.88
1/31/2017	11.99
2/1/2017	11.81
2/2/2017	11.93
2/3/2017	10.97
2/6/2017	11.37
2/7/2017	11.29
2/8/2017	11.45
2/9/2017	10.88
2/10/2017	10.85
2/13/2017	11.07
2/14/2017	10.74
2/15/2017	11.97
2/16/2017	11.76
2/17/2017	11.49
2/20/2017	11.49
2/21/2017	11.57
2/22/2017	11.74
2/23/2017	11.71
2/24/2017	11.47
2/27/2017	12.09
2/28/2017	12.92
3/1/2017	12.54
3/2/2017	11.81
3/3/2017	10.96
3/6/2017	11.24
3/7/2017	11.45
3/8/2017	11.86
3/9/2017	12.3
3/10/2017	11.66
3/13/2017	11.35
3/14/2017	12.3
3/15/2017	11.63
3/16/2017	11.21
3/17/2017	11.28
3/20/2017	11.34
3/21/2017	12.47
3/22/2017	12.81
3/23/2017	13.12
3/24/2017	12.96
3/27/2017	12.5
3/28/2017	11.53
3/29/2017	11.42
3/30/2017	11.54
3/31/2017	12.37
4/3/2017	12.38
4/4/2017	11.79
4/5/2017	12.89
4/6/2017	12.39
4/7/2017	12.87
4/10/2017	14.05
4/11/2017	15.07
4/12/2017	15.77
4/13/2017	15.96
4/14/2017	15.96
4/17/2017	14.66
4/18/2017	14.42
4/19/2017	14.93
4/20/2017	14.15
4/21/2017	14.63
4/24/2017	10.84
4/25/2017	10.76
4/26/2017	10.85
4/27/2017	10.36
4/28/2017	10.82
5/1/2017	10.11
5/2/2017	10.59
5/3/2017	10.68

5/4/2017	10.46
5/5/2017	10.57
5/8/2017	9.77
5/9/2017	9.96
5/10/2017	10.21
5/11/2017	10.6
5/12/2017	10.4
5/15/2017	10.42
5/16/2017	10.65
5/17/2017	15.59
5/18/2017	14.66
5/19/2017	12.04
5/22/2017	10.93
5/23/2017	10.72
5/24/2017	10.02
5/25/2017	9.99
5/26/2017	9.81
5/29/2017	9.81
5/30/2017	10.38
5/31/2017	10.41
6/1/2017	9.89
6/2/2017	9.75
6/5/2017	10.07
6/6/2017	10.45
6/7/2017	10.39
6/8/2017	10.16
6/9/2017	10.7
6/12/2017	11.46
6/13/2017	10.42
6/14/2017	10.64
6/15/2017	10.9
6/16/2017	10.38
6/19/2017	10.37
6/20/2017	10.86
6/21/2017	10.75
6/22/2017	10.48
6/23/2017	10.02
6/26/2017	9.9
6/27/2017	11.06
6/28/2017	10.03
6/29/2017	11.44
6/30/2017	11.18
7/3/2017	11.22
7/4/2017	11.22
7/5/2017	11.07
7/6/2017	12.54
7/7/2017	11.19
7/10/2017	11.11
7/11/2017	10.89
7/12/2017	10.3
7/13/2017	9.9
7/14/2017	9.51
7/17/2017	9.82
7/18/2017	9.89
7/19/2017	9.79
7/20/2017	9.58
7/21/2017	9.36
7/24/2017	9.43
7/25/2017	9.43
7/26/2017	9.6
7/27/2017	10.11
7/28/2017	10.29
7/31/2017	10.26
8/1/2017	10.09
8/2/2017	10.28
8/3/2017	10.44
8/4/2017	10.03
8/7/2017	9.93
8/8/2017	10.96
8/9/2017	11.11
8/10/2017	16.04
8/11/2017	15.51
8/14/2017	12.33
8/15/2017	12.04
8/16/2017	11.74
8/17/2017	15.55

8/18/2017	14.26
8/21/2017	13.19
8/22/2017	11.35
8/23/2017	12.25
8/24/2017	12.23
8/25/2017	11.28
8/28/2017	11.32
8/29/2017	11.7
8/30/2017	11.22
8/31/2017	10.59
9/1/2017	10.13
9/4/2017	10.13
9/5/2017	12.23
9/6/2017	11.63
9/7/2017	11.55
9/8/2017	12.12
9/11/2017	10.73
9/12/2017	10.58
9/13/2017	10.5
9/14/2017	10.44
9/15/2017	10.17
9/18/2017	10.15
9/19/2017	10.18
9/20/2017	9.78
9/21/2017	9.67
9/22/2017	9.59
9/25/2017	10.21
9/26/2017	10.17
9/27/2017	9.87
9/28/2017	9.55
9/29/2017	9.51
10/2/2017	9.45
10/3/2017	9.51
10/4/2017	9.63
10/5/2017	9.19
10/6/2017	9.65
10/9/2017	10.33
10/10/2017	10.08
10/11/2017	9.85
10/12/2017	9.91
10/13/2017	9.61
10/16/2017	9.91
10/17/2017	10.31
10/18/2017	10.07
10/19/2017	10.05
10/20/2017	9.97
10/23/2017	11.07
10/24/2017	11.16
10/25/2017	11.23
10/26/2017	11.3
10/27/2017	9.8
10/30/2017	10.5
10/31/2017	10.18
11/1/2017	10.2
11/2/2017	9.93
11/3/2017	9.14
11/6/2017	9.4
11/7/2017	9.89
11/8/2017	9.78
11/9/2017	10.5
11/10/2017	11.29
11/13/2017	11.5
11/14/2017	11.59
11/15/2017	13.13
11/16/2017	11.76
11/17/2017	11.43
11/20/2017	10.65
11/21/2017	9.73
11/22/2017	9.88
11/23/2017	9.88
11/24/2017	9.67
11/27/2017	9.87
11/28/2017	10.03
11/29/2017	10.7
11/30/2017	11.28
12/1/2017	11.43

12/4/2017	11.68
12/5/2017	11.33
12/6/2017	11.02
12/7/2017	10.16
12/8/2017	9.58
12/11/2017	9.34
12/12/2017	9.92
12/13/2017	10.18
12/14/2017	10.49
12/15/2017	9.42
12/18/2017	9.53
12/19/2017	10.03
12/20/2017	9.72
12/21/2017	9.62
12/22/2017	9.9
12/25/2017	9.9
12/26/2017	10.25
12/27/2017	10.47
12/28/2017	10.18
12/29/2017	11.04
1/1/2018	11.04
1/2/2018	9.77
1/3/2018	9.15
1/4/2018	9.22
1/5/2018	9.22
1/8/2018	9.52
1/9/2018	10.08
1/10/2018	9.82
1/11/2018	9.88
1/12/2018	10.16
1/15/2018	10.16
1/16/2018	11.66
1/17/2018	11.91
1/18/2018	12.22
1/19/2018	11.27
1/22/2018	11.03
1/23/2018	11.1
1/24/2018	11.47
1/25/2018	11.58
1/26/2018	11.08
1/29/2018	13.84
1/30/2018	14.79
1/31/2018	13.54
2/1/2018	13.47
2/2/2018	17.31
2/5/2018	37.32
2/6/2018	29.98
2/7/2018	27.73
2/8/2018	33.46
2/9/2018	29.06
2/12/2018	25.61
2/13/2018	24.97
2/14/2018	19.26
2/15/2018	19.13
2/16/2018	19.46
2/19/2018	19.46
2/20/2018	20.6
2/21/2018	20.02
2/22/2018	18.72
2/23/2018	16.49
2/26/2018	15.8
2/27/2018	18.59
2/28/2018	19.85
3/1/2018	22.47
3/2/2018	19.59
3/5/2018	18.73
3/6/2018	18.36
3/7/2018	17.76
3/8/2018	16.54
3/9/2018	14.64
3/12/2018	15.78
3/13/2018	16.35
3/14/2018	17.23
3/15/2018	16.59
3/16/2018	15.8
3/19/2018	19.02

3/20/2018	18.2
3/21/2018	17.86
3/22/2018	23.34
3/23/2018	24.87
3/26/2018	21.03
3/27/2018	22.5
3/28/2018	22.87
3/29/2018	19.97
3/30/2018	19.97
4/2/2018	23.62
4/3/2018	21.1
4/4/2018	20.06
4/5/2018	18.94
4/6/2018	21.49
4/9/2018	21.77
4/10/2018	20.47
4/11/2018	20.24
4/12/2018	18.49
4/13/2018	17.41
4/16/2018	16.56
4/17/2018	15.25
4/18/2018	15.6
4/19/2018	15.96
4/20/2018	16.88
4/23/2018	16.34
4/24/2018	18.02
4/25/2018	17.84
4/26/2018	16.24
4/27/2018	15.41
4/30/2018	15.93
5/1/2018	15.49
5/2/2018	15.97
5/3/2018	15.9
5/4/2018	14.77
5/7/2018	14.75
5/8/2018	14.71
5/9/2018	13.42
5/10/2018	13.23
5/11/2018	12.65
5/14/2018	12.93
5/15/2018	14.63
5/16/2018	13.42
5/17/2018	13.43
5/18/2018	13.42
5/21/2018	13.08
5/22/2018	13.22
5/23/2018	12.58
5/24/2018	12.53
5/25/2018	13.22
5/28/2018	13.22
5/29/2018	17.02
5/30/2018	14.94
5/31/2018	15.43
6/1/2018	13.46
6/4/2018	12.74
6/5/2018	12.4
6/6/2018	11.64
6/7/2018	12.13
6/8/2018	12.18
6/11/2018	12.35
6/12/2018	12.34
6/13/2018	12.94
6/14/2018	12.12
6/15/2018	11.98
6/18/2018	12.31
6/19/2018	13.35
6/20/2018	12.79
6/21/2018	14.64
6/22/2018	13.77
6/25/2018	17.33
6/26/2018	15.92
6/27/2018	17.91
6/28/2018	16.85
6/29/2018	16.09
7/2/2018	15.6
7/3/2018	16.14

7/4/2018	16.14
7/5/2018	14.97
7/6/2018	13.37
7/9/2018	12.69
7/10/2018	12.64
7/11/2018	13.63
7/12/2018	12.58
7/13/2018	12.18
7/16/2018	12.83
7/17/2018	12.06
7/18/2018	12.1
7/19/2018	12.87
7/20/2018	12.86
7/23/2018	12.62
7/24/2018	12.41
7/25/2018	12.29
7/26/2018	12.14
7/27/2018	13.03
7/30/2018	14.26
7/31/2018	12.83
8/1/2018	13.15
8/2/2018	12.19
8/3/2018	11.64
8/6/2018	11.27
8/7/2018	10.93
8/8/2018	10.85
8/9/2018	11.27
8/10/2018	13.16
8/13/2018	14.78
8/14/2018	13.31
8/15/2018	14.64
8/16/2018	13.45
8/17/2018	12.64
8/20/2018	12.49
8/21/2018	12.86
8/22/2018	12.25
8/23/2018	12.41
8/24/2018	11.99
8/27/2018	12.16
8/28/2018	12.5
8/29/2018	12.25
8/30/2018	13.53
8/31/2018	12.86
9/3/2018	12.86
9/4/2018	13.16
9/5/2018	13.91
9/6/2018	14.65
9/7/2018	14.88
9/10/2018	14.16
9/11/2018	13.22
9/12/2018	13.14
9/13/2018	12.37
9/14/2018	12.07
9/17/2018	13.68
9/18/2018	12.79
9/19/2018	11.75
9/20/2018	11.8
9/21/2018	11.68
9/24/2018	12.2
9/25/2018	12.42
9/26/2018	12.89
9/27/2018	12.41
9/28/2018	12.12
10/1/2018	12
10/2/2018	12.05
10/3/2018	11.61
10/4/2018	14.22
10/5/2018	14.82
10/8/2018	15.69
10/9/2018	15.95
10/10/2018	22.96
10/11/2018	24.98
10/12/2018	21.31
10/15/2018	21.3
10/16/2018	17.62
10/17/2018	17.4

10/18/2018	20.06
10/19/2018	19.89
10/22/2018	19.64
10/23/2018	20.71
10/24/2018	25.23
10/25/2018	24.22
10/26/2018	24.16
10/29/2018	24.7
10/30/2018	23.35
10/31/2018	21.23
11/1/2018	19.34
11/2/2018	19.51
11/5/2018	19.96
11/6/2018	19.91
11/7/2018	16.36
11/8/2018	16.72
11/9/2018	17.36
11/12/2018	20.45
11/13/2018	20.02
11/14/2018	21.25
11/15/2018	19.98
11/16/2018	18.14
11/19/2018	20.1
11/20/2018	22.48
11/21/2018	20.8
11/22/2018	20.8
11/23/2018	21.52
11/26/2018	18.9
11/27/2018	19.02
11/28/2018	18.49
11/29/2018	18.79
11/30/2018	18.07
12/3/2018	16.44
12/4/2018	20.74
12/5/2018	20.74
12/6/2018	21.19
12/7/2018	23.23
12/10/2018	22.64
12/11/2018	21.76
12/12/2018	21.46
12/13/2018	20.65
12/14/2018	21.63
12/17/2018	24.52
12/18/2018	25.58
12/19/2018	25.58
12/20/2018	28.38
12/21/2018	30.11
12/24/2018	36.07
12/25/2018	36.07
12/26/2018	30.41
12/27/2018	29.96
12/28/2018	28.34
12/31/2018	25.42
1/1/2019	25.42
1/2/2019	23.22
1/3/2019	25.45
1/4/2019	21.38
1/7/2019	21.4
1/8/2019	20.47
1/9/2019	19.98
1/10/2019	19.5
1/11/2019	18.19
1/14/2019	19.07
1/15/2019	18.6
1/16/2019	19.04
1/17/2019	18.06
1/18/2019	17.8
1/21/2019	17.8
1/22/2019	20.8
1/23/2019	19.52
1/24/2019	18.89
1/25/2019	17.42
1/28/2019	18.87
1/29/2019	19.13
1/30/2019	17.66
1/31/2019	16.57

2/1/2019	16.14
2/4/2019	15.73
2/5/2019	15.57
2/6/2019	15.38
2/7/2019	16.37
2/8/2019	15.72
2/11/2019	15.97
2/12/2019	15.43
2/13/2019	15.65
2/14/2019	16.22
2/15/2019	14.91
2/18/2019	14.91
2/19/2019	14.88
2/20/2019	14.02
2/21/2019	14.46
2/22/2019	13.51
2/25/2019	14.85
2/26/2019	15.17
2/27/2019	14.7
2/28/2019	14.78
3/1/2019	13.57
3/4/2019	14.63
3/5/2019	14.74
3/6/2019	15.74
3/7/2019	16.59
3/8/2019	16.05
3/11/2019	14.33
3/12/2019	13.77
3/13/2019	13.41
3/14/2019	13.5
3/15/2019	12.88
3/18/2019	13.1
3/19/2019	13.56
3/20/2019	13.91
3/21/2019	13.63
3/22/2019	16.48
3/25/2019	16.33
3/26/2019	14.68
3/27/2019	15.15
3/28/2019	14.43
3/29/2019	13.71
4/1/2019	13.4
4/2/2019	13.36
4/3/2019	13.74
4/4/2019	13.58
4/5/2019	12.82
4/8/2019	13.18
4/9/2019	14.28
4/10/2019	13.3
4/11/2019	13.02
4/12/2019	12.01
4/15/2019	12.32
4/16/2019	12.18
4/17/2019	12.6
4/18/2019	12.09
4/19/2019	12.09
4/22/2019	12.42
4/23/2019	12.28
4/24/2019	13.14
4/25/2019	13.25
4/26/2019	12.73
4/29/2019	13.11
4/30/2019	13.12
5/1/2019	14.8
5/2/2019	14.42
5/3/2019	12.87
5/6/2019	15.44
5/7/2019	19.32
5/8/2019	19.4
5/9/2019	19.1
5/10/2019	16.04
5/13/2019	20.55
5/14/2019	18.06
5/15/2019	16.44
5/16/2019	15.29
5/17/2019	15.96

5/20/2019	16.31
5/21/2019	14.95
5/22/2019	14.75
5/23/2019	16.92
5/24/2019	15.85
5/27/2019	15.85
5/28/2019	17.5
5/29/2019	17.9
5/30/2019	17.3
5/31/2019	18.71
6/3/2019	18.86
6/4/2019	16.97
6/5/2019	16.09
6/6/2019	15.93
6/7/2019	16.3
6/10/2019	15.94
6/11/2019	15.99
6/12/2019	15.91
6/13/2019	15.82
6/14/2019	15.28
6/17/2019	15.35
6/18/2019	15.15
6/19/2019	14.33
6/20/2019	14.75
6/21/2019	15.4
6/24/2019	15.26
6/25/2019	16.28
6/26/2019	16.21
6/27/2019	15.82
6/28/2019	15.08
7/1/2019	14.06
7/2/2019	12.93
7/3/2019	12.57
7/4/2019	12.57
7/5/2019	13.28
7/8/2019	13.96
7/9/2019	14.09
7/10/2019	13.03
7/11/2019	12.93
7/12/2019	12.39
7/15/2019	12.68
7/16/2019	12.86
7/17/2019	13.97
7/18/2019	13.53
7/19/2019	14.45
7/22/2019	13.53
7/23/2019	12.61
7/24/2019	12.07
7/25/2019	12.74
7/26/2019	12.16
7/29/2019	12.83
7/30/2019	13.94
7/31/2019	16.12
8/1/2019	17.87
8/2/2019	17.61
8/5/2019	24.59
8/6/2019	20.17
8/7/2019	19.49
8/8/2019	16.91
8/9/2019	17.97
8/12/2019	21.09
8/13/2019	17.52
8/14/2019	22.1
8/15/2019	21.18
8/16/2019	18.47
8/19/2019	16.88
8/20/2019	17.5
8/21/2019	15.8
8/22/2019	16.68
8/23/2019	19.87
8/26/2019	19.32
8/27/2019	20.31
8/28/2019	19.35
8/29/2019	17.88
8/30/2019	18.98
9/2/2019	18.98

9/3/2019	19.66
9/4/2019	17.33
9/5/2019	16.27
9/6/2019	15
9/9/2019	15.27
9/10/2019	15.2
9/11/2019	14.61
9/12/2019	14.22
9/13/2019	13.74
9/16/2019	14.67
9/17/2019	14.44
9/18/2019	13.95
9/19/2019	14.05
9/20/2019	15.32
9/23/2019	14.91
9/24/2019	17.05
9/25/2019	15.96
9/26/2019	16.07
9/27/2019	17.22
9/30/2019	16.24
10/1/2019	18.56
10/2/2019	20.56
10/3/2019	19.12
10/4/2019	17.04
10/7/2019	17.86
10/8/2019	20.28
10/9/2019	18.64
10/10/2019	17.57
10/11/2019	15.58
10/14/2019	14.57
10/15/2019	13.54
10/16/2019	13.68
10/17/2019	13.79
10/18/2019	14.25
10/21/2019	14
10/22/2019	14.46
10/23/2019	14.01
10/24/2019	13.71
10/25/2019	12.65
10/28/2019	13.11
10/29/2019	13.2
10/30/2019	12.33
10/31/2019	13.22
11/1/2019	12.3
11/4/2019	12.83
11/5/2019	13.1
11/6/2019	12.62
11/7/2019	12.73
11/8/2019	12.07
11/11/2019	12.69
11/12/2019	12.68
11/13/2019	13
11/14/2019	13.05
11/15/2019	12.05
11/18/2019	12.46
11/19/2019	12.86
11/20/2019	12.78
11/21/2019	13.13
11/22/2019	12.34
11/25/2019	11.87
11/26/2019	11.54
11/27/2019	11.75
11/28/2019	11.75
11/29/2019	12.62
12/2/2019	14.91
12/3/2019	15.96
12/4/2019	14.8
12/5/2019	14.52
12/6/2019	13.62
12/9/2019	15.86
12/10/2019	15.68
12/11/2019	14.99
12/12/2019	13.94
12/13/2019	12.63
12/16/2019	12.14
12/17/2019	12.29

12/18/2019	12.58
12/19/2019	12.5
12/20/2019	12.51
12/23/2019	12.61
12/24/2019	12.67
12/25/2019	12.67
12/26/2019	12.65
12/27/2019	13.43
12/30/2019	14.82
12/31/2019	13.78
1/1/2020	13.78
1/2/2020	12.47
1/3/2020	14.02
1/6/2020	13.85
1/7/2020	13.79
1/8/2020	13.45
1/9/2020	12.54
1/10/2020	12.56
1/13/2020	12.32
1/14/2020	12.39
1/15/2020	12.42
1/16/2020	12.32
1/17/2020	12.1
1/20/2020	12.1
1/21/2020	12.85
1/22/2020	12.91
1/23/2020	12.98
1/24/2020	14.56
1/27/2020	18.23
1/28/2020	16.28
1/29/2020	16.39
1/30/2020	15.49
1/31/2020	18.84
2/3/2020	17.97
2/4/2020	16.05
2/5/2020	15.15
2/6/2020	14.96
2/7/2020	15.47
2/10/2020	15.04
2/11/2020	15.18
2/12/2020	13.74
2/13/2020	14.15
2/14/2020	13.68
2/17/2020	13.68
2/18/2020	14.83
2/19/2020	14.38
2/20/2020	15.56
2/21/2020	17.08
2/24/2020	25.03
2/25/2020	27.85
2/26/2020	27.56
2/27/2020	39.16
2/28/2020	40.11
3/2/2020	33.42
3/3/2020	36.82
3/4/2020	31.99
3/5/2020	39.62
3/6/2020	41.94
3/9/2020	54.46
3/10/2020	47.3
3/11/2020	53.9
3/12/2020	75.47
3/13/2020	57.83
3/16/2020	82.69
3/17/2020	75.91
3/18/2020	76.45
3/19/2020	72
3/20/2020	66.04
3/23/2020	61.59
3/24/2020	61.67
3/25/2020	63.95
3/26/2020	61
3/27/2020	65.54
3/30/2020	57.08
3/31/2020	53.54
4/1/2020	57.06

4/2/2020	50.91
4/3/2020	46.8
4/6/2020	45.24
4/7/2020	46.7
4/8/2020	43.35
4/9/2020	41.67
4/10/2020	41.67
4/13/2020	41.17
4/14/2020	37.76
4/15/2020	40.84
4/16/2020	40.11
4/17/2020	38.15
4/20/2020	43.83
4/21/2020	45.41
4/22/2020	41.98
4/23/2020	41.38
4/24/2020	35.93
4/27/2020	33.29
4/28/2020	33.57
4/29/2020	31.23
4/30/2020	34.15
5/1/2020	37.19
5/4/2020	35.97
5/5/2020	33.61
5/6/2020	34.12
5/7/2020	31.44
5/8/2020	27.98
5/11/2020	27.57
5/12/2020	33.04
5/13/2020	35.28
5/14/2020	32.61
5/15/2020	31.89
5/18/2020	29.3
5/19/2020	30.53
5/20/2020	27.99
5/21/2020	29.53
5/22/2020	28.16
5/25/2020	28.16
5/26/2020	28.01
5/27/2020	27.62
5/28/2020	28.59
5/29/2020	27.51
6/1/2020	28.23
6/2/2020	26.84
6/3/2020	25.66
6/4/2020	25.81
6/5/2020	24.52
6/8/2020	25.81
6/9/2020	27.57
6/10/2020	27.57
6/11/2020	40.79
6/12/2020	36.09
6/15/2020	34.4
6/16/2020	33.67
6/17/2020	33.47
6/18/2020	32.94
6/19/2020	35.12
6/22/2020	31.77
6/23/2020	31.37
6/24/2020	33.84
6/25/2020	32.22
6/26/2020	34.73
6/29/2020	31.78
6/30/2020	30.43

Ann Bulkley

Americas (English)ContactFeedbackHelp

ACTIONS & CRITERIA

REGULATORY

RATINGS RESOURCES

EntityFind a Rating...Submit

RATINGS ACTIONSPRESS RELEASESRATINGS CRITERIA AND MODELSPRESALE REPORTSREQUESTS FOR COMMENTSIGNIFICANT CRITERIA AND MODEL ERRORS

TC PipeLines L.P.

Issuer Credit Rating						
Rating Type	Rating	Rating Date	Last Review Date	Regulatory Identifiers	CreditWatch/ Outlook	CreditWatch/ Outlook Date
Local Currency LT	BBB Regulatory Disclosures	23-Jul-2019	28-May-2020	EE	Stable	23-Jul-2019
Foreign Currency LT	BBB Regulatory Disclosures	23-Jul-2019	28-May-2020	EE	Stable	23-Jul-2019

View Ratings Definitions

Debt Types