STATE OF MICHIGAN
DEPARTMENT OF ATTORNEY GENERAL

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DANA NESSEL
ATTORNEY GENERAL

March 24, 2020

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

Dear Ms. Felice:

Re: MPSC Case No. U-20642

Enclosed find the ***Attorney General's public version of the Testimony and Exhibits of Sebastian Coppola,*** and related Proof of Service.

Sincerely,

Joel King

Digitally signed by Joel King
Date: 2020.03.24 17:24:40 -04'00'

Joel B. King
Assistant Attorney General

cc: All Parties

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

MPSC Case No. U-20642

In the matter of the application of	)
DTE GAS COMPANY	)
for authority to increase its rates, amend	)
its rate schedules and rules governing the	)
distribution and supply of natural gas,	)
and for miscellaneous accounting authority	)

Direct Testimony

And Exhibits

of

Sebastian Coppola

On behalf of

Attorney General Dana Nessel

March 24, 2020

TABLE OF CONTENTS

I. Introduction

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

A. My name is Sebastian Coppola. I am an independent business consultant. My office is at 5928 Southgate Rd., Rochester, Michigan 48306.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I am a business consultant specializing in financial and strategic business issues in the fields of energy and utility regulation. I have more than thirty years of experience in public utility and related energy work, both as a consultant and utility company executive. I have testified in several regulatory proceedings before the Michigan Public Service Commission (MPSC or Commission) and other regulatory jurisdictions. I have prepared and/or filed testimony in rate case proceedings, revenue decoupling reconciliations, gas conservation programs, Gas Cost Recovery (GCR) cases and Power Supply Cost Recovery (PSCR) cases, and other proceedings. As accounting manager and later financial executive for two regulated gas utilities with operations in Michigan and Alaska, I have been intricately involved in regulatory proceedings related to gas cost recovery cases, gas purchase strategies, rate case filings and power plant cost analysis. I have also supported other witnesses in testimony before the MPSC in various rate setting and other regulatory proceedings.

Q. PLEASE LIST SOME OF THE MORE RECENT CASES YOU HAVE PARTICIPATED IN BEFORE THE MPSC AND OTHER REGULATORY AGENCIES.

A. Here is a partial list of the most recent regulatory cases in which I have participated:

- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in Consumer Energy Company (CECo) 2018-2019 GCR reconciliation case U-20209.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2018-2019 GCR reconciliation case U-20215.
- Provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2018 PSCR Reconciliation in case U-20203.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Reconciliation in case U-20202.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 electric rate Case U-20561 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Michigan Power Company (I&M) 2019 electric rate Case U-20239 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019 gas rate Case U-20479 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019-2020 GCR Plan case U-20245.

- Filed testimony on behalf of the Michigan Attorney General in CECo 2019-2020 GCR Plan case U-20233.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Plan case U-20221.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2019-2020 GCR Plan case U-20235.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2019-2020 GCR plan case U-20239.
- Filed rebuttal testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017-2018 GCR reconciliation case U-20076.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017-2018 GCR reconciliation case U-20075.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 gas rate Case U-20322 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in I&M Tax Credit C Calculation in case U-20317.
- Filed direct testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Tax Credit C Calculation in case U-20298.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2017-2018 GCR Reconciliation case U-20078.
- Filed testimony on behalf of the Michigan Attorney General in CECo Tax Credit C Calculation for the Gas and Electric Divisions in case U-20309.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2018 electric rate Case U-20276 on several issues, including excess deferred taxes, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric (DTEE) 2018 rate Case U-20162 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.

Appendix A elaborates further on my qualifications in the regulated energy field.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by the AG to perform an independent analysis of DTE Gas Company's ("Company" or "DTE Gas") Rate Case filing U-20642. This testimony presents a report of that analysis with related recommendations.

Q. WHAT TOPICS ARE YOU ADDRESSING IN YOUR TESTIMONY?

A. I am addressing the following major topics in this case:

1. The level of Gas Sales
2. The level of Operations and Maintenance expenses
3. Incentive Compensation
4. The level of proposed Rate Base and Capital Expenditures
5. The Company's Cost of Capital and Working Capital
6. The Company's Proposed Monthly Service Charges for Residential and Small Commercial customers

The absence of a discussion of other matters in my testimony should not be taken as an indication that I agree with those aspects of DTE Gas's rate case filing. The narrow focus of my testimony is, instead, a consequence of focusing on priority issues within the available resources.

Q. IS YOUR TESTIMONY ON THESE TOPICS ACCOMPANIED BY EXHIBITS?

A. Yes. I am sponsoring the following exhibits, which were either prepared by me or under my direct supervision:

1. Exhibit AG-1 DTE Energy Investor Presentation Information

2. Exhibit AG-2 Contingency Capital Expenditures
3. Exhibit AG-3 Quality Assurance Program Information
4. Exhibit AG-4 Service Lines Alterations
5. Exhibit AG-5 Service Lines Alterations – Cost Disallowance
6. Exhibit AG-6 Belle Isle Main Replacement
7. Exhibit AG-7 Transmission Routine Capital Expenditures
8. Exhibit AG-8 Transmission Routine Capital Expenditures Disallowance
9. Exhibit AG-9 DTE Gas-NEXUS Cost Overrun
10. Exhibit AG-10 Van Born Total Project Costs
11. Exhibit AG-11 Fort Street Main Replacement Actual 2019 Costs
12. Exhibit AG-12 ILI Projects Actual 2019 Costs
13. Exhibit AG-13 Southfield 24" Main Replacement Project
14. Exhibit AG-14 IT ClickSoft Project
15. Exhibit AG-15 IT EGMS Project
16. Exhibit AG-16 Reported Gas Leaks 2011-2018
17. Exhibit AG-17 MRP Projects and Rankings 2018-2021
18. Exhibit AG-18 Project Probability Risk Assessment Model
19. Exhibit AG-19 Capitalized Incentive Compensation Costs
20. Exhibit AG-20 Capital Expenditures Summary, Rate Base and Depreciation
21. Exhibit AG-21 Overall Cost of Capital
22. Exhibit AG-22 Cost of Common Equity Capital
23. Exhibit AG-23 Cost of Common Equity Capital-DCF
24. Exhibit AG-24 Cost of Common Equity-CAPM
25. Exhibit AG-25 Cost of Common Equity-Risk Premium
26. Exhibit AG-26 Peer Group Analysis-Capital Structure
27. Exhibit AG-27 Market to Book Ratios
28. Exhibit AG-28 Gas ROE Decisions by Regulatory Commissions
29. Exhibit AG-29 Historical Sales Analysis and Growth Rates
30. Exhibit AG-30 Gas Sales Rate A Sales Revenue Adjustment
31. Exhibit AG-31 Gas Sales Rate 2A Sales Revenue Adjustment

32. Exhibit AG-32 Gas Sales Rate GS-1 Sales Revenue Adjustment
33. Exhibit AG-33 Gas Sales Rate GS-2 Sales Revenue Adjustment
34. Exhibit AG-34 Gas Sales Rate S Sales Revenue Adjustment
35. Exhibit AG-35 End-User Transportation Revenue Adjustment
36. Exhibit AG-36 Total Revenue Adjustment
37. Exhibit AG-37 Power Generation Transportation Deliveries 201-2019
38. Exhibit AG-38 New EUT Customer Load
39. Exhibit AG-39 EUT Deliveries Comparison Actual to Prior Rate Cases
40. Exhibit AG-40 HPP Appliance Program Revenues and Cost and Profit Margin
41. Exhibit AG-41 O&M Expense Adjustments Summary
42. Exhibit AG-42 O&M Expense-CPI Adjustment
43. Exhibit AG-43 Health Care Cost Adjustment
44. Exhibit AG-44 CPI Rates by IHS
45. Exhibit AG-45 Merchant Fee 2018 to Future Test Year
46. Exhibit AG-46 Merchant Fee Uncollectible Accounts Analysis
47. Exhibit AG-47 Uncollectible Accounts Expense Adjustment
48. Exhibit AG-48 Incentive Compensation Performance Measures Achieved
49. Exhibit AG-49 IT Capital Usage Charge Disallowed
50. Exhibit AG-50 IT Projects Testimony and Exhibit Case No. U-20561
51. Exhibit AG-51 Revenue Deficiency Calculation
52. Exhibit AG-52 CONF DTE Gas Peer Group Book Common Equity Ratio
53. Exhibit AG-53 CONF Moody’s Rating Change DTE Internal Memorandum
54. Exhibit AG-54 DTE Gas Calculation of CFO Pre-WC to Debt Ratio
55. Exhibit AG-55 Value Line Analysis of Water Companies
56. Exhibit AG-56 Value Line Analysis of Stock Market Volatility

<u>II. SUMMARY CONCLUSIONS & RECOMMENDATIONS</u>

Q. PLEASE PROVIDE A SUMMARY OF YOUR CONCLUSIONS AND ADJUSTMENTS TO THE COMPANY'S REVENUE DEFICIENCY CALCULATION BEFORE YOU ADDRESS EACH TOPIC IN DETAIL.

A. The Company filed for a base rate increase of $203.8 million. This rate increase represents an overall increase in rates of 12.1% with an 8.3% increase to residential customers. As a result of the rate case adjustments I propose in my testimony, the average residential customer would see an increase of approximately 3.5% in their total bill.

It is noteworthy to point out that during the five-year period from 2014 to 2018, the Company earned a return on common equity on a regulatory basis generally at or above the authorized ROE rate. In 2018, DTEE had an earned ROE of 9.5% and a revenue sufficiency of $29.1 million.[1]

Based on the foregoing analysis, I have identified several cost disallowances to the Company's proposed cost levels and capital projects, which I recommend that the Commission approve. As a result of these adjustments, I have determined that the Company has a revenue deficiency of $65.5 million. This result should not be surprising given the fact that the Company had a revenue sufficiency of $29.1 million in the 2018 historical test year.

[1] Exhibit A-1, Schedule A-1, and A-2, Schedule A2, page 4.

Based on my analysis of the Company's case, I have reached the following summary conclusions and recommendations:

1. I propose adjustments to increase gas sales, end-user transportation service and other revenues which reduce the Company's filed revenue deficiency by $28.3 million.
2. I propose a lower level of Operations and Maintenance expenses of $60.9 million for the test year.
3. I propose a reduction in capital expenditures of $146.6 million and a reduction in rate base of $116.7 million, which reduce the revenue deficiency by $8.3 million.
4. I propose a reduction in depreciation expense of $4.5 million pertaining to the proposed reductions in capital expenditures.
5. I recommend an authorized rate of return on equity of 9.50% in comparison to the Company's proposed ROE rate of 10.50%, a permanent capital structure with 50% common equity and 50% long-term debt, and higher amount of short-term debt, which results in a reduction in the revenue deficiency of $36.9 million.
6. I recommend that the Commission reject the Company's proposed increase in the Monthly Customer Service Charges for Rate Schedules A, 2A and GS-1 and preferably keep those monthly charges at the same current levels, or in the alternative increase them by no more than $1 per month.

The remainder of my testimony provides further details and support for these summary conclusions and recommendations.

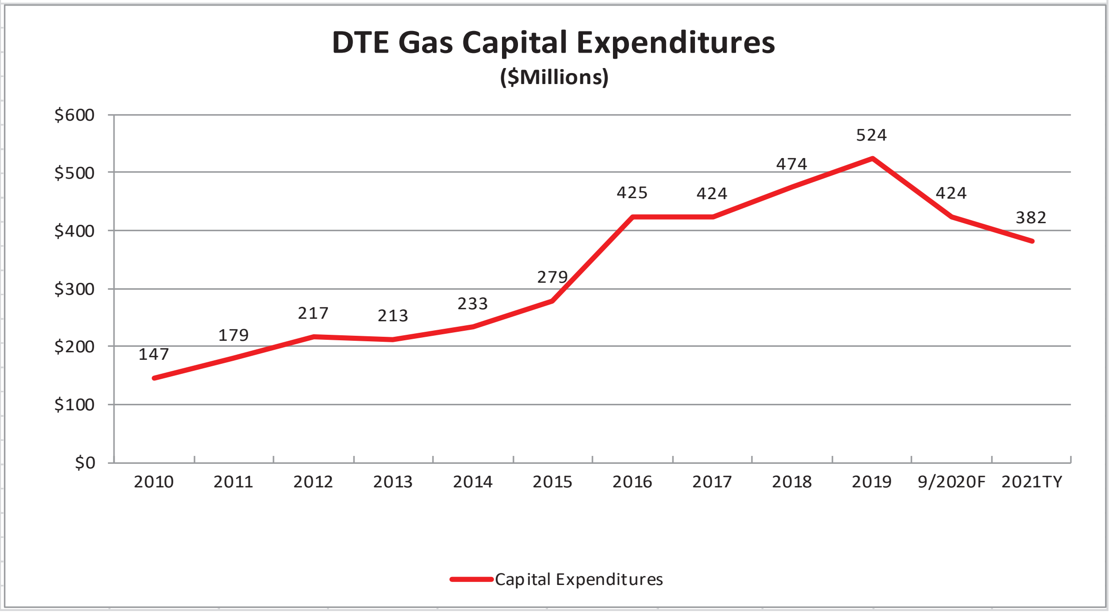
III. LARGE INCREASE IN RATE BASE AND CAPITAL EXPENDITURES

Q. PLEASE DISCUSS YOUR CONCERNS WITH THE LEVEL OF CAPITAL EXPENDITURES PROPOSED BY THE COMPANY AND THE RESULTING INCREASE IN RATE BASE.

A. In this general rate case, DTE Gas has proposed capital expenditures of $474 million for 2018, $515 million for 2019, $424 million for the 9 months ending September 2020 ($565 million annualized), and an additional $381 million for the 12 months ending September 2021. The total proposed capital expenditures over this 45-month period are nearly $1.8 billion. These expenditures follow capital expenditures of $1.1 billion made during the prior three years from 2015 to 2017.[2] The following chart in Table 1 shows the dramatic increase in capital expenditures over recent years, in comparison to more moderate amounts in prior years.

[2] DTE Gas response to discovery request AGDG-3.170a.

Table 1



Until 2012, the Company was able to keep capital expenditures below $200 annually. Eight years later, the level of annual capital expenditures has more than doubled to $524 million.

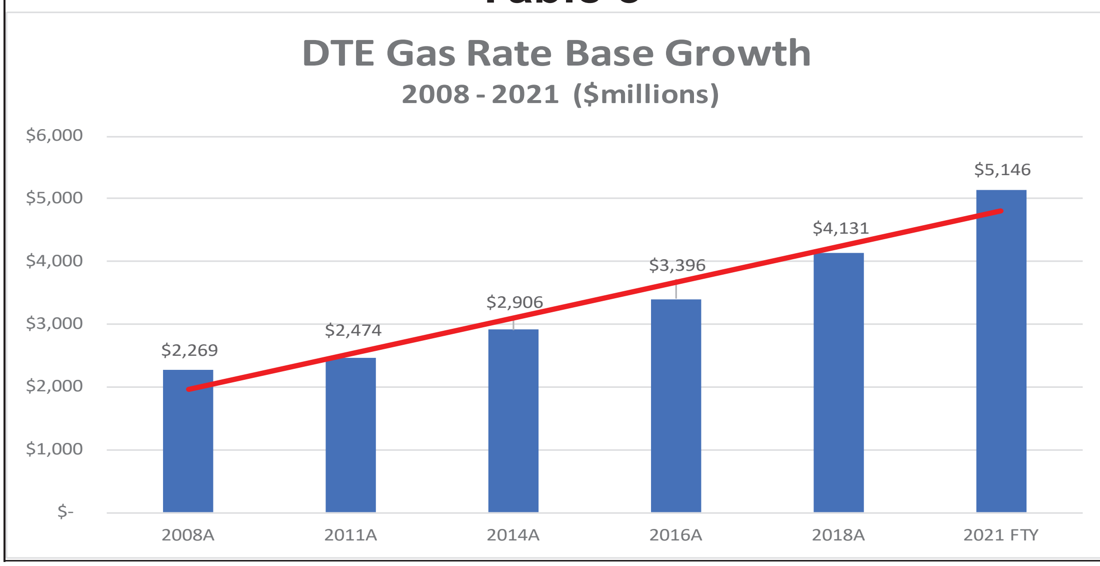
The capital expenditures have fueled an alarming increase in rate base. As shown below in Table 2, rate base has been growing at high-single digit to double digit rates in recent years and the Company is proposing to increase rate base again in this rate case by 25%, to $5.1 billion. The proposed level of rate base in this rate case is more than double the amount of rate base the Company had 13 years ago.

Table 2 DTE Gas Rate Base Growth 2009 to Projected 2021 Test Year						
Rate Base Year	2008A	2011A	2014A	2016A	2018A	2021 FTY
Docket No.	U-15985	U-16999	U-17999	U-18999	U-20642	U-20642
Rate Base [1] (Millions)	$ 2,269	$ 2,474	$ 2,906	$ 3,396	$ 4,131	$ 5,146
Year over Year Change		9%	17%	17%	22%	25%
Cumulative Change over 2008 Rate Base		9%	28%	50%	82%	127%

[1] Historical actual rate base in each docket, except 2021 FTY is proposed amount.

This significant increase in rate base is illustrated by the following chart included in Table 3, which shows the accelerated trend of increases in recent years. The current trend has significant negative implications for customer bills, as discussed later in my testimony.

Table 3



Q. WHAT DO YOU BELIEVE IS DRIVING THIS DRAMATIC INCREASE IN CAPITAL EXPENDITURES AND RATE BASE SINCE 2008?

A. I believe there are two main drivers. First, replacement of aging infrastructure and new capital spending to address market growth have required an increase in capital expenditures, which have accelerated investment to some degree. The Company continues to propose ever-increasing capital expenditures to replace cast iron mains, service lines and related facilities. Some of this work is necessary and must be done. However, the Company has intensified the pace of replacement of pipelines and other facilities without sufficient engineering analysis to support the increase in capital expenditures.

The Company also seems to be experiencing moderate customer growth in its market area. However, moderate customer growth has existed in prior years. Prior to 2012, DTE Gas was able to manage replacement of aging infrastructure and also invest in new facilities to meet market growth within a more reasonable increase in rate base. Therefore, customer growth and replacement of aging infrastructure by themselves do not fully explain the significant increase in capital expenditures and rate base since 2011.

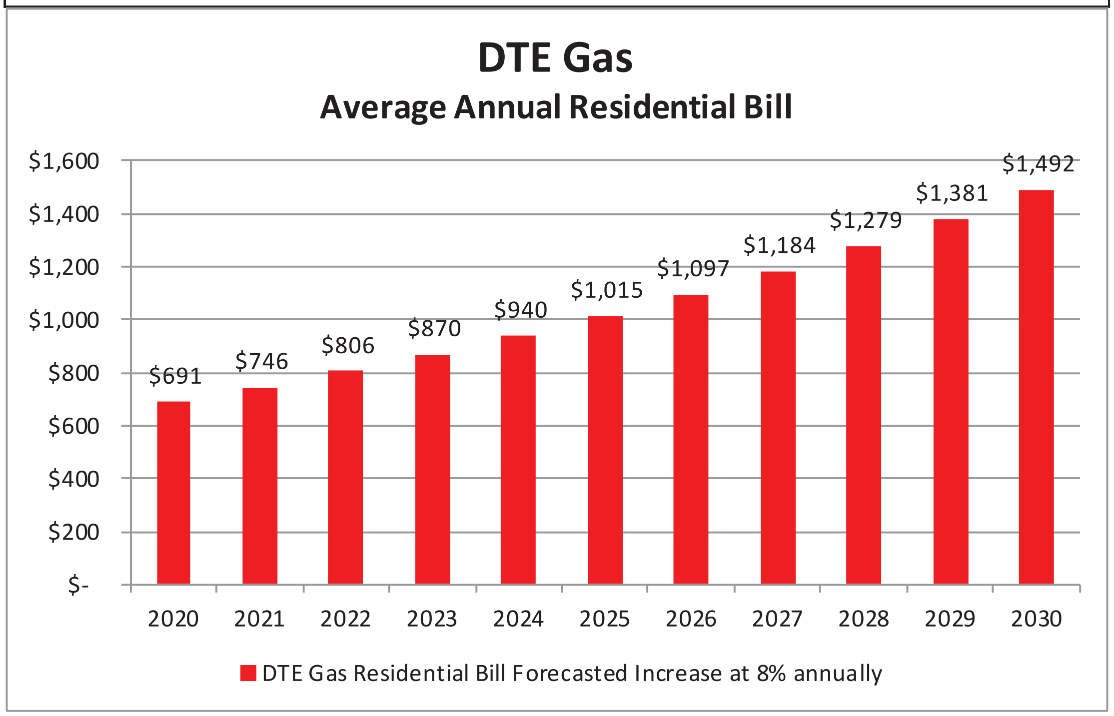
Second and perhaps a bigger driver, the replacement of aging gas infrastructure has given the Company an opportunity to accelerate rate base growth in order to increase earnings growth. For utility companies, earnings growth is directly related to rate base growth. As shown in the tables above, large increases in capital expenditures result in double digit increases in rate base, which in turn fuels earnings growth, dividend growth and stock price appreciation for shareholders.

The Company's parent company, DTE Energy, has been quite clear and aggressive in communicating to investors and securities analysts its goal of increasing operating earnings at the gas utility at an average annual rate of 8% to 9%. Exhibit AG-1 includes pertinent pages from an October 2, 2019 Investor Presentation, which show this drive to increase earnings through increased capital spending at the utility. They also show how investors and shareholders have been well rewarded. For a utility such as DTE Gas with limited sales and revenue growth, the increase in earnings comes almost entirely from the increase in capital expenditures and rate base. The presentation is devoid of any discussion about sales or revenue growth to propel earnings growth at the utility.

Q. HAVE YOU DETERMINED WHAT THE IMPACT ON RESIDENTIAL CUSTOMER BILLS COULD BE OVER THE COMING YEARS IF THE COMMISSION APPROVES THE PROPOSED RATE INCREASE AND THAT RATE OF INCREASE CONTINUES INTO FUTURE YEARS?

A. Yes. The Company has proposed to increase residential rates in this rate case by 8%. If we assume that the Company continues on the current pace of capital expenditures with annual rate cases and rate increases, the average residential total annual electric bill in 10 years will more than double, from $691 in 2020 to $1,492 in 2030.[3] Table 4 below shows the potential increase in the average residential gas bill if the current trend in rate base growth continues and gas commodity costs remain the same.

Table 4



This potential escalation in annual customer bills would pose a significant burden on all residential customers, and especially those with fixed and low income. In addition, this dramatic potential increase in residential bills does not take into consideration potential increases in gas commodity costs and further escalations in capital expenditures. Should

[3] Current average gas bill in 2020 of $691 = Total Rate A revenue of $822,022,000 divided by 1,190,442 Rate A residential customers per Exhibit A-16, Schedule F2, page 1 and Exhibit A-15, Schedule E-2, page 2. Current bill escalated at 8% per year through 2030.

commodity gas costs increase significantly from current low prices in the coming years, customers may run into even greater bill affordability problems.

The compounding effect of large additions to rate base will continue to increase customer rates to unaffordable levels for many customers, particularly those in fixed and lower income brackets. Simply put, this trend is not sustainable for customers. To avoid likely bill affordability problems in the future, the Company needs to moderate and be more selective in its capital spending in the coming years.

IV. Review of Capital Expenditures

Q. IN YOUR ANALYSIS, HAVE YOU DETERMINED SPECIFIC AREAS WHERE CAPITAL EXPENDITURES COULD BE REDUCED?

A. Yes. I have analyzed the Company's forecasted capital expenditures by major department or functional area and I have identified more reasonable expenditure levels that the Commission should consider.

A. Contingent Capital Expenditures

The Company has disclosed that it has included total contingency costs of $22,555,000 in its forecasted capital expenditures for the 21 months ending September 2021. This amount includes $15.3 million of contingency costs for routine capital projects and $7.3 million for other capital projects. Exhibit AG-2 includes the detailed schedules supporting these amounts as provided by the Company in response to discovery.

In the Company's prior rate case, Case No. U-18999, the Commission addressed this issue and determined that contingency amounts should be excluded from capital expenditures and rate base. The Commission similarly affirmed this exclusion in its order in Case Nos. U-18255, U-18124, U-18014, U-17999, U-17990, U-17767, U-17735 and U-20162.

The fact that these added costs are contingent means that they may not be spent in whole or in part. Despite the Company's claim that the amounts may be spent, it does not mean that these costs belong in rate base. It is not fair or reasonable for the Company to recover the depreciation expense and the return on the investment on potential costs that may not be actually incurred but have been added to rate base.

Therefore, I recommend that the Commission exclude the $22,555,000 from the forecasted capital expenditures in this rate case filing.

B. Quality Assurance Program

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSED QUALITY ASSURANCE PROGRAM.

A. Beginning on page 7 of her direct testimony, Company witness Alida Sandberg states that the Company is implementing a quality assurance (QA) program structured to ensuring process conformance with regulations and internal procedures and standards. She further states that the Company is fully committed to pipeline safety and wants to take proactive steps to improve the operation, reliability and safety of the gas system. As part of the program the Company has hired a consultant to provide oversight over planned steel construction projects with a focus on welding and strength testing as a stop gap until it gets the QA program fully implemented in 2021.

The proposed capital expenditures to implement the QA program are $3.1 million to be spent from 2019 to the end of future test year. The entire description of the program is about a page of testimony as summarized above.

Q. WHAT IS YOUR ASSESSMENT OF THE PROPOSED QA PROGRAM?

A. In discovery the Company was asked to explain why quality assurance has not already been part of its operating and construction process, and what problems and shortcomings the Company has been experiencing to require taking proactive steps to improve the operation, reliability and safety of the gas system through a new QA program.

In its response, the Company stated that its current practice is to follow company standards and procedures when performing work on operations and construction projects. It also stated that the Company performs inspections required by federal regulations on pipe, components, welds and steel pipe coatings before a pipeline is put into service. The discovery response further states that the QA program would focus on process conformance and adherence to regulations, procedures, standards and detecting and correcting process non-conformities.

The response does not provide a convincing argument. It appears that the proposed QA program will do most of the same activities that the Company is already performing, i.e., ensuring compliance to internal procedures, standards and federal regulations. It is not clear what process non-conformities the Company seeks to identify and correct, but that activity should be part of basic project management that the Company should already have in place.

In response to the question of what problems or shortcomings the Company has been experiencing to require the establishment of a new QA program at a cost $3.1 million, the Company only offered the explanation that it is experiencing attrition in its workforce. If this is the problem, the solution is better training and not an overlay of a new QA program.

The hiring of a consulting firm to help the Company with steel construction projects and bridge the knowledge gap of its workforce is also perplexing. The Company has been building steel pipelines for decades and should know by now how to build projects involving steel pipelines. There is no evidence presented that all the knowledge has now disappeared and hiring a consultant at a cost of $1.7 million is necessary.

The Company's response to discovery requests AGDG-3.143a-c and STDG1.12 are included in Exhibit AG-3 showing also the components of the $3.1 million proposed cost.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A. The Company has not made a compelling case that spending $3.1 million on a new QA program is necessary and justified by the evidence presented. The Company is proposing a program to perform activities that are already being done. Therefore, I recommend that the Commission remove the proposed $3.1 million from the forecasted capital expenditures in this rate case.

C. Distribution Plant

As shown on page 1 of Exhibit A-12, Schedule B5, the Company has forecasted more than $1.0 billion in capital expenditures for the 33 months ending September 2021 for additions to Distribution Plant. After reviewing the testimony of Company witness Sandberg, related exhibits, and responses to discovery, I have identified capital expenditure reductions applicable to several areas.

1. Service Alterations

Q. PLEASE EXPLAIN YOUR DISALLOWANCES OF CAPITAL EXPENDITURES FOR SERVICE ALTERATIONS.

A. As shown on page 2, line 4, of Exhibit A-12, Schedule B5.1, the Company had average capital expenditures of $10.9 million for service alterations during the 5 years from 2014 to 2018 and has forecasted capital expenditures of $16.4 million for 2019, $13.8 million for the 9 months ending September 2020, and $17.2 million for the 12 month ending September 2021. On page 12 of her direct testimony, witness Sandberg states that despite a forecasted decrease in units, DTE Gas is experiencing an increasing trend in hard surface restorations and higher contractor costs beginning in 2020.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR SERVICE ALTERATIONS?

A. In response to discovery, the Company provided the number of service alterations performed from 2016 to 2019 and forecasted for 2020 and 2021. The data shows an increase in hard surface restoration in 2019 from 2018, but no clear trend. In fact, the Company had 838 hard surface restorations in 2016 which dropped to 713 in 2017 and returned to 821 in 2018. Therefore, the increase to 1,097 hard surface restoration in 2019 is not a trend but a one-year increase. The Company's projection of increasing hard surface restorations in 2020 and 2021 is not supported by any evidence of a trend. Exhibit AG-4 includes the response to discovery request AGDG-3.147c with this information.

To assess the reasonableness of the Company's forecasted capital expenditures for service renewals, I averaged the unit cost to perform a service alteration for the three years from 2017 to 2019 as provided on page 12 of Ms. Sandberg's direct testimony. The average cost is $3,646 per service alteration. To this base cost, I applied an 8% increase in contractor costs as provided by the Company in response to discovery. The adjusted cost of $3,938 multiplied by the forecasted number of service alterations to be performed for the 9 months ending September 2020 results in a forecasted cost of $11,763,000. In comparison, the Company forecasted $13,801,000. The difference of $2,038,000 shows an inflated and excessive forecast by the Company and should be disallowed.

Similarly, applying the adjusted unit cost of $3,938 to the 3,554 forecasted service alterations to be completed for the 12 months ending September 2021 results in a forecasted amount of $13,996,000. This amount is $3,183,000 less than the amount of $17,179,000 forecasted by the Company. I recommend that this excessive amount in the Company forecast also be removed from forecasted capital expenditures.

Therefore, in total, I recommend that the Commission remove $5,221,000 from the Company's forecasted capital expenditures pertaining to service alterations. Exhibit AG-5 shows the calculations to arrive at this disallowance amount.

2. Belle Isle Main Replacement

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR THE BELLE ISLE MAIN REPLACEMENT.

A. Beginning on page 17 of her direct testimony, witness Sandberg discusses the unplanned replacement of the Belle Isle main completed in 2019. In discovery, the Company was asked to explain the necessity to complete this project and the related cost. In response, the Company stated that the project began in December 2018 when the main was damaged during an electric utility project. As a result of the damage, the Company had to replace the 4" steel main under the Detroit River at a cost of $2.4 million. The electric utility, which we assume is DTE Electric, reimbursed the Company for only $1 million of the cost to replace the main. Exhibit AG-6 includes the Company's response to discovery request AGDG-3.151a.

Q. WHAT IS YOUR ASSESSMENT OF THE BELLE ISLE MAIN REPLACEMENT PROJECT?

A. From the information provided by the Company, it seems clear that the Belle Isle main replacement was an unplanned project resulting solely from the damage caused by the electric utility. The partial reimbursement of $1 million is insufficient and the Company should have obtained full reimbursement of the entire cost of the project of $2.24 million. DTE Gas customers should not pay for damage caused by another utility.

Therefore, I recommend that the Commission remove the amount of $1,240,000 that the Company incurred in 2019 above the reimbursement amount and now seeks to recover in rate base in this rate case.

3. Main Replacement Program (MRP)

As shown on page 1, line 20, of Exhibit A-12, Schedule B5.1, the Company spent $143.1 million on the MRP program in 2018 and has forecasted that it will increase spending to $196.2 million in 2019, and to $183.4 million for the first 9 months of 2020. For the 12 months ending in September 2021, the Company shows a forecasted spending level of

$61.1 million. However, this amount pertains to the last three months of 2020, which makes the total year 2020 capital expenditures reach $244.5 million.

As shown in Exhibit A-12, Schedule B5.2, beginning in 2021, the Company proposes to restart the Infrastructure Recovery Mechanism (IRM) with proposed capital expenditures of $232.4 million. The IRM would continue into future years with capital expenditures in the $232.4 million level through the year 2025. Given the history of increased spending on the MRP, it is likely that this level of spending will increase further in future rate cases.

The Company has continued to escalate the size of the program in each prior rate case and other cases specific to the MRP. As shown in Exhibit A-12, Schedule B6, the Company proposed the MRP for the first time in August 2010 in Case No. U-16407. At that time, the Company proposed to replace 30 miles of targeted mains for an annual capital spending of $17.4 million. Shortly thereafter, in 2012, in case No. U-16999, the Company proposed, and the Commission approved, an escalation of the program for replacement of 66 miles of main at an annual spending level of $46.9 million. Case No. U-16999 also established the IRM as a mechanism for the Company to more quickly recover the cost of capital additions for the MRP and other programs.

In 2014, in Case No. U-17701, the Company proposed to again increase the annual spending level to $78.3 million by 2017 and to replace 103 miles of main annually. In December 2015, the Company filed a rate case in Case No, U-17999 and requested a further increase in the capital expenditures for the MRP to $93.8 million in 2017 with plans to replace 123 miles of main. Subsequent to that rate case, the Company scaled down the number of miles of main to be replaced but maintained the same proposed spending level as shown in Exhibit A-12, Schedule B6.

In rate Case No. U-18999, filed in November 2017, the Company once more requested a further escalation of the program capital expenditures to $169.7 million for 2019 and increasing it to $193.0 million in 2020. In this rate case, the Company has proposed to increase the spending level by an additional $41.4 million to $232.4 million beginning in 2021.[4] This trend of ever escalating spending on the MRP is likely to continue unabated in future years when the Company files new rate cases, until the Commission holds DTE accountable to a set budget.

In other words, what began as a modest program of $17.4 million to replace cast iron mains and other unprotected and deteriorating gas mains has now mushroomed into monstrous program of $245 million in 2020 without counting the meter move out program.

Q. WHAT REASONS DOES THE COMPANY OFFER FOR THE FURTHER ESCALATION OF THE PROGRAM IN THIS RATE CASE?

A. The Company points to two drivers for the $41.4 million increase in the program spending beginning in 2020. First, the Modified Grid Approach (MGA) that the Company proposed in an earlier rate case and began in 2016 is not yielding the anticipated cost savings. On

[4] Due to other changes the amounts are not additive.

the contrary, it is increasing construction costs. Company witnesses Andrew Dewey discusses this problem beginning on page 8 of his direct testimony. Apparently, in the initial cost analysis to justify moving to the MGA, the Company did not include all the necessary costs to install mains and services, retest lines and perform other tasks.

Second, the Company is experiencing significant cost increases from contractors hired to perform some of the mains and service line installations under the MRP. With the escalation of the MRP program and similar increases in the main replacement programs by other utilities in Michigan and other areas of the U.S., contractor services are in high demand and availability of resources is limited. This dramatic increase in demand for contractor services with limited availability of resources has resulted in significant annual cost escalations. Unless the demand for contractor services ebbs with more rational limitations on the pace of main replacement by gas utilities, the cost escalation problem will not improve and in fact may get worse.

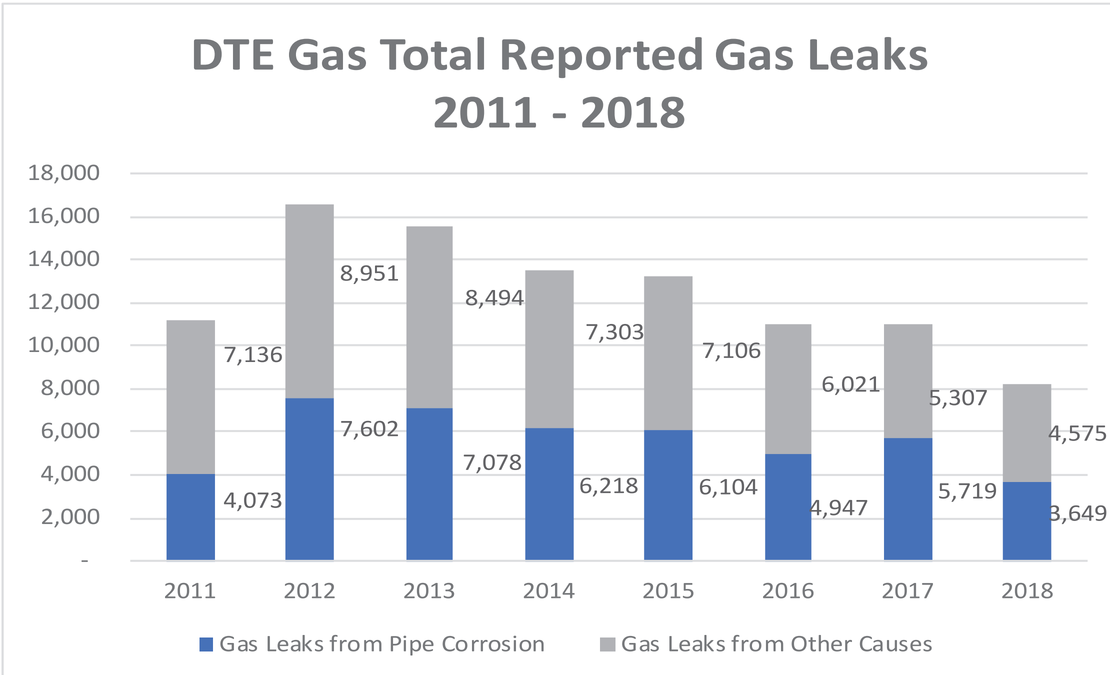
Q. HAS THE COMPANY PROVIDED ANY HARD EVIDENCE OR ANALYSIS TO SUPPORT THE CONTINUED ESCALATION OF THE PROGRAM IN THIS RATE CASE OR PRIOR RATE CASES?

A. No. The Company points to the number of gas leaks reported each year as its main justification to further accelerate spending, and states generally that by replacing leaky mains or mains at risk of rupture it is increasing safety and minimizing potential risk. Although reducing risk and increasing safety are laudable goals that we can all embrace, there must be more quantitative and qualitative analysis performed to show that the rate of deterioration of the gas mains and services is accelerating to justify increasing annual capital expenditures by more than 10-fold between 2010 and 2019. Without this quantitative evidence, the current pace of main replacement and the escalating capital expenditures have become totally subjective.

Q. HAS THE NUMBER OF GAS LEAKS REPORTED BY THE COMPANY INCREASED IN RECENT YEARS?

A. No. In response to discovery, the Company provided the number of reported leaks from 2011 to 2018 as filed with Pipeline and Hazardous Materials Safety Administration (PHMSA) unit of the U.S. Department of Transportation. The report shows that during this eight-year period the total number of gas leaks on mains and service lines peaked in 2012 at 16,553, and has steadily decreased to 8,224. These numbers, as provided by the Company in response to data request AGDG-2.121, are included in Exhibit AG-16. The chart in the following table also shows the total number of leaks by year and the number that are the result of corrosion.

Table 5



What is important to point out is that not all reported leaks are the result of deteriorating pipes from corrosion. As the chart above shows, less than half of the leaks are from pipe corrosion. More than half of the reported gas leaks are from other causes, such as equipment failures, excavation damage, poor material and installation problems and unknown sources. Exhibit AG-16 provides a more detailed report of major causes.

In conclusion, the gas leak data does not support the Company's rationale that the pace of replacement of cast iron and steel mains must be accelerated and the MRP capital expenditures further escalated in this rate case because of a surge in gas leaks.

Q. WHAT LEVEL OF CAPITAL EXPENDITURES FOR THE MRP SHOULD THE COMMISSION APPROVE IN THIS RATE CASE AND GOING FORWARD?

A. As I stated earlier, the Company has not provided any compelling evidence that the level of capital expenditures approved in Case No. U-18999 for the MRP is not adequate or appropriate. On the contrary, the gas leak data show that leaks are declining from historical levels. The Company needs to work within a construction budget equal to the amount approved in Case No. U-18999 of $193.0 million. Maintaining this level of spending and not going over budget will relieve some of the pressure on contractor services and help moderate the escalating cost of main and services replacement over time.

This financial discipline of staying within a construction budget combined with further improvements and cost efficiencies extracted from the MGA and non-MGA projects should allow the Company to do more pipe replacements with the same amount of available funds.

Q. ARE YOU PROPOSING ANY CHANGES TO THE AMOUNT OF FUNDING DEDICATED TO PIPELINE INTEGRITY, THE MMO MAC INITIATIVE AND METER MOVE-OUT PROGRAM WITHIN THE IRM?

A. No. These programs will add an additional $55.7 million in capital spending in 2020 and $50.3 million annually in 2021 and future years.

Q. WHAT CAPITAL EXPENDITURE DISALLOWANCE FOR THE MRP PROGRAM ARE YOU PROPOSING AS A RESULT OF MAINTAINING THE CAPITAL SPENDING LEVEL AT $193 MILLION?

A. The Company proposed $244,541,000 in capital expenditures for 2020, which is $51,541,000 higher than the $193.0 million spending limit. For the 9 months ending September 2020, the prorated disallowance amount is $38,656,000. The remaining amount of $12,885,000 falls into rate base for the 12 months ending period September 2021.[5] I recommend that the Commission remove the $38,656,000 and $12,885,000 from the calculation of rate based in this rate case.

For 2021, the Company has proposed capital expenditures of $232,400,000, which is $39,400,000 above the $193.0 million spending limit I have proposed. Because these capital expenditures will be recovered through the IRM beginning in January 2021, I recommend that the Commission approve only the inclusion of $193.0 million for the MRP in the IRM calculation for 2021 and future years.

Q. ARE THERE OTHER OBSERVATIONS YOU WANT TO MAKE WITH REGARD TO THE MRP?

A. Yes. I have two major observations. The first pertains to the MRP projects undertaken by the Company and how they rank in the risk priority scale. The second pertains to the

[5] $51,541,000 - $38,656,000 = $12,885,000.

probability risk model that the Company is developing and how it could be applied to MRP projects and well as to non-MRP projects.

With regard to MRP priority projects, in discovery, the Company was asked to provide the list of MRP projects completed in 2018 and 2019, and those scheduled to be completed in 2020 and 2021. The lists of projects provided by the Company shows a very disturbing pattern of MRP projects being completed or scheduled for completion that are very low on the risk ranking spectrum.

For example, the list of projects completed in 2018 shows that of the approximately 125 projects completed, 30 projects had a risk priority ranking of well below 200 and as low as 85,356th. These are not high priority projects when a risk score of 1 indicates the higher priority project. Similarly, of the approximately 100 projects completed in 2019, 40 projects had risk ranking scores well below 200 and as low as 25,171st. Although I understand that these projects may have been selected from a master list that may have been compiled a year or two ago, a project that is ranked 85,356th or 25,171st on the list cannot be considered a priority project to be completed in 2018 or in 2019.

The same problem is evident with projects selected and scheduled for completion in 2020 and 2021. Additionally, projects scheduled for 2021 have no associated project costs in order to permit validation of the capital expenditures proposed by the Company. Exhibit AG-17 provides the lists of projects from 2018 to 2021.

The MRP project lists show a troubling practice by the Company of completing projects that have been scored and ranked very low on the priority scale for replacement. While the Company states in testimony that it is working to improve safety and reliability of the gas system, the actual practice deviates significantly from the story line with low risk projects being completed ahead of higher risk projects. If this practice is not remedied quickly, I recommend that the Commission suspend the MRP program until the Company presents a more effective approach.

With regard to the project probability risk model, the Company has stated that it is still working on completing and refining this model. In discovery, the Company was asked to explain how the Company will determine the probability of pipe failure. In its response, the Company stated that the probability of corrosion failure would be determined by establishing the likelihood of a deterioration in pipe wall loss and other factors such as wall thickness and cathodic protections. The Company was also asked to explain how the model considers the consequence of a potential failure. The responses to the discovery questions are included in Exhibit AG-18.

The probability risk model holds the promise of more accurately assessing the replacement of specific segments for at-risk distribution mains and service lines when combined with engineering and laboratory analysis of pipe samples in order to determine the deterioration rate of underground pipe by material type and pipe size in different soil conditions. Such hard evidence used within the probability model would be useful to help establish the pace and schedule of replacement of certain segments of the Company's pipeline system.

I recommend that the Commission encourage the Company to make wide use of the probability model with regard to MRP projects, as well as other pipeline and gas facilities replacement projects, when combined with pipe material analysis and engineering research.

D. Transmission Plant

As shown on page 1 of Exhibit A-12, Schedule B5, the Company has forecasted more than $161 million in capital expenditures for the 33 months ending September 2021 for additions to Transmission Plant. After reviewing the testimony of Company witness Sandberg, related exhibits, and responses to discovery, I have identified capital expenditure reductions applicable to several areas.

1. Routine Plant Additions

Q. PLEASE EXPLAIN YOUR DISALLOWANCES OF CAPITAL EXPENDITURES FOR ROUTINE TRANSMISSION PLANT.

A. As shown on page 2, line 2, of Exhibit A-12, Schedule B5.1, the Company had average annual capital expenditures for routine transmission plant additions of nearly $6.0 million during the five years from 2014 to 2018. The Company forecasted capital expenditures of $8.5 million for 2019, $6.4 million for the 9 months ending September 2020, and $8.9 million for the 12 months ending September 2021.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR ROUTINE TRANSMISSION PLANT ADDITIONS?

A. In discovery, the Company was asked to provide the actual routine transmission plant additions for 2019, and also present the normalized routine expenditures excluding prior period insurance proceeds and sales and use tax adjustments. In response, the Company provided actual expenditures for 2019 of $6,305,000 which are $2,141,000 below the amount forecasted. The Company also provided the normalized historical capital expenditures from 2014 to 2018. Exhibit AG-7 includes the Company's response to discovery requests AGDG-3.172 and STDG-6.9.

Using the normalized capital expenditures for the five years from 2015 to 2019, the result is an average annual amount spent of $7,291,000. This amount is $1,620,000 lower than the amount forecasted by the Company for the 12 months ending September 2021 and $956,000 lower than the prorated amount forecasted for the 9 months ending September 2020. Exhibit AG-8 shows the calculations to arrive at those amounts.

My analysis shows that the Company's forecasted capital expenditures are overly inflated and excessive. Therefore, I recommend that the Commission remove capital expenditures of $2,141,000 for the year 2019, $956,000 for the 9 months ending September 2020, and $1,620,000 for the 12 months ending September 2021.

2. DTE Gas NEXUS Project

Q. PLEASE EXPLAIN YOUR DISALLOWANCES OF CAPITAL EXPENDITURES FOR THE DTE GAS NEXUS PROJECT.

A. Beginning on page 29 of her direct testimony, Ms. Sandberg describes the capital projects undertaken by DTE Gas to connect with the NEXUS Pipeline. Her testimony states that the DTE Gas projects were placed into service in October 2018. According to her testimony, $5.5 million of the project closeout costs carried into 2019 with additional project costs of $22.6 million for 2018 shown on line 8 of Exhibit A-12, Schedule B5.1, page 1.

Q. WHAT IS YOUR ASSESSMENT OF THE TOTAL CAPITAL EXPENDITURES INCURRED BY DTE GAS FOR THE NEXUS PROJECT?

A. In discovery, the Company was asked to provide the actual capital expenditure incurred with regard to the NEXUS project and explain any variance of 5% or greater in comparison to the capital expenditures proposed in the prior rate case. In response, the Company stated that the actual costs for the DTE Gas Nexus project were $211.6 million, in comparison to the $201.0 million forecasted in Case No. U-17999. The actual amount is an overspend amount of $10.6 million. Exhibit AG-9 includes the Company response to discovery request AGDG-3.156.

The discovery response states that the reason for increased spending of $10.6 million is attributed to the delay in the NEXUS pipeline receiving its FERC certificate, which caused the DTE Gas NEXUS project completion date to be delayed from November 2017 to October 2018. This delay, in turn, caused higher contracted services, higher internal labor costs, and higher capitalized funds during construction (AFUDC) for DTE Gas.

The increase in capital expenditures is an issue between DTE Gas and the NEXUS Pipeline Company. Customers should not pay for higher capital expenditures incurred as a result of a delay in a project being built by another party with whom the Company has entered into an agreement to build connecting facilities. It is not fair or reasonable for customers to absorb an additional $10.6 million, plus the return on those additional capital expenditures over the life of the facilities, which will amount to millions of dollars. This is particularly concerning given that the NEXUS pipeline is a projected partially owned by an affiliate of the Company.

The Commission should not permit the recovery of the additional costs of $10.6 million, irrespective of whatever benefits the Company may claim the connecting facilities will provide to customers. The Commission approved recovery of the initial forecasted capital expenditures of $201 million, and the additional $10.6 million are not related to any new incremental benefits. This amount simply reflects cost overruns caused by the delay in the project construction of a pipeline owned by an affiliated company.

Therefore, I recommend that the Commission remove the $10.6 million of capital expenditures propose by the Company for inclusion in the projected rate base.

3. Van Born Project

Q. PLEASE EXPLAIN YOUR DISALLOWANCES OF CAPITAL EXPENDITURES FOR THE VAN BORN PROJECT.

A. Beginning on page 40 of her direct testimony, Ms. Sandberg describes the Van Born project as the installation of a new pipeline and regulating equipment to loop or duplicate two existing pipelines in order to provide a redundant source of gas supply to part of the Company's southeast Michigan market area. Currently, the Company has a 30" pipeline that supplies natural gas to two industrial customers and a 36" pipeline that supplies 160,000 customers in a market area to the southwest of Detroit.

The Company is concerned that an incident on the 36" pipeline could interrupt needed gas supply to 160,000 customers, particularly during the winter heating season. To remedy the risk of an outage, the Company proposes to build a new 7-mile pipeline with a diameter of 24" from the Willow Gate Station to connect with the existing 30" pipeline. The result would be a parallel line to the 36" line from the Willow Gate Station to the River Rouge distribution gate station that feeds the market area.

According to Ms. Sandberg, the proposed pipeline loop would mitigate a potential supply outage to 120,000 of the 160,000 customers from a potential rupture of the 36" line. As shown on line 14 of page 1 of Exhibit A-12, Schedule B5.1, the capital expenditures proposed for recovery in this rate case are $12.3 million.

Q. WHAT IS YOUR ASSESSMENT OF THE VAN BORN PROJECT AND THE ASSOCIATED CAPITAL EXPENDITURES?

A. In discovery, the Company was asked to provide the total capital expenditures of the project from inception to completion. The Company reported that the total cost of the project is forecasted at $96.0 million to be incurred from the year 2020 through 2024. The amount proposed in this rate case represents only 13% of the total project cost.

In response to discovery, the Company provided a map of the service area that would not benefit from the Van Born pipeline loop and would still leave 40,000 customers at risk of a potential outage. The geographical area is larger than the area that would have the benefit of the redundant pipeline, although the number of customers at risk of a potential outage is less.

In discovery, the Company was also asked to explain how another supply line from the same gate station at Willow will significantly reduce the risk of a gas supply interruption, and whether a different route connected to another supply source would better mitigate the risk of a potential gas supply outage. In response, the Company stated that the Willow Gate Station has the flexibility of supply interconnections with more than one transmission pipeline, and the Company will review the piping configurations in the design phase to provide redundancy of supply sources to the Van Born project.

Exhibit AG-10, includes the discovery responses discussed above.

It also appears that the Company will need to file an Act 9 application to receive Commission approval to build the pipeline for the Van Born project. The project schedule on page 27 of Exhibit A-12, Schedule B5.3, shows the filing of the Act 9 application starting on March 1, 2021 and ending May 1, 2022.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION WITH REGARD TO THE VAN BORN PROJECT AND THE ASSOCIATED CAPITAL EXPENDITURES?

A. This project is still too premature to include in rate base in this case. The Company has not yet completed the design phase of the project other than a high-level conceptual design. The fact that it has not yet determined how to connect to alternative source pipelines at the Willow Gate Station is an indication of the preliminary nature of this project.

Also, the fact that the Company will not file an Act 9 application until March 2021 is further evidence of the very early stage and conceptual nature of the project. The Commission should not approve capital expenditures for inclusion in rate base at such an early stage and with no approval yet granted for an upcoming Act 9 application.

Also of concern is that 40,000 customers, or 25% of the total group, would still be at risk of a potential outage even after spending $96 million to loop the existing pipelines. It would seem the Company could propose a more effective solution to encompass all customers at risk.

As a result of the premature nature of the project and the incomplete solution offered by the Company, I recommend that the Commission reject the proposed capital expenditures of $12.4 million included in this rate case. I have reduced this amount by the $1,775,000 already disallowed under Contingency Capital Expenditures for a net incremental disallowance of 10,625,000.

4. Fort Street Main Replacement Project

Q. PLEASE EXPLAIN YOUR DISALLOWANCES OF CAPITAL EXPENDITURES FOR THE FORT STREET MAIN REPLACEMENT PROJECT.

A. On page 3 of Exhibit A-12, Schedule B5.3, the Company describes the Fort Street main replacement program scheduled to be completed in 2019 at a cost of $11,824,087. In discovery the Company was asked to confirm that the project was completed, and the actual cost incurred in 2019. Exhibit A-11 includes the Company's response to discovery request AGDG-3.174.

In response, the Company stated that it completed the project in 2019 at a cost of $10,140,000. The actual cost is $1,684,087 less than the forecasted amount included in the forecasted rate base in this rate case. I recommend that the Commission remove this amount from rate base.

5. In-Line-Inspection (ILI) Assessments

Q. PLEASE EXPLAIN YOUR DISALLOWANCES OF CAPITAL EXPENDITURES FOR CERTAIN ILI ASSESSMENT PROJECTS.

A. In Exhibit A-12, Schedule B5.3, the Company describes several ILI assessment projects undertaken or to be undertaken between 2019 and the end of the future test year. I will discuss four projects where I propose adjustments to the capital expenditures forecasted by the Company in this rate case. The four projects are the Northeast Belt 24” ILI Expansion, the Loreed Ludington 16” ILI Expansion, the Southfield 24” Pipe Replacement, and the South Grand Rapids 22” ILI Expansion.

Q. PLEASE DISCUSS YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR THE NORTHEAST BELT 24” EXPANSION PROJECT.

A. On page 30 of Exhibit A-12, Schedule B5.3, the Company describes the Northeast Belt ILI project scheduled to be completed between 2019 and 2020. The Company forecasted that it would spend $5,388,727 on the project in 2019. In discovery the Company was asked to provide the actual costs incurred in 2019. In response, the Company reported that the actual amount spent in 2019 was $3.6 million. Exhibit AG-12 includes the Company’s response to discovery request AGDG-3.189e with the actual cost information.

The actual cost is $1,788,727, or 33% less than the forecasted amount included in the forecasted rate base in this rate case. I recommend that the Commission remove this amount from rate base.

Q. PLEASE DISCUSS YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR THE LOREED LUDINGTON 16" EXPANSION PROJECT.

A. On page 32 of Exhibit A-12, Schedule B5.3, the Company describes the Loreed Ludington ILI project scheduled to be completed in 2019 at a forecasted cost of $5,55,745. In discovery, the Company was asked to provide the actual cost incurred in 2019. In response, the Company reported that the actual amount spent in 2019 was $3.5 million. Exhibit AG-12 includes the Company's response to discovery request AGDG-3.189e with the actual cost information.

The actual cost is $2,050,745, or 37% less than the forecasted amount included in the forecasted rate base in this rate case. I recommend that the Commission remove this amount from rate base.

Q. PLEASE DISCUSS YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR THE SOUTHFIELD 24" PIPE REPLACEMENT PROJECT.

A. On page 34 of Exhibit A-12, Schedule B5.3, the Company describes the Southfield 24" pipe replacement project scheduled to be completed in 2021. The project consists of both an ILI assessment and pipe replacement. The Company forecasted that it would spend

$4,000,000 on the project before the end of the future test year. In discovery, the Company was asked to explain what engineering design work had been completed on this project. In response, the Company stated that no engineering design work had been completed. Exhibit AG-13 includes the Company's response to discovery request AGDG-3.190a.

From the project schedule in Exhibit A-12, Schedule B5.3, it is apparent that the engineering on this project won't be completed until early 2021 with potential construction during the summer of 2021. This project is very early in the development phase with no engineering work yet completed. It is basically a conceptual project with a ballpark amount of $4 million estimated and included in the future test year.

The project is premature for inclusion in the projected rate base in this rate case. The forecasted capital expenditures are simply a placeholder amount. In prior rate cases, the Commission has rejected such preliminary cost amounts for inclusion in rate base that function as placeholder amounts.

I recommend that the Commission remove the amount of $4.0 million from the capital expenditures proposed by the Company in this rate case.

Q. PLEASE DISCUSS YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR THE SOUTH GRAND RAPIDS 22" ILI EXPANSION PROJECT.

A. On page 36 of Exhibit A-12, Schedule B5.3, the Company describes the South Grand Rapids ILI project scheduled to be completed in 2021. The Company forecasted that it would spend $3,000,000 on the project before the end of the future test year. From the project schedule, it is apparent that the engineering on this project will not be completed until late 2020 with potential construction during the summer of 2021.

This is another project that is very early in the development phase with no engineering work yet completed. It is basically a conceptual project with a ballpark amount of $3 million estimated and included in the future test year. The project is premature for inclusion in the projected rate base in this rate case. The forecasted capital expenditure is simply a placeholder amount. As stated earlier, in prior rate cases, the Commission has rejected such preliminary cost amounts for inclusion in rate base that function as placeholder amounts.

I recommend that the Commission remove the amount of $3.0 million from the capital expenditures proposed by the Company in this rate case.

Q. WHAT IS THE TOTAL AMOUNT OF CAPITAL EXPENDITURES DISALLOWANCE FOR ILI EXPANSION PROJECTS THAT YOU RECOMMEND?

A. The total amount of capital expenditures that I recommend should be disallowed is $10,839,472. Of this amount $3,839,472 falls in 2019 and $7.0 million falls in the 12 months ending September 2021.

E. General Plant - IT Projects

The Company has proposed two major Information Technology (IT) projects pertaining to operating areas of the Company. The two projects are: the ClickSoft Field Management System (ClickSoft) and the Electronic Gas Management System (EGMS). In total, the two projects entail $12.4 million in capital expenditures between 2019 and the end of the future test year. I will discuss each project separately.

1. ClickSoft Project

Q. PLEASE BRIEFLY DESCRIBE THE CLICKSOFT PROJECT.

A. As shown on page 9 of Exhibit A-12, Schedule B5.3, the Company plans to replace its current Field Service Management system and related server with a new cloud-based system offered by ClickSoft. According to the Company the new system will allow flexibility for field personnel to complete work using various mobile phones and an in-truck mobile data terminal. The system will supposedly provide routing optimization, real time location of crews for work dispatching, and quicker customer response time. No quantification of these benefits was provided.

According to the Company, the ClickSoft system will need to be designed and configured to meet the Company's requirements with applicable software development, testing and training of employees. The forecasted cost of this system is $8.9 million, with nearly half of the cost to be incurred between 2019 and the 9 months ending September 2020, and the remainder during the 12 months ending September 2021.

Q. WHAT IS YOUR ASSESSMENT OF THE CLICKSOFT PROJECT AND THE RELATED FORECASTED CAPITAL EXPENDITURES?

A. In response to discovery, the Company stated that the current Field Service Management system was installed in 2014 and five years later is already considered to be at the end of its life. The Company also reported that the current system is still functional, although the vendor will not provide more system updates. Asked to explain why the current system needs to be replaced, the Company repeated the "end of life" rationale, along with no support for future upgrades to the system. The discovery response also points to the lack of desired features, other potential moves to cloud systems, and maintaining multiple platforms. It is not clear what multiple platforms are being referenced.

The Company was also asked to provide a business case for the project with cost savings or financial benefits provided by the new ClickSoft system over the relevant time period. The Company's response stated that DTE Gas is not implementing the ClickSoft system for financial savings, but to get new operationality and mitigate risks of the current system. Exhibit AG-14 includes the discovery responses discussed above.

From reading the project description in Exhibit A-12, Schedule B5.3, and the Company's responses to discovery, it is readily apparent the Company wants a more current system with new features and exciting mobile phone connectivity, although the current system is still functional and only 5 years old. The desired functions and features of the new system need to be justified by adequate financial and non-financial benefits. The Company has not provided a business case that justifies undertaking this project at this time.

With the Company spending staggering amounts in capital expenditures to replace deteriorating pipelines, service lines and other gas facilities to provide safe and reliable service to customers, the capital expenditures proposed for this project should be dedicated to more critical construction programs.

My recommendation is that, until the Company makes a more compelling business case to undertake this IT project, the forecasted capital expenditures of $8.9 million should be removed from this rate case.

2. EGMS Project

Q. PLEASE BRIEFLY DESCRIBE THE EGMS PROJECT.

A. As shown on page 11 of Exhibit A-12, Schedule B5.3, the Company plans to replace its current gas nominations Gas Management system with a new software system, new servers and new web applications. According to the Company, the new system will allow customers to access the system using their own digital devices, provide ease of use and convenience, and potentially mitigate security vulnerabilities of the current system. No quantification of these benefits was provided.

The forecasted cost of this system is $3.5 million, with approximately $800,000 to be incurred in 2019 and the remaining $2.7 million in the 9 months ending September 2020.

Q. WHAT IS YOUR ASSESSMENT OF THE EGMS PROJECT AND THE RELATED FORECASTED CAPITAL EXPENDITURES?

A. In discovery the Company was asked to explain how long the EGMS has been obsolete and unsupported by the vendor, why the Company allowed the system to go obsolete and unsupported, how DTE Gas has been using the system since it has been unsupported, and why the upgrade and addition of servers is necessary.

In response, the Company stated that DTE Gas is several software versions behind the vendor's current software releases and vendor support is limited due to the older version of software currently in operation. The Company refused to answer the other questions, other than to state that the existing servers are at the end of their life and the new system will require additional servers. The responses to discovery are included in Exhibit AG-15.

The response to discovery shows that the Company failed to keep up with vendor releases of system software updates and now finds itself in a situation where the vendor can only provide limited support for the system. This is a problem of the Company's own making. It is unreasonable for the Company to now request a replacement of the system at a cost of $3.5 million, and unfair to customers if this cost is included in rate base.

The Company's description of benefits in Exhibit A-12, Schedule B5.3 is unpersuasive and falls significantly short from a compelling business case that this system will provide both financial and non-financial benefits that justify the investment of $3.5 million.

With the Company spending staggering amounts in capital expenditures to replace deteriorating pipelines, service lines and other gas facilities to provide safe and reliable service to customers, the capital expenditures proposed for this project should be dedicated to more critical construction programs.

My recommendation is that, until the Company makes a more compelling business case to undertake this IT project, the forecasted capital expenditures of $3.5 million should be removed from this rate case.

F. Capital Expenditures Adjustments - Summary

Q. WHAT IS YOUR OVERALL RECOMMENDATION REGARDING THE AMOUNT OF ADJUSTMENTS TO THE COMPANY'S CAPITAL EXPENDITURES AND RATE BASE?

A. The chart below summarizes my proposed reductions in capital expenditures in those areas where the level of capital expenditures presented by the Company is excessive, unnecessary or unsupported.

Table 6		
Summary of AG Disallowed Capital Expenditures		
		Amount **(millions)**
Contingent Capital Expenditures	$	22.6
Quality Assurance Program		3.1
Distribution Plant		
Service Alterations		5.3
Belle Isle Main Replacement		1.2
Main Replacement Program		51.5
Transmission Plant		
Routine Projects		4.7
Non-Routine Projects		33.7
General Plant		
Major IT Projects		12.4
Incentive Compensation		
Capitalized Amount		12.1
Total	**$**	**146.6**

Based on my analysis and information presented in my testimony above, the Commission should reduce the Company's proposed capital expenditures by $146.6 million and average rate base by $116.7 million. Exhibit AG-20 provides additional details and calculations of these amounts.

V. Cost of Capital

Q. **WHAT IS THE CAPITAL STRUCTURE YOU RECOMMEND FOR USE IN THE OVERALL RATE OF RETURN CALCULATION?**

A. I recommend that the capital structure shown on page 1 of Exhibit AG-21 be used in this case. Lines 1 and 3 show the projected long-term debt and common equity (the permanent capital of the Company) for the test period ending September 2021. The permanent capital balances in this exhibit reflect two changes. First, I reduced permanent capital by $62 million and have included this amount in short-term debt. The Company projected a lower use of short-term debt in the projected test year even though it is projecting a higher level of working capital. The short-term debt level in my capital structure is set equal to the amount used in the historic period. Second, I have allocated the remaining permanent capital of $3.9 billion to long-term debt and common equity on a 50%/50% basis.

Q. PLEASE EXPLAIN WHY YOU INCREASED SHORT-TERM DEBT BY $62 MILLION.

A. The Company's proposed reduction in short-term debt from $207 million in 2018 to $145 million in the projected test year is unsupported. Considering the projected increase in construction work and operating costs, the Company should need more short-term debt (not less) to fund those cash requirements until it issues permanent capital. Therefore, on a conservative basis I have set the level of short-term debt at $207 million, which is the same level utilized in the historic test period.

Q. DID YOU CALCULATE THE DIFFERENCE IN REVENUE REQUIREMENTS RELATED TO INCREASING SHORT-TERM DEBT AND REDUCING PERMANENT CAPITAL?

A. Yes. The increase in short-term debt of $62 million reduces revenue requirements by approximately $4.1 million. The revenue requirement reduction reflects the lower cost of short-term debt of 2.7%, compared to the cost of long-term debt and common equity, which are approximately 4% and 14%, respectively, on a pre-tax basis.

Q. WHY DID YOU INCREASE LONG TERM DEBT AND REDUCE COMMON EQUITY TO ACHIEVE A 50%/50% CAPITAL STRUCTURE?

A. The Company has proposed a permanent capital structure with a common equity component of 52%. While this percentage is lower than the 2018 historical test year percent of 53.75%, there are other factors to consider, which are discussed below.

First, the common equity ratio of the peer group averages around 50%. Exhibit AG-26 provides this information. It is worth pointing out that this lower average common equity level supports these companies' utility operations as well as non-utility operations, which tend to be riskier. The riskier non-utility operations require a higher common equity cushion to maintain similar credit ratings. Therefore, if we adjusted for the higher equity capital required by the non-utility businesses, the equity capital for the utility portion of the peer group's capital structure would be lower than 50%.

Second, in Case U-18999, the Commission directed the Company to develop a plan to move to a 50%/50% balanced capital structure, which I discuss in more detail below.

Third, DTE Gas is a captive subsidiary of DTE Energy. DTE Energy, which is a publicly traded company, had a permanent capital common equity ratio of 43% at the end of 2019 and 44% at the end of 2018. DTE Energy can make the Company's common equity ratio whatever it wants. The same executive management that runs DTE Energy controls the Company's major decisions. At any time, management can direct how much capital it wants to inject into the Company from the parent company and call it equity capital, even though in reality it is debt. The result is a common equity ratio of 52% or 53% at DTE Gas, when the parent company only has a common equity ratio of 43%. Such freedom to receive phantom equity capital would not exist if DTE Gas itself was a publicly traded company.

Q. **YOU STATED THAT THE COMMON EQUITY RATIO OF THE PEER GROUP USED TO ASSESS THE COST OF COMMON EQUITY IS AROUND 50%. PLEASE EXPLAIN WHY THIS IS RELEVANT IN DETERMINING THE COMMON EQUITY RATIO FOR THE COMPANY IN THIS CASE.**

A. As shown in Exhibit AG-26, the average common equity ratio of the peer company group for 2019 was 50.3%. The cost of equity for those companies in the peer group is highly dependent on the financial risk reflected in their capital structure. Thus, it is critical to synchronize the capital structure of the Company to the peer group average as closely as possible in order to have consistency with the cost of equity capital derived from those peer group companies. The Company's proposed common equity capital ratio of 52.0% creates a disconnect that is not acceptable. Additionally, it is more costly to customers.

I will also point out that the average common equity ratio of the gas peer group used by Company witness Bente Villadsen in the calculation of the cost of equity is 48%. This equity ratio is even lower than the average equity ratio of my peer group and four percentage points lower than the 52% equity ratio recommended by Company witness Edward Solomon. Exhibit AG-52 CONFIDENTIAL includes the Company's response to discovery request AGDG-4.237 CONFIDENTIAL showing the 48% common equity ratio.

Q. HOW DID THE COMPANY ATTEMPT TO SUPPORT THE HIGHER COMMON EQUITY LEVEL IN ITS RATE CASE TESTIMONY?

A. On pages 9 and 10 of his direct testimony, Mr. Solomon states that the 52% Common Equity ratio is based on (a) maintaining financial soundness and creditworthiness; (b) the Company's significant capital expenditure investment program; (c) that the Company's authorized ROE has declined from 11% in 2012; and (d) the Company faces systematic and unsystematic risks, including the poverty level and declining population in the City of Detroit. Additionally, on page 11 of his direct testimony, Mr. Solomon references the Company's credit downgrade by Moody's Investor Service (Moody's) due to the Company's investment program and tax reform.

Q. PLEASE DISCUSS THE COMMISSION'S DIRECTIVE TO DTE GAS IN ITS ORDER OF SEPTEMBER 13, 2018 IN CASE No. U-18999 RELATING TO THE CAPITAL STRUCTURE.

A. In paragraph J on page 127 of the September 13, 2018 rate order in Case No. U-18999, the Commission directs that "DTE Gas shall, in its next rate case, articulate its strategy to return to a balanced capital structure and the steps it will take to reach the goal."

Q. DID COMPANY WITNESS SOLOMON ADDRESS THIS ISSUE IN HIS DIRECT TESTIMONY AND EXHIBITS?

A. No. This is a troubling omission by the Company with significant implications, particularly given the fact that both the Commission and the ALJ in U-18999 discuss this issue at length. In the discussion of this issue on pages 43 and 44 of the rate order, the Commission states that it agrees with the ALJ and (a) "…adopts the PFD's recommendation that the Commission should encourage DTE Gas to move to a more balanced 50/50 capital structure…"; and (b) DTE should present its strategy on this point or alternatively present an analysis on why the Company is unable to move to a balanced capital structure. Further, the Commission states that "…a pro-forma debt capacity analysis using rating agency methodology ratio benchmarks could be included to bolster DTE Gas' arguments."

Q. DO YOU AGREE WITH MR. SOLOMON'S ANALYSIS ON THE NEED FOR A 52% COMMON EQUITY RATIO?

A. No. First, with regard to the Moody's credit downgrade, the downgrade places the Company's credit rating by Moody's still above the credit rantings of the other rating agencies. The previous Moody's rating for DTE Gas of Aa3 was somewhat "out of line" and higher than the ratings assigned by the other agencies. This fact was outlined in an internal Company memorandum by the Manager of Corporate Finance. The internal memorandum also states that the Company does not expect to see an increase in the cost of debt from the Moody's downgrade. Exhibit AG-53 CONFIDENTIAL includes the Company's response to discovery question AGDG-1.73a.03 and supporting documents showing the credit rating misalignment. The new Moody's credit rating of A1 (Stable) is still one notch above the A credit ratings by Standard & Poor's (S&P) and Fitch Investor Services (Fitch).

Second, the Company has provided no analysis on its credit metrics and how they might be impacted by moving to a 50% Common Equity ratio, as directed by the Commission order. My own analysis shows that there is no near-term problem in moving to a 50% Common Equity ratio. In discovery, the Company was asked to identify which key financial metric might be imperiled if the Company moved from a 52% to a 50% Common Equity ratio. In response, Mr. Solomon stated that the Moody's "CFO Pre-WC to Debt ratio" would fall by 0.5%, but that it would not reach the 15% downgrade trigger level.[6] Exhibit AG-54 includes the Company's response to discovery request AGDG-1.73d with this information. As stated earlier, Moody's still rates the Company credit one notch above the other rating agencies.

In response to discovery request AGDG-1.75, the Company shows the CFO Pre-WC to Debt ratio for 2018 at 18.5% with average common equity ratio of 53.75%, which is approximately 4 percentage points over the 50% level.[7] Based on this information, on page of Exhibit AG-21, I have calculated on a pro-forma basis the 2018 CFO Pre-WC to

[6] The CFO Pre-WC ratio is the ratio of Cash Flow for Operations before Working Capital to Total Debt.
[7] See Exhibit AG-54.

Debt ratio. My calculation shows that the ratio would likely fall to approximately 17% and still be well above the 15% downgrade trigger level.

I will also point out that, according to Exhibit A-1, Schedule A2, the earned ROE for DTE Gas in 2018 was 9.5%, which is the same as the ROE rate that I propose in this rate case. As such, in my opinion the Company has adequate cushion above the Moody's CFO Pre-WC to Debt ratio threshold with a 50% common equity ratio in its permanent capital structure.

Third, with regard to the Company's large capital expenditures program, to some extent this issue is within the Company's control. In my testimony on rate base and capital expenditures in this rate case, I have identified several areas where capital expenditures can be reduced without imperiling the safety or reliability of the Company's gas system.

Fourth, as for Mr. Solomon's claims that the Company faces higher business risk for serving the city of Detroit with its high poverty levels and declining population, I will point out that (1) the number customers in the City of Detroit are only 18% of its total customer base[8]; and (2) Detroit is experiencing a major resurgence in many areas with younger people moving into the city due to expanding job opportunities. Also, the problems with poverty levels and historically declining population are not unique to Detroit. These

[8] DTE Gas response to discovery response AGDG-1.72.

problems also exist in the service areas of many of the companies that are part of the Company's peer group.

Fifth, the regulatory environment in Michigan has been very supportive and has insulated the Company from various business and economic risks. This, in turn, has allowed the Company to earn consistent returns at or above its cost of equity capital.

Therefore, Mr. Solomon's direct testimony on the higher risks faced by the Company and the need to set a common equity ratio of 52% in the capital structure are largely conjecture and unsupported by the evidence.

Q. DID YOU CALCULATE THE DIFFERENCE IN REVENUE REQUIREMENT OF INCREASING THE COMMON EQUITY RATIO FROM 50% TO 52%?

A. Yes. If the Commission were to adopt a 52% common equity level in this case, revenue requirements would be higher by approximately $7.9 million. This reflects the Company's shift of approximately $79 million from long term debt to common equity capital and the difference between the Company's pretax cost of common equity of 14% versus the pretax cost of long-term debt of approximately 4.2%.

Q. DID YOU MAKE ANY OTHER ADJUSTMENTS TO OTHER ITEMS INCLUDED IN THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A. No.

Q. **WHAT RETURN ON EQUITY AND OVERALL RETURN ON CAPITAL ARE YOU RECOMMENDING IN THIS CASE?**

A. I am recommending an overall after-tax return on capital of 5.25% which includes a return on common equity of 9.50%, as shown in Exhibit AG-21.

Q. WHAT COST RATE DID YOU UTILIZE FOR LONG TERM DEBT?

A. I have utilized the 4.16% rate determined by Company witness Edward Solomon.

Q. WHAT COST RATE DID YOU UTILIZE FOR SHORT TERM DEBT AND THE OTHER COMPONENTS OF THE CAPITAL STRUCTURE?

A. For Short Term Debt and Deferred Taxes, I utilized the cost rates recommended by Company witness Solomon. For JDITC, I have excluded the $21,000 balance from the capital structure because this small balance has no impact on the calculation of the overall cost of capital.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OVERALL COST OF CAPITAL ON PAGE 1 OF EXHIBIT AG-21.

A. To develop the overall cost of capital on line 12, column (f), I have first developed the percentage weighting of each capital component in column (d) by dividing the individual capital balances in column (b) by the total of all capital components in that column. Next, I have multiplied the weightings in column (d) by the cost rates in column (e) to arrive at the values in column (f). The total of the individual values in column (f) is the total cost of capital of 5.25%.

Regarding the pretax weighted cost of capital on line 12, column (h), I have multiplied each cost component in column (f) by the conversion factors in column (g). These conversion factors are included to reflect the impact of income and other taxes paid by the Company for calculation of the pretax weighted cost of 6.52% in column (h).

Q. WHAT GENERAL PRINCIPALS HAVE YOU CONSIDERED IN DETERMINING THE COST OF COMMON EQUITY FOR THE COMPANY?

A. A utility company is entitled to a fair return that will allow it to attract capital and be sufficient to assure investors of its financial soundness. In its opinion in Bluefield Water Works and Improvement Company v Public Service Commission of West Virginia (the "Bluefield Case") 262 U.S. 679 (1923), the United States Supreme Court indicated that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that being made at the same time…on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties….

The principals of the Bluefield Case were re-affirmed by the U.S. Supreme Court in 1944 in the case FPC v Hope Natural Gas Company, 320 U.S. 591.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE COST OF COMMON EQUITY IN EXHIBIT AG-22.

A. Determining the cost of common equity for an enterprise or an industry group is inexact, since investors can only estimate what the future cash flows from any enterprise may be over time. Because of this uncertainty, most financial experts will not rely solely on one method. To determine the cost of common equity, I have utilized three distinct methods. They are the Discounted Cash Flow (DCF) Method, the Capital Asset Pricing Model (CAPM), and the Utility Risk Premium approach. These methodologies have previously been accepted by the Commission and have been generally accepted by regulatory commissions in other jurisdictions in the United States.

Also, I have considered the circumstances in the Capital Markets as of February 2019 and any potential changes in the risk profile of DTE Gas and the state of the Michigan economy. While Exhibit AG-22 shows a weighted average cost of common equity of 8.59% using the three methods, I recommend an authorized rate of return on equity of 9.50% for the reasons explained later in this section of my testimony. In connection with these methods for determining the cost of common equity, I have considered the cost of common equity for a proxy group of peer companies.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF YOUR PROXY GROUP OF PEER COMPANIES?

A. To develop my peer group, I started with the ten gas utility companies followed by the Value Line Investment Survey in its "Natural Gas Utility Industry" section. I removed two companies for the following reasons. The companies that I removed are (1) UGI Corporation due to its foreign investments and propane investments, which is 50% of its business; and (2) Chesapeake Utilities, which had revenues of approximately $600 million in 2018 because of its relatively small size and also less than 50% of these revenues being from regulated utility operations.

The result is the group of eight companies shown in Exhibit AG-23, all of which have growing earnings and dividends.

Q. HOW DOES YOUR PEER GROUP OF EIGHT COMPANIES COMPARE TO THE COMPANY'S PEER GROUP?

A. The Company's peer group presented by witness Bente Villadsen consists of a group of 14 companies. These companies include five water utility companies, the eight gas utility companies that comprise my peer group, and Chesapeake Utilities, which I did not include for the reason discussed above. Witness Villadsen presents these companies (1) as a gas group; (2) as a water group; and (3) as a combined group.

Q. DO YOU BELIEVE THAT THE COMPANY'S PROPOSED PEER GROUP IS APPROPRIATE?

A. No. The inclusion of the five water companies is not necessary and should be disregarded. Four of the five water companies selected by witness Villadsen are small entities with annual revenues of approximately $700 million or less and with one as low as $50 million in revenue. In comparison, DTE Gas reported more than $1 billion in revenue for the year 2018.[9] Smaller companies have unique characteristics, such as low stock trading volume and illiquidity in the financial markets, which increase their cost of doing business and their cost of capital. As such, they are not appropriate comparable companies to include in a peer group for calculation of the cost of common equity.

In addition, the common stocks of the five water companies have been trading at Price to Earnings ratios of between 32 to 41 times trailing earnings during February 2020, and also at high market to book equity ratios well above the gas utilities in the peer group. In comparison, the common stocks of the gas utilities in the peer group have been trading at an average P/E ratio of 27 times trailing earnings during February 2020. The high P/E ratios for the water utilities distort the calculations performed by witness Villadsen in her proposed ATWACC approach used to calculate the cost of common equity.

Some of the water companies are likely acquisition targets due to their smaller size and the continuing consolidation taking place in the water industry. In Exhibit AG-55, I included a Value Line report on the Water Industry, which addresses the fragmented nature of the industry and the expected acquisition activity.

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[9] Exhibit A-3, Schedule C-3.

Furthermore, there are significant structural differences between gas utilities and water companies. Gas companies are subject to volatility in natural gas prices, state mandated energy conservation programs, and risk of gas explosions, among other unique factors affecting the gas industry. On the other hand, water utilities do not face the same water supply price volatility, and with the exception of arid areas on the west coast, do not have state-mandated water conservation programs or similar risks as gas utilities.

Because of the above factors, I find the inclusion of water companies in a gas utility peer group inappropriate, unwise, and unnecessary. The gas peer group I have proposed is adequate and appropriate.

Q. HOW DOES THE INCLUSION OF THE WATER COMPANIES IN THE PEER GROUP AFFECT THE COST OF COMMON EQUITY OUTCOMES IN THE COMPANY'S CASE?

A. As can be seen from Figure 15 on page 47 of witness Villadsen's direct testimony, the CAPM ROE results for the water industry are 0.6% to 1.1% higher than the gas group. On page 51, the simple DCF result for the water group is 13.4%, versus the gas sample result of 12.1%. It should be noted that these results are after applying the After-Tax Weighted Cost of Capital (ATWACC) methodology that Dr. Villadsen seems to favor. I will discuss the problems with the ATWACC methodology in more detail later in my testimony. Nevertheless, the inclusion of water companies in the peer group is fraught with problems and biases the calculation of the cost of equity toward higher rates than appropriate.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE COMPANY'S PROPOSED WATER COMPANY PEER GROUP AND THE COMBINED PEER GROUP WITH WATER UTILITIES?

A. The Commission should reject the Company's peer groups, which include water utilities and small gas utilities. Instead, the Commission should adopt my proposed peer group as a better comparable group of companies for DTE Gas.

<u>Discounted Cash Flow (DCF) Approach</u>

Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW ("DCF") APPROACH.

A. The DCF approach is based on the proposition that the price of any security reflects the present value of all future cash flows (dividend flows) from the security discounted at a single discount rate, which in the case of common stocks is the required return of equity. Expressed mathematically, the resulting equation can be reconfigured to solve for the required rate of return and this equation is:

$$R = D/P + g$$

where "R" = the Required Equity Return
"D/P" = the Dividend Yield on the Security
and "g" = the expected growth rate in dividends

Generally, the "D" or dividend is known, and the "P" or stock price is also known as the stock trades each day. Also, recent growth in the dividend is known or estimates of growth furnished by stock analysts can be relied upon with some degree of certainty. With this information, one can solve for "R," which is the required rate of return.

Q. PLEASE EXPLAIN THE RESULTS OF YOUR DCF ANALYSIS.

A. The results of my DCF analysis are summarized in Exhibit AG-23. The stock price information in column (c) on this exhibit reflects the average of the high and low prices for each of these equity securities on each of the 30 trading days from January 1, 2020 to February 13, 2020. The annual dividend in column (d) is the projected annual dividend level for the 2020-2021 period as projected by the Value Line Investment Survey. Column (h) shows the average long-term earnings growth rate based on Value Line projections of earnings per share through the year 2023 and Yahoo Finance analysts' projected growth over the next five years. The resulting calculation of the DCF Method indicates an average required return on common equity of 9.08% for the proxy group.

This result is lower than the Company's "simple" DCF study result of 12.1%, but comparable to the Company's "multi-stage" DCF result of 8.7% calculated by witness Villadsen and shown in Figure 16 on page 51 of her testimony. It is important to keep in mind that the Company's results were determined using witness Villadsen's ATWACC process which, as discussed later, should be disregarded.

Q. **PLEASE EXPLAIN WHY WITNESS VILLADSEN'S COST OF EQUITY IS SO MUCH HIGHER.**

A. The 12.1% "Simple" DCF result can be explained as follows. First, in Exhibit A-14, Schedule D5.7, Panel A, witness Villadsen computes and shows the basic DCF result of 10% for her proposed peer group of gas companies. This result drops to 9.3% if South Jersey Industries is removed from the Company's peer group due to its inflated earnings growth of 13.1%, which is not a sustainable rate of growth for the company. The adjusted DCF result of 9.3%, which is prior to witness Villadsen's application of the ATWACC calculations, is very comparable to the 9.08% DCF cost of equity that I calculated.

Second, starting with the 10.0% result noted in the preceding paragraph, witness Villadsen derives a 7.4% after-tax cost of equity for the gas peer group based on the market value of each of the companies in the peer group. The 7.4% result is shown in column 10 of the same Schedule D5.7, Panel A. It is important to recognize that this outcome is a function of an average common equity ratio of 70% as noted in column 4 of Schedule D5.7.

Third, on Schedule D5.8, witness Villadsen redistributes the average after tax cost of 7.4% back to the debt and common equity components based on a 52% common equity ratio (not the 70% market to book ratio previously used), which results in her ROE determination of 12.1%.

The key driver in this complex process of calculations is the ratio by which market-based equity exceeds book value equity. This process of determining the After-Tax Weighted Average Cost of Capital is simply a math process to drive an upward adjustment of the final ROE rate using stock market premiums over book equity values.

The resulting effect of this ATWACC approach is that higher market to book ratios in the utility industry (due to lower interest rates and other factors), if embraced by regulatory commissions, would lead to higher ROEs awarded in rate cases and a form of future bonus earnings for achieving higher stock prices for utility investors.

Also, the Commission should recognize the inherent circularity of the ATWACC process. For example, if the ATWACC approach was to become universally embraced by regulatory commissions, the ROEs awarded in regulatory proceedings would increase. The inflated ROEs would result in higher utility earnings, stock prices and higher market to book ratios for utility common stocks. The subsequent calculated ROEs in new rate cases under the ATWACC method would then produce even higher awarded ROEs because the ATWACC would use the higher stock market equity capitalization.

Likely because of this cost inflating circularity and the complexity of the methodology, the ATWACC method has not been embraced by the utility industry. In fact, the Company could not cite any state regulatory commissions in the U.S. that have adopted this methodology for purposes of setting an authorized ROE in a utility rate case. According to testimony by a colleague of witness Villadsen in case No. U-18999, the instances where this methodology has been used involve (1) property taxation disputes in Colorado; (2) a valuation dispute before the FERC; and (3) revenue adequacy hearings for railroads, as well as a revenue adequacy hearing involving Alabama Power related to its special rate "RSE". Therefore, the Commission should disregard the ATWACC approach to calculating the DCF cost of common equity.

Q. PLEASE ASSESS THE RESULTS OF THE DCF ANALYSIS YOU PERFORMED.

A. The DCF analysis relies upon financial market information for the dividend yield portion of the equation. However, it also relies upon judgments of growth prospects of security analysts, which may or may not be consistent with the beliefs of investors. I will point out that the forecasted growth rates for the proxy group include some very high growth rates, in some cases as high as 9.95%.

These high growth rates appear to be the result of a temporary rebound in earnings from a low point in recent years. While these earnings may materialize in the short term, such high rates are not sustainable long-term growth rates for gas utilities given that customer and revenue growth continue to be barely in low single digits. As such, the results of the DCF analysis in some cases reflect a return on equity rate that is somewhat higher than what investors currently expect in the long term. Nevertheless, I place a fairly high degree of reliability in the DCF results when considered in conjunction with the results of other approaches to determining the cost of common equity.

Capital Asset Pricing Model Approach

Q. PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL APPROACH TO DETERMINING THE COST OF COMMON EQUITY CAPITAL.

A. The Capital Asset Pricing Model ("CAPM") is based on the proposition that the expected return on a common equity security is a function of risk as measured by the "Beta" of that security. In equation form, CAPM is as follows:

$k_e = R_f + (B \times R_p)$ *where*

k_e = *The market cost of common equity for a specific security*

R_f = *the "risk free" rate of return*

R_p = *the overall return of the market less the risk free rate (over several years)*

B = *the systematic risk of a particular common equity security vs. the market*

Q. PLEASE EXPLAIN THE BETA OR "*B*" COMPONENT OF THE EQUATION.

A. This measure of risk reflects the extent to which the price of a particular security varies in relationship to the movement of the overall market. Some securities vary less in price over time than the overall market. In these cases, the Beta will be less than 1.00. Securities that vary over time more than the overall market will have a Beta that is greater than 1.00.

Q. PLEASE EXPLAIN EXHIBIT AG-24 SHOWING THE RESULTS OF THE CAPM APPROACH.

A. Exhibit AG-24 shows the results of the CAPM method based upon (1) a projected 3.1% risk free rate as explained below; (2) Beta information available from Value Line; and (3)

Historical Market Risk Premium (R_p) information of 6.91% based on the Ibbotson Classic Yearbook through 2018.

As described in Exhibit AG-24, the 3.1% risk-free rate I used is based upon the projected interest rate of 2.57% for the ten year U. S. Treasury bond by IHS as of February 2020, which was provided by the Company, plus a 50 basis points spread between the 10-year and the 30-year U. S. Treasury bond. This reflects the average spread during February 2020. The resulting 3.1% is the projected interest rate for 30-year U. S. Treasury bonds and represents the risk-free rate used in the CAPM calculation.

As shown in Exhibit AG-24, I have added the peer group risk premium of 4.53% to the 3.1% risk-free rate to arrive at the 7.63% ROE rate under the CAPM method

The 4.53% group risk premium is the risk premium for the total stock market of 6.91% shown in column (d) multiplied by the average beta of 0.66 from column (c). These factors are explained further in Exhibit AG-24.

Q. PLEASE ASSESS THE CAPM APPROACH.

A. I believe that CAPM has value in assessing the relative risk of different stocks or portfolios of stocks. As such, it can be useful. However, the key issue with CAPM is that is assumes that the entire risk of a stock can be measured by the "Beta" component and as such the only risk an investor faces is created by fluctuations in the overall market. In actuality, investors take into consideration company-specific factors in assessing the risk of each particular security. As such, I give the CAPM approach less weight than the DCF approach in determining the cost of common equity.

Q. PLEASE COMMENT ON WITNESS VILLADSEN'S CALCULATIONS OF CAPM COMMON EQUITY COST RATES RANGING FROM 9.0% TO 10.2%.

A. In Figure 15 on page 47 of her direct testimony, witness Villadsen presents 6 different CAPM cost of equity estimates and 6 different ECAPM estimates for her gas sample companies. The Commission should not rely upon any of these CAPM or ECAPM results. All of the estimates have been determined utilizing either (1) the discredited ATWACC process discussed earlier under the DCF section of my testimony, or (2) using the Hamada Adjustment process with non-standard betas. Both of these methods provide faulty and inflated results.

Witness Villadsen's basic CAPM results have been determined under two scenarios. Scenario 1 utilizes the historical risk premium results of 6.91% and her Scenario 2 utilizes a higher risk premium of 7.91%, which she states is forward looking. Using these MRP rates, she derives basic results of 8.1% and 8.6% for the two scenarios. These results are then adjusted upward using the ATWACC and Hamada Adjustment process mentioned above, and the result is the CAPM rates on page 47 of her direct testimony.

Q. DOES WITNESS VILLADSEN EXPLAIN WHY SHE BELIEVES THAT CURRENT OR FUTURE RISK PREMIUMS MAY BE HIGHER THAN THE 6.91% RISK PREMIUM DERIVED FROM HISTORIC RETURNS?

A. Yes. On page BV-41; lines 4 and 5 of her direct testimony, she states that Bloomberg has recently estimated the forward looking MRP at 7.29% relative to 20-year bond yields (not 30-year bond yields). Also, on line 7 and 8 of the same page, she states that she has undertaken a forward-looking analysis of the S&P 500 and it shows a market risk premium (MRP) of 9.34% based upon an expected market return of 12.69%. The analysis performed to arrive at the 12.69% DCF market return is presented in Exhibit A-14, Schedule D5.18.

Q. WHAT IS YOUR ASSESSMENT OF THE ANALYSIS PERFORMED TO ARRIVE AT THE 12.69% MARKET RETURN USING THE DCF MODEL?

A. I have reviewed this analysis and find it to be seriously flawed. First of all, the DCF model works well for companies that pay a steady and growing dividend. In the calculation performed by Dr. Villadsen of the S&P 500 group of companies, if the company does not pay a dividend, it is disregarded rendering the result less representative of the so-called "market."

Second, many of the companies in the S&P group are in the oil and gas industry with significant stock price volatility. When reviewed, the analysis reflects DCF ROE outcomes that are highly doubtful. For example, the analysis shows bizarre DCF returns, such as a forecasted ROE of 178.9% for Cimarex Energy Devon Energy, a forecasted 44.1% ROE for Cabot Oil & Gas, a forecasted ROE of 63.8% for Helmrich & Payne, and other similarly improbable outcomes.

Witness Villadsen averages these results together with other lower outcomes to produce a 12.69% forecasted ROE for the S&P 500. From this percentage she deducts her long-term risk-free rate of 3.35% to arrive at a 9.34% MRP, which she then uses to develop an inflated cost of equity result for the utility peer group.

The Commission should disregard the cost of equity calculation of the utility peer group using the MRP derived from an unreliable approach based on the S&P 500 group for the reasons discussed above.

Q. WHAT IS YOUR ASSESSMENT OF WITNESS VILLADSEN'S ECAPM RESULTS, WHICH ARE 0.2% TO 0.5% HIGHER THAN HER CAPM RESULTS.

A. First, it is worth noting that her ECAPM results have been developed using the ATWACC and Hamada methodologies discussed earlier and are corrupted by these faulty methodologies.

Witness Villadsen explains her ECAPM approach beginning on page BV-44 of her testimony. She states that research has shown that "…low-beta stocks tend to have higher risk premiums than predicted by the CAPM…" Her equation for the ECAPM is very similar to the CAPM equation, except that she introduces an alpha factor into the equation ranging from 1.0% to 7.32%.

I will point out that the classic CAPM approach typically uses short-term treasury rates as the risk-free rate. However, most witnesses in rate cases use the 30-year treasury bond as the risk-free rate, which usually is higher than short-term treasury rates. Accordingly, the need for the corrections made within the ECAPM are usually unnecessary.

To my knowledge, the ECAPM is not widely accepted as a cost of equity methodology among gas and electric regulatory commissions in the United States. One of the few regulatory commissions outside of the U.S. that has spoken on the subject of ECAPM is the Alberta Utilities Commission of Canada in its order of October 7, 2016. That regulatory commission noted on page 45, paragraph 199 of the order that the ECAPM "…appears to be a model that could contribute to the Commission's determination of a fair allowed ROE…." However, later in the same paragraph, the commission noted the high degree of judgement required by the ECAPM methodology, and reached the conclusion that, [c]onsequently, the Commission will not rely heavily on the ECAPM results in this proceeding."

In summary, the use of the 30-year treasury rate (not short-term rates) as the risk-free rate in the CAPM method resolves the need to use the ECAPM method and the inflated results that it produces.

Q. WHAT IS YOUR OVERALL ASSESSMENT OF THE COST OF EQUITY METHODOLOGIES USED BY WITNESS VILLADSEN?

A. While witness Villadsen's various methods used to calculate the cost of equity capital are inventive, they are highly unconventional, not generally accepted, and are based in part upon her opinion that risk levels have permanently risen since the 2007-2008 financial crisis. The Commission should reject these alternative approaches for the reasons previously discussed and because they are clearly an attempt to inflate the Company's true cost of common equity.

Utility Risk Premium Approach

Q. PLEASE EXPLAIN THE UTILITY RISK PREMIUM METHOD OF ESTIMATING THE COST OF COMMON EQUITY.

A. In general, one can estimate the cost of common equity by estimating three components and adding them together. The three components are (1) the risk-free rate of return on 30-year U. S. Treasury Bonds; (2) the historical differential between yields of the rated utility bonds of the Company and the 30-year U.S. Treasury Bonds; and (3) the average return differential of utility common stocks over utility bonds.

Q. PLEASE EXPLAIN YOUR UTILITY RISK PREMIUM ANALYSIS RESULTS.

A. Exhibit AG-25 shows the three components required to estimate the cost of common equity under this approach. The results for this approach reflect a return on common equity of 8.55%. To arrive at this result, I used the historical spread of gas utility common stock returns relative to utility bonds of 4.0%. Also, I used a 1.45% average spread for utility bonds (A rated and BBB rated) over the 30-year U.S. Treasury bond rate. This spread is the average spread of new utility bonds issued during the 12 months ended June 2019 period over 30-year U.S. Treasuries for (1) A rated bonds of 124 basis points; and (2) BBB rated bonds of 166 basis points. For the risk-free rate, I used the projected 30-year Treasury rate of 3.10% discussed under the CAPM section of my testimony.

Q. **HOW HAS THE ECONOMIC AND INTEREST RATE ENVIRONMENT CHANGED IN RECENT YEARS FOR THE COMPANY?**

A. The Michigan economy has substantially recovered from the most recent recession and interest rates are stable at lower levels thanks in part to the monetary policy of the Federal Reserve Bank. These factors have placed the Company in a better position with respect to sales levels, interest rates, and uncollectible sales amounts. The Company's access to the capital markets and that of its sister company is strong as witnessed by (1) DTE Gas issuing $280 million of 10-year and 30-year long-term debt with rates ranging from 2.95% to 3.72% in October 2019; and (2) DTE Electric's issuance in February 2019 of $650 million of new 30-year long-term debt at a rate of 3.95%.

The Company's senior secured debt is rated at A/A1, and its commercial paper program is rated P-2 by Moody's Investor Service. Also, the Company's parent, DTE Energy, accessed the capital markets in 2019 issuing $1.6 billion of new long-term debt with maturities ranging from 3 to 10 years with interest rates ranging from 2.25% to 3.4%.

Accordingly, the Company's recommendation that the authorized rate of return on common equity should be increased to 10.50% to continue to have access to capital markets is unsupported by the evidence and is largely based on unconventional methodologies applied to CAPM and DCF cost of equity calculations. The results of my

DCF analysis, CAPM analysis, and Utility Risk Premium Approach point to a calculated cost of equity closer to 8.5%.

Q. PLEASE DISCUSS WHAT RETURN ON EQUITY RATES OTHER REGULATORY COMMISSIONS HAVE GRANTED IN 2018 AND 2019?

A. Since 1990, return on equity rates granted by regulatory commissions in the U.S. have been in a steady decline, from over 12.7% in 1990 to approximately 9.6% in 2018 and 9.76% in 2019. This decline has generally followed the significant decline in interest rates and the rate of inflation.

Exhibit AG-28 shows the ROEs granted by state regulatory commission to U.S. gas utilities in 2018 and 2019. The majority of the 39 ROE decisions in 2018 and 29 decisions in 2019 are at rates well below 10%. As shown on page 3 of the exhibit, only 5 decision in 2018 and 7 decisions in 2019 are at rates of 10% or greater. These higher rates are from regulatory commissions in Michigan and Wisconsin, which represent outliers among other regulatory commissions around the country. ROEs in California have been over 10%, reflecting the unique challenges of that state (wildfires and earthquakes). Decisions in Florida, Georgia and South Carolina with ROEs above 10% reflect three special situations, i.e., utility companies with multi-year agreements that have capped annual adjustments to rates. In one of these situations involving Florida City Gas, no application for an increase is permitted before June 2022. In another situation involving Atlanta Gas Light, the Commission reduced the prior ROE from 10.75% to 10.25% and limited annual increases are permitted but excess earnings may also be subject to refund. Clearly these are unique situations.

For most of the other gas utilities that have business and financial risks comparable to DTE Gas, the ROE rates have averaged around 9.5% in the past two years. This evidence supports my proposed ROE rate of 9.50% and makes the Company's current ROE rate of 10% excessive. The Company's proposed ROE rate of 10.50% is even further removed from reality and clearly unsupportable.

Q. SHOULD THE COMMISSION BE CONCERNED THAT ESTABLISHING AN AUTHORIZED ROE OF 9.50% IN THIS CASE WILL LEAD TO IMPAIRMENT OF THE COMPANY'S ABILITY TO ACCESS THE CAPITAL MARKETS?

A. No. In recent general rate case proceedings, certain rate case applicants have raised arguments that they should receive a ROE of 10% or higher to ensure the financial soundness of the business and to maintain its strong ability to attract capital in addition to being compensated for risk. Exhibit AG-28 shows several gas utilities that have accessed the capital markets at competitive interest rates since receiving a ROE near or below the average rate of 9.50%.

Similarly, there is no evidence equity investors have abandoned utilities that have been granted ROEs below 10%. On the contrary, stock investors continue to migrate to utility stocks, recognizing that authorized ROEs are still above the true cost of equity. Exhibit AG-27 shows the market to book ratios for each of the peer group companies, and many of these companies have received rate orders during the past few years reflecting ROEs as low as 9.25%. Yet this group of companies has an average Market to Book common equity value ratio of nearly 2.1 times.

This information is provided to dispel the myth that the Company must receive a ROE at or above 10%, or it will face dire consequences in the financial markets.

The fact that the Company needs to raise capital because of a large capital investment program to upgrade its infrastructure and for other purposes is not unique to DTE Gas. Other gas utilities face the same issues and are able to raise capital with ROEs well below 10.0%. Therefore, this issue is another “red herring”.

Q. ON PAGE 52 OF ITS SEPTEMBER 13, 2018 ORDER IN CASE NO. U-18999, THE COMMISSION POINTED TO INCREASED VOLATILITY IN THE CAPITAL MARKETS AS A REASON TO AUTHORIZE A 10% ROE RATE. SHOULD STOCK MARKET VOLATILITY OR THE VIX INDEX BE A CONCERN IN ESTABLISHING A FAIR ROE RATE FOR THE COMPANY?

A. No. In answering this question, I will first point out that even though witness Villadsen discusses the stock market volatility at length on pages 25 through 27 of her direct testimony, she states “A measure of the market’s expectations for volatility is the VIX index, which measures the 30-day implied volatility of the S&P 500 index.” She then goes on to discuss higher levels of the VIX “…in December 2018 and again in early August 2019, each time concurrent with a significant drop in the stock market….”

The stock market has historically been very volatile. In some periods, stock prices move up and down more dramatically than at other times. The key factor is that the VIX is telling us something about risk in the market over the next 30 days and not the risk several months in the future. In setting ROE rate for utilities, the Commission's focus is the long-term financial health of the utility not the short-term gyrations of the stock market.

As a second point, in Exhibit AG-56, I have included a Value Line Funds article written by Mitchell Appel, President of Value Line Funds. Mr. Appel states that volatility is not risk. He also points out that volatility in 2017 was low by historical standards and it was near normal levels in 2018. Mr. Appel goes on to say later in this article that "…volatility is only risk if you act during down times, that is, only if you sell a stock."

Additionally, I will submit that those who invest money in equity portfolios over longer periods of time and particularly in utility stocks have an aversion to market volatility and the VIX. In fact, utility stocks are a safe haven for investors during times of uncertainty and volatility because they are not as susceptible to volatility as the general stock market. This is reflected in the average Beta value of 0.66 of the utility peer group used in the CAPM discussed earlier, in contrast with the general stock market value of 1. Therefore, the Commission should not give any weight to arguments that the Company's ROE should reflect investors' concerns with stock market volatility.

Q. DO YOUR CALCULATIONS FOR THE LONG-TERM COST OF COMMON EQUITY REFLECT THE UNUSUAL CIRCUMSTANCES IN THE CAPITAL

MARKETS THAT BEGAN IN LATE FEBRUARY 2020 RELATED TO THE CORONAVIRUS?

A. No. The information on stock prices, dividends yield, earnings projections, long-term interest rates and market risk premiums were collected before the recent upheaval in the financial markets. Therefore, those factors and the resulting calculations of ROEs which I have performed reflect relatively normal and long-term expectations. It would not be appropriate or advisable to use financial market factors from what could likely be a short-term event to calculate the long-term cost of equity and set ROE rates from such short-term financial data.

For example, while utility stock prices have declined since late February 2018 and dividends yields have increased, which would increase the DCF cost of equity if such short-term information were used, the 30-year U.S. treasury rate has declined significantly to below 2% in comparison to the 3.1% rate used in my calculation of the cost of common equity with the CAPM and Risk Premium methods. If such a low risk-free rate were used, it would result in a proposed ROE rate of near 7%. It would not be appropriate to recalculate the cost of equity for any of the three methods using such short-term financial information during an unusual event that could be temporary.

Q. PLEASE EXPLAIN YOUR CONCLUSION CONCERNING THE APPROPRIATE RETURN ON EQUITY RATE THE COMMISSION SHOULD USE IN THIS CASE.

A. In Exhibit AG-22, I have summarized the cost of equity rates from the three methods I discussed above. The range of returns for the industry peer group is from 7.63% at the low end, using the CAPM approach and 9.08% at the high end using the DCF approach.

As explained earlier in my testimony, I give 50% weight to the DCF method as a more reliable approach to estimating the cost of equity, which from my analysis is a rate of 9.08%. In this regard, on line 4 of Exhibit AG-22, I have calculated a weighted return on equity of the three methodologies using a 50% weight for DCF and 25% for each of the other two methods. The result is a weighted average cost of common equity of 8.59%. To this base cost of equity capital, I have added an additional premium adjustment of 91 basis points to arrive at a recommended ROE rate of 9.50% for DTE Gas Company in this rate case for the reasons explained below.

First, the extent to which investors anticipate higher interest rates is uncertain. As such, while the cost of common equity under the DCF approach is an accurate assessment of expectations for the forecasted test year and the long-term, the cost of equity methodologies may produce a different result should higher interest rates become a reality. In this regard, a potential 10% correction in utility stock prices due to higher interest rates or other events would produce a 0.40% increase in the cost of capital under the DCF approach. In effect, the 91-basis points premium I have added to the base cost of common equity would cover more than a 20% correction in utility stock prices.

Second, natural gas prices are at historically low levels, which accord the Company the opportunity to expand gas sales and gas deliveries. However, state mandated energy efficiency and conservation programs are limiting sales growth, which combined with large capital expenditures programs, are increasing distribution rates. Higher rates could make the Company less competitive with other fuel sources and create customer discontent, thus limiting earnings growth.

Third, I understand that the Commission would be reluctant to grant a ROE at the 8.5% true cost of capital at this time, preferring instead a more gradual reduction. The 9.5% ROE rate I have proposed is a reasonable reduction from the last granted ROE of 10.0% to DTE Gas in 2018, which was nearly two years ago.

Q. IF THE COMMISSION APPROVES A 10.0% COST OF COMMON EQUITY IN THIS CASE (AS IT DID IN CASE NO. U-18999), WHAT IS THE COST TO CUSTOMERS COMPARED TO AN ROE OF 9.50%.

A. If the Commission were to grant a 10.0% ROE in this case versus a 9.50% ROE, the additional cost to customers is approximately $14 million annually. There is no need to burden customers with this additional cost, when historically the Company has been earning well above its true cost of common equity.

I recommend that the Commission take note of the evidence and arguments I have presented in my testimony and grant the Company a ROE of no more than 9.50%.

VI. Revenue Adjustment

Q. WHAT ADJUSTMENTS ARE YOU PROPOSING WITH REGARD TO THE COMPANY'S FORECASTED REVENUE FOR THE PROJECTED TEST YEAR?

A. In my analysis, I have discovered that the Company's projected revenues for Gas Sales, End-User Transportation, Off-System Transportation and Exchange Services, and the Appliance Service Program are significantly understated. The total incremental revenue that I propose is $35.9 million. In the testimony below I explain further the reasons for this proposed revenue adjustment.

A. Gas Sales Revenue

Q. WHAT ARE YOUR FINDINGS FROM ANALYZING THE COMPANY'S PROJECTED LEVEL OF GAS SALES?

A. In Exhibit A-15, Schedules E-1.1, Company witness George Chapel presents the Company's forecast of gas sales for the projected test year of October 2020 to September 2021. The Company has forecasted total gas sales of 155 Bcf for the projected test year. This level of sales represents a decrease of approximately 5.9 Bcf, or 3.7%, from the actual weather-normalized gas sales in 2018.

According to Mr. Chapel, the Company has calculated the forecasted sales based on various regression projection models applied to customers' historical gas consumption during the two-year period from August 2017 to July 2019.[10] The models also make use of other historical and projected data, including weather degree days, expected energy efficiency factors, population growth, manufacturing activity and other econometric data. Additionally, the Company has included adjustments to forecasted gas sales to take into consideration the higher heat content of the gas it purchases.

After reviewing the sales forecast, I have determined that the Company has significantly underestimated the gas sales volume for its residential, commercial, and industrial customers and the related test year revenue.

Q. WHAT IS THE BASIS FOR YOUR CONCLUSION THAT FORECASTED GAS SALES ARE UNDERSTATED?

A. In discovery, I requested that the Company provide the weather-normalized actual gas sales and the average number of customers for each year from 2014 to 2019 for each rate schedule. Based on the information provided by the Company, I calculated the average gas usage per customer for each of the customer rate schedules. Exhibit AG-29 shows the average gas usage per customer for the historical years from 2014 to 2019, along with the forecasted 2020, 2021, and projected test year periods. In this exhibit, I have also calculated the percent change in average gas usage per customer, year-over-year, from

[10] George Chapel direct testimony at page 14, line 5.

2014 to 2021 and for the projected test year, along with the average compound rate of decline or increase for the historical 3-year and 5-year periods.

The analysis shows that actual weather-normalized average usage for residential Rate A customers has varied little in recent years. Some years show a slight decline and other years an increase, but overall residential gas usage per customer has averaged a slight decline of approximately 0.6% per year during the 5-year period and a slight increase of 0.06% over the 3-year period.

Rate 2A residential customers' gas usage has shown a larger variations year-over-year. However, the percentage decline over the 3-year and the 5-year periods is nearly identical at 1.75% and 1.78%, respectively.

Rate GS-1 small commercial customers' gas usage has generally followed the same pattern as residential Rate A usage with relatively small variations year-over-year. However, over the most recent three years, the compound rate of growth has been 1.24% and only a slight increase of 0.06% over the five-year period.

Rate GS-2 larger commercial and industrial customers' gas usage has shown a dramatic compound average annual increase of 12.7% over the 3-year period and a decrease of 1.37% over the 5-year period.

Rate S school customers' gas usage has experienced larger variations year-over-year, but over the 3-year and 5-year period it has experienced growth rates of 7.87% and 3.81%.

Q. HOW DO THE COMPANY'S FORECASTED SALES PER CUSTOMER COMPARE TO THE HISTORICAL TRENDS?

A. When analyzing the Company's gas sales forecast for 2020, 2021, and the forecasted test year, gas usage per customer is forecasted to decline for all rate schedules from 1.1% to 19.7%. Rate 2 forecasted sales per customer decline by 2.5% in 2020 with a further decline of 1.5% in 2021 for a cumulative decline of 3.7% for the projected test year from the actual average usage in 2019. Rate 2A forecasted sales per customer decline 1.5% from 2019 to the end of the forecasted test year. Rate GS-1 forecasted sales per customer decline 5.5% over the same period.

According to the Company's forecast, Rate GS-2 sales per customer decline more dramatically by 19.7% from actual 2019 to the end of the forecasted test year. Rate S sales per customers are also forecasted to decline cumulatively by 4.8% from 2019 to the end of the future test year, despite the rate of increase of 3.81% to 7.87% experienced in the most recent 3 and 5-year historical periods.

The analysis in Exhibit AG-29 clearly shows that the rate of decline in average customer usage forecasted by the Company from 2019 to the projected test year is excessive and not supported by historical data or trends.

Q. TO WHAT DO YOU ATTRIBUTE THE SIGNIFICANT DECLINE IN AVERAGE CUSTOMER USAGE FOR ALL CUSTOMER RATE SCHEDULES IN THE COMPANY'S FORECAST FOR THE TEST YEAR?

A. In his direct testimony, Mr. Chapel discusses certain assumptions and adjustments that he has made to the regression model's gas sales forecast to reflect exogenous factors, such as incremental energy efficiency and forecasted changes in the heat content of gas sales. These adjustments, plus the fact that the model includes customer usage data for only two years, could account for most of the discrepancy. Two years of gas usage from August 2017 to July 2019, although recent, is a relatively short time period and prone to large year-over-year variations. As described later in my testimony, I believe at least a three-year period of recent customer usage data is a more reasonable approach to forecast future gas usage.

With regard to energy efficiency, or energy waste reduction (EWR), Mr. Chapel assumed an annual rate of decline in customer usage of 1.0% from August 2019 to September 2021. Although the 3 and 5-year historical rates of decline in sales in Exhibit AG-29 appear to reflect some level of reduction in gas sales from energy efficiency, they do not support the much larger rate of decline forecasted by the Company for 2020, 2021, and the projected test year.

The EWR program and predecessor energy efficiency program have been in place for about a decade. Although the Company and its consultants calculate theoretical rates of energy reductions based on activities and improvements that customers make to their homes and place of business, the actual data in Exhibit AG-29 shows that those theoretical energy reductions do not always translate into actual energy losses for the Company. The law of diminishing returns also comes into play with the EWR program as incremental investments produce fewer energy reductions over time once house insulation, smart thermostats and other energy efficiency remediations reach a practical limit.

Q. WHAT ADJUSTMENT TO THE SALES FORECAST HAS THE COMPANY MADE WITH REGARD TO THE HEAT CONTENT OF THE GAS?

A. The heat content of gas is measured in British Thermal Units (Btu). Beginning on page 12 of his direct testimony, Mr. Chapel discusses the issue with the recent increase in the Btu content of the gas and the reduction in sales volumes. He has determined that the average Btu factor per cubic foot was 1,050 during the two-year period of gas sales usage he used in his sales forecast model. Also, he has concluded that for the forecasted test year a Btu factor of 1,060 would be appropriate based on the heating value of gas receipts during the summer of 2019. Based on these two factors, he has calculated an adjustment factor of 0.9907 which he has applied to the results of his forecast model to take into consideration the lower sales volumes from the expected increase in the heat content of the gas during the future test year.

Q. DID YOU MAKE A SIMILAR BTU ADJUSTMENT TO YOUR FORECASTED GAS SALES DISCUSSED LATER IN YOUR TESTIMONY?

A. No. Although I understand why it was necessary for Mr. Chapel to make a Btu adjustment to his forecast model sales projections due the increase in Btu value between the historical gas usage period ending July 2019 and the more recent increases in the Btu value, I have taken a different approach in my forecast of gas sales for the future test year.

As described in further detail below, I used the actual weather normalized gas usage per customer for the year ended December 2019. During this 12-month period, the Btu content of the gas received by the Company was 1,060.[11] The gas usage data I used already reflects the higher Btu content of the gas for the base period from which I start my forecast for the future test year. Therefore, no further adjustment is necessary.

Q. DID YOU DETERMINE A MORE REALISTIC FORECAST OF GAS SALES FOR THE PROJECTED TEST YEAR?

A. Yes. In Exhibit AG-30, I calculated a forecast of residential Rate A gas sales of 113,757,911 Mcf for the projected test year. This forecast exceeds the Company's forecast by 4,341,677 Mcf. To arrive at the revised forecast, I began with the average weather-normalized gas usage per residential customer of 94.86 Mcf for the year 2019. To this number, I applied the 3-year annual rate of usage change of 0.06% and prorated it for the period from the end of 2019 to the end of the projected test year.

These calculations resulted in a lower average usage per customer of 94.97 Mcf for the projected test year. I then multiplied this number by the average number of residential customers provided by the Company for the projected test year to arrive at the forecast of 113,757,911 Mcf.

[11] DTE Gas response to discovery request AGDG-1.24a.

Similarly, for Rate 2A customers in Exhibit AG-31, I calculated an average usage per customer of 685.41 Mcf for the projected test year using the 3-year average annual rate of decline of 1.78%. I then multiplied this average usage by the average number of commercial customers provided by the Company for the projected test year to arrive at the forecast of 4,256,412 Mcf. My forecast for Rate 2A customers' gas sales is 70,967 Mcf, lower than the Company's projection for the test year.

In Exhibit AG-32, for Rate GS-1 customers, I applied the 3-year average annual rate of growth of 1.24% to the 2019 customer usage to arrive at an average use per customer of 473.18 Mcf for the projected test year. Multiplied by the number of customers the result is forecasted gas sales of 42,238,342 Mcf. This forecast is 3,184,828 Mcf higher than the Company forecast.

In Exhibit AG-33, for Rate GS-2 customers, I applied a zero rate of change and used the same 2019 customer usage of 49,174.70 Mcf for the projected test year. Multiplied by the number of customers the result is forecasted gas sales of 862,862 Mcf. This forecast is 169,589 Mcf higher than the Company forecast. Given the large divergence between the 3-year and 5-year rate of change in the average usage per customers, I decided to take a more conservative approach and used the same usage per customer as of the latest reported data in 2019. This approach is a more favorable outcome for the Company than if I had used the 3-year average annual sales per customer growth rate of 12.7%.

In Exhibit AG-34, for Rate S customers, I applied the 3-year average annual rate of growth of 7.87% to the 2019 customer usage to arrive at an average use per customer of 7,986.22 Mcf for the projected test year. Multiplied by the number of customers the result is forecasted gas sales of 1,756,969 Mcf. This forecast is 292,378 Mcf higher than the Company forecast.

Q. DID YOU CALCULATE THE IMPACT ON REVENUE AND REVENUE REQUIREMENT AS A RESULT OF THE HIGHER GAS SALES?

A. Yes. Exhibits AG-30 through AG-34 show the calculation of the incremental revenue related to the incremental forecasted gas sales for applicable Rate Schedule customers. To calculate the additional revenue, I applied the current gas sales rates to the incremental gas sales. The combined incremental revenue for all gas sales rate schedules is $23,587,533.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A. The Company's forecasted revenue for the projected test year is not accurate because gas sales for the projected period are understated. The Company's gas sales forecast includes losses of sales from energy efficiency and other factors that are not likely to materialize to the level projected by the Company. The Commission should reject the Company's gas sales forecast for the projected test year and instead adopt my forecast as presented in Exhibits AG-30 through, AG-34.

Therefore, I recommend that the Commission increase the revenue forecasted by the Company for the future test year by $23,587,533. This in turn reduces the revenue requirement and revenue deficiency projected by the Company for the future test year.

B. End-User Transportation Revenue

Q. WHAT ARE YOUR FINDINGS FROM ANALYZING THE COMPANY'S PROJECTED LEVEL OF GAS DELIVERIES TO END-USER TRANSPORTATION CUSTOMERS?

A. In Exhibit A-15, Schedule E7, Company witness Henry Decker presents the Company's forecast of gas transportation volumes for the projected test year of October 2020 to September 2021. The Company has forecasted total transportation volume of 145.9 Bcf for the projected test year. This level of sales represents a decrease of approximately 7.9 Bcf, or 5%, from the actual transportation volumes billed in 2018. As shown on page 2 of the exhibit, the decline is attributed primarily to lower gas deliveries to power generation customers (11.3 Bcf) and customers closings plants or switching to non-transportation rates (1.3 Bcf). The decline in gas deliveries is partially offset by deliveries to new customers and increased usage by existing customers.

According to Mr. Decker's direct testimony, the lower transportation volume to power generation customers for the projected test year is the result of the Company using the average annual delivery volume to this customer group during the 5-year period from 2014 to 2018. The average volume delivered during the five-year period was 49.5 Bcf. In comparison, the Company transported 60.7 Bcf of gas to these customers in 2018.[12] In his direct testimony, Mr. Decker further explained that the lower projected transportation volumes are appropriate because gas deliveries to power generation plants vary with weather during the summer months.

Q. WHAT LEVEL OF GAS TRANSPORTATION DELIVERIES DO YOU PROPOSE FOR POWER GENERATION CUSTOMERS FOR THE PROJECTED TEST YEAR?

A. In discovery, the Company was asked to provide the actual deliveries to power generation plans for the year 2019. The 2019 data shows that the Company delivered 60.6 Bcf of gas to these customers during the latest year. The 2019 gas deliveries are almost identical to the 60.7 Bcf of gas deliveries in 2018 even with fewer cooling degree days, which are normally accompanied by lower gas usage by Peaker power plants. Exhibit AG-37 includes the 2019 information provided by the Company.

Using the gas deliveries to power generation customers for the 5-year period 2015 to 2019 results in average annual gas deliveries of 55.1 Bcf. This volume is 5.6 Bcf higher than the 49.5 Bcf calculated by Mr. Decker from 2014 to 2018. The 55.1 Bcf volume represents a more recent period and likely more reflective of the gas deliveries to this customer group during the future test period from October 2020 to September 2021. I recommend that the

[12] Henry Decker direct testimony beginning on page 16.

Commission adopt the 55.1 Bcf volume for calculating end-user transportation revenue for the future test year.

Q. ARE YOU PROPOSING ANY OTHER ADJUSTMENTS TO GAS TRANSPORTATION DELIVERIES FOR THE PROJECTED TEST YEAR?

A. Yes. I have two other adjustments to propose. First, on page 17, lines 6-12, Mr. Decker discusses the closure of three plants and the loss of gas deliveries to these customers. In discovery, the Company was asked to provide the volumes delivered to the three customers from 2017 to 2019. In response to discovery, the Company corrected Mr. Decker's testimony stating that one of plants had been sold and reopened under different ownership. The reopened plant used 288 MMcf of gas in 2019. Exhibit AG-38 includes the Company response to the discovery question.

This volume of transportation deliveries was not included in the Company's forecast for the future test year. I recommend that the Commission include the additional volume of 288 MMcf in the calculation of the forecasted revenue for end-user transportation.

Second, the Company has reduced gas deliveries for the future test year by 401 MMcf Energy Optimization losses as shown on line 3 of page 2 of Exhibit A-15, Schedule E7. The premise in arriving at this reduction in gas deliveries is that commercial and industrial customers in transportation rate schedules ST and LT will achieve Energy Optimization savings of 1% over the future test year. Although the Company has implemented an energy waste reduction program, there is no evidence presented in this rate case that transportation customers have actually achieved such a level of energy reduction, which has resulted in a loss of gas deliveries. Without such evidence, it is neither fair nor reasonable to reduce future gas deliveries and revenue. I recommend that the Commission remove this adjustment of 401 MMcf in the calculation of end-user transportation revenue for the future test year.

Q. IN YOUR ANALYSIS OF THE TRANSPORTATION GAS DELIVERIES FORECASTED BY THE COMPANY IN PRIOR RATE CASES HAVE YOU SEEN A PATTERN OF INACCURACY?

A. Yes. In discovery, the Company was asked to compare the transportation volumes forecasted in the prior three rate cases to the actual volumes delivered for the same time period. As shown in the schedule provided by the Company and included in Exhibit AG-39, in each of the three rate cases the Company's forecast for the future test year was considerably less than the actual volumes delivered. The volume variance ranges from 12 Bcf to 24 Bcf, which in the worst case is an understated estimate of nearly 19%.

In addition to this overall volume comparison, the Company provided the comparison of volumes forecasted for power generation customers in the last two rate cases to the actual volumes delivered. The response shows that the forecast underestimated gas deliveries between 14 and 17 Bcf. Exhibit AG-39 includes this discovery response.

This information shows a consistent pattern of underestimated gas delivery volumes forecasted by the DTE Gas for the future test year and lends credence to the adjustments I have proposed above.

Q. DID YOU CALCULATE THE IMPACT ON REVENUE FROM THE HIGHER GAS TRANSPORTATION DELIVERIES?

A. Yes. Exhibit AG-35 shows the calculation of the incremental revenue related to the forecasted higher gas transportation deliveries. To arrive at the incremental revenue, I applied the current transportation rates to the additional volume for each rate schedule. The result is incremental revenue of $1,864,560, which should be included in the future test year.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A. The Company's calculation of transportation gas deliveries to power generation customers is understated. A revised calculation of average gas deliveries over a more recent 5-year period which includes actual deliveries from 2019 shows that gas deliveries to this customer group should be increased by 5.6 Bcf (5,600 MMcf).

The Company's forecast also excluded the return of a chemical plant customer for 2019 and future years. The future test year should include an additional volume of gas deliveries of 288 MMcf.

The Company has not adequately supported the projected loss of 401 MMcf of gas deliveries for energy efficiencies expected to be achieved by its customers.

Therefore, I recommend that the Commission increase the revenue and operating income forecasted by the Company for the future test year by $1,864,560.

C. Appliance Service Program Revenue

Q. ARE YOU PROPOSING ANY OTHER ADJUSTMENTS TO THE COMPANY'S PROJECTED REVENUE?

A. Yes. I am proposing an adjustment to the Appliance Service Program's ("ASP" or "HPP") profit margin for the projected test year. The profit margin is the difference between program revenues and related program expenses. In Exhibit A-13, Schedule C3, line 11, the Company forecasted the same revenue of $75.4 million for the projected test year as it billed for 2018.

In response to discovery, the Company provided the actual revenues for the HPP from 2013 to 2019 with related operating expenses. The response shows a steady increase in revenues, with 2019 revenues reaching $82.2 million, or $6.8 million above the 2018 level. Exhibit AG-40 includes the response to data request AGDG-2.100b.

In Exhibit AG-40, I have also calculated the profit margin or operating income between revenues and operating expenses. From this calculation, it is apparent that the year 2018 is not representative of the revenue and profit margin earned in the most recent year of

2019, or for that matter in the prior two years of 2016 and 2017. In other words, using the 2018 revenues, operating expenses and profit margin as a proxy for future test year amounts would result in an accurate and unreasonable forecast amount.

Although using the Company's preferred approach of the most recent actual year amounts for the future test year would result in forecasted revenue of $82.2 million, operating expense of $61.6 million, and profit margin of $20.6 million, I recommend a 3-year average to normalize any variations in expense that could arise in the future test year. The use of a 3-year or 5-year historical average for forecasting revenue and costs has been widely accepted by the Commission in prior rate cases in a variety of situations. In this situation the use of a 3-year average reflects more recent data and the continuing escalation of revenue and expenses, and is slightly more advantageous for the Company than the use of a 5-year average

As shown in Exhibit AG-40, using a 3-year average amount over the 2017 to 2019 period results in forecasted revenue of $77.0 million, an expense amount of $58.6 million, and a profit margin of $18.4 million. In comparison to the profit margin amount of $15.6 million included in the Company rate case filing, my proposed approach increases the profit margin, or operating income, for the future test year by $2.8 million.

Therefore, I recommend that the Commission increase the Company's projected operating income by $2.8 million. Alternatively, if the Commission concludes that the 2019 financial results for the HPP should be used instead of the 3-year average, the amount of adjustment to the operating income is $5.0 million.

Q. WHAT IS YOUR TOTAL ADJUSTMENT TO OPERATING INCOME AS A RESULT OF THE REVENUE ADJUSTMENTS YOU HAVE PROPOSED?

A. Exhibit AG-36 summarizes each of the proposed revenue or margin adjustments. The total increase to operating income and therefore the decrease in revenue requirement is $28,252,093. I recommend that the Commission reflect this reduction to the Company's revenue deficiency.

VII. O&M Expenses Adjustments

Q. WHAT AMOUNT OF O&M EXPENSE DID THE COMPANY INCUR DURING 2018 AND WHAT IS THE LEVEL OF PROJECTED EXPENSE REQUESTED FOR THE 12 MONTHS ENDING SEPTEMBER 2021?

A. As shown in Exhibit A-13, Schedule C5, the Adjusted Historical Test Period expense level in the Company's case for Other O&M is $402.2 million for 2018. The Company's projected expense for future test year ending in September 2021 is $485.3 million, which is an increase of $83.1 million, or 21% over the amount in 2018.

The $83.1 million increase in O&M expense includes $26.1 million of projected inflation adjustments and several other projected cost increases totaling $57.0 million for new or expanded programs. Some of the cost increases are not adequately justified or supported.

In my testimony below I will recommend necessary adjustments. My proposed adjustments are summarized in Exhibit AG-41.

A. Inflation Adjustments - O&M Expense

Q. DO YOU AGREE WITH THE COMPANY'S RECOMMENDATION TO INCLUDE INFLATIONARY INCREASES IN THE PROJECTED O&M EXPENSE?

A. No. Approximately $26.1 million of the Company's requested O&M increase represents inflation increases estimated by the Company based on a blend of the Consumer Price Index (CPI) and a 3% forecasted annual wage increase for union, non-union, and the employees of contractors. The blended annual inflation rate developed by the Company is 2.9%, as shown on Exhibit A-13, Schedule C12. Use of such a "blended rate" has not been approved by the Commission in any past general rate cases.

More importantly, and contradicting some of the Company's testimony in this case, DTE Gas has not experienced across-the-board inflation pressure on its operating costs. In fact, according to Company witness Michael Cooper, actual O&M costs have remained well below the inflation trend line from 2009 to 2018.[13] Company witness R. M. Telang echoes the same accomplishment, noting that "…actual O&M costs have remained well below the inflation trend line at 1% per year from 2008 to 2018."[14] It is therefore difficult to

[13] Michael Cooper revised direct testimony at page 54.
[14] See Discovery Response AGDG-3.191.

understand why the Company would project inflation-related cost increases at an annual rate of 2.9% for 2019, 2020, and the nine months in 2021.

The Company has been very vocal in stating that investments in technology will result in a reduction in O&M costs. The Company has not provided any evidence that its operations are facing inflationary cost pressures that it cannot manage in the course of operating its business. It is more than likely, based on historical data, that the proposed $26.1 million in inflation cost increases will not happen and that the Company can manage its business to avoid such costs.

I am aware that in prior rate cases the Commission has allowed inflation cost increases for O&M expenses. However, the Commission has also rejected blended inflation cost factors that include internal salary increases with CPI factors as proposed by the Company in this case. **As a matter of policy, it is not advisable to allow utilities to escalate costs for forecasted future inflation. It becomes a self-fulfilling prophecy to increase future costs with inflation increases, which then fuel and justify further inflationary trends. The Commission should only grant inflation cost increases when those increases are actually experienced and/or are likely to occur, and not because it has been past practice to do so. In this case, the evidence is clear that projected inflation cost increases are not warranted.**

As such, I have removed the entire $26.1 million of projected inflation increases from the future test year O&M expense. I recommend that the Commission approve the disallowance of this unnecessary forecasted expense.

B. Alternative Inflation Adjustment

Q. IF THE COMMISSION DECIDES TO ALLOW SOME FUTURE INFLATIONARY COST ADJUSTMENT, SHOULD IT ACCEPT THE COMPANY'S PROPOSED INFLATION RATES?

A. No. As noted above, in Exhibit A-13, Schedule C5, the Company recommends the inclusion of $26.1 million for inflation increases. To compute this inflation amount, the Company uses the composite rates it determined in Exhibit A-13, Schedule C12. This exhibit page shows that a 3% inflation rate is estimated for Company labor costs (a 56.1% weighting), and contractor's costs (a 32.6% weighting). For the remainder of its O&M costs (11.3%) the Company has escalated this component by the CPI rates of 2.9% in all periods. The result of these calculations is a set of composite or blended projected rates of inflation of 2.9% for all periods (with 2021 at 2.2% on a pro-rated basis for nine months).

The blended rates are a creation of the Company. The Company controls the rate of wage increases it grants to its employees, including union employees, through collective bargaining agreements and with contractors through contractual arrangements. It truly becomes a self-fulfilling prophecy for the Company to estimate and recover inflationary cost increases of 3% that it can then grant to its employees and contractors. It is important for the Commission to encourage fiscal restraint. Therefore, such internally projected inflationary cost increases should not be granted.

However, if the Commission is predisposed to allow the Company to recover projected inflationary cost increases, I recommend that the recovery amount reflect only the Consumer Price Index for Urban cities (CPI-U) inflation factors. In this regard, if the Commission decides to again use the CPI-Urban index, it should use the most recent information available. The CPI-Urban index inflation rates proposed by the Company are now stale. Exhibit AG-44 includes a copy of the CPI-Urban index inflation rates from IHS Markit for 2019, 2020, and 2021. These rates are 1.8% for 2019 and 2020 and 1.7% for 2021. These rates are generally lower than what the Company has proposed.

In Exhibit AG-42, I have calculated the inflationary cost increases under this approach. The amount of inflation cost adjustment would be approximately $15.8 million, or $10.3 million below the amount proposed by the Company.

The Commission should not grant any inflationary cost increases above the $15.8 million. In fact, given the evidence presented above, the Commission would be justified in removing the entire $26.1 million of projected inflation increases, which is my primary proposal in this case.

C. Pension Expense

Q. DO YOU AGREE WITH THE COMPANY'S SUGGESTED COST INCREASES FOR PENSION EXPENSE OF $4.1 MILLION SHOWN IN EXHIBIT A-13, SCHEDULE C5.9?

A. No. In Case No. U-13898, the Company received approval from the Commission to defer negative pension expense into a regulatory liability account. In recent years, the balance in the account has been declining due to positive pension expense. The Company now believes that the negative balance will be exhausted during the projected test year. However, the Company anticipates that the increase in pension expense is temporary and will likely reverse to negative expense again in future years.

Exhibit A-13, Schedule C5.9, shows that Pensions and Benefits includes pension expense of $2.0 million on line 2 and an item titled "Pension Overlay" of $2.2 million on line 3. After reviewing Mr. Cooper's testimony on page 10, it seems clear that the $2.2 million he characterizes in his exhibits as the "Pension Overlay" is simply an updating of certain assumptions from the original pension expense estimate, such as a 17.5% actual investment return through August 2019 and a far lower pension costs discount rate.

The Company believes that, absent an additional order from the Commission, it will be required to begin recognizing positive pension expense against operating income and in the revenue requirement in this rate case. Therefore, Mr. Cooper's recommendation is that the Company be authorized to defer the expense and recognize a regulatory asset for any pension expense once the balance in the regulatory liability account is fully extinguished.

I agree with Mr. Cooper's recommendation, especially since he believes that recognizing any positive pension expense in this rate case would be a temporary situation. Therefore, assuming the Commission approves the proposed deferred accounting treatment of the pension expense, I have removed the $4.1 million of pension expense that the Company included in O&M expense.

D. Health Care Costs

Q. THE COMPANY HAS FORECASTED THAT ITS ACTIVE EMPLOYEE HEALTH CARE EXPENSES WILL INCREASE FROM $13.6 MILLION IN 2018 TO $19.3 MILLION IN THE FUTURE TEST YEAR. DO YOU AGREE WITH THIS INCREASE?

A. No. Over the last six years, the Company's health care expenses have varied from year to year with some years showing increases and other years showing decreases. Exhibit AG-43 shows these costs from 2014 to 2019 as provided by the Company in response to discovery.[15] The expense ranges were $12.1 million in 2016 to $16.7 million in 2018 after excluding a one-time refund of $3.0 million. More recently, in 2019 health care costs

[15] DTE Gas response to discovery request AGDG-1.43.

fell to $15.6 million, or $1.1 million below the normalized prior year expense. Over the five years, the annual percentage change in health care expense averages 3.34%.

Mr. Cooper discusses health care expenses for active employees beginning on page 17 of his direct testimony. Similar to his approach in past rate cases, he has included a forecast by Aon as an exhibit to his testimony, which claims that medical inflation will range from 5.5% to 6.0% during the 2019 to 2021 period. Similar forecasts in the past have anticipated high inflation projections which have not materialized for the Company. The Company's forecast of $19.3 million for health care costs is highly inflated and not representative of actual cost increases experienced in recent years.

My analysis shows that an expense level of $16.6 million for the future test year is sufficient and supportable. I arrive at this forecasted amount by using the latest actual expenses from 2019 of $15.6 million, to which I have applied the average rate of increase of 3.34% over the five-year period from 2015 to 2019. This calculation is shown in Exhibit AG-43.

I recommend that the Commission approve the $16.6 million in forecasted expense and remove $2.7 million of expense from the Company's forecasted O&M expense.

E. Wellness Expenses

Q. EXHIBIT A-13, SCHEDULE C5.9 SHOWS AN INCREASE IN WELLNESS PROGRAM EXPENSE IN THE AMOUNT OF $0.9 MILLION, WHICH IS

ALMOST DOUBLE THE EXPENSE AMOUNT IN 2018. DO YOU AGREE WITH THIS INCREASE?

A. No. The Company's affiliate, DTE Electric, proposed a similar increase in Wellness Program expense in its pending electric rate case, Case No. U-20561.

I filed testimony in that case in November 2019 recommending that the Commission deny recovery of these additional costs. In my testimony, I pointed out that I had asked the Company through discovery to (a) explain the reasons for the increase in these expenses; (b) provide any studies the Company has conducted regarding why the additional expenditures are justified; and (c) provide a list of other utility companies and the amounts they were spending on wellness programs[16]. The Company was unable to provide any useful information in response to these questions.

On page 20 in his direct testimony in this rate case, Mr. Cooper discusses the expanded wellness program in general terms and points to an increased focus on diabetes, obesity, hypertension and injury prevention. However, this type of education on diabetes prevention, obesity, hypertension and cardiovascular management programs are programs that the health care providers, such as Blue Cross and Blue Shield, provide as part of their health care coverage programs. In other words, what the Company has proposed is largely duplicative of other programs available to employees.

[16] See Discovery responses AGDE-1.25c and d.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON THE INCREASE IN WELLNESS EXPENSES?

A. The Company has not provided sufficient evidence to justify the higher expense for the future test year. Therefore, I recommend that the Commission remove the additional expense of $0.9 million from the Company's proposed O&M expense in this rate case.

F. Supplemental Severance Plan (MCN Pension Make-Whole)

Q. EXHIBIT A-13, SCHEDULE C5.9 SHOWS $0.9 MILLION OF EXPENSE FOR SUPPLEMENTAL SEVERANCE PLAN EXPENSE. DO YOU AGREE WITH THE INCLUSION OF THIS EXPENSE IN THE FORECASTED O&M EXPENSE?

A. No. Company witness Cooper discusses the benefit plan supporting this expense on page 19 of his testimony. While the Company calls this benefit plan a Supplemental Severance Plan, in reality it is a plan that pays benefits to certain employees to make up for the difference in the richer retirement benefits for those employees who previously participated in the former MCN Energy Group pension plan with the benefits in the Company's current DTE pension plan. It should be clear that this benefit plan was put into place as a result of the acquisition of MCN Energy Group by DTE Energy. As such, the cost of this plan should be a DTE Energy corporate expense assigned to the cost of the acquisition and not an expense recoverable in the rates of the Company's utility operations. DTE Energy waited until several years after the acquisition of MCN to address this issue and now wants customers to pay for a corporate acquisition expense.

I recommend that the Commission disallow recovery of this inappropriate expense and remove $877,000 from the Company proposed O&M expense for the future test year.

G. Merchant (Credit/Debit Card) Fees

Q. IN EXHIBIT A-13, SCHEDULE C5.4, THE COMPANY SHOWS THAT CUSTOMER MERCHANT FEES ARE FORECASTED TO INCREASE FROM $5.4 MILLION IN 2018 TO $11.7 MILLION IN THE FUTURE TEST YEAR. DO YOU AGREE WITH THIS PROJECTION?

A. No. Company witness Henry Campbell provides a very brief discussion of merchant fees in his direct testimony and simply states that all merchant fees are incurred by DTE Electric Company and 35% are allocated to DTE Gas. This short reference to an allocation percentage does not provide sufficient insight into the reasonableness of the increase of $6.3 million in the forecasted expense included in the future test year. In effect, the Company has proposed to more than double the 2018 expense from $5.4 million to $11.7 million in about two and half years.

Q. WHAT IS YOUR ASSESSMENT OF THE MERCHANT FEE PROGRAM?

A. In response to discovery, the Company provided additional information which shows that the growth in merchant fees is primarily driven by the use of credit cards by non-residential customers. Credit card fees for non-residential customers are forecasted to increase from $2.4 million in 2018 to $6.8 million in the future test year, which is a 183% increase. Residential customer fees are projected to increase from $3.0 million in 2018 to $4.8

million in the future test year, which is an increase of 65%. Exhibit AG-45 includes the Company response to discovery request AGDG-1.13 showing this information.

The popularity of the payment by credit/debit card program has grown as the Company has promoted this cost-free option to its customers. The number of credit card fee transactions for residential customers was 761,937 per month in 2018 and increased to 847,715 in 2019. The number of transactions for non-residential customers was 83,188 on average per month in 2018, and has increased from 41,648 per month in 2015 to 105,109 transaction per month in 2019.[17]

The Company clearly needs to take some action to curtail the use of credit and debit cards and limit the escalating cost of this no-fee program. In Case No. U-20561, DTE Electric proposed to limit the use of debit/credit card payments by non-residential customers to only those customers whose annual bill is less than $75,000. In this rate case, DTE Gas did not make a similar proposal. In response to discovery, the Company stated that if a similar proposal was adopted for DTE Gas, merchant fees would decrease by $3.2 million on an annual basis beginning on January 1, 2021. The amount for the first nine months of 2021 would be $2.4 million as a reduction applicable to the future test year. Exhibit AG-45 includes the Company's response to discovery request AGDG-1.17a with this information.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

[17] DTE Gas response to discovery request AGDG-3.197b.

A. Although the proposal to limit the use of credit cards for non-residential customers with an annual bill of $75,000 or less would be a small improvement in comparison to the current wide-open credit card program, it does not go far enough to significantly reduce O&M expense.

The premise of the credit/card payment program is to increase convenience for residential customers who prefer to pay bills through a credit card or in the case of a customer who may be in arrears in bill payments to avoid a potential shut-off of service. This need for convenience does not exist to the same extent for non-residential or commercial customers who incur much larger gas bills in the course of operating their business. The higher the amount of the gas or electric bill that is paid through a credit card, the higher the fee that DTE Gas and DTE Electric must pay to the credit card company. The current trend of escalating credit and debit card fees is unsustainable.

Therefore, I recommend that the Commission remove all merchant fees pertaining to non-residential customers from the future test year in the amount of $6,844,000 and direct the Company to limit the use of no-fee credit/debit card payment to only residential customers.

Although I am not proposing a disallowance of merchant fees for the future test year pertaining to residential customers, the 65% escalation in fees from $3.0 million in 2018 to $4.8 million in the future test year is troubling and that rate of increase needs to tempered in future years. The Commission should also direct the Company to avoid promoting the use of credit or debit cards to residential customers to minimize further escalations in the cost of this program.

H. Uncollectible Accounts Expense

Q. WHAT ADJUSTMENTS TO UNCOLLECTIBLE ACCOUNTS EXPENSE FOR THE PROJECTED TEST YEAR DO YOU RECOMMEND?

A. I recommend an adjustment to reduce projected test year uncollectible account expense by $1.2 million. In response to discovery request AGDG-1.141c, the Company provided an analysis showing that uncollectible costs were avoided in 2016 when customers with bills in arrears used credit cards to pay their outstanding bill. The amount of the avoided cost was $2.3 million in 2019. Exhibit AG-46 includes the response to discovery request AGDG-1.141c.

During 2019, the Company's merchant fees expense for residential customers totaled $3.6 million. The merchant fees for residential customers are expected to increase from $3.0 million in 2018 to $4.8 million in the future test year. It is logical to assume that as more customers use credit cards to pay their gas bill, additional uncollectible costs will be avoided. In Exhibit AG-47, I have calculated the forecasted uncollectible accounts cost savings of $1,181,000 for the future test year based on the expected increase in credit card use by residential customers and the related increase in merchant fees.

I took a similar proposal in the DTE Electric rate case U-20561, and although the Commission has not yet issued an order in that rate case, my proposal was accepted by the Administrative Law Judge in the Proposal for Decision issued on March 5, 2020.

Therefore, I recommend that the Commission reduce the Uncollectible Accounts Expense proposed by the Company in this rate case by approximately $1.2 million.

I. Demand Response Pilot Program

Q. PLEASE DISCUSS THE COMPANY'S PROPOSAL TO BEGIN A DEMAND RESPONSE PROGRAM.

A. Beginning on page 25 of his direct testimony, Company witness Rajan Telang discusses briefly the Company's plan to initiate a Demand Response pilot program to potentially reduce peak day gas demand particularly in case of gas supply restrictions and emergencies. Initiation of such a pilot program was ordered by the Commission in its September 11, 2019 order in Case No. U-20464. Item B of that order states that "The Commission Staff shall work with the utilities to propose natural gas response tariffs in the utilities' next round of natural gas rate cases filed after the date of this order."

Q. WHAT IS YOUR ASSESSMENT OF THE $4.0 MILLION DEMAND RESPONSE PILOT PROGRAM EXPENSE WHICH THE COMPANY SEEKS TO RECOVER IN THIS RATE CASE?

A. Although DTE Gas has included $4.0 million in O&M expense in the projected test year to develop a pilot program, according to Mr. Telang's testimony, the program has not yet been defined. Without more information on the details of the program, its features, the number of participants and how it will be structured, it is not possible to make a proper assessment of the reasonableness of the requested expense amount of $4.0 million.

Given that the development of the program is in response to the Commission's order in case No. U-20464, the best course of action is for the Company to defer any costs in a regulatory asset up to the $4.0 million and request recovery in rates in a future rate case. This appears to be an alternative rate treatment that the Company is expecting. On page 47 of her direct testimony, Company witness Theresa Uzenski has requested authorization to record the costs of the pilot program in account 182.3, Other Regulatory Debits, to defer the costs for determination in a future rate case.

I recommend that the Commission approve the deferred accounting treatment of the Demand Response program up to the $4.0 million amount, and concurrently remove this amount from the Company's proposed O&M expense for the future test year.

J. Damage Prevention Costs

Q. PLEASE DISCUSS THE COMPANY'S PROPOSAL TO EXPAND THE DAMAGE PREVENTION GROUP.

A. On pages 25 and 26 of his direct testimony, witness Mark Johnson discusses the Company's plans to expand its damage prevention team (field liaison personnel and analytical staff) in 2019 to provide more direct education, support and oversight to excavators. According to witness Johnson, the goal is to improve community safety by reducing damage to gas facilities.

In 2019, the Company has also implemented a MISS DIG ticket predictive analytic risk ranking software program to enable field personnel to focus on high risk tickets. Mr. Johnson's Exhibit A-20, Schedule J3 shows that damages per thousand tickets has averaged around 5 incidents per 1,000 MISS DIG requests in the 3-year period from 2016 to 2018, and the 2019 data reported was not yet complete for the full year. The 5 incidents per 1,000 requests translated to an incident rate of 0.5%, or half of one percent.

Mr. Johnson proposed to add 3 new employees to the team and increase annual expense by $1.5 million. Approximately $1.0 million of the increase pertains to labor costs and the remainder for non-labor expenses.[18]

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S REQUEST?

A. In discovery the Company was asked to explain why an expansion of the education program for excavators is necessary. In its response, the Company stated that "Yearly, approximately 70% of all damages on DTE Gas facilities can be attributed to excavators…knowledge gaps [about]…proper soft excavation techniques [and]…required use of the MISS DIG system…."

[18] DTE response to discovery request AGDG-2.136b and c.

Although these may be all valid reasons, it is not clear what additional steps or activities the Company plans to take with three more employees that will significantly prevent future incidents. The Company currently participates in the MISS DIG 811 Board and has relationships with most contractors in the service area who request line markings through MISS DIG. The Company also conducts a large radio advertising campaign to warn homeowners and excavators about the need to call MISS DIG before digging. Gas bill inserts and other communication to customers and other constituencies frequently warn about digging without first calling MISS DIG.

In other words, there is insufficient evidence presented by the Company about additional substantial activities that will be undertaken to justify the increase in expense of $1.5 million and the incremental financial and non-financial benefits.

If there are benefits from significant reductions in damage incidents, the cost savings from those prevented incidents should more than offset the incremental cost of hiring three new employees and other related expenses. For example, it stands to reason that success in this program could lead perhaps to lower injuries and damages expense, and fewer repair costs to gas facilities.

My conclusion is that there is insufficient evidence to justify the $1.5 million in increased expense. However, if cost savings arise from the expanded damage prevention program, those cost savings should in effect “self-fund” the higher expense of hiring three new employees and other related expenses. Therefore, I recommend that the Commission remove the $1.5 million of increased expense from the projected test year O&M.

K. Incentive Compensation Expense

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE COMPANY'S INCENTIVE PAY PLANS AND THE AMOUNT OF EXPENSE THE COMPANY SEEKS TO RECOVER IN THIS RATE CASE.

A. In this rate case, the Company seeks to recover $13.7 million of employee incentive payments which have been included in the future test year. Based upon the information provided on page 50 of the direct testimony of Company witness Michael Cooper, $2.5 million pertains to the Annual Incentive Plan (AIP), $6.8 million pertains to the Rewarding Employees Plan (REP), and $4.3 million pertains to the Long-Term Incentive Plan (LTIP). I will also point out that 67% of the $13.7 million requested is to recover costs related to the DTE Corporate Services LLC employees (the LLC employees) whose performance metrics are often related to the performance of DTE Energy (not just DTE Gas).

2019 Annual Incentive Plan – the AIP is an annual bonus program focused on the following major categories and specific measures:

1. 40% on Financial Performance: For DTE Gas employees the metrics are DTE Gas Operating Earnings, DTE Gas Adjusted Cash Flow, and DTE Energy Earnings per Share. For the LLC employees in this plan, the financial metrics are 100% dependent upon DTE Energy EPS and DTE Energy Cash Flow.

2. 20% on Customer Satisfaction (Customer Satisfaction Index, Improvement in Customer Satisfaction, and MPSC Customer Complaints).

3. 20% on Employee Engagement (Employee Engagement Gallup rating, OSHA Incident Rate, and OSHA Dart Rate).

4. 20% on Operating Excellence (Gas Distribution system improvement, Gas Distribution response time, Lost and Unaccounted for gas, Gas compression reliability, and Meter Assembly Checks Backlog).

It should be noted that the LLC employee metrics for Customer Satisfaction and Employee Engagement are dependent on all of DTE Energy performance (not that of just DTE Gas).

These measures are for the year 2019. A review of the measures in place for the prior five years reveals that certain measures and target levels have varied from year to year. These changes make a direct comparison over the years more challenging.

2019 Rewarding Employees Plan – The REP is very similar in design and function to the AIP with some variations in the non-financial measures. Where the AIP is designed for senior level managers at DTE Gas and its affiliates, the REP covers all other non-union employees of these companies.

The REP is also applicable to the LLC employees providing support services to DTE Gas.

2019 Long Term Incentive Plan – The LTIP is an annual stock grant plan focused on achieving three-year goals and specifically on the following measures:

1. 60% on Common Stock Total Shareholder Return vs. a Peer Group.

2. 20% Balance Sheet Ratio of Funds from Operations to Debt.
3. 20% DTE Gas Average Return on Equity.

The weight of the measures varies depending on whether the employee works for DTE Gas or the LLC corporate services group.

The testimony of Company witness Michael Cooper provides more details on the AIP, REP, and LTIP.

Q. WHAT IS YOUR ASSESSMENT OF EACH OF THESE INCENTIVE PAY PLANS?

A. My overall assessment is that the three incentive plans are too heavily skewed toward measures that directly benefit shareholders and not customers. Additionally, the customer benefits presented by the Company are based on a faulty premise of historical cost savings and an expectation that future targets of performance will be achieved.

With regard to the AIP and REP, nearly half of the incentive payout at target level relates to the Company and its parent, DTE Energy, achieving net income, earnings per share and cash flow goals. Despite the argument by the Company that achieving these goals somehow benefits customers, there is no direct relationship to customer benefits. These goals are in place to maximize profits and increase cash flow to pay dividends to shareholders. It is even more inappropriate to charge customers for incentive pay costs related to achieving DTE Energy earnings per share since those earnings include earnings from the electric and non-utility businesses of DTE Energy. The Commission should not allow recovery of incentive payments related to these financial goals.

As to the Customer Satisfaction grouping of measures, this category in 2019 represents 20% of the total measures. However, as shown in Exhibit A-19, Schedule I9, the benefits achieved are far less than the costs as measured by the Company.

With regard to the Employee Engagement category, the measures contained therein, although worthy goals, do not rise to the level of being measures that are visible to customers nor do they create direct customer benefits. They are primarily internal goals related to employee satisfaction and deployment of safe practices in the workplace.

As to the Operating Excellence category, the measures contained therein are basic operating goals. Again, these are worthy internal goals to measure performance of the departments responsible for those operations, but they have no direct visibility to customers. The only measure that has a visible link to customers is the Gas Distribution Response Time metric which represent a small portion of the expected payout.

Q. **WHAT IS YOUR ASSESSMENT OF THE LTIP?**

A. The LTIP is a plan strictly designed to induce management to create shareholder value. It is weighted heavily (60%) on total shareholder return for DTE Gas employees and 80% in the case of the LLC employees, which is stock price appreciation and dividends paid over a period of time. The Company's total return is then measured against a group of peer companies to trigger a payout. This has nothing to do with creating direct benefits for DTE Electric customers and everything to do with creating value for DTE Energy shareholders. Similarly, the other two measures, the Debt coverage ratio and DTE Electric return on equity, are also very removed from any quantifiable benefits that directly accrue to customers. To some degree these last two items are actually duplicative of the Net Income and Cash Flow measures included in the AIP and REP plans.

The arguments put forth by Mr. Cooper in his testimony that some of these measures will create a healthier company and therefore customers should pay for LTIP expenses are not convincing.

Q. **WHAT IS YOUR OPINION OF THE CUSTOMER BENEFITS CALCULATED BY MR. COOPER TO JUSTIFY RECOVERY OF THE INCENTIVE PAYMENTS?**

A. In Exhibit A-19, Schedule I7, Mr. Cooper has shown a calculation which purports to show that the expected operating and financial cost savings in 2019 of $15 million will exceed the incentive plan payments by $1.3 million.

The table below reflects a summarization of Mr. Cooper's calculated benefits and the costs shown on Exhibit A-19, Schedule I7.

Millions of Dollars	**Benefits**	**Incent. Comp. Payouts**	**Difference**
Financial Performance	$ 7.1	$ 8.1	$(1.0)
Customer Satisfaction	0.2	1.9	(1.7)
Employee Engagement	1.4	1.5	(0.1)
Operating Excellence	6.2	2.2	4.0
Total	**$15.0**	**$13.7**	**$1.3**

Although the Operating Excellence cost savings appear to exceed the allocation of incentive expense allocated to these measures, nearly all the cost savings pertain to Lost and Accounted For gas costs which are mainly outside the control of the Company.

On pages 53 and 54 of his direct testimony, Mr. Cooper discusses the incentive metrics measuring Financial Performance. His discussion on the Company controlling the increase in O&M costs from 2008 to 2018 below the rate of inflation is inconsistent with the proposed increase in O&M costs in this rate case and the request to recover inflationary cost increases of $26 million.

The Company's claim that it has realized cost savings by preventing higher interest rates by managing its credit ratings is unconvincing. It is management's basic task to manage the finances of the Company so as to maintain healthy credit ratings, without needing an incentive to do so.

Mr. Cooper's calculated benefits for Customer Satisfaction and Employee Engagement have been determined by considering avoided costs related to customer complaints and lower absenteeism and higher productivity of employees as well as fewer safety incidents. Unfortunately, the Company has generally fallen short of its performance targets in these areas.

Q. WHAT ASSUMPTION ABOUT PERFORMANCE LEVELS HAS THE COMPANY MADE TO JUSTIFY THE INCLUSION OF INCENTIVE COMPENSATION EXPENSE IN O&M FOR THE FUTURE TEST YEAR?

The proposed incentive compensation payouts assume that the Company will achieve 100% target performance in all of the 16 individual measures listed in Exhibit A-19, Schedule I7. Company Exhibit A-19, Schedule I1 shows the 2016 to 2018 results for DTE Gas for the non-financial measures and as can be seen, the Company has fallen short of the targets approximately 50% of the time. For example, in 2018 DTE Gas achieved only five of the 12 non-financial performance measures at 100% of the target level or higher. Moreover, five of these measures were at "less than threshold," which is the minimum level required to cause a payout for these specific measures.

For example, in response to discovery request AGDG-1.52 Supplemental, the Company provided its AIP and REP results for 2019. The information shows that the Company was below the Threshold Level on one of its Customer Satisfaction Improvement metrics, as well as its OSHA Dart Rate and LAUF metrics. Also, the Company was between the

Threshold and Target levels on five metrics, including the two Customer Satisfaction metrics, the MPSC complaint metric, the OSHA reportable incidents rate metric, and the Gas Response Time metric. In summary, the Company achieved the target level with respect to six out of fourteen operational metrics, which is a 43% success rate. Exhibit AG-48 includes the Company's response to AGDG-1.52 Supplemental.

Mr. Cooper's testimony and the historical track record provide no assurance that all operating performance measures can be achieved at 100% of target level in the future with any consistency, as he has assumed in calculating the incentive compensation expense that the Company seeks to recover in this rate case.

Q. **WHAT IS YOUR RECOMMENDATION WITH REGARD TO INCENTIVE PAYMENTS BEING RECOVERED IN CUSTOMER RATES?**

A. On page 50 of his direct testimony, Mr. Cooper has included a table showing the components of the incentive compensation expense that the Company has included in the O&M expense for the projected test year. For the reasons described above, I recommend that the Commission remove the entire $8.1 million related to financial performance measures.

With regard to the portion of incentive compensation relating to operating measures, my initial instinct is to also disallow this portion in its entirety, as I have recommended in prior cases due to the fact that the Company has not made a sufficiently compelling case to justify recovery of these costs. However, I am cognizant of the fact that the Commission recently has allowed recovery of a portion of the short-term incentive pay related to operating performance measures with regard to DTE Electric and Consumers Energy. In that vein, I recommend that the Commission allow recovery of only 50/% of the incentive compensation expense that the Company has identified pertaining to operating performance measures.

In the table on page 50 of Mr. Cooper's testimony, the Company shows $5.6 million of incentive compensation related to operating performance measures. However, as stated earlier, this amount assumes that 100% of the operating measures will be achieved at the 100% target level. I recommend that the Commission allow recovery of only 50% of the $5.6 million, or $2.8 million.

Therefore, the Commission should deny recovery of the remaining of the $10.9 million in incentive compensation expense proposed by the Company.

Q. IS THERE A PORTION OF INCENTIVE COMPENSATION THAT THE COMPANY INCLUDES IN CAPITAL ADDITIONS AND RATE BASE, WHICH IS NOT INCLUDED IN THE CHART ON PAGE 50 OF MR. COOPER'S DIRECT TESTIMONY?

A. Yes. The chart on page 50 of Mr. Cooper's direct testimony only includes the projected incentive compensation pertaining to O&M expense for the projected test year. In addition, each year the Company allocates and capitalizes a portion of both short-term and long-term incentive compensation, which is included in rate base. In response to discovery, the Company provided information on the amount of incentive compensation capitalized for 2018 through the end of future test year. Pages 2 to 5 of Exhibit AG-19 include the information provided in response to discovery.

The amounts capitalized pertaining to 2018 through the end of the projected test year are $17.1 million in total, with $12.1 million pertaining to short-term compensation and $5.0 million to long-term compensation. I have adjusted these amounts to reflect the Commission's prior decisions to allow recovery of only incentive compensation pertaining to operating performance measures for the short-term incentive plans and no recovery for long-term incentive compensation.

Page 1 of Exhibit AG-19 includes a schedule showing this adjustment, which results in total disallowance of approximately $12.1 million. Of this amount, $5.0 million pertains to short-term incentive compensation related to financial measures and $6.1 million is for long-term incentive compensation, all of which relates to financial measures. I recommend that the Commission remove these amounts from projected rate base.[19]

In addition, I recommend that the Commission direct the Company to identify in future rate cases the amount of capitalized incentive compensation included in projected rate base for the projected periods in the same detail as provided in the chart on page 50 of Mr. Cooper's revised direct testimony. Furthermore, the Company should affirm in filed testimony that it has removed from historical rate base all incentive compensation

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[19] See also Exhibit AG-20, lines 16 and 17.

previously disallowed by the Commission. This information will facilitate the analysis of allowable incentive compensation included in rates and will ensure its accuracy.

L. IT Project Costs in Capital Usage Charge

Q. PLEASE DISCUSS THE INCLUSION OF IT PROJECT COSTS IN THE CAPITAL USAGE CHARGE BILLED BY DTE ELECTRIC TO DTE GAS.

A. On page 45 of her direct testimony, Ms. Uzenski discusses the increase in the Capital Usage Charge included in Exhibit A-13, Schedule C5.6, line 15. Within DTE Energy, DTE Electric is usually responsible to capitalize the cost of IT projects that common to both DTE Electric and DTE Gas. In turn DTE Electric bills DTE Gas for its applicable share of the depreciation expense and return on the IT investments (return on and of the investment) as Capital Usage Charge, which DTE Gas records as O&M expense.

In discovery, I requested that the Company provide the amount billed to DTE Gas with regard to 7 projects which I recommended in DTE Electric rate Case No. U-20561 should be disallowed. The 7 projects are: Applied Innovation, Digital Innovation, Success Factors Program, Web Portal Rebuild, Bill Redesign, Pay to Purchase, and the Fixed Bill project.

In its response, the Company identified the amount billed or to be billed pertaining to each project. The total amount for the 7 projects is $1,835,000.[20] I propose that this amount be removed from the Company's proposed O&M expense for the future test year for the same

[20] See Exhibit AG-49 which includes DR AGDG-3.206.

reasons I described in my direct testimony in Case No. U-20561. In Exhibit AG-50 to this rate case, I have included a copy of the pertinent testimony I filed in Case U-20561 on this matter and the related exhibits.

Although the Commission has not yet issued an order in Case No. U-20561, the Administrative Law Judge in her Proposal for Decision has recommended the full disallowance of the capital expenditures proposed by DTE Electric pertinent to those 7 projects. Therefore, I recommend that the Commission remove the amount of $1,835,000 from the forecasted O&M expense in this rate case.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR O&M EXPENSES.

A. Operations and maintenance expenses represent a large part of the Company's cost structure. My analysis of the expense level proposed by the Company has determined that expenses in certain areas are excessive or unnecessary and should be removed. I recommend total reductions to O&M expenses of $60.9 million as discussed above and summarized in the following table. Exhibit AG-41 provides additional details of the areas where I have proposed O&M expense adjustments.

Summary of O&M Expense Reductions	Amount ($Millions)
Inflation Expense Adjustment	$ 26.1
Pension, Health Case and Other Benefits	8.6
Demand Response Expense	4.0
Credit/Debit Card Fees	6.8
Uncollectible Accounts Expense	1.2
Employee Incentive Compensation	10.9
Other Expenses	3.3
Total Reduction	**$ 60.9**

VII. Depreciation Expense

Q. **DO YOU PROPOSE AN ADJUSTMENT TO DEPRECIATION EXPENSE FOR THE PROJECTED TEST YEAR?**

A. Yes. As a result of the reductions in capital expenditures proposed above in my testimony and the impact on capital additions included in rate base, I have calculated a reduction in depreciation expense of $4,505,000. The calculation of this amount is shown in Exhibit AG-20 and is based on the same depreciation rates used by the Company on page 2 of Exhibit A-13, Schedule C6.

I recommend that the Commission reduce the depreciation expense proposed by the Company for the projected test year by $4,505,000.

IX. Adjustments To Revenue Deficiency

Q. WHAT ARE THE TOTAL ADJUSTMENTS AND THE REVISED REVENUE DEFICIENCY YOU RECOMMEND?

A. Exhibit AG-51 summarizes the adjustments to rate base and operating income. The net result is a revised revenue deficiency of $65.5 million, which is a reduction of $138.3 million from the Company's requested level of $203.8 million.

I recommend the Commission adopt these adjustments and issue an order granting rate relief to the Company in an amount not exceeding $65.5 million.

X. Rate Design

Q. WHAT INCREASE IN THE MONTHLY SERVICE CHARGE FOR RESIDENTIAL CUSTOMERS HAS THE COMPANY PROPOSED?

A. In his direct testimony, Company witness Habeeb Maroun proposes to increase the monthly service charge for residential customers (Rate Schedules A and 2A) from $11.25 to $13.90 per month. Mr. Maroun also proposes to increase the monthly customer service charge for small commercial customers in rate schedule GS-1 from $31.00 to $40.00.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The proposed change from $11.25 to $13.90 per month represents an increase of nearly 24%. Such a large increase could cause rate shock to customers in smaller households who use less gas than the average customer. They would see their monthly gas bill increase drastically without using any more gas.

Fixed monthly charges also discourage energy conservation. It is best to increase the volumetric rate paid by customers because the higher cost encourages conservation. The customer can take steps to reduce usage and thus lower the gas bill. The customer cannot reduce fixed monthly charges.

Similarly, small commercial customers who take service under rate GS-1 would see an increase of 29% in their monthly charge. This is also a significant increase for smaller commercial customers.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission maintain the current rate of $11.25. The Company's proposed monthly charge of $13.90 would result in an annual charge of $167, which would represent a large portion of the total annual gas bill for small households. However, if the Commission sees some merit in increasing the monthly service charge, in the interest of rate gradualism, I recommend that the Commission not increase the monthly charge by more than $1 to $12.25.

Similarly, for the GS-1 rate, the Commission should limit the increase to no more than $1 and preferably keep it at the current level of $31.00.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does. However, I reserve the right to amend, revise and supplement my testimony to incorporate new information that may become available.

Experience and Qualifications of Sebastian Coppola

Mr. Sebastian Coppola is an independent energy business consultant and president of Corporate Analytics, Inc., whose place of business is located at 5928 Southgate Rd., Rochester, Michigan 48306.

EMPLOYMENT BACKGROUND

Mr. Coppola has been an independent consultant for nearly 20 years. Before that, he spent three years as Senior Vice President and Chief Financial Officer of SEMCO Energy, Inc. with responsibility for all financial operations, corporate development and strategic planning for the company's Michigan and Alaska regulated and non-regulated operations. During the period at SEMCO Energy, he had also responsibility for certain storage and pipeline operations as President and COO of SEMCO Energy Ventures, Inc. Prior to SEMCO, Mr. Coppola was Senior Vice President of Finance for MCN Energy Group, Inc., the parent company of Michigan Consolidated Gas Company (now DTE Gas Company).

ENERGY INDUSTRY EXPERIENCE

During his 27-year career at SEMCO Energy, MCN Energy and MichCon, he held various analytical, accounting, managerial and executive positions, including Manager of Gas Accounting with responsibility for maintaining the accounting records and preparing financial reports for gas purchases and gas production. In this role, he had also responsibility for preparing Gas Cost Recovery (GCR) reconciliation analysis and reports, and supporting preparation of testimony for the cost of gas reconciliation proceedings before the MPSC. Over the years, Mr. Coppola also held the positions of Treasurer, Director of Investor Relations,

Experience and Qualifications
of Sebastian Coppola

Director of Accounting Services, Manager of Corporate Finance, Manager of Customer Billing and Manager of Materials Inventory and Warehousing Accounting. In many of these positions he interacted with various operating areas of the company and was intricately involved in construction and operating programs, defining gas purchasing strategies, rate case analysis, cost of capital studies and other regulatory proceedings.

Mr. Coppola is intricately knowledgeable of capital markets and financial institutions. As Treasurer and Vice President of Finance, he has directed the issuance of more than $2 billion in securities, including common stock, corporate bonds, tax-deductible preferred stock and high-equity value convertible securities. He has established bank lines of credit, commercial paper and asset acquisition facilities. He has had extensive interactions with equity and debt investors, financial analysts, rating agencies and other members of the financial community.

ENERGY INDUSTRY REGULATORY EXPERIENCE

As a business consultant, Mr. Coppola specializes in financial and strategic business issues in the fields of energy and utility regulation. He has more than forty years of experience in public utility and related energy work, both as a consultant and utility company executive. He has testified in several regulatory proceedings before State Public Service Commissions. He has prepared and/or filed testimony in electric and gas general rate case proceedings, power supply and gas cost recovery mechanisms, revenue and cost tracking mechanisms/riders, multi-year rate plans and incentive ratemaking, and other regulatory matters.

Experience and Qualifications
of Sebastian Coppola

As accounting manager and later financial executive for two regulated gas utilities with operations in Michigan and Alaska, he has been intricately involved in operating and construction programs, gas cost recovery and reconciliation cases, gas purchase strategies and rate case filings.

Mr. Coppola has extensive experience with gas utilities in the areas of gas operations, gas supply and regulatory proceedings. He has led or participated in the financial operations, gas supply planning and/or gas cost recovery arrangements of two major gas utilities in Michigan and in Alaska. He has prepared testimony in multiple electric and gas general rate cases, Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) reconciliation proceedings, Cast Iron and Pipeline Replacement Programs and other regulatory cases on behalf of the Michigan Attorney General, Citizens Against Rate Excess (CARE), the Public Counsel Division of the Washington Attorney General, the Illinois Attorney General and the Ohio Office of Consumers Counsel in electric and gas utility rate cases, including AEP Ohio, Ameren-Illinois Utilities, Avista, Consumers Energy, Detroit Edison, MichCon (DTE Gas), Michigan Gas Utilities Corp, PacifiCorp, Peoples Gas, Puget Sound Energy, SEMCO, Upper Peninsula Power Company, Washington Gas, and Wisconsin Public Service Company.

As accounting manager and later financial executive for two regulated gas utilities, he has been intricately involved in construction materials procurement, gas purchase strategies and CGR reconciliation cases. He has had direct responsibility for preparing GCR reconciliation analysis and reports, and supporting preparation of testimony for the cost of gas reconciliation proceedings before the Michigan Public Service Commission (MPSC). He is intricately familiar

Experience and Qualifications of Sebastian Coppola

with construction projects, the power supply and gas cost recovery mechanisms, gas supply and pricing issues, and regulatory issues faced by utilities.

As manager of customer billing, Mr. Coppola developed intricate knowledge of customer billing and meter reading operations. As manager of materials inventory and warehousing accounting, he also developed intricate knowledge of pipeline and materials procurement, warehousing and construction operations including safety compliance issues. Mr. Coppola has testified extensively on gas utility pipeline, service lines and inside meters replacement programs related to at-risk pipes that provide safety issues to customers and the general public.

In his role as Treasurer and Chairman of the MCN/MichCon Risk Committee from 1996 through 1998, Mr. Coppola was involved in reviewing and deciding on the appropriate gas purchase price hedging strategies, including the use of gas future contracts, over the counter swaps, fixed price purchases and index price purchases.

In March 2001, Mr. Coppola testified before the Michigan House Energy and Technology Subcommittee on Natural Gas Fixed Pricing Mechanisms. Mr. Coppola frequently participates in natural gas issue forums sponsored by the American Gas Association and stays current on various energy supply issues through review of industry analyst reports and other publications issued by various trade groups.

Experience and Qualifications
of Sebastian Coppola

- **Specific Regulatory Proceedings And Related Experience:**
  - Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
  - Filed testimony on behalf of the Michigan Attorney General in Consumer Energy Company (CECo) 2018-2019 GCR reconciliation case U-20209.
  - Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2018-2019 GCR reconciliation case U-20215.
  - Provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking.
  - Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2018 PSCR Reconciliation in case U-20203.
  - Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Reconciliation in case U-20202.
  - Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
  - Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 electric rate Case U-20561 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
  - Filed testimony on behalf of the Michigan Attorney General in Indiana Michigan Power Company (I&M) 2019 electric rate Case U-20239 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
  - Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019 gas rate Case U-20479 on several issues, including

Experience and Qualifications
of Sebastian Coppola

sales, operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.

- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019-2020 GCR Plan case U-20245.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019-2020 GCR Plan case U-20233.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Plan case U-20221.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2019-2020 GCR Plan case U-20235.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2019-2020 GCR plan case U-20239.
- Filed rebuttal testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017-2018 GCR reconciliation case U-20076.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017-2018 GCR reconciliation case U-20075.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 gas rate Case U-20322 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in I&M Tax Credit C Calculation in case U-20317.
- Filed direct testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Tax Credit C Calculation in case U-20298.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2017-2018 GCR Reconciliation case U-20078.
- Filed testimony on behalf of the Michigan Attorney General in CECo Tax Credit C Calculation for the Gas and Electric Divisions in case U-20309.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2018 electric rate Case U-20276 on several issues, including excess deferred taxes, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 PSCR Reconciliation in case U-20068.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric (DTEE) 2018 rate Case U-20162 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund for the Electric Division in case U-20286.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Integrated Resource Plan in case U-20165.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund case U-20287 for the natural gas business.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit B refund case U-20189.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 electric rate Case U-20134 on several issues, including capital expenditures, cost of capital, rate design and other items.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 16-0197.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR reconciliation case U-17941-R.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2018-2019 GCR Plan case U-18417.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit A refund case U-20102.
- Filed testimony on behalf of the Michigan Attorney General in I&M 2018 PSCR Plan case U-18404.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR Plan case U-18412.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company (UPPCO) 2018 Tax Credit A refund case U-20111.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit A refund case U-20106.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Plan case U-18403.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Plan case U-18402.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017 gas rate Case U-18999 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 gas rate Case U-18424 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR reconciliation case U-17918-R.
- Assisted the Michigan Attorney General in the review of several GCR and PSCR cases during 2017 and 2018, and proposed terms for settlement of those cases.
- Assisted the Michigan Attorney General in the filing of comments with the Michigan Public Service Commission relating to rate case

Experience and Qualifications
of Sebastian Coppola

filing requirements in case U-18238, refunds of tax savings from the lower federal tax rate in case U-18494 and Performance Based Regulation.

- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 15-0209.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 electric Rate Case U-18255 on a several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 electric rate Case U-18322 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital and other items.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the re-opening of proceedings in the restructuring of the Peoples Gas's main replacement program and gas system modernization plan in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Michigan Energy Resources Corporation (UMERC) application for a certificate of public necessity and convenience to build two power plants in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO application for a certificate of public necessity and convenience to build a pipeline in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Public Counsel Division of the Washington Attorney General in Puget Sound Energy's 2016 Complaint for Violation of Gas Safety Rules in Docket No. UE-160924.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 PSCR Plan case U-18143.

Experience and Qualifications
of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 Power Supply Cost Recovery (PSCR) reconciliation case U-17678-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 gas general rate case U-18124 on a several issues, including revenue, operations and maintenance costs, capital expenditures, working capital, cost of capital and other items.
- Filed testimony on behalf of the Illinois Attorney General for the restructuring of the Peoples Gas's main replacement program in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2014-2015 GCR Plan reconciliation case U-17332-R.
- Filed testimony on behalf of the Michigan Attorney General in the formation of UMERC and the transfer of Michigan assets of Wisconsin Public Service Corporation and Wisconsin Electric Company to UMERC in Case U-18061.
- Filed testimony on behalf of the Michigan Attorney General in CECo Court of Appeals Remand Case U-17087 for review of the Automated Meter Infrastructure (AMI) opt-out fees.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 electric Rate Case U-17990 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2016-2017 GCR Plan case U-17940.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 electric Rate Case U-18014 on a several issues, including revenue, revenue decoupling, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2016-2017 GCR Plan case U-17942.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR Plan case U-17941.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015 gas general rate case U-17999 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, Revenue Decoupling Mechanism (RDM) program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016-2017 GCR Plan case U-17943.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR Plan case U-17918.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan reconciliation case U-17334-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 PSCR Plan case U-17920.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan reconciliation case U-17333-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 gas general rate case U-17882 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, infrastructure cost recovery mechanism, cost of capital and other items..
- Filed testimony on behalf of the Michigan Attorney General in CECo Gas Choice and End-User Transportation tariff changes case U-17900.
- Analyzed the gas rate case filings of MGUC in Case U-17880 and assisted the Michigan Attorney General in settlement of the case.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR reconciliation case U-17317-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2013-2014 GCR Plan reconciliation case U-17131-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2014 electric Rate Case U-17767 on a several issues, including operations and maintenance costs, capital expenditures, AMI program, cost of capital and other items.

Experience and Qualifications
of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015-2016 GCR Plan case U-17691.
- Filed testimony on behalf of the Illinois Attorney General in Ameren Illinois Company's 2015 general rate case on operation and maintenance costs in Docket 15-0142.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 electric Rate Case U-17735 on a several issues, including sales, operations and maintenance costs, capital expenditures, cost of capital, AMI program, revenue decoupling and infrastructure cost recovery mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015-2016 GCR Plan case U-17693.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2015-2016 GCR Plan case U-17690.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 PSCR Plan case U-17678.
- Analyzed the electric rate case filings of Northern States Power in Case U-17710 and Wisconsin Public Service Company U-17669, and assisted the Michigan Attorney General in settlement of these cases.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2013-2014 GCR Plan reconciliation case U-17133-R.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan reconciliation cases U-17130-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan reconciliation case U-17132-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 gas general rate case U-17643 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, cost of capital and other items..
- Filed testimony on behalf of the Illinois Attorney General in Wisconsin Energy merger with Integrys on the Peoples Gas and Coke Company's Accelerated Main Replacement Program Docket 14-0496.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of Citizens Against Rate Excess in Wisconsin Public Service Company's 2013 PSCR plan reconciliation case U-17092-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR plan case U-17317.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 OPEB Funding case U-17620.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan case U-17333.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2014-2015 GCR Plan case U-17331.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan case U-17334.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Company's 2014 PSCR plan case U-17299.
- Filed testimony in March 2013 on behalf of the Michigan Attorney General in CECo's electric Rate Case U-15645 on remand from the Michigan Court of Appeals for review of the AMI program.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-17298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2012-2013 GCR Reconciliation case U-16920-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2012-2013 GCR Reconciliation case U-16921-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2012-2013 GCR Reconciliation case U-16924-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2012-2013 GCR Reconciliation case U-16922-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) reconciliation case U-16881-R.
- Filed testimony in Puget Sound Energy's 2013 Power Cost Only Rate Case on behalf of the Public Counsel Division of the Washington

Experience and Qualifications of Sebastian Coppola

Attorney General in Docket No. UE-130167 on the power costs adjustment mechanism.

- Filed testimony in PacifiCorp's 2013 General Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130043 on power costs, cost allocation factors, O&M expenses and power cost adjustment mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan case U-17132.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan case U-17130.
- Filed testimony on behalf of the Michigan Attorney General in CECo's 2012 electric Rate Case U-17087 on a several issues, including cost of service methodology, rate design, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism and other revenue/cost trackers.
- Filed reports on gas procurement and hedging strategies of four gas utilities before the Washington Utilities and Transportation Commission on behalf of the Washington Attorney General – Office of Public Counsel in April 2013.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2011-2012 GCR Plan reconciliation cases U-16481-R and U-16483-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) plan case U-17091.
- Filed testimony in MichCon's 2012 gas Rate Case U-16999 on a several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism.
- Filed testimony on behalf of the Washington Attorney General – Office of Public Counsel on executive and board of directors' compensation in the 2012 Avista general rate case.

Experience and Qualifications of Sebastian Coppola

- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2011 Power Supply Cost Recovery (PSCR) reconciliation case U-16421-R.
- Filed testimony on behalf of the Ohio Office of Consumers Counsel in AEP Ohio's power supply restructuring case in June 2012.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2012-2013 GCR Plan cases U-16920 and U-16922.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-16881.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Corporation's 2012 PSCR plan case U-16882.
- Filed testimony for the Michigan Attorney General in CECo's gas business Pilot Revenue Decoupling Mechanism in case U-16860.
- Filed testimony for the Michigan Attorney General in Consumers Energy Gas 2011 Rate Case U-16855 on several issues, including sales volumes, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO and MGUC 2010-2011 GCR Plan reconciliation cases U-16147-R and U-16145-R.
- Filed testimony for the Michigan Attorney General in Consumers Energy 2011 electric Rate Case U-16794 on several issues, including electric sales forecast, revenue decoupling mechanism, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in CECo's electric business Pilot Revenue Decoupling Mechanism in case U-16566.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO and MGUC 2011-2012 GCR Plan cases U-16483 and U-16481.
- Filed testimony for the Michigan Attorney General in Detroit Edison 2010 electric Rate Case U-16472 on several issues, including revenue

decoupling mechanism, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.

- Filed testimony for the Michigan Attorney General in SEMCO 2009-2010 GCR reconciliation case U-15702-R.
- Filed testimony for Michigan Attorney General in MGUC 2009-2010 GCR reconciliation case U-15700-R.
- Filed testimony for Michigan Attorney General, in Consumers Energy Gas 2010 Rate Case U-16418 on several issues, including sales volumes, operations and maintenance costs, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General, in SEMCO 2010 Rate Case U-16169 on several issues, including sales volumes, rate design, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony, for Michigan Attorney General in Consumers Energy 2009 electric Rate Case U-16191 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost and capital expenditures.
- Filed testimony for Michigan Attorney General, in MichCon 2009 gas Rate Case U-15985 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General and was cross-examined in Consumers Energy 2009 gas Rate Case U-15986 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO and MGUC 2010-2011 GCR Plan cases U-16147 and U-16145.
- Prepared testimony and assisted Michigan Attorney General in settlement of SEMCO 2009-2010 GCR case U-15702.
- Prepared testimony and assisted Michigan Attorney General in settlement of MGUC 2009-2010 GCR case U-15700.

Experience and Qualifications
of Sebastian Coppola

- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO 2008-2009 GCR case U-15452 and reconciliation case U-15452-R.
- Prepared testimony and assisted Michigan Attorney General in discussions and settlement of MGUC 2008-2009 GCR reconciliation case U-15450-R.
- Prepared testimony for Michigan Attorney General in SEMCO GCR 2007-2008 Reconciliation Case U-15043-R.
- Prepared testimony for Michigan Attorney General filed in MGUC 2007-2008 GCR Reconciliation Case U-15040-R.
- Participated in drafting of testimony for all aspects of SEMCO rate case filing with the Regulatory Commission of Alaska (RCA) in 2001.
- Filed testimony in 2001 before the (RCA) and was cross-examined on the financing plans for the acquisition of Enstar Corporation and the capital structure of SEMCO.
- Developed a cost of capital study in support of testimony by company witness in the Saginaw Bay Pipeline Company rate request proceeding in 1989.
- Prepared testimony for company witness on cost of capital and capital structure in MichCon 1988 gas rate case.
- Filed testimony in MichCon gas conservation surcharge case in 1986-87.
- Testified before MPSC ALJ in MichCon customer bill collection complaints in 1983.
- Participated in analysis of uncollectible gas accounts expense for inclusion in rate filings between 1975 and 1988.
- Participated in analysis of allocation of corporate overhead to subsidiaries and use of the “Massachusetts Formula” at MichCon and at SEMCO in 1975 and 2000.
- Prepared support information on GCR and rate case-O&M testimony at MichCon from 1975 to 1988.
- Filed testimony in MichCon financing orders in 1987 and 1988.

**Experience and Qualifications
of Sebastian Coppola**

- Participated in rate case filing strategy sessions at MichCon and SEMCO from 1975 to 2001.
- Provided Hearing Room assistance and guidance to counsel on financial and policy issues in various cases from 1975 to 2001.

EDUCATIONAL BACKGROUND

Mr. Coppola did his undergraduate work at Wayne State University, where he received the Bachelor of Science degree in Accounting in 1974. He later returned to Wayne State University to obtain his Master of Business Administration degree with major in Finance in 1980.