STATE OF MICHIGAN
DEPARTMENT OF ATTORNEY GENERAL

P.O. BOX 30755
LANSING, MICHIGAN 48909

DANA NESSEL
ATTORNEY GENERAL

June 3, 2021

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

Dear Ms. Felice:

Re: <u>MPSC Case No. U-20940</u>

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

Sincerely,

Joel King
Digitally signed by Joel King
Date: 2021.06.03 19:51:03 -04'00'

Joel B. King
Assistant Attorney General

cc: All Parties

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

MPSC Case No. U-20940

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

June 3, 2021

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 testimony on behalf of the Michigan Attorney General in DTE Michigan Lateral Company (DMLC) 2021 Act 9 filing to convert a pipeline and build two interconnections for transportation services to DTE Gas Company in case No. U-20894.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2021 power plant and tree trimming securitization costs in case No. U-21015.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2021 PSCR plan case No. U-20802.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019-2020 GCR reconciliation case No. U-20234.
- Filed testimony on behalf of the Maryland Office of Public Counsel in Washington Gas Light 2020 gas rate case No. 9651 on capital additions, rate base, depreciation expense, O&M costs and other issues.
- Filed testimony on behalf of the Michigan Attorney General in the CECo 2020 Karn Electric Power Generating Units 1 & 2 Retirement Cost and Bond Securitization Case U-20889.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR plan reconciliation in case No. U-20222.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2020-2021 GCR plan case No. U-20543.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Gas Company (SEMCO) 2020-2021 GCR plan case No. U-20551.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy (CECo) 2020 electric rate Case U-20697 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in in the complaint against Upper Peninsula Power Company’s (UPPCO) Revenue Decoupling Mechanism (RDM) in Case No. U-20150.

- Filed testimony on behalf of the Michigan Attorney General in CECo 2019 gas rate Case U-20650 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 DTE Gas 2019 gas rate Case U-20642 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 DTE Gas 2018-2019 GCR reconciliation Case U-20210.
- Prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company on behalf of the Maryland Office of People's Counsel filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.
- 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 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 Consumers Energy Company (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 Energy Gas Company (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.

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-20940. 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. Uncollectible Accounts Expense
3. Operations and Maintenance expenses
4. Incentive Compensation
5. Rate Base and Capital Expenditures

6. Cost of Capital and Working Capital
7. Depreciation Expense
8. Customer Monthly Charges

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 Service Alterations Adjustment
3. Exhibit AG-3 Service Renewal Adjustment
4. Exhibit AG-4 Service Abandonment Adjustment
5. Exhibit AG-5 Market Attachment Data
6. Exhibit AG-6 Market Attachments Cost Adjustment
7. Exhibit AG-7 Belle Isle Line Replacement
8. Exhibit AG-8 Thin or No Soil Pipeline Replacements
9. Exhibit AG-9 No Soil Pipeline Exposure Segments
10. Exhibit AG-10 Alpena-West Branch Line Replacement
11. Exhibit AG-11 Van Born Project Costs and Design
12. Exhibit AG-12 Northeast Belt Line
13. Exhibit AG-13 IT ClickSoft Project
14. Exhibit AG-14 IT EGMS Project
15. Exhibit AG-15 Systems Sustainment Projects

16. Exhibit AG-16 End of Life Devices
17. Exhibit AG-17 Renewable Natural Gas Project
18. Exhibit AG-18 Cap Ex Amount Spent 2020
19. Exhibit AG-19 Capital Expenditures Summary, Rate Base and Depreciation
20. Exhibit AG-20 Working Capital
21. Exhibit AG-21 Overall Cost of Capital
22. Exhibit AG-22 DTE Gas Calculation of CFO Pre-WC to Debt Ratio
23. Exhibit AG-23 Cost of Debt vs. Equity with Lower Debt Rating
24. Exhibit AG-24 Cost of Common Equity Capital
25. Exhibit AG-25 Cost of Common Equity Capital-DCF
26. Exhibit AG-26 Cost of Common Equity-CAPM
27. Exhibit AG-27 Cost of Common Equity-Risk Premium
28. Exhibit AG-28 Peer Group Analysis-Capital Structure
29. Exhibit AG-29 Market to Book Ratios
30. Exhibit AG-30 Gas ROE Decisions by Regulatory Commissions
31. Exhibit AG-31 DTE Gas Peer Group Equity Ratios
32. Exhibit AG-32 CONF Moody's Rating Change DTE Internal Memorandum
33. Exhibit AG-33 Value Line Analysis of Water Companies
34. Exhibit AG-34 Value Line California Water Company
35. Exhibit AG-35 Value Line Analysis of Stock Market Volatility
36. Exhibit AG-36 Gas Sales Information
37. Exhibit AG-37 Gas Sales Covid Sales Forecast
38. Exhibit AG-38 Gas Sales Covid Sales Trend
39. Exhibit AG-39 Gas Sales Revenue Adjustment
40. Exhibit AG-40 EUT Customers Transferred to Gas Sales
41. Exhibit AG-41 End-User Transportation Power Generation Volumes
42. Exhibit AG-42 End-User Transportation Revenue Adjustment
43. Exhibit AG-43 End-User Transportation Forecast vs. Actual Volume
44. Exhibit AG-44 Midstream Revenue 2015 to 2020
45. Exhibit AG-45 Midstream Revenue Adjustment

46. Exhibit AG-46 Appliance Program Revenue Adjustment
47. Exhibit AG-47 Total Revenue Adjustment
48. Exhibit AG-48 Uncollectible Accounts Expense Calculation 2020
49. Exhibit AG-49 Accounts Receivable Arrears and Net Charge-offs
50. Exhibit AG-50 Uncollectible Accounts Expense Calculation 2022
51. Exhibit AG-51 Other O&M Expense Adjustments Summary
52. Exhibit AG-52 CPI Factors
53. Exhibit AG-53 O&M Expense-CPI Adjusted
54. Exhibit AG-54 O&M Expense-Storage, Transmission and Distribution
55. Exhibit AG-55 O&M Expense-Transmission ROW Clearing
56. Exhibit AG-56 O&M Expense-TIMP Integrity
57. Exhibit AG-57 O&M Expense-MAOP Records Review
58. Exhibit AG-58 O&M Expense-Meters AOC
59. Exhibit AG-59 O&M Expense-Meter Reading
60. Exhibit AG-60 Health Care Cost Adjustment
61. Exhibit AG-61 Credit Cards Fees 2020
62. Exhibit AG-62 O&M Expense – Customer Representatives Surge
63. Exhibit AG-63 Injuries and Damages Adjustment
64. Exhibit AG-64 Injuries and Damages 2020 Expense and Initiatives
65. Exhibit AG-65 Office Capital Usage Charges Disallowed
66. Exhibit AG-66 Customer Service Aspirational Cost Savings
67. Exhibit AG-67 Customer Service Best in Class Goals
68. Exhibit AG-68 Capital Usage Charge Disallowed – Customer Service Projects 1
69. Exhibit AG-69 Capital Usage Charge Disallowed – Customer Service Projects 2
70. Exhibit AG-70 IT Projects Capital Usage Charge Disallowed
71. Exhibit AG-71 Incentive Compensation to O&M and Capitalized
72. Exhibit AG-72 Incentive Compensation Measures Achieved
73. Exhibit AG-73 Revenue Deficiency Calculation

II. SUMMARY CONCLUSIONS & RECOMMENDATIONS

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 $194.8 million. This rate increase represents an increase in base rates of 23% and an overall increase in rates of 12.3%, with an 11.1% increase to residential customers.[1] As a result of the rate case adjustments I propose in my testimony, the average residential customer would see an increase of approximately 2.0% in their total bill.

It is noteworthy to point out that during the five-year period from 2015 to 2019, the Company earned a return on common equity on a regulatory basis generally at or above the authorized ROE rate. In 2019, DTE Gas had an earned ROE of 10.6%.[2]

Based on my 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 $19.0 million. This result should not be surprising given the fact that the Company earned a return on equity above the authorized level in the 2019 historical test year.

[1] Exhibit A-16, Schedule F2, page 1. The overall increase includes the gas cost in customer bills, which divides the rate increase by a larger cost base, thus lowering the rate of increase of the $194.8 million.
[2] Exhibit A-1, 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 $43.7 million.
2. I propose a lower level of Operations and Maintenance expenses of $84.5 million for the test year.
3. I propose a reduction in capital expenditures of $150.3 million and a reduction in rate base of $134.6 million, which reduce the revenue deficiency by $9.5 million.
4. I propose a reduction in depreciation expense of $5.4 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 10.25%, and a permanent capital structure with 50% common equity and 50% long-term debt, which results in a reduction in the revenue deficiency of $29.1 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.

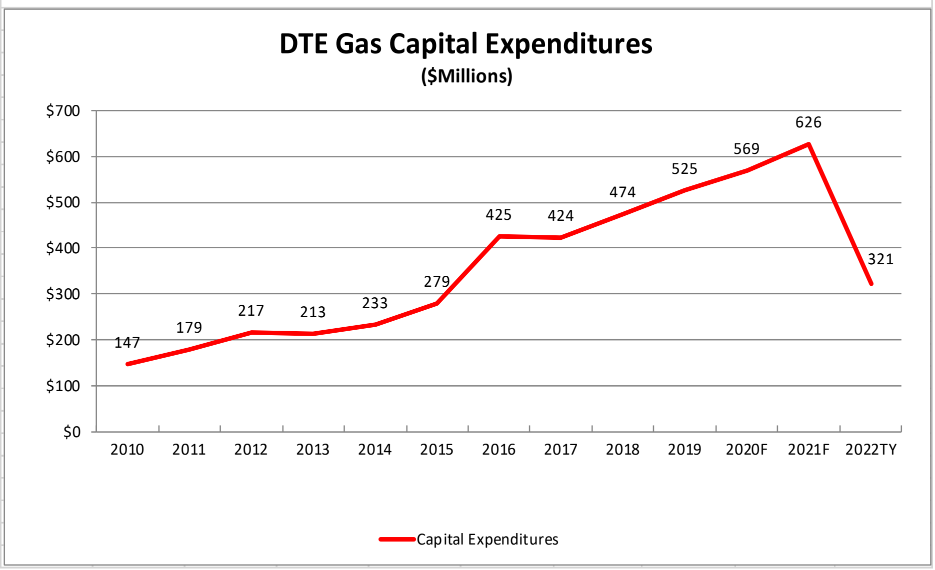
The remainder of my testimony provides further details and support for these summary conclusions and recommendations.

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 $569.4 million for 2020, $626.2 million for 2021, and an additional $320.9 million for 2022. The total proposed capital expenditures over this 36-month period are nearly $1.2 billion.[3] These expenditures follow capital expenditures of $1.4 billion made during the prior three years from 2017 to 2019.[4] 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.

Table 1



[3] Exhibit A-12, Schedule B5.
[4] DTE Gas response to discovery request U-20246-AGDG-3.170a and U-20246-Exhibit A-12, Schedule B5.

Until 2012, the Company was able to keep capital expenditures below $200 million annually. Eight years later, the level of annual capital expenditures has more than doubled, to $524 million. The test year forecast also follows a repeating pattern of showing a decline in spending from prior years, only to be exceeded by a large amount when the test year approaches. For example, in Case No. U-20642, the Company forecasted $382 million[5] of spending for the 2021 test year and now in this case the total capital spending for 2021 is nearly 64% higher at $626 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 26%, to $5.6 billion. The proposed level of rate base in this rate case is approaching three times the amount of rate base the Company had 13 years ago.

Table 2
DTE Gas Rate Base Growth
2008 to Projected 2022 Test Year

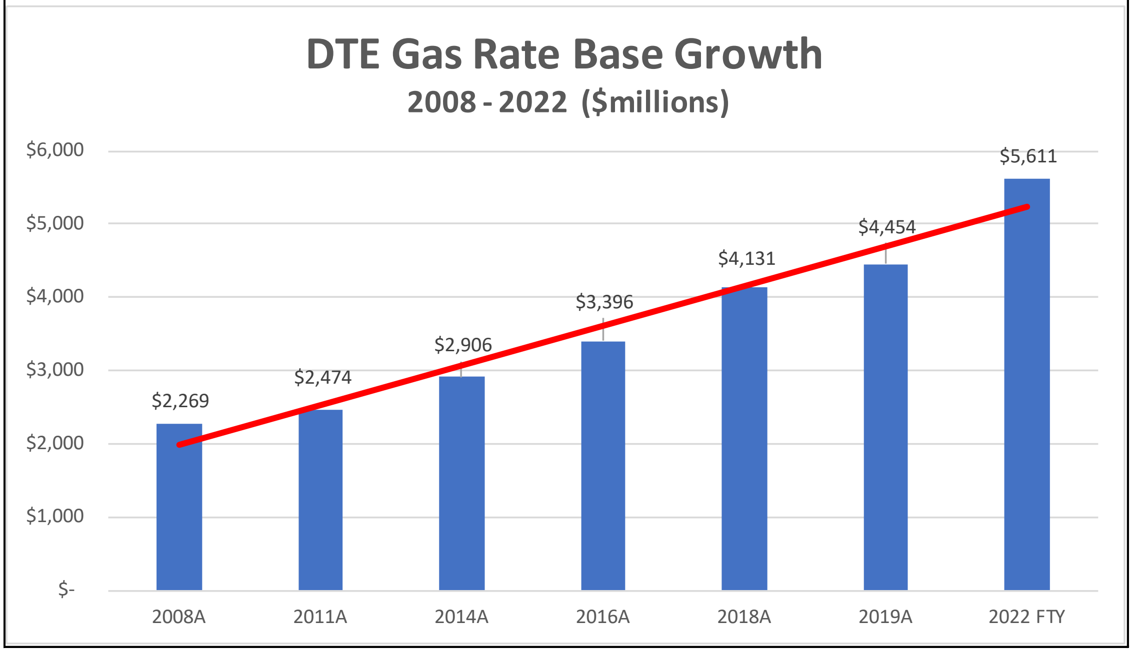
Rate Base Year	2008A	2011A	2014A	2016A	2018A	2019A	2022 FTY
Docket No.	U-15985	U-16999	U-17999	U-18999	U-20642	U-20940	U-20940
Rate Base [1] (Millions)	$ 2,269	$ 2,474	$ 2,906	$ 3,396	$ 4,131	$ 4,454	$ 5,611
Year over Year Change		9%	17%	17%	22%	8%	26%
Cumulative Change over 2008 Rate Base		9%	28%	50%	82%	96%	147%

[1] Historical actual rate base in each docket, except 2022 FTY is proposed amount.

[5] MPSC Case No. U-20642, Exhibit A-12, Schedule B5.

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. Recent investor presentations reaffirm the same goals.

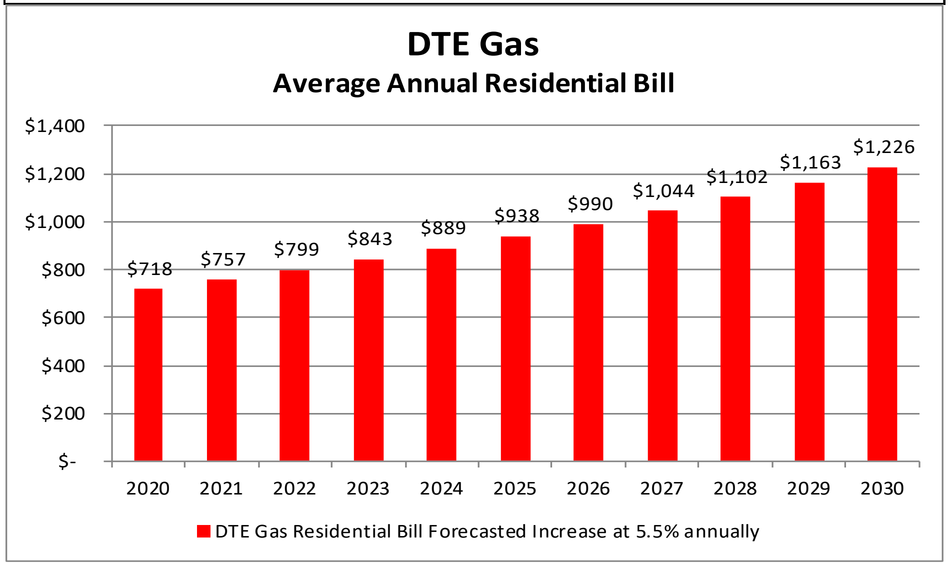
Q. HAVE YOU DETERMINED WHAT THE IMPACT ON RESIDENTIAL CUSTOMER BILLS COULD BE OVER THE COMING YEARS IF THE COMMISSION APPROVES THE PROPOSED RATE INCREASE AND THAT RATE OF INCREASE CONTINUES INTO FUTURE YEARS?

A. Yes. The Company has proposed to increase residential rates in this rate case by 11%. If we assume that the Company continues its current pace of capital expenditures with annual rate cases and rate increases, the average residential total annual gas bill in 10 years will nearly double, from $718 in 2020 to $1,226 in 2030.[6] 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.

---

[6] Current average gas bill in 2020 of $718 = Total Rate A revenue of $872,738,000 divided by 1,215,517 Rate A residential customers per Exhibit A-16, Schedule F2, page 1 and Exhibit A-16, Schedule F3, page 1. Current bill escalated at 5.5% per year through 2030 (11.1% increase from 2020 to 2022 divided by 2).

Table 4



Such an 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 gas commodity costs increase significantly in the coming years from current low prices, 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 bill affordability problems, 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 $13,034,000 in its forecasted capital expenditures for the 36 months ending December 2022. This amount represents contingency costs for large capital projects. Exhibit A-12, Schedule B5.10 includes the detailed schedule supporting this amount. Beginning on page 25 of her direct testimony, Company witness Alicia Sandberg states that, having considered the feedback received in prior rate cases, the Company decided to limit the inclusion of contingency project cost to only large capital projects. Although this is a welcome development, the remaining contingency costs still suffer from the same problems that any contingency costs present.

In the Company's prior rate cases, Case Nos. U-17999 and 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 orders 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, and some may have actually been spent in subsequent periods, it does not mean that these costs belong in rate base. It is neither fair nor 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.

The Company has not presented any new or compelling information in this rate case that should change the Commission's well-established precedent. Therefore, I recommend that the Commission exclude the $13,034,000 from the forecasted capital expenditures in this rate case filing.

B. Distribution Plant

As shown on page 1 of Exhibit A-12, Schedule B5, the Company has forecasted approximately $548 million in capital expenditures for the 36 months ending December 2022 for additions to Distribution Plant. After reviewing the testimony of Company witness Daniel Brudzynski, related exhibits, and responses to discovery, I have identified capital expenditure reductions applicable to several areas.

1. Service Alterations

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

A. As shown on page 2, line 6 of Exhibit A-12, Schedule B5.1, the Company had average capital expenditures of $12.6 million for service alterations during the 5 years from 2015 to 2019 and has forecasted capital expenditures of $16.5 million for 2020, $18.4 million for 2021, and $17.8 million for 2022. On page 16 of his direct testimony, witness Brudzynski presents the number of service alternations performed in prior years and forecasted for 2020 through 2022, along with the related capital spending. He also calculates a cost per unit for each year.

In his testimony, Mr. Brudzynski explains that the increase in the cost per unit beginning in 2021 relates to the Company's decision to begin to perform cross bore inspections after installing service lines. The Company forecasts that unit costs will increase from $3,816 in 2019 to $4,357 in 2021, and then decline slightly to $4,337 in 2022. The actual cost per unit in 2020 was $3,800.[7] The 2021 cost per unit represents an increase of $557, or 15%, over the actual cost in 2020.

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

A. In response to discovery, the Company stated that it expects the cost to perform a cross bore inspection will be $392 on only 2,608 service line alterations, or 61% of the total alternations planned for 2021.[8] If we assume that both the forecasted cost and number of cross bores actually occur in 2021, this additional cost represents only $239[9] of the total

---

[7] DTE Gas response to AGDG-3.49.
[8] DTE Gas response to AGDG-3.54b.
[99] $392 x 61% = 239.

projected increase in the unit cost of $557. The remainder of $318 per unit is unexplained and unknown.

Furthermore, the use of cross bore inspections is a new procedure with no historical track record as to the actual cost to perform this procedure or the actual number of service alterations that may require a cross bore inspection. These unknowns make the forecast very speculative. At this time, the best way to forecast the cost for service alternations for 2021 and 2022 is to use the most recent cost incurred in 2020 of $3,800 per unit. This amount is in line with the three-year average cost of $3,779 from 2018 to 2020.

Using the $3,800 cost per unit and multiplying it by the number of units forecasted for 2021 and 2022 results in forecasted capital expenditures of $16,169,000 and $15,629,000, respectively. The Company's forecasted capital expenditures for 2021 of $18,541,000 and $17,838,000 for 2022 exceed my calculations by $2,372,00 and $2,209,000, respectively.

Given the unexplained portion of the increase in unit costs and the significant uncertainty with the Company's forecast, I recommend that the Commission remove the total amount of $4,581,000 from the Company's forecasted capital expenditures pertaining to service alterations. Exhibit AG-2 shows the calculations to arrive at this disallowance amount.

<u>2. Service Renewals</u>

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR SERVICE RENEWALS.

A. Beginning on page 17 of his direct testimony, witness Brudzynski presents the number of service renewals performed in prior years and forecasted for 2020 through 2022 along with the related capital spending. He also calculates a cost per unit for each year.

In his testimony, Mr. Brudzynski explains that the increase in the cost per unit beginning in 2020 reflects certain actions that the Company took in 2020 to respond to the COVID-19 pandemic and resulting changes in work rules. Mr. Brudzynski identified three actions taken by the Company: (1) the decision to shift resources from O&M work to capital expenditure work, (2) the use of personal protection equipment (PPE), and (3) the rental of additional vehicles to avoid having multiple employees in the same vehicle to minimize virus contamination.

The result was an increase in the unit cost to perform service renewals of nearly $1,000, from $4,924 in 2019 to $5,914 in 2020. The Company also extended this increase to 2021 and 2022, with unit costs of $6,177 and $6,200, respectively.[10] Of the nearly $1,000 increase in unit cost, $883 represents increased labor and overhead costs from the shift in costs from O&M to capital expenditures.[11] Part of this cost increase appears to also be the result of the Company shifting work from outside contractors to its own employees, at a higher cost per unit.[12]

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S ACTIONS TO SHIFT LABOR COSTS TO CAPITAL EXPENDITURES IN 2020 AND THE IMPACT ON

[10] Daniel Brudzynski's direct testimony at page 17.
[11] Exhibit AG-3 and DR AGDG-3.56a.
[12] Exhibit AG-3 and DR AGDE-3.56c.

FORECASTED CAPITAL EXPENDITURES FOR SERVICE RENEWALS IN 2021 AND 2022?

A. I find the action of shifting labor costs from O&M expense to capital expenditures troublesome and detrimental to the Company's customers who will ultimately pay higher rates. Although the increased cost for PPE and rental vehicles is justifiable, the shift of costs from O&M to capital expenditures is not. It is apparent from Mr. Brudzynski's testimony and other information gathered in response to discovery that the Company wanted to mitigate the impact on its 2020 earnings from the potential loss of revenue and higher operating costs from a prolonged lockdown.[13]

As a result, the Company decided to reassign certain employees to perform construction work and deferred doing maintenance and repair work. An example was the deferral of repairing gas leaks.[14] It is likely that in other cases, resources and costs were assigned to capital expenditures without a real need for those resources to perform fully productive tasks. By shifting costs from O&M expense to capital expenditures in 2020 through 2021, the Company has inflated rate base and seeks to recover those costs in future years through depreciation, plus a return on investment, while taking the benefit of lower O&M expense in 2020 financial results for shareholders. Such a practice and the resulting consequences should not be acceptable to the Commission. The shift in resources was not to address any

[13] Exhibit AG-3 and DR AGCUBDG-1.11.
[14] Exhibit AG-3 and DR AGDG-3.56b.

additional construction workload, but apparently to shield the Company's financial bottom line.

Based on the incremental labor and overhead costs of $883 per unit charged to capital expenditures, I have calculated the total incremental cost at $6,657,000. This is the total of $1,983,000 from 2020 ($883 x 2,246 units), $2,296,000 for 2021, and $2,296,000 for 2022 ($883 x 2596 units).

Therefore, I recommend the Commission remove the total amount of $6,657,000 from the Company's forecasted capital expenditures and resulting rate base amount.

3. Service Abandonments

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR SERVICE ABANDONMENTS.

A. Beginning on page 28 of his direct testimony, witness Brudzynski discusses service abandonments and presents the number of units completed in prior years and forecasted for 2020 through 2022 along with the related capital spending. He also calculates a cost per unit for each year.

In his testimony, Mr. Brudzynski explains that the increase in the cost per unit from 2019 to 2020 relates to certain actions that the Company undertook in 2020 to respond to the COVID-19 pandemic and changes in work rules. These are the same issues discussed under Service Renewals.

The result was an increase in the unit cost to perform service renewals of nearly $650, from $1,992 in 2019 to $2,629 in 2020. The increase in the 2020 unit cost is approximately $1,200 from the 2018 unit cost of $1,448. In response to discovery, the Company could not provide an adequate explanation for why the unit cost in 2019 increased by 38% over 2018.[15] In response to discovery, the Company also identified the incremental cost of $834 per unit from the shift of labor and overhead resources to capital expenditures.[16]

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S ACTIONS TO SHIFT LABOR COST TO CAPITAL EXPENDITURES IN 2020?

A. As stated earlier, I find the action of shifting labor costs from O&M expense to capital expenditures troublesome and detrimental to the Company's customers who will ultimately pay higher rates. Such a practice and the resulting consequences should not be acceptable to the Commission. The shift in resources was not to address any additional construction workload, but apparently to shield the Company's financial bottom line.

Based on the incremental labor and overhead costs of $834 per unit charged to capital expenditures I have calculated the total incremental cost at $1,568,000 ($834 x 1,880 units). I recommend that the Commission remove this amount from the Company's forecasted capital expenditures and resulting rate base amount.

---

[15] Exhibit AG-4 and DR AGDG-11.358.
[16] Exhibit AG -4 and DR AGDE-3.66.

4. New Market Attachments

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR NEW MARKET ATTACHMENTS.

A. As shown on page 2, line 13 of Exhibit A-12, Schedule B5.1, the Company had average capital expenditures of $43.5 million for new market attachments during the 5 years from 2015 to 2019 and has forecasted capital expenditures of $69.4 million for 2020, $67.0 million for 2021, and $68.7 million for 2022. In response to discovery, the Company reported that actual capital expenditures for 2020 were lower than forecasted by $4.4 million. The Company also provided actual detailed cost components and the number of new attachments from 2015 to 2020 and forecasted for 2021 and 2022.[17]

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR NEW MARKET ATTACHMENTS?

A. My analysis shows that a portion of the cost for new market attachments for 2021 and 2022 is inflated and needs to be reduced. The new market attachments consist of two primary categories, area expansion program attachments and other routine attachments. I found the forecast for area expansion program attachments reasonable and I propose no adjustments in that category.

With regard to the other routine attachments, I calculated an average actual cost per attachment of $5,403 for the year 2020. I also calculated an average cost per attachment

[17] Exhibit AG-5 includes DR AGDG-3.70b.

of $5,200 for the three-year period from 2018 to 2020 using the information provided by the Company in response to discovery request AGDG-3.70b.[18] In comparison, the Company has forecasted a unit cost of $6,917 for 2021 and $6,828 for 2022. These unit costs represent an increase of 28% and 26%, respectively over the 2020 average cost per attachment.

To establish a reasonable cost estimate for 2021 and 2022, I used the actual three-year average cost per unit of $5,200 and escalated that amount by 4%, representing an annual inflation rate of increase of 2% over two years. The resulting cost per unit is $5,408, which I applied to the forecasted number of routine attachments of 7,184 for 2021 and 7,501 for 2022, to arrive at forecasted capital costs of $38,794,000 and $40,565,000, respectively.

The amount of capital expenditures that I calculated for 2021 and 2022 are $10,901,000 and $10,653,000 lower than the Company's forecasts. Exhibit AG-6 shows the calculations to arrive at these cost adjustments. I recommend that the Commission removed these amounts from the Company's forecasted capital expenditures and related rate base additions.

5. Belle Isle Main Replacement

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

[18] *Id*.

A. Beginning on page 58 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 $2.5 million, which the Company capitalized in 2019 and included in rate base. The contractor that caused the damage to the pre-existing pipeline was doing work in the area for DTE Electric. DTE Electric apparently shared a portion of the cost, but the amount is not clear from the Company's responses to discovery. Exhibit AG-7 includes the Company's responses to several discovery requests on this matter.

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

A. From the information provided by the Company, it is clear that the Belle Isle main replacement was an unplanned project resulting solely from the damage caused by a construction contractor working on behalf of DTE Electric. Although in response to discovery the Company stated that it was partially at fault for not accurately marking the pre-existing pipeline due to an error in its pipeline map, customers should not pay for such errors or omissions. The responsibility for these costs lies with either the Company or its affiliate, DTE Electric.

Therefore, I recommend that the Commission remove the entire amount of $2.4 million from rate base. Furthermore, I recommend that the Commission order the Company to permanently remove this amount from rate base so that it is not included in future rate case filings.

C. Transmission Plant

Transmission plant additions consist of both routine projects and large capital projects. Below, I will discuss adjustments to both routine transmission projects and large capital projects.

1. Routine Transmission Plant

As shown on page 2, line 19 of Exhibit A-12, Schedule B5.1, the Company spent an average annual amount of $7.5 million on routine transmission plant additions during the five years from 2015 to 2019. The amount of $7.4 million spent in 2019 was in line with the average amount during the historical five years. For 2020, the Company increased the capital spending in this area to $15.0 million, primarily to replace the K-Line pipeline and lower the Cedar Creek 10" Muskegon to Ludington pipeline.

For 2021, the Company has proposed $15.5 million in spending, with the increase over the baseline spending amount of $7.5 million going toward lowering two pipeline segments at a combined cost of approximately $2.8 million and replacing four main line valves at a cost of $4.1 million. Similarly, for 2022, in addition to the $7.5 million of base expenditures, the Company proposes to spend $7.5 million to rebury six partially exposed pipeline segments, replace the Northwest Gas Station regulator for $1.3 million, and replace three mainline valves. Exhibit AG-8 includes the Company's responses to two interrogatories showing the amounts discussed here.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S PROPOSED CAPITAL SPENDING FOR 2021 AND 2022 ON THE REMEDIATION OF PIPELINE SEGMENTS WITH THIN OR NO SOIL COVER?

A. The Company wants to spend nearly $11.8 million to remediate the problem with small segments of eight pipelines being either exposed with no soil cover or having a thin soil cover. The eight pipeline segments targeted for 2021 and 2022 are:

- Austin-Detroit A Bradley Drain
- Austin-Detroit B Bradley Drain
- Alpena West Branch Drain
- Alpena Cedar River
- Alpena AuGres River
- Central Line Bending 4 inch Wabasis Creek
- Reed Muskegon 8 inch John Beem Drain
- Austin-Muskegon 6 Mile Rd.

In each case, soil erosion has exposed a small portion of the pipeline or has left a very low level of soil cover. In response to discovery, the Company identified that for three of the pipelines only 10 linear feet of pipe was exposed, and the other segments having thin soil cover for a portion of the pipeline. However, the Company wants to spend millions of dollars to replace hundreds of feet of pipeline to a lower depth through either open trenching or with more costly directional drilling.

For example, for the Alpena West Branch Drain Line Lowering project, the Company wants to replace 800 feet of the 16” pipeline when only 10 feet of the pipeline is exposed.[19] According to federal rules, transmission pipelines need to be buried at a minimum depth of 36 inches below grade. When pipelines lose soil cover over time in certain sections of the pipeline, the solution that the Company seeks to employ is to reestablish the required depth by replacing a longer section of the pipeline and rebury that section to the required depth. The Company has not discussed or presented any other, less costly, solutions that may be available.

In discovery, the Company was asked why, for example, the Company cannot reestablish the soil cover over the short section of the pipeline that is exposed (10 feet in three of the cases) by bringing in more soil. The Company’s response was that adding enough soil cover to meet DTE’s standards is not feasible. The Company did not specify to which standards it is referring. This makes it impossible to determine what is or is not feasible. It appears the Company may have tried some other solutions such as concrete shielding to prevent erosion from nearby drains, with mixed results.[20]

However, in its responses, the Company has been generally dismissive and unwilling to try other alternatives to spending millions of dollars, preferring instead to use its preferred approach of cutting, replacing, and reburying long sections of pipe, where only small

[19] See Exhibit A-12, Schedule B5.5, page 12 and DR AGDG-11.359b and 11.359c included in Exhibit AG-9.
[20] Exhibit AG-10 includes DR AGDG-3.75b - d.

sections require some remediation. The Company needs to show that it has rigorously explored other less costly alternatives before undertaking the pipeline replacement option.

The Commission should not accept the proposed capital expenditures until the Company makes a convincing case that other alternatives have been thoroughly explored and evaluated. In conclusion, I recommend that at this time the Commission reject the Company's forecasted capital expenditures of $11.8 million for 2021 and 2022 for the eight soil-cover pipeline remediation projects.

2. Van Born Project

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

A. In Exhibit A-12, Schedule B5, line 13, the Company proposes capital expenditures for the Van Born project of approximately $1.0 million for 2020, $9.9 million for 2021, and $22.0 million for 2022.

Beginning on page 42 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 would feed the market area in case of an interruption in supply on the 36" line. It is not clear from Ms. Sandberg's testimony if the Company intends to operate both the 24" and 36" pipelines simultaneously at less than full capacity throughout the year or have one of the pipelines sit idle until called upon in the case of a rare supply emergency.

According to Ms. Sandberg, the proposed pipeline loop would mitigate a potential supply outage to only 120,000 of the 160,000 customers from a potential rupture of the 36" line.

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

A. On page 45 of her testimony, Ms. Sandberg discloses that the total cost of the project is forecasted at $96.0 million to be incurred from the year 2020 through 2024. If history is any guide, a project of this size will likely cost more than projected once detailed design and construction is bid out. Therefore, the Commission should consider the $96 million as a starting point. The amount proposed in this rate case represents only 34% of the currently-estimated total project cost of $96 million.

The Company proposed this same project in its prior rate case No. U-20642. The proposal here is generally unchanged from the prior proposal. In response to discovery in Case No. U-20642, the Company provided a map of the service area that would not benefit from the Van Born pipeline loop and would still be at risk of a potential outage to 40,000 customers. 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 in both this rate case and the prior case, the Company was also asked to explain why a third pipeline is needed when the two existing pipelines could back each other up in case of a supply emergency. The Company's response that only one operating pipeline for a period of time would not provide sufficient gas supply to the large industrial customers is not convincing. Although the two large industrial customers could potentially face a short-term supply curtailment or suspension until the supply emergency is resolved, the Company would still be able to supply its 120,000 or 160,000 residential and small commercial customers by interconnecting the two existing pipelines at critical locations.

Additionally, it is not clear how another supply line from the same gate station at Willow will significantly reduce the risk of a gas supply interruption, or 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. However, a catastrophic supply interruption at the

Willow Gate Station that would shut down the entire station would be problematic. Exhibit AG-11 includes the discovery responses discussed above.

According to Ms. Sandberg, the Company plans to file an Act 9 application in the third quarter of 2021 to receive Commission approval to build the pipeline for the Van Born project. In Case No. U-20642, the Company had planned to file the Act 9 application on or about March 2021.[21] Apparently, the filing has now been delayed by at least six months. The Act 9 proceeding will likely address the issues raised above and a determination will be made whether a third pipeline is necessary and the Company's proposal is the best solution.

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 the third quarter of 2021 is further evidence of the very early stage and conceptual nature of the project. The

[21] MPSC Case U-20642, Exhibit A-12, Schedule B5.3, page 27, Project Schedule.

Commission should not approve capital expenditures for inclusion in rate base at such an early stage and with no approval yet granted of the 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 at least $96 million to loop the existing pipelines. The alternatives presented in Table 4 on page 44 of Ms. Sandberg's testimony show that developing a backup source of supply to the 40,000 customers is too costly and unacceptable.

Because of the still premature nature of the project and the uncertainty of whether the Act 9 proceeding will result in the approval of this pipeline project, I recommend that the Commission reject the proposed capital expenditures of $32.9 million included in this rate case. This amount has been reduced by the $1,775,000 already disallowed under Contingency Capital Expenditures for a net incremental disallowance of $10,625,000.

3. East Jefferson Main Replacement Project

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR THE EAST JEFFERSON MAIN REPLACEMENT PROJECT.

A. Line 17 of Exhibit A-12, Schedule B5, shows the Company's forecasted capital expenditures for the East Jefferson Main replacement project with approximately $1.0 million for 2021 and $14.0 million for 2022. Page 25 of Exhibit A-12, Schedule B5.5, provides additional details on the project, as does the direct testimony of Ms. Sandberg beginning on page 62.

According to the testimony of Ms. Sandberg, this project originated from a potential road reconstruction project to be undertaken by the City in Detroit sometime in 2023-2024. The project will entail the retirement of 11.5 miles of cast iron main and the installation of 14.5 miles of plastic pipe along with other related activities.

Q. WHAT IS YOUR ASSESSMENT OF THE EAST JEFFERSON PROJECT AND THE ASSOCIATED CAPITAL EXPENDITURES?

A. After reviewing the Company's testimony and particularly the project description, schedule, and forecasted costs, it is evident that this project is still in a very preliminary stage. In fact, the project schedule on page 25 of Exhibit A-12, Schedule B5.5 states in a footnote that the project schedule is preliminary and still subject to coordination with the City of Detroit. The $990,000 and $14.0 million in capital expenditures forecasted for 2021 and 2022 appear to be ballpark amounts as placeholders of future expenditures. The Commission has repeatedly rejected the inclusion of placeholder amounts in rate base.

This project is still too premature for inclusion in rate base in this rate case. Therefore, I recommend that the Commission remove the capital expenditures of approximately $15.0 million from the Company's total forecasted capital expenditures.

4. Middlebelt Deration Project

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR THE MIDDLEBELT DERATION PROJECT.

A. Beginning on page 54 of her direct testimony, Ms. Sandberg discusses the Company's MAOP (Maximum Allowable Operating Pressure) Records Review program. As a result of federal regulatory requirements, the Company must verify that it has sufficient records to ascertain the physical and operational characteristics of its gas transmission pipelines in High Consequence Areas and be able to verify that its records can substantiate the MAOP. Where gaps in records exist, the Company must remedy the shortfalls by performing physical inspection of the pipeline, including reestablishing its MAOP through pressure tests and other procedures.

As discussed on page 53 of Ms. Sandberg's testimony and further detailed on page 21 of Exhibit A-12, Schedule B5.5, the Company discovered that it had 240 MAOP record gaps with regard to the Middlebelt pipeline. To remedy this problem, the Company has decided to abandon sections of the pipeline and related facilities and install new sections of pipeline, valves, and a station pressure regulator. The cost for the remediation is shown on line 15 of Exhibit A-12, Schedule B5, at $2,970,000 in 2021.

Q. WHAT IS YOUR ASSESSMENT OF THE MIDDLEBELT DERATION PROJECT?

A. The number of record gaps for the Middlebelt pipeline is alarming. It is apparent that the Company did not keep sufficient or adequate records to be able to verify the physical and operational characteristics of the pipeline and related facilities in order to ascertain the MAOP.

Although the requirements that transmission pipeline operators have adequate records to verify the MAOP and other pipeline operating characteristics was issued in 2011, it does not mean that DTE gas should not have kept adequate records of the construction of its pipelines and facilities. This should have included records of pressure tests performed before placing those pipeline and facilities into service. These are basic operating requirements to ensure the safe installation and operation of high-pressure facilities, going back to the 1960s, 1950s and even prior decades.

The Company has the sole responsibility to ensure it maintains adequate records of its pipelines and related facilities, both now and in the past. The fact that adequate records do not exist is not a problem that should be remedied entirely on the backs of customers. Although a strong argument can be made that the cost to remedy the record gaps should be entirely absorbed by the Company, it is fair and reasonable for the Company to absorb at least 50% of the cost and recover the other 50% in base rates as an accommodation for the long passage of time since the pipeline was installed.

It is noteworthy to point out that customers are already paying for the cost of the MAOP record review. In response to discovery, the Company reported that from 2015 to 2020, the Company incurred $9.4 million to perform this review and those costs have been capitalized and included in rate base.[22] Customers will pay for these costs for decades to come and should not be further burdened with the entire cost of any necessary remediation to pipelines and facilities when record gaps are discovered.

[22] DTE response to DR AGDG-3.98a and 11.375.

Therefore, I recommend that the Commission remove $1,485,000 of capital expenditures for this project from the Company's 2021 forecasted total capital expenditures and rate base.

5. Northeast Beltline Pipeline Project

Q. PLEASE EXPLAIN YOUR PROPOSED DISALLOWANCE OF CAPITAL EXPENDITURES FOR THE NORTHEAST BELTLINE PROJECT.

A. On page 34 of her direct testimony, Company witness Renee Tomina briefly discusses the project to retrofit the Northeast Beltline pipeline and the problems encountered in completing the project. Ms. Tomina points to the complexity in the location of one of the pig traps and the narrow window of connecting the new piping to the existing piping and placing those sections into service. She also points to a complex permitting process and the necessary revisions to the scope of the project due to unexpected local township requirements. To clarify, "pig traps" refers to an adjacent facility to the pipeline to catch the inline inspection (ILI) tool after travelling through the pipe and performing the inspection of the pipeline's physical integrity.

Page 29 of Exhibit A-12, Schedule B5.5, provides additional details on this project. The scope of work is defined as requiring the installation of the ILI launcher and receiver. According to the project schedule in the exhibit, the project began in 2018 with land acquisition and was followed by engineering design in the Spring of 2019, permitting and construction of phase one in 2020, and final construction in April 2021. The total project cost is shown at $5,767,022.

Q. WHAT IS YOUR ASSESSMENT OF THE NORTHEAST BELTLINE PROJECT?

A. In discovery, the Company was asked to explain what amount of the total current project cost was due to the unexpected complexities and project schedule delays. In its response, the Company stated that 80%, or $3.7 million, of the cost increase over the original budget was due to the unexpected complexities and schedule delays.[23] This information implies that the Company incurred a cost overrun of $4,625,000 ($3,700,000 ÷ 0.80). With the current project cost forecasted at $5,767,022, it means the original project budget was approximately $1,142,000. Therefore, the cost overrun of $4,625,000 represent more than 400% of the original cost estimate.

This is an alarming cost overrun for a project that should be rather straightforward if well planned and executed. It is difficult to understand why the Company could not anticipate the referenced complexity of the project. The project is located in the Ann Arbor market area, which the Company should know well after serving the area for nearly a century. Installing ILI tool launchers and receivers is a task that the Company has performed for decades and should be well-versed in performing. The complexity with permitting and resulting project scope changes should not occur if the Company does sufficient project pre-planning and design, and coordinates closely with the municipality before starting construction of the project.

Clearly, something fundamentally wrong occurred with this project that rises to the level of imprudent behavior, either from insufficient upfront work or other imprudent actions or

[23] Exhibit AG-12 includes DR AGDG-4.119c.

inactions. Customers should not pay for this significant cost overrun. I recommend that the Commission remove the amount of $4,625,000 from the Company's forecasted capital expenditures with 83%, or $3,839,000, pertaining to 2020, and the remainder of $786,000 for 2021, based on the project cost estimate by year shown on page 29 of Exhibit A-12, Schedule B5.5.

Furthermore, the Commission should direct the Company to remove any disallowed amounts, previously capitalized, from plant balances to avoid inclusion of these amounts in rate base in future rate cases.

D. Gas Information Technology Projects

The Company segregates the costs for Information Technology (IT) projects into two major categories. IT projects pertaining solely to DTE Gas are categorized as Gas Information Technology projects and accounted for on the books of the Company as capital projects. The capital costs for these projects are summarized on line 27 of Exhibit A-12, Schedule B5, and further detailed in Exhibit A-12, Schedule B5.4.1.

Other IT projects that are common to both DTE Gas, DTE Electric, and other subsidiaries of DTE Energy Company are recorded as capital additions on the books of DTE Electric and the costs are shared through a capitalized charge to DTE Gas reflected in O&M expense. The capitalized charge includes the depreciation expense and return on investment in the total capitalized cost of the projects. These costs are part of the Rents on line 15 of Exhibit A-13, Schedule C5.6, page 1, and further detailed in Exhibit A-13, Schedule C5.12.

All IT projects are managed by the DTE Energy Corporate IT group. Mr. Jaison Busby presented testimony in this rate case pertaining to both specific DTE Gas IT projects and shared projects, with other witnesses adding additional operating perspective on the IT projects that touch their areas of responsibility.

In this section of my testimony, I will address certain DTE Gas only IT projects where I believe cost adjustments or disallowances are warranted. Later, in the O&M section of my testimony, I will address certain cost adjustments pertaining to shared IT projects.

1. ClickSoft Project

Q. PLEASE BRIEFLY DESCRIBE THE CLICKSOFT PROJECT.

A. As shown on page 41 of Exhibit A-12, Schedule B5.5, 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. Based on information provided in Case No. U-20642, the forecasted cost of this system is $8.9 million. The Company did not provide a total cost update in this rate case. Page 41 of Exhibit A-12, Schedule B5.5 only shows the amount to be spent between 2020 and 2022, which totals to $6.8 million.

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

A. In the Company's previous rate case No. U-20642, I addressed this project and recommended that the Commission reject the capital expenditures and rate base additions pertaining to this system. My conclusion has not changed. In response to discovery in the prior rate case and similarly in this rate case, the Company stated that the current Field Service Management system was installed in 2014 and six 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 no longer provide system updates. Asked to explain why the current system needs to be replaced, the Company repeated the "end of life" rationale, along with no vendor support for future upgrades to the system. The discovery response also points to the lack of desired features, potential move 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 net present value cost/benefit analysis for the project with cost savings or financial benefits provided by the new ClickSoft system over the relevant 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-13 includes the discovery responses discussed above from both this case and the prior rate case.

From reading the project description in Exhibit A-12, Schedule B5.5, and the Company's responses to discovery, it is readily apparent that the Company wants a more current system with new features and exciting mobile phone connectivity, although the current system is still functional and only 6 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 $6.8 million should be removed from this rate case.

2. EGMS Project

Q. PLEASE BRIEFLY DESCRIBE THE EGMS PROJECT.

A. As described on page 34 of Mr. Busby's direct testimony, the Electronic Gas Management System (EGMS) is a gas nomination system utilized by a group of employees to accept, validate, schedule, and process gas nomination requests on the DTE Gas and DTE Gathering Pipelines.

The Company plans to replace its current gas nominations Gas Management system with a new software system and new web applications. According to information provided by the Company in the prior rate case, the new system will allow transportation 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 other than small savings for report generation using the TIPS reporting system. Mr. Busby also points to reductions in errors when entering wrong nominations, but these are also relatively minor benefits.

In response to a request to provide a net present value cost/benefit analysis, the Company stated that it was not available and points to Mr. Busby's testimony and filed exhibits. The responses to discovery are included in Exhibit AG-14.

As shown on line 9 of Exhibit A-12, Schedule B5.4.1, the forecasted cost of this system is \$2.1 million from 2020 to 2022, plus approximately \$1.2 million incurred in 2019. It is not known what the total cost of the project is. The Company refused to provide that information, as shown in discovery response AGDG-8.258a included in Exhibit AG-14.

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

A. In discovery in the prior rate case No. U-20642, 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 those discovery requests are also included in Exhibit AG-14.

The responses to discovery show 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. In fact, the Company's own IT personnel now maintain the system and perform software fixes when needed. 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 at least $3.3 million, and unfair to customers if this cost is included in rate base.

It is also concerning that this system will be used by DTE Gathering Pipelines, an affiliate of DTE Gas, as stated on page 34 of Mr. Busby's testimony. In discovery, the Company denied that the system will be partially used by DTE Gathering Pipelines. However, this after the fact revision is not convincing. DTE Gas should not absorb the entire cost of the project if affiliated companies partially benefit from its use.

In summary, the Company's description of purported benefits is unpersuasive and falls significantly short of making a compelling business case that this system will provide both financial and non-financial benefits that justify the investment of at least $3.3 million.

My recommendation is that the actual and forecasted capital expenditures of $3.3 million from 2019 to 2022 should be removed from this rate case. Furthermore, the Commission should direct the Company to remove any disallowed amounts, previously capitalized, from plant balances to avoid inclusion of these amounts in rate base in future rate cases.

<u>3. IT Sustainment Work & Expenditures</u>

Q. PLEASE EXPLAIN YOUR PROPOSED DISALLOWANCE OF CAPITAL EXPENDITURES FOR IT SUSTAINMENT PROJECTS.

A. Beginning on page 14 of his direct testimony and also on page 20, Mr. Busby discusses the type of work performed in the Sustainment category and costs included within this category. On page 14, Mr. Busby explains that Sustainment covers spending to run the organization, such as basic internal labor, base operation and system maintenance costs to apply software patches, data adjustments, performance tuning, and administrative activities, including tracking and resolution of issues reported by end users.

These functions are basic operation and maintenance functions. However, the Company has been categorizing them as capital expenditures and adding them to rate base where it can earn a return on investment and recover the amount spent over future years. Line 7 of Exhibit A-12, Schedule B5.4.1 shows costs of $750,000 in 2019, $1,638,000 in 2020, $809,000 in 2021, and $780,000 in 2022 for a total amount of $3,977,000 over the four-year period.

In discovery, the Company was asked to explain why it classifies these costs as capital expenditures when they seem to be operation and maintenance expenses. In response, the Company stated that it follows its accounting policy whereby upgrades and enhancements are capitalized if it is probable that those expenditures will result in additional functionality, new software design, or changes to existing software design. Exhibit AG-15 includes the discovery response.

It is clear from reading Mr. Busby's description of the work done in this area that it does not rise to the level of work that is capitalizable under the Company's accounting policy. These costs are routine operating and maintenance costs, and they should be expensed each year. Therefore, I recommend that the Commission remove the amount of $3,977,000 from the Company's forecasted capital expenditures for the years 2019 to 2022, and also direct the Company to expense these costs in future years.

To allow the Company to recover the applicable amount of O&M expense for 2022, I have included $780,000 of expense in my O&M expense exhibit, as discussed later in my testimony. I recommend that the Commission accept this increase in O&M expense for the projected test year.

Q. ARE THERE OTHER COST ELEMENTS INCLUDED UNDER THE CATEGORY OF SUSTAINMENT?

A. Yes. On line 6 of Exhibit A-12, Schedule B5.4.1, the Company shows capital expenditures for End-of-Life Gas Device Program. The amounts are $1,635,000 for 2019, $1,583,000 for 2020, $1,270,000 for 2021, and $2,870,000 for 2022. Beginning on page 21 of his direct testimony, Mr. Busby discusses the Company's program of periodically replacing laptop and desktop computers along with monitors, tablets, network hardware, and other related equipment. The Company's program is a five-year replacement cycle with routine replacement of 20% of the devices whether or not they are still functioning and useful.

In discovery the Company was asked to explain why it is replacing still useful and functioning devices after five years, to provide the number of failures experienced within or after five years, and to also provide the potential reduction in capital expenditures if the replacement cycle was extended 2 more years to 7 years. In response, the Company stated that it replaces devices based on specified industry standards and OEM specifications, and the life expectancy established by its internal team of experts. The discovery responses also stated that the Company does not keep track of device failures and that it could not provide any changes in capital expenditures for extending the replacement program to a 7-year cycle. Exhibit AG-15 includes the discovery responses.

Q. WHAT IS YOUR ASSESSMENT OF THE END-OF-LIFE REPLACEMENT CYCLE AND THE PROPOSED CAPITAL EXPENDITURES?

A. There is no apparent justification to have such a short cycle of replacement. The Company could not provide any evidence that it would be experiencing significant failures of the electronic devices after 5 years and that extending the replacement cycle to 7 years is not feasible. To rely on manufacturers' suggested replacement cycles is neither reasonable nor prudent and perpetuates a cycle of planned obsolescence. The manufacturers' goal is to sell equipment and their incentive is to sell more and earlier.

It is also troubling that the Company would not evaluate a longer replacement cycle and willingly provide the potential changes in capital expenditures of going to a 7-year cycle.

Q. HAVE YOU CALCULATED WHAT THE POTENTIAL REDUCTION IN CAPITAL EXPENDITURES WOULD BE IF THE COMPANY MOVED TO A 7-YEAR REPLACEMENT CYCLE?

A. Yes. In Exhibit AG-16, I calculated the potential reduction in capital expenditures from 2019 to 2022 at $2,102,000. I arrived at this amount by establishing the replacement cost base using the 5-year replacement cycle followed by the Company, and then dividing that base by 7 to arrive at the annual amount for each year. The $2,102,000 is the difference between the 5 and 7-year amounts.

I recommend that the Commission remove the $2,102,000 from the Company's forecasted capital expenditures.

Therefore, in total for the Sustainment category, I recommend a reduction in capital expenditures of approximately $6.1 million.

4. BioGreen Gas Program Redesign

Q. PLEASE EXPLAIN YOUR PROPOSED DISALLOWANCE OF CAPITAL EXPENDITURES FOR THE BIOGREEN GAS PROGRAM REDESIGN PROJECT.

A. On page 43 of his direct testimony, Mr. Busby describes the BioGreen Gas Program Redesign as a project to raise awareness and support for renewable natural gas (RNG), which is a replacement for a previous program. The Company has proposed $800,000 between 2020 and 2021 to make certain system modifications and redesign to allow customers to enroll and participate in the program.

The objective of the BioGreen program is for customers to offset a portion of their carbon footprint by supposedly buying natural gas extracted from landfills. The Company currently has an arrangement to buy landfill gas from one landfill site in Canton, Michigan, and may add a couple more in 2022.

In response to discovery, the Company stated that the cost of this program and its predecessor program are not being recovered in rates.[24] However, the system modification costs have been included in capital expenditures in this case. It is not clear why IT costs should be an exception.

The benefit of this program to the larger customer base is difficult to justify. The program is very preliminary with unknown customer participation numbers and a limited near-term

[24] Exhibit AG-17 included DR AGDG-8.261.

scope, due to the relatively small volume of landfill gas available. I recommend that the Commission remove the $800,000 of capital costs from the forecasted capital expenditures in 2020 and 2021.

5. Field Sketch Enhancements

Q. PLEASE EXPLAIN YOUR PROPOSED DISALLOWANCE OF CAPITAL EXPENDITURES FOR THE IT FIELD SKETCH ENHANCEMENTS PROJECT.

A. In response to discovery, the Company stated that it is no longer investing in this project after discovering incompatibility issues with other related systems.[25] On line 15 of Exhibit A-12, Schedule B5.4.1, the Company had included capital expenditures of $427,000 in 2019, $398,000 in 2020, $300,000 in 2021, and $150,000 in 2022 for a total amount of $1,275,000 over the four-year period.

I recommend that the Commission remove those amounts from the Company's total forecasted capital expenditures. In addition, I recommend that the Commission order the Company to remove all amounts capitalized and included in rate base as of the date of the order to prevent any previously capitalized amounts for this project from being included in rate base in future rate case filings.

E. Capital Expenditures 2020 Adjustment to Actual

Q. PLEASE EXPLAIN WHAT OTHER ADJUSTMENTS TO CAPITAL EXPENDITURES FOR 2020 YOU PROPOSE.

[25] DTE Gas response to DR AGDG-8.263a.

A. In discovery, the Company was asked to provide the actual capital expenditures incurred in 2020 for the routine capital programs identified on page 2 of Exhibit A-12, Schedule B5.1. In response, the Company provided the requested information for 2020 showing the detailed components and a total actual capital expenditure amount of $233,407,000. Exhibit AG-18 includes the information provided.

The total actual expenditures for 2020 are $5,195,000 lower than the amount of $238,602,000 that the Company had forecasted for the year. The amount of $5,195,000 was not spent in 2020 and should not be included in the approved rate base in this rate case. I recommend that the Commission remove this amount from the Company's proposed rate base amount.

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.

Summary of AG Disallowed Capital Expenditures		
		Amount (millions)
Contingent Capital Expenditures	$	13.0
Distribution Plant		
Service Alterations		4.6
Service Renewals		6.5
Service Abandonments		1.5
New Market Attachments		30.6
Belle Isle Main Replacement		2.4
Transmission Plant		
Pipeline Soil Cover Remediation		11.7
Van Born Project		32.9
East Jefferson Main Replacement		15.0
Middlebelt Deration Project		1.5
Northeast Beltline Project		4.6
Gas IT Projects		
ClickSoft System		6.8
EGMS		3.3
Sustainment Projects		6.1
Biogreen Program Redesign		0.8
Field Sketch Enhancements		1.3
Other		7.7
Total	**$**	**150.3**

Based on my analysis and information presented in my testimony above, the Commission should reduce the Company's proposed capital expenditures by $150.3 million and average rate base by $134.6 million, including a $19.7 million reduction in working capital. Exhibit AG-19 provides additional details and calculations of these amounts.

V. Working Capital

Q. THE COMPANY HAS PROPOSED $1.029 BILLION OF WORKING CAPITAL IN THIS CASE. DO YOU AGREE WITH THIS LEVEL OF WORKING CAPITAL?

A. No. I recommend two changes in the Working Capital level, which total $19.7 million, and reduce the amount of Working Capital to $1.001 Billion. The first change is to set the Company's Customer Accounts Receivable level at the historic 2019 level of $214.1 million. The Company increased customer accounts receivable by $10.7 million between the 2019 historical year and the 2022 projected test year. The second change I recommend is to remove $10.7 million of Deferred Covid Uncollectible balance. The two changes are shown in Exhibit AG-20.

Q. PLEASE EXPLAIN WHY CUSTOMER ACCOUNTS RECEIVABLES SHOULD BE SET AT THE HISTORIC 2019 AVERAGE LEVEL?

A. The increase in the Customer Accounts Receivable balance proposed by the Company in this case is approximately 4.2% from 2019 to 2022 and is in line with the projected increase in revenues over the same period assuming that 100% of the rate relief requested in this case is granted. However, this outcome is not likely. Additionally, the increasing number of customers who are paying their gas bills with credit and debit cards should reduce accounts receivable as a percentage of revenues.[26] The Company believes this trend will continue and has included additional merchant fees in projected O&M expense as shown on Exhibit C5.8 page 2.

Q. HAVE ACCOUNTS RECEIVABLE AS A PERCENTAGE OF REVENUES DECLINED BETWEEN 2018 AND 2019?

[26] See DTE Gas discovery response AGDG-7.231d showing the dollar value of Accounts Receivable being settled by credit cards and debit cards from 2017 to 2020.

A. Yes. Average customer accounts receivable as a percentage of revenues declined from 17.7% in 2018 to 15.6% in 2019. The data supporting these statistics is shown on page 2 of Exhibit AG-19. This lower percentage is consistent with the increased use of credit and debit cards by customers, which has accelerated gas bill payment and lowered outstanding accounts receivable balances.

Q. PLEASE EXPLAIN WHY YOU REMOVED THE DEFERRED ASSET BALANCE FOR DEFERRED EXCESS COVID UNCOLLECTIBLE COSTS FROM WORKING CAPITAL?

A. As I will discuss later in my testimony under the Uncollectible Accounts Expense section, there is no need to record a deferred balance for COVID-related uncollectible gas accounts because the Company has not experienced any significant increase in uncollectible costs due the COVID lockdown. As a result, I recommend that the Commission remove the $10.7 million regulatory asset balance from working capital.

VI. 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 December 2022. The permanent capital balances in this exhibit reflect two changes. First, I reduced the level of common equity to $2.158 billion (an $82 million reduction from the Company's case). Second, I have included this $82 million amount as additional long-term debt. The result is the allocation of total permanent capital ($4.3 billion) to long-term debt and common equity on a 50%/50% 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 51.9%. While this percentage is lower than the 2019 historical test year percent of 52.75%, there are other factors to consider which are discussed below.

First, the common equity ratio of the peer group is approximately 47%. Exhibit AG-27 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 somewhat 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 47%.

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 39% at the end of 2020 and 43% at the end of 2019. DTE Energy can make the common equity ratio of DTE Gas whatever it wants. The same executive management that runs DTE Energy controls the Company's major decisions. Management can direct at any time how much in capital it wants to inject into the Company from the parent company and call it equity capital, even though in reality it is debt. As a result, DTE Energy management has artificially set the common equity ratio of DTE Gas at nearly 52%, when the parent company only has a common equity ratio of approximately 40%. Such freedom to inject phantom equity capital into the capital structure 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 47%. PLEASE EXPLAIN WHY THIS IS RELEVANT IN DETERMINING THE COMMON EQUITY RATIO FOR THE COMPANY IN THIS CASE.**

A. As shown in Exhibit AG-27, the average common equity ratio of the peer company group for 2020 was 47.2%. 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 51.9% 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 approximately four percentage points lower than the 52% equity ratio recommended by Company witness Edward Solomon.

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

A. Mr. Solomon summarizes his reasons for a 52% common equity ratio on page 12 of his testimony and follows with several pages of discussion through page 29. I will address these points later in my testimony. Also, he points out that the Company's 52% suggested equity level is conservative given the average common equity of the peer group companies which he indicates is 56.8% at the utility level.

Q. WHAT IS YOUR OPINION OF WITNESS SOLOMON'S 56.8% CALCULATED PEER GROUP EQUITY RATIO PRESENTED IN EXHIBIT A-17, SCH. G3?

A. In discovery, the Company was asked to provide the source of the information used in the calculation of the 56.8% equity and explain what it represents.[27] The responses show several shortcomings. The financial ratios reflect a single point in time of the capital structure during 2019 with some companies' capital structure balances as of September 2019 and others as of December 2019. This time inconsistency is superseded by the problem that the capital structures of these companies are not averaged over multiple periods during the year. The convention in establishing a regulatory capital structure is to

[27] Exhibit AG-31 include discovery response AGDG-6.209b, c and d.

use a 13-month average. At minimum, an average equity ratio over a 12-month period or over four quarters should have been used.

Second, the companies that make up the 56.8% equity ratio are not the same companies that the Company uses to determine the cost of equity for its selected peer group. As stated earlier, this presents a major disconnect between the financial risk of the selected companies for the 56.8% equity ratio and the companies used in the calculation of the cost of common equity.

Third, and even more critical, the equity ratio of 56.8% does not represent the average equity ratio approved by the state commissions regulating those companies. Although the Company attempts to portray the equity ratios of the companies in Exhibit A-17, Schedule G3, as representative of the equity ratio approved in each company's rates, they are far from that. The equity ratios were calculated by the Company using equity capital balances reported by the companies in their public financial reports as of either September or December 2019.

In summary, the equity ratios presented by the Company in Exhibit A-17, Schedule G3, are at best misleading and certainly not reflective of equity ratios accepted by regulatory commissions. Therefore, the Commission should not rely on the equity ratio information provided by the Company.

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, the Commission directed 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 IN CASE U-20642?

A. No. This was a troubling omission by the Company with significant implications, particularly given the fact that both the Commission and the ALJ in U-18999 discussed this issue at length. In the discussion of this issue on pages 43 and 44 of the U-18999 rate order, the Commission stated that it agreed 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 stated that "…a pro-forma debt capacity analysis using rating agency methodology ratio benchmarks could be included to bolster DTE Gas' arguments."

Q. WAS THIS ISSUE OF MOVING TOWARD A BALANCED CAPITAL STRUCTURE ADDRESSED IN THE U-20642 SETTLEMENT AGREEMENT APPROVED BY THE COMMISSION?

A. Yes. In paragraph 12 of the Settlement Agreement, DTE Gas agreed to file a plan in this rate case that moves the Company toward a more balanced capital structure. There is no ambiguity about this agreement.

Q. WHAT IS THE COMPANY'S POSITION ON ACHIEVING A BALANCED CAPITAL STRUCTURE ISSUE IN THIS CASE?

A. Despite the Commission's directive in Case U-18999 and the Settlement Agreement in Case U-20642 calling for a move to a "balanced capital structure", the Company has not presented a plan to do so. Instead, on page 8 of his testimony, Company witness Edward Solomon recommends a 48% long-term debt ratio and a 52% common equity ratio. He also states that, apparently against his preference, Company witness Rajan Telang directed him to "…use 48.1% long-term debt and 51.9% common equity…", presumably as a means to show some minimal movement toward compliance with the Settlement Agreement.

On page 12 of his testimony, Mr. Telang cites the concept of "gradualism" on this point. However, the Company did not present a plan to get to a balanced 50/50 capital structure that would support a concept of gradualism. To the contrary, in his testimony Mr. Solomon lays out a number of reasons in an attempt to justify a 52% equity ratio.

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

A. No. Mr. Solomon makes several claims in an attempt to support his recommendation that a 52% common equity ratio should be maintained. His key points are summarized below.

1. The cost to customers will be higher if the equity ratio is lowered
2. Other utilities are increasing their equity ratios
3. Moody's 2019 downgrade of DTE Gas

4. Peak short-term debt at $300 million is problematic
5. DTE Electric's metrics are better than DTE Gas with depreciation being a factor
6. Cash flow volatility due to weather effects and the impact on key ratios

In my testimony below, I will respond to each of his claims.

Q. DO YOU AGREE WITH MR. SOLOMON THAT A HIGHER COST TO CUSTOMERS WILL RESULT FROM MOVING TO A 50% EQUITY LEVEL?

A. No. In discovery the Company was asked to provide the analysis to support his claim on page 8 of his testimony that "…increased debt costs will increase customer rates…." In his response to the discovery request Mr. Solomon stated that the "…Company has not performed such an analysis...."[28]

My analysis in Exhibit AG-22 shows that the Company's cash flow ratio results, at a 50% common equity level, does not reach the 15% debt to cash flow coverage threshold to trigger a potential downgrade by Moody's. Moreover, even if other factors occurred at some future date and the Company was downgraded by Moody's, from A1 to A2, the relevant consideration would be how much more interest would the Company pay on its long-term debt and whether the savings from using less common equity more than offset the higher debt cost.

Although I do not believe that the Company will be downgraded based on moving to a 50% common equity ratio, for sake of argument I have calculated what it would cost in

[28] DTE response to DR AGDG-6.200.

case a one notch downgrade by Moody's would occur. My analysis suggests that issuing debt at a debt rating of A2/A instead of A1/A may result in an additional 15 basis points of debt cost. However, the lower cost of having less equity in the capital structure would more than offset this additional cost. As shown in my analysis in Exhibit AG-23, the net annual savings to customers from the Commission approving a 50% equity ratio would be between $5.2 million and $8.4 million. The lower end of this range assumes that long-term debt costs go up by 15 basis points over time. The higher end of the range assumes that no significant change in the debt interest rate will occur.

Therefore, Witness Solomon's claims regarding higher customer costs are false.

Q. DO YOU AGREE WITH MR SOLOMON'S CLAIMS THAT UTILITY COMPANIES HAVE BEEN INCREASING THEIR COMMON EQUITY RATIOS OVER THE PAST THREE YEARS?

A. Some lower credit rated utilities with ratings of BBB have increased their equity ratios since the TCJA was passed to avoid being downgraded. In other cases, where utilities had strong credit ratings Mr. Solomon's statement is not true. Immediately after the TCJA was enacted, the rating agencies placed a number of companies on "credit watch" and this caused some realignment among some utilities and their regulators to adopt a more cautious approach to leverage. Many companies were not so adversely impacted by the TCJA and have not had a need to increase their equity ratios. For example, Northwest Natural Gas has actually decreased its equity ratio from 54.2% in 2016 to 49.3% in 2020 and it still maintains an "A" rating. Therefore, Mr. Solomon's claim is unsubstantiated.

Q. MR. SOLOMON DISCUSSES THE MOODY'S DOWNGRADE OF DTE GAS IN 2019 AT LENGTH IN HIS TESTIMONY. WHAT IS YOUR RESPONSE?

A. Mr. Solomon attempts to position the Moody's downgrade of DTE Gas in 2019 as something just short of a cataclysmic event. In fact, prior to the downgrade, Moody's had the Company rated two notches higher than the other two credit agencies and simply lowered its rating to be more in line to where it should have been. It is important to point out that Moody's still rates DTE Gas one notch higher than the comparable ratings of the other two rating agencies, Standard & Poor's (S&P) and Fitch Investor Service (Fitch).

In my testimony in Case No. U-20642, I discussed this same issue and it is perplexing why Mr. Solomon continues to raise this matter as it is a non-issue. As I stated in my testimony in U-20642, 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. The new Moody's credit rating of A1 (Stable) is still one notch above the A credit ratings by S&P and Fitch. 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-32 CONFIDENTIAL includes the Company's response to discovery question U20642-AGDG-1.73a.03 and supporting documents showing the credit rating misalignment. Mr. Solomon was a co-author of that internal correspondence.

Therefore, the Commission should disregard Mr. Solomon's testimony on this matter as no more than a scare tactic to prevent setting the equity ratio at a 50% balanced level.

Q. DO MR. SOLOMON'S COMMENTS REGARDING SHORT-TERM DEBT HAVE ANY VALIDITY?

A. Only minimally. Mr. Solomon's testimony on short-term debt is not entirely accurate. The Company's use of short-term debt is its most inexpensive source of capital. He spends considerable time on pages 17 and 18 of his testimony discussing the Company's peak short-term debt of $300 million in 2019 and how short-term debt requires some level of common equity support. In discovery, the Company was asked to provide the details of how Moody's computes the Company's cash flow to debt ratio "CFO pre-W/C to debt." The information provided by the Company shows that in the Moody's calculation the short-term debt for 2019 was at $167 million, which is far below the peak level that witness Solomon claimed to be relevant. [29]

Moreover, many companies, including some utility companies, sell their Accounts Receivable in order to reduce debt. In discovery, the Company was asked to explain if it had considered the sale of accounts receivable as a financing option. In its response, the Company stated that it had not analyzed this financing option and seemed concerned about the "discount" on the sale and "more aggressive collection" presumably as negative factors to dismiss the idea.[30] The response shows a lack of understanding about this financing option that could be beneficial to lower short-term debt if it is really a concern for the Company.

[29] DTE Gas response to AGDG-6.205.
[30] DTE Gas response to AGDG-6.203a.

Q. DOES WITNESS SOLOMON'S COMPARISON OF DTE ELECTRIC AND DTE GAS AND THE HIGHER DEPRECIATION COMPONENT AT DTE ELECTRIC HAVE ANY RELEVANCY?

A. No. While it is true that DTE Electric depreciates its property at a faster rate than DTE Gas, the electric utility requires more capital investment because it is involved in both generation and distribution of power. In contrast, DTE Gas is only a retail distributor of natural gas. DTE Electric is rated Aa3 by Moody's whereas DTE Gas is rated A1 by that firm. The stronger rating for DTE Electric may reflect a stronger cash flow situation due to depreciation among other factors. This comparison does little to support Mr. Solomon's argument for a 52% common equity ratio for DTE Gas.

Q. WITNESS SOLOMON DISCUSSES WEATHER VARIATIONS AS IMPACTING THE COMPANY'S CASH FLOW RATIOS. DO YOU AGREE THAT WEATHER VARIATIONS REQUIRE A HIGHER COMMON EQUITY RATIO?

A. No. While weather can impact cash flows and earnings, it can either increase or reduce cash flows depending if weather is colder or warmer-than-normal. Weather can change month to month and year to year. Not only are gas utilities such as DTE Gas affected by weather, but also electric utilities. Electric utilities, such as DTE Electric depend on hot summer months to sell electricity. Mild summers reduce their revenues, earnings, and cash flow.

In my experience with the rating agencies, they do not react to items they believe to be short-term variations. They are concerned with the "long-term." For example, in discussing the impact of the coronavirus on page 1 and 2 of its July 23, 2020 report,[31] Moody's notes at the end of the first paragraph on page 2 "…We see these issues as temporary and not reflective of the core operations or long-term financial or credit profile of DTE Gas…" Consistent with this thinking, on page 3 of the same report under "Factors that could lead to a downgrade," Moody's notes as factors, CFO pre-WC falling below 15%, a change in the regulatory environment, and insufficient cost recovery. Clearly, Moody's is more concerned with long-term impacts and not about weather variances that can increase or decrease cash flows in the short-term.

Q. DID YOU CALCULATE THE DIFFERENCE IN REVENUE REQUIREMENT OF INCREASING THE COMMON EQUITY RATIO FROM 50% TO 51.9%?

A. Yes. If the Commission were to adopt a 51.9% common equity level in this case, the revenue requirement would be higher by approximately $8.4 million. This reflects the Company's shift of approximately $81 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%.

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

A. No.

[31] See DTE Gas response AGDG-6.202 Attachment, which is the Moody's report referenced.

Q. **WHAT RETURN ON EQUITY AND OVERALL RETURN ON CAPITAL DO YOU RECOMMEND IN THIS CASE?**

A. I recommend an overall after-tax return on capital of 5.21%, 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 used the 3.97% rate determined by Company witness 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.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OVERALL COST OF CAPITAL IN 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 5.21%.

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 capital of 6.51% 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-23.

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 any 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 in 2020 and early 2021 and any potential changes in the risk profile of DTE Gas and the economy in the state of the Michigan. While Exhibit AG-23 shows a weighted average cost of common equity of 9.12% 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 $500 million in 2018, because of its relatively small size.

The result is the group of eight companies shown in Exhibit AG-24, 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 15 companies. These companies include six 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 six water companies is not necessary and should be disregarded. Four of the six water companies selected by witness Villadsen are small entities with annual revenues of approximately $600 million or less and with one as low as $53 million in revenue. In comparison, DTE Gas reported more than $1.4 billion in revenue for the year 2019.[32] Smaller companies have unique characteristics, such as low stock trading volume and illiquidity in the financial markets, which increase their cost of doing business

[32] Exhibit A-1, Schedule A2.

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 this case.

In addition, the common stocks of five of the six water companies have been trading at Price to Earnings (P/E) ratios of between 30 to 37 times trailing earnings during the fourth quarter of 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 peer group have been trading at an average P/E ratio of 19 times trailing earnings during early 2021.

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-33, I have included a Value Line report on the Water Industry that addresses the fragmented nature of the industry and the expected acquisition activity.

Q. ARE WATER COMPANIES COMPARABLE TO GAS UTILITIES?

A. No. 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.

Moreover, even if the Commission believed that the inclusion of water companies might be appropriate, several revisions to the peer group of water companies and the data presented by the Company would be warranted as explained below. For example, witness Villadsen shows a DCF growth rate for SJW Group of 14.6%. However, SJW merged with Connecticut Water Service in late 2019, thereby increasing its customer base from 231,000 to 370,000 customers (a 60% increase). Given the magnitude of this merger, significant synergies are likely, which are driving future earnings estimates. Because of the recent merger, this water company is a poor candidate to be in a "Water Peer Group."

Additionally, witness Villadsen's DCF growth rate of 15.1% for California Water shown on Schedule D5.5 is inappropriate. This rate of earnings growth was calculated from a deflated base of earnings. The current Value Line actual and projected earnings for California Water are shown in Exhibit AG-34. Based on more recent and normalized actual and forecasted earnings from the January 8, 2021 Value Line report, earnings are projected to increase from $2.00 per share in 2020 to $2.15 per share in 2021, which represents a 2% annual growth rate. witness Villadsen's DCF forecasted growth rate of 15.1% for California Water is simply a mechanical aberration which should be disregarded.

Because of the factors enumerated above, 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 17 on page 58 of witness Villadsen's direct testimony, the simple DCF result for the combined gas and water group is 11.8%, versus the gas sample result of 11.1%. This is because of an average DCF ROE of 12.8% for the water group, driven by high growth rates for California Water and SJW Group, which are erroneous as explained above. Regarding the CAPM results in Figure 17 of witness Villadsen's testimony, the results are somewhat more consistent, but it should be noted that these results for both CAPM, ECAPM, and DCF 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 skews 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 dividends and earnings 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-24. 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 February 18, 2021 to March 31, 2021. The annual dividend in column (d) is the projected average annual dividend level for the 2021-2022 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 2025 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 9.40% for the proxy group.

This result is lower than the Company's "simple" DCF study result for the gas group of 11.1%, but comparable to the Company's "multi-stage" DCF result of 8.7% calculated by witness Villadsen and shown in Figure 17 on page 58 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 DCF COST OF EQUITY FOR THE GAS SAMPLE IS SO MUCH HIGHER.**

A. The key difference between my 9.4% DCF cost of capital and witness Villadsen's DCF estimate for the gas group at 11.1% is the growth rates utilized. The growth rates she uses average 7.1% and were determined in the later part of 2020 and based exclusively on Value Line data. My DCF average growth rate is 5.7% and is an average of data from Value Line (6.7%) and data produced by other analysts and available through Yahoo (5.0%). I will point out that her growth estimates are stale at this point and the failure to use more than one source for estimates of growth is a questionable approach. Witness Villadsen's pre-ATWACC DCF cost of capital for her gas group is 10.7%.[33] The application of the ATWACC calculations escalate the DCF ROE rate to 11.1%.

[33] Exhibit A-14, Schedule D5.7 Panel A, column 3.

Q. PLEASE DESCRIBE THE ATWACC PROCESS AND WHY ITS APPLICATION BY THE COMPANY IN THIS CASE IS FLAWED?

A. Witness Villadsen's 11.1% Simple DCF for the gas group can be explained as follows. First, in Exhibit A-14, Schedule D5.7, she computes and shows the basic DCF result of 10.7% for her peer group of gas companies.

Second, starting with the 10.7% result noted in the preceding paragraph, witness Villadsen derives a 6.8% after-tax cost of capital for the gas peer group based on the market value of each of the companies in the peer group. The 6.8% 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 56% as noted in column 4 of Schedule D5.7.

Third, on Schedule D5.8, witness Villadsen redistributes the average after tax cost of 6.8% back to the debt and common equity components based on a 52% common equity ratio (not the 56% market to book ratio previously used), which results in her ROE determination of 11.1%.

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 mathematical 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.

Most likely because of this cost inflating circularity and the complexity of the methodology, the ATWACC method has not been embraced in 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 customer 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 9.44%.

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.

<u>Capital Asset Pricing Model Approach</u>

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-25 SHOWING THE RESULTS OF THE CAPM APPROACH.

A. Exhibit AG-25 shows the results of the CAPM method based upon (1) a projected 2.75% risk free rate as explained below; (2) Beta information available from Value Line; and (3)

Historical Market Risk Premium (R_p) information of 7.25% based on the Ibbotson Classic Yearbook through 2020.

As described on Exhibit AG-25, the 2.75% risk-free rate I used is based upon the projected interest rate of 2.00%[34] for the ten-year U. S. Treasury bond, plus a 75 basis point spread between the 10-year and the 30-year U. S. Treasury bond. This 75-basis point adjustment reflects the average spread during March 2021. The resulting 2.75% 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-25, I have added the peer group risk premium of 6.39% to the 2.75% risk-free rate to arrive at the 9.14% ROE rate under the CAPM method.

The 6.39% group risk premium is the risk premium for the total stock market of 7.25% shown in column (d) multiplied by the average beta of 0.88 from column (c). These factors are explained further in Exhibit AG-25.

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,

[34] The 2.0% rate reflects rates in March 2021 averaged with the Blue-Chip Forecast of 10 Year US Treasuries in 2023 of 2.3% (Per discovery response AGDG 6.182).

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 GAS GROUP CAPM COMMON EQUITY COST RATES RANGING FROM 9.4% TO 9.9%.

A. In Figure 14 on page 50 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 ATWACC methodology, which I 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 a 2.3% risk free rate and the historical risk premium results of 7.15% (1926-2019) and her Scenario 2 utilizes a 2.05% risk free rate and a higher risk premium of 7.35% (based on inputs from Bloomberg), which she states is forward looking. Using these MRP rates, she derives basic results of 8.5% in each case 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 50 of her direct testimony. She also characterizes her results and the historic MRP of 7.15% as conservative.

Q. DOES WITNESS VILLADSEN EXPLAIN WHY SHE BELIEVES THAT CURRENT OR FUTURE RISK PREMIUMS MAY BE HIGHER THAN THE 7.15% RISK PREMIUM DERIVED FROM HISTORIC RETURNS SINCE 1926?

A. Yes. On page 45; lines 10 to 13 of her direct testimony, she states "…I believe the 7.15 percent long-term risk historical average MRP value I rely on is a low-end estimate of what the market risk premium will be during the period at issue in this proceeding. I similarly believe that the 7.35 percent I rely on for my Scenario 2 is also conservative as the FERC approach would result is a substantially higher MRP." The result is that these two MRP rates (including the 7.35% forward looking rate) turn out to be lower than the 9.12% MRP discussed below.

However, on page 46 of her testimony, she states that utilizing FERC MRP methodology results in a 9.12% MRP as of November 30, 2020. Her analysis on this point is included on Schedule D5.17 and the workpapers supporting that schedule.

Q. WHAT IS YOUR ASSESSMENT OF THE ANALYSIS PERFORMED BY WITNESS VILLADSEN TO ARRIVE AT THE 9.12% MARKET RISK PREMIUM USING THE DCF MODEL?

A. I have reviewed this analysis and find it to be seriously flawed because of data inconsistency and the fact that several companies have been filtered out of the analysis. For example, in certain calculations, data is displayed for 58 companies but growth rates are shown for only 34 companies. This is due to witness Villadsen eliminating all companies whose growth outcomes were outside of her arbitrary 0% to 20% range. Other areas of the analysis show many omissions as well. In the calculation performed by witness Villadsen of the S&P 500 group of companies, if the company does not pay a dividend, it is also disregarded, rendering the result less representative of the so-called "market."

Furthermore, because of the COVID-19 pandemic, all of the companies in the airline industry and the cruise line industry (mature industries with slower growth) have been filtered out due to negative projected earnings. This in turn creates an upward bias to the outcome of this analysis. I estimate that this analysis covers approximately 60% of the companies that make up the S&P 500 group.

Witness Villadsen averages these results together to produce a 11.17% forecasted ROE for the S&P 500. From this percentage she deducts her long-term risk-free rate of 2.05% to arrive at a 9.12% MRP.

The Commission should disregard the MRP derived in this analysis since it is from an unreliable approach based on only a portion of the S&P 500 group, among other reasons discussed above.

Q. WHAT IS YOUR ASSESSMENT OF WITNESS VILLADSEN'S ECAPM 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 47 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 "…Consequently, 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.

<u>Utility Risk Premium Approach</u>

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-26 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 1.80% 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 October 2020 period over 30-year U.S. Treasuries for (1) A rated bonds of 171 basis points; and (2) BBB rated bonds of 185 basis points. For the risk-free rate, I used the projected 30-year Treasury rate of 2.75% discussed under the CAPM section of my testimony.

Q. ON PAGE 55 OF HER TESTIMONY, WITNESS VILLADSEN DISCUSSES HER "RISK PREMIUM APPROACH". WHAT IS YOUR POSITION ON HER APPROACH AND THE ROE'S PRODUCED BY IT OF 9.3% TO 9.6%?

A. While the 9.3% to 9.6% ROE results are close to my overall recommendation, this study is flawed and a poor tool to use to estimate the cost of common equity for utility companies. Witness Villadsen has examined rate case ROEs set by utility commissions from 1990 to 2020 relative to risk free rates (long U.S. Treasury bonds) during this time frame. The problem with this approach is that this model is devoid of any utility market data related to stock prices, dividends, growth or utility stock returns, and risk parameters normally associated with the DCF, CAPM, and the more standard Utility Risk Premium approach. Instead, her model is oriented around the reaction of utility rate commissions as interest rates change. This is not a valid empirical approach to calculating the cost of equity capital and, as such, the Commission should disregard it.

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

A. As a result of the Covid-19 pandemic, the United States entered a recession in 2020, with Gross Domestic Product falling from $21.4 trillion in 2019 to $20.9 trillion in 2020. The combined effects of federal government assistance payments to businesses, stimulus payments to individuals, and low interest rates are producing a strong economic rebound with Value Line now projecting that Gross Domestic Product will reach $22.4 trillion in 2021. This is a 7% increase over the 2020 level.[35] The Michigan economy has rebounded in line with the national economy.

The Company's access to the capital markets, along with that of its sister company, DTE Electric, is strong as witnessed by (1) DTE Gas issuing $250 million of 10-year and 30-year long-term debt with rates ranging from 2.35% to 3.20% in August 2020; and (2) DTE Electric issuing $1.7 billion of 10 year and 30-year long-term debt at rates ranging from 2.25% to 2.95% in February and March 2020.

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 2020 issuing $1.8 billion of new long-term debt with maturities ranging from 2 to 60 years.

[35] Value Line Investment Survey dated April 2, 2021 at page 1500.

Accordingly, the Company's recommendation that the authorized rate of return on common equity should be increased to 10.25% to continue to have access to capital markets is unsupported by the evidence. The proposed ROE 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 9.2%.

Q. PLEASE DISCUSS WHAT RETURN ON EQUITY RATES OTHER REGULATORY COMMISSIONS HAVE GRANTED IN 2019 AND 2020?

A. Since 1990, return on equity rates for gas utility companies granted by regulatory commissions in the U.S. have been in a steady decline, from over 12.7% in 1990 to approximately 9.76% in 2019 and 9.46% in 2020. This decline has generally followed the significant decline in interest rates.

Exhibit AG-29 shows the ROEs granted by state regulatory commission to U.S. gas utilities in 2019 and 2020. The majority of the 29 ROE decisions in 2019 and 34 decisions in 2020 are at rates well below 10%. As noted on page three of this exhibit, only 7 decisions in 2019 and 1 decision in 2020 are at rates of 10% or greater. These higher rates are from Wisconsin, which is an outlier among the regulatory commissions around the country. ROEs in California have been over 10% reflecting the unique challenges of that state (wildfires and earthquakes). The 2019 decision in Georgia is a situation involving Atlanta Gas Light, where the Georgia commission reduced the prior ROE from 10.75% to 10.25%. This is a multi-year agreement with limited annual increases permitted and with excess earnings being subject to refund. Clearly this situation is very different from how utility regulation operates in Michigan and in most other jurisdictions.

For most of the other gas utilities that have business and financial risks comparable to DTE Gas, the ROE rates have averaged around 9.50% in the past two years. This evidence supports my proposed ROE rate of 9.50% and makes the Company's current ROE rate of 9.90% excessive. The Company's proposed ROE rate of 10.25% 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-29 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-28 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 9.10%. Yet this group of companies has an average Market to Book common equity value ratio of nearly 1.6 times.

This information is provided to dispel the myth that the Company must receive a ROE near 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 of 9.50% or below. 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 29 through 31 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 rates 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-35, 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. For example, 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 0.88 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. PLEASE EXPLAIN YOUR CONCLUSION CONCERNING THE APPROPRIATE RETURN ON EQUITY RATE THE COMMISSION SHOULD USE IN THIS CASE.

A. In Exhibit AG-23, 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 8.55% at the low end, using the Utility Risk Premium approach, and 9.40% 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 9.12%. In this regard, on line 4 of Exhibit AG-23, 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 9.12%. To this base cost of equity capital, I have added an additional premium adjustment of 38 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 very well 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.

Second, natural gas prices are at historically low levels, which afford 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 9.20% true cost of capital at this time, preferring instead a more gradual reduction. The 9.50% ROE rate I have proposed is a reasonable reduction from the last granted ROE of 9.90% to DTE Gas.

Q. IF THE COMMISSION APPROVES A 9.90% COST OF COMMON EQUITY IN THIS CASE (AS IT DID IN CASE NO. U-20642), WHAT IS THE COST TO CUSTOMERS COMPARED TO AN ROE OF 9.50%.

A. If the Commission were to grant a 9.90% ROE in this case versus a 9.50% ROE, the additional cost to customers is approximately $12 million annually. There is absolutely 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%.

VII. 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, Midstream Services, and the Appliance Service Program are significantly understated. The total incremental revenue that I propose is $43.7 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. On line 14 of page 1 of Exhibit A-15, Schedule E1, Company witness George Chapel presents the Company's forecast of gas sales for the projected 2022 test year. The Company forecasted total gas sales of 152 Bcf for the projected test year. This level of sales represents a decrease of approximately 8 Bcf, or 5%, from the actual weather-normalized gas sales of 160 Bcf in 2019.

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 2018 to July 2020.[36] The models also make use of other historical and projected data, including number of customers, 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 estimated impact on sales from the COVID-19 pandemic.

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

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

A. In discovery, the Company was asked to provide the weather-normalized actual gas sales and the average number of customers for each year from 2014 to 2021 for each rate schedule. In response, the Company provided a limited amount of information from September 2015 to April 2021 and also the external adjustments made to the forecast model for the estimated impact of the COVID-19 lockdown on sales. The Company also provided information on estimated sales reductions from Energy Waste Reduction (EWR) and the increase in sales from changes in customer counts from sources other than new

[36] Exhibit AG-36 DR AGDG-5.145, 5.53, and 5.154.

customer attachments. Exhibit AG-37 includes discovery responses AGDG-5.146 and 5.157d with related attachments.

Based on the information provided by the Company, I have determined that the sales from increases in customer counts more than offset the reduction in sales from the EWR program for 2021 and 2022. However, the Company assumed that the estimated impact on sales in 2020 attributed to the COVID-19 pandemic would continue into 2021 and 2022, although somewhat abated. As discussed on pages 10-12 of Mr. Chapel's direct testimony and shown in the attachment to discovery response AGDG-5.146 in Exhibit AG-37, the Company has reduced forecasted sales for 2021 and 2022 by a cumulative volume of 7,225 MMcf, which it attributes to the continued impact of COVID-19 into the projected test year of 2022. The largest forecasted sales reductions are for Residential Rate A and Commercial Rate GS-1 customer groups, with a small reduction for School Rate S.

I find this conclusion unreasonable and unsupported by recent sales data. Although it appears that the lockdown beginning in March 2020 and continuing to a lesser degree into the first quarter of 2021 may have had some impact on residential and commercial sales during the first half of 2020 due to the initial reaction to the lockdown and financial concerns by customers, the evidence now shows that any previous impact on sales has begun to reverse and will likely disappear by 2022, as residential and commercial customers return to normal routines.

This reversal is apparent from analyzing the weather-normalized sales data provided by the Company for the 12 months ended August 2019, 12 months ended August 2020, and

12 months ended April 2021. As shown in Exhibit AG-38, normalized residential gas sales declined by 1.9% during the 12 months period ended August 2020 from the 12 months ended August 2019, likely as a result of the initial reactions and uncertainty brought by the COVID-19 lockdown. However, during the 12 months ended April 2021 normalized Residential Rate A sales increased by 1.2% in comparison to the 12 months ended August 2020 period. This is a clear indication that the initial reduction in sales during the first half of 2020 has dissipated and apparently reversed.

The same trend is apparent when reviewing the comparison of normalized sales for commercial sales Rate GS-1 and the School Rate S. The rate of sales decline for GS-1 customers has moderated from 4.5% to 3.5%, reflecting some increases in sales in recent months. For School Rate S, the rate of decline of 2.3% has reversed to an increase of 7% in the most recent 12 months ended April 2021.

Therefore, the projections by the Company that the COVID pandemic will continue to impact sales into 2022 is unsupported by recent data and from reasonable expectations that residential, commercial, and school customers will continue to return to normal or near-normal activities. Supporting these expectations is also the fact that the economy continues to grow with employment and wage increases. These economic factors bode well for further sales increases, particularly in the commercial sector.

Q. DID YOU DETERMINE THE INCREASE IN REVENUE FOR THE PROJECTED TEST YEAR BY REMOVING THE COVID-19 SALES REDUCTION FORECASTED THE COMPANY?

A. Yes. In Exhibit AG-39, I show the cumulative sales reduction of 7,225 Mcf forecasted by the Company for 2021 and 2022 that has been attributed to COVID-19 for Schedules Rate A, GS-1, and S. By applying the current volumetric distribution rate to each rate schedule sales, I have calculated an increase in revenue of $25,700,107 from removing the COVID attributed sales from the Company's sales forecast.

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

A. Yes. In reviewing the direct testimony of Company witness Henry Decker, I discovered that a dozen end-use transportation customers moved from transportation service to regular gas sales service under Rate Schedule GS-1. According to Mr. Decker's testimony, the transfer of the annual load is approximately 0.4 Bcf or 400,000 Mcf.[37]

I response to discovery, the Company reported that the gas sales forecast for the average GS-1 customer for 2022 was 411 Mcf.[38] This volume multiplied by the 12 customers who moved to GS-1 sales means that only 4,932 Mcf of gas sales were included in the 2022 gas sales forecast when those customers previously used 400,000 Mcf annually. In effect the Company's sales forecast is understated by the difference of 395,068 Mcf (400,000 – 4,932).

[37] Henry Decker direct testimony at page 16. On lines 8 through 14, Mr. Decker identifies total loss of 0.8 Bcf with 0.3 Bcf attributed to Exelon and 0.15 Bcf to two customers. The remaining amount is 0.4 Bcf attributed to a dozen small customers moving to Rate Schedule GS-1 gas sales.
[38] Exhibit AG-40 includes DR AGDG-5.162b and 13.413.

By applying the current GS-1 distribution rate of $3.4909 per Mcf, I have determined that the Company's forecasted gas sales revenues need to be increased by an additional $1,379,143.

Q. WHAT IS THE TOTAL INCREASE IN GAS SALES REVENUE THAT YOU PROPOSE?

A. I recommend that the Commission adopt a total revenue increase of $27,079,250 for the projected test year as a reasonable adjustment to the Company's pessimistic and understated revenue projection.

B. End-User Transportation (EUT) Revenue

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

A. On page 1 of Exhibit A-15, Schedule E7, Mr. Decker presents the Company's forecast of gas transportation volumes for the 2022 projected test year. The Company forecasted total transportation volume of 146.2 Bcf for the projected test year. This level of sales represents a decrease of approximately 10.5 Bcf, or 6.7%, from the actual transportation volumes billed in 2019. As shown on page 2 of the exhibit, the decline is attributed primarily to changes in customers' operational requirements, customers closing their facilities or transferring to gas sales rates, energy optimization, and changes in power generation gas deliveries. The decline in gas deliveries is partially offset by deliveries to new transportation customers.

In my testimony below, I will discuss certain adjustments to the Company's proposed EUT gas deliveries in the areas of power generation, decreases in miscellaneous forecasted volumes, and the energy optimization volume reduction.

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

A. 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 September 2015 to August 2020. The average volume delivered during this five-year period was 59.1 Bcf.[39] On page 2 of Exhibit A-15, Schedule E7, he adjusted this average amount to 61.4 Bcf for the 12 months ended December 2022. In comparison, the Company transported 61.7 Bcf of gas to these customers in 2019. In his direct testimony, Mr. Decker states that the Company used a five-year average due to the unpredictable operation of the Peaker power plants it serves and the volatility due to summer temperatures, natural gas prices, power plant outages, new power generations customers, and power plants ceasing operation.

[39] Henry Decker direct testimony beginning on page 15.

In his testimony, Mr. Decker presented information for annual cycles ended August with the most recent year being 12 months ended August 2020. In discovery, the Company was asked to provide the actual deliveries to power generation for the five calendar years from 2016 to 2020 in order to obtain more current information. The calendar year information shows a slightly higher 5-year average of 59.6 Bcf versus the Company's calculation of 59.1 Bcf.[40]

More importantly, the five-year history shows that, with the exception of 2017, the remaining four years had power generation gas deliveries above 60 Bcf, with 2020 reaching 67 Bcf. The deliveries of 46.9 Bcf in 2017 appear to be an aberration. The volatility in deliveries that Mr. Decker seems to emphasize in his testimony is not showing in the actual deliveries, other than in small changes from year to year, particularly in the most recent three years.

Therefore, a five-year average is not an appropriate basis to calculate a projection of the power generation deliveries that are likely to occur in 2022. The average of the most recent three years results in power generation volumes of 63.1 Bcf. Removing the 2017 anomalous volumes and using the other four years results in an average volume of 62.8 Bcf. This four-year average is only slightly lower than the 3-year average.

[40] Exhibit AG-41 includes DR AGDG-5.151a.

Q. HAS THERE BEEN A PATTERN OF ACTUAL POWER GENERATION VOLUMES EXCEEDING THE PROJECTED VOLUMES INCLUDED IN THE LAST THREE RATE CASES?

A. Yes. In prior rate cases, the Company has forecasted power generation volumes based on the five-year average. In response to discovery, the Company provided schedules that show actual volumes exceeding forecasted volumes in Case No. U-17999 by 14.2 Bcf, and in Case No. U-18999 by 17.3 Bcf. With regard to Case No. U-20642, the forecasted test year used in that rate case is not complete yet. However, based on the first six months of the test year, the comparison shows that actual power generation deliveries have exceeded the forecasted volumes in that case by 1.9 Bcf, with the summer months yet to come when most of the peaking generation occurs. Exhibit AG-41 includes this comparative volume information.

In other words, the evidence is clear that the fiver-year average approach preferred by the Company has significantly understated the forecast for power generation deliveries. The Commission should not allow this problem to reoccur in this rate case.

Q. WHAT IS YOUR RECOMMENDATION?

A. My recommendation is to use the average volumes of 63.1 Bcf for the most recent three calendar years for the simple reason that they represent the most recent usage by power generation customers. The difference between the 63.1 Bcf, or 63,100 MMcf, and the Company's forecast of 61,353 MMcf is approximately 1,747 MMcf.

In Exhibit AG-42, I calculated the incremental revenue applicable to the additional 1,747 MMcf of transportation deliveries at approximately $497,000. Therefore, I recommend that the Commission adopt the 63.1 Bcf volume and related incremental revenue of $497,000 for the projected 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 regarding an unsupported reduction in forecasted deliveries for 2022 and the removal of forecasted energy optimization volume reductions.

With regard to the first item, beginning on page 16, lines 22-25, and going into line 7 of page 17, Mr. Decker discusses the loss of transportation deliveries to specific customers and leaves unexplained 4.7 Bcf of reductions in forecasted deliveries to various EUT customers.[41] His testimony simply states that this forecasted decrease is due to lower 2022 volumes spread out among various EUT customers. He also states that the volume projections were developed using actual volumes from the 12 months ended July 2020 and from specific customer dialogue.

In discovery, the Company was asked to provide a copy of the analysis showing how it arrived at the 4.7 Bcf projected volume reduction. In its response, the Company basically

[41] On page 16, lines 22, Mr. Decker identifies a total loss of 9.0 Bcf for the projected test year and attributes 4.5 Bcf and 1.0 Bcf to three customers. These total to 5.5 Bcf. This decrease is partially reduced by 1.2 Bcf of new load from two customers, leaving 4.7 Bcf unexplained (9.0 – 5.5 + 1.2 = 4.7 Bcf).

repeated Mr. Decker's testimony with no further support to justify the lower projection, other than to state that it was based on a 5.0 Bcf reduction due to recent actuals. Exhibit AG-43 includes the discovery response.

In addition to being incomplete, this explanation is contradicted by actual gas deliveries for 2020. In response to discovery, the Company provided a schedule that shows actual 2020 EUT gas deliveries at 155.1 Bcf, which are only slightly below the 2019 deliveries of 155.4 Bcf. This information shows that the 2020 customer volume losses were miniscule. Exhibit AG-43 also includes discovery response AGDG-5.177a with this information.

This is not the first time that the Company has underestimated forecasted EUT volumes. A comparison of actual gas deliveries to the volumes forecasted in prior rate cases reveals that the Company has grossly underestimated future gas deliveries. In Case No. U-17999, the Company underestimated total EUT deliveries by 14.5 Bcf. Similarly, in Case No. U-18999, the Company underestimated EUT volumes by 23.8 Bcf. With regard to Case No. U-20642, actual EUT volumes for the first six months of the projected test year are running 0.4 Bcf above forecast despite the impact on manufacturing and other large volume commercial and industrial customers from the COVID-19 pandemic. Exhibit AG-43 includes the gas delivery comparisons.

In summary, the Company's unsupported reduction in 2022 EUT deliveries of 4.7 Bcf is not credible. Therefore, I recommend that the Commission adopt my adjustment to remove this reduction in EUT deliveries and increase EUT revenue by $3,257,000, as calculated in Exhibit AG-42.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR THE ENERGY OPTIMIZATION VOLUMES?

A. The Company has reduced gas deliveries for the future test year by 880 MMcf for 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 projected test year. Although the Company has implemented an energy waste reduction program for various customer groups, 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 to the Company. Without such evidence, it is neither fair nor reasonable to reduce future gas deliveries and revenue.

It is also informative to note that in the prior rate Case No. U-20642, the Company forecasted 401 MMcf of energy optimization losses, or less than half the volume forecasted in this case. Both forecasts have been unsupported. Therefore, I recommend that the Commission reject the EUT volume reduction of 880 MMcf in the calculation and as a result increase end-user transportation revenue for the projected test year by $918,000.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A. The Company has understated its EUT volumes and revenue forecast for the projected test year in the three areas discussed above. Therefore, as calculated in Exhibit AG-42, I recommend that the Commission increase the Company forecasted revenue by $4,672,241.

C. Midstream Services Revenue

Q. WHAT ARE YOUR FINDINGS FROM ANALYZING THE COMPANY'S PROJECTED LEVEL OF REVENUE FOR MIDSTREAM SERVICES?

A. In Exhibit A-13, Schedule C3.3, Mr. Decker presents the Company's forecast of revenues for Contract Storage, Park & Loan, Off-system Transportation and Exchange Services for the projected test year. After reviewing Mr. Decker's direct testimony and responses to several discovery requests, I have determined that the revenue forecast for off-system transportation is reasonable. However, I found that the revenue forecast for contract storage, park & loan services and exchange gas services are significantly understated.

Q. PLEASE DISCUSS YOUR FINDINGS WITH REGARD TO THE SERVICES THAT ARE UNDERSTATED.

A. In determining its Midstream Services forecasted revenues for the projected test year, the Company generally used a three-year average of the actual revenues billed from 2017 to 2019. In response to discovery, the Company provided actual revenues for 2020 in addition to prior years. In total, Midstream revenues in 2020 were approximately $4 million higher than in 2019 and $38 million higher than in 2017. Generally, Midstream revenues since 2018 have been on a significant uptrend.[42]

Therefore, using the most recent three years from 2018 to 2020 to forecast 2022 revenues is more appropriate and advisable. In Exhibit AG-45, I have calculated the three-year average revenue for contract storage, park & loan, and exchange services, and compared those amounts to the Company's forecast. The difference is an increase in revenue of $5,311,000.

I recommend that the Commission adopt the updated three-year calculation and increase the Company's Midstream revenue by $5,311,000.

D. Appliance Service Program Revenue

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

A. Yes. I propose an adjustment to the Appliance Service Program's ("ASP" or "HPP") profit margin for the projected test year.[43] 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 $82.2 million for the projected test year as it billed for 2019.

---

[42] Exhibit AG-44 includes DR AGDG-5.179a with attachment.

[43] Company witness Henry Decker discusses the Appliance Service program on page 35 of his direct testimony.

In response to discovery, the Company provided the actual revenues for the HPP from 2014 to 2020 with related operating expenses. The response shows a steady increase in revenues, with 2020 revenues reaching $86.6 million, or $4.4 million above the 2019 level. Exhibit AG-46 includes the response to data request AGDG-5.173b with this information.

In Exhibit AG-46, I have also calculated the profit margin or operating income between revenues and operating expenses. From this calculation, it is apparent that the year 2019 is not representative of the revenue and profit margin earned in the most recent year of 2020, or for that matter in any of the prior five years. In other words, using the 2019 revenues, operating expenses, and profit margin as a proxy for future test year amounts would result in an inaccurate and unreasonable forecast amount.

Adopting the Company's preferred approach of using the most recent revenue amount for this item, I propose to use the actual revenue of $86.6 million for 2020 and the related operating expenses of $60.6 million and profit margin of $26.6 million as the best information to project 2022 operating income. This results in an increase in operating income of $6.6 million over the Company's forecast.

Q. HAS THE COMPANY RAISED CERTAIN OBJECTIONS WITH USING 2020 REVENUES AND OPERATING EXPENSES?

A. Yes. In response to discovery, the Company states that it performed fewer appliance repair calls in 2020 due to warmer-than-normal weather and customer concerns with the COVID-19 virus. As such, the Company points out that operating expenses were lower than they would have been otherwise. These concerns are not credible. First, customer concerns with COVID-19 would not have prevented customers from having repair work done on the gas furnace and other appliances. These are necessities and customers need to have working appliances in order keep the house or business heated, and the household functioning for cooking, washing, drying clothes, and satisfying other similar needs.

Second, the Company has provided no analysis to support the premise that warmer or colder-than-normal weather has a significant impact on the number of calls made and its operating expenses. Third, the Company's revenues increased in 2020 by $4.4 million over the prior year. Unless, the Company significantly increased it service fee per call, the higher revenue contradicts the premise that fewer calls were made in 2020. Although operating expenses decreased in 2020 from 2019, this is likely the result of the Company and its subcontractors operating the program more efficiently than in prior years.

Q. HAS THE COMPANY SHOWN AN INCLINATION TO UNDERSTATE THE FORECASTED REVENUE AND OPERATING INCOME OF THE APPLIANCE SERVICE PROGRAM?

A. Yes. At least in the last three rate cases, the Company has proposed to use the actual revenue amount and related operating income from the historical test year in forecasting for the projected test year. As shown from the uptrend in revenue in Exhibit AG-46, those forecasts have fallen short of actual in every case.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission adopt the 2020 revenue and operating expenses shown in Exhibit AG-46 and increase the Company's projected operating income by $6.6 million.

Q. WHAT IS THE TOTAL REVENUE INCREASE THAT YOU RECOMMEND?

A. As shown in Exhibit AG-47, I recommend that the Commission approve a total increase of $43,662,491 to the Company's forecasted revenue.

VIII. O&M Expenses Adjustments

Q. WHAT AMOUNT OF O&M EXPENSE DID THE COMPANY INCUR DURING 2019 AND WHAT IS THE LEVEL OF PROJECTED EXPENSE REQUESTED FOR THE 12 MONTHS ENDING DECEMBER 2022?

A. As shown in Exhibit A-13, Schedule C1, the Company is requesting recovery of $591.1 million in O&M expenses for the future test year 2022, which is $81.7 million more than the historical test year. The following table summarizes the major components:

	Millions of Dollars		
O & M Expense Category	**2019 Test Yr.**	**Increase (Decrease)**	**Projected 2022 Test Yr.**
Company Use & LAUF Gas	$ 38.9	$ (11.5)	$ 27.4
Uncollectible Accounts Exp.	37.8	2.4	40.2
Other O&M	432.7	90.8	523.5
Total O&M	**$ 509.4**	**$ 81.7**	**$ 591.1**

In my testimony below, I will address the Uncollectible Accounts expense forecasted by the Company and related adjustments. With regard to the Other O&M expense, the $90.8 million increase in expense includes $30.7 million of projected inflation adjustments and several other projected cost increases 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 to the Other O&M category are summarized in Exhibit AG-51.

A. Uncollectible Accounts Expense

Q. PLEASE SUMMARIZE HOW THE COMPANY ARRIVED AT ITS PROPOSED $40.2 MILLION EXPENSE AMOUNT FOR UNCOLLECTIBLE GAS ACCOUNTS FOR THE PROJECTED TEST YEAR.

A. Company witness Tamara Johnson discusses the uncollectible expense beginning on page 17 of her direct testimony and also sponsors Exhibit A-13, Schedule C5.7. Company witness Theresa Uzenski sponsors Exhibit A-13, Schedule C5.7.1 in support of the proposed uncollectible expense deferral and amortization.

Exhibit A-13, Schedule C5.7, shows that the Company started its calculation of the uncollectible expense for the test year by using three years of booked uncollectible expense from 2016, 2017, and 2019. The Company averaged the three years of expense to arrive at a three-year average amount of $31,623,000. I will point out here that the historical amounts represent the uncollectible expense that the Company estimated and recorded on its books in those years and they do not reflect the actual bad debt charge-offs in those years. Later in my testimony, I will discuss how using actual net charge-offs is a more sound approach.

To the three-year average amount of $31,623,000, the Company adds an arbitrary amount of $6,190,000 to arrive at the amount of $37,813,000, which equates to the uncollectible expense it recorded in 2019. In effect, the Company has abandoned the three-year average and established 2019 as the appropriate uncollectible expense base from which to forecast the 2022 test year amount. To the 2019 base amount the Company adds an amortization amount of $2,385,000 to arrive at its forecasted uncollectible expense of $40,198,000 for the year 2022.

Q. HOW DID THE COMPANY CALCULATE THE $2,385,000 AMORTIZATION AMOUNT?

A. The $2,385,000 amortization amount represents the difference between the 2019 baseline amount of $37,813,000 and the $27,000,000 uncollectible expense assumed in the settlement agreement in Case No. U-20642. This difference of $10,813,000 was increased by $1,111,000 of uncollectible expense that the Company decided to defer for 2020 as a result of the Commission order in Case No. U-20757. The total of the two amounts is $11,913,000, which the Company has proposed to amortize over five years at an annual amount of $2,385,000.

Q. DO YOU AGREE WITH THE COMPANY'S $40.2 MILLION FORECAST FOR UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. No. There are several problems with the Company's forecast of $40.2 million of uncollectible expense. First, it assumes that the single year of uncollectible expense of

$37.8 million recorded by the Company in 2019 is representative of the uncollectible costs that will be incurred in 2020, 2021, and 2022. This is not the case.

In response to discovery, the Company reported that it recorded uncollectible expense of $35.1 million in 2020, which is lower than the 2019 amount.[44] This is despite the concern that the COVID-19 lockdown would increase uncollectible cost in 2020. It did not. To arrive at the $35.1 million the Company increased the Average Reserve Factor to 23% of accounts receivable from 21% in prior years. This had the effect of increasing uncollectible expense by $2.8 million.

Additionally, the Company lowered the amount of Estimated Recoveries to $10 million in comparison to an average of $12.5 million in the prior two years. This increased uncollectible expense by $2.5 million. If these two items are adjusted to normal levels, the $35.1 million of uncollectible expense for 2020 should have been $29.8 million. Apparently, the Company expected a greater number of customers to avoid paying their bills. In response to another discovery request, the Company stated that "There had not been a material increase in bad debt or uncollectible accounts in the past 12 months."[45] This discovery response undermines the Company's calculation of uncollectible expense of $35 million for 2020 and exposes the unsupported recording of deferred uncollectible costs which have not materialized.

[44] Exhibit AG-48 includes DR AGDG-13.397.
[45] Id., DTE Gas response to Staff Data Request JEU-1.8.

Second, it is unknown at this time what the level of uncollectible costs will be in 2021 and 2022 with any degree of certainty to permit the recovery of $11.9 million of deferred uncollectible costs over five-years beginning in 2022. As discussed above, given the fact that uncollectible costs have not risen since the onset of the COVID-19 pandemic and related lockdown, there is no reason to expect that in 2021 and 2022 uncollectible costs will increase over 2020. With more customers and businesses returning to normal work schedules, an improving economy, and billions of dollars of financial assistance coming from the federal and state governments, the ability for customer to pay their gas bills will improve rather than deteriorate. With the improving ability to pay, the 2020 adjusted uncollectible expense of $29.8 million will likely drop to or near the $27 million level stated in the settlement in Case No. U-20642. Therefore, the need to defer $10.8 million of uncollectible costs is not necessary or advisable, because it is not likely to materialize.

Third, in response to discovery, the Company provided the amount of past due accounts receivable at each quarter end from the first quarter of 2018 to the first quarter of 2021, along with the amount of accounts receivable charged-off from non-payment for the same time period. This information, which is included in Exhibit AG-49, shows that past due accounts receivable for the four quarterly periods after the start of the COVID-19 lockdown are lower than the same quarterly periods in 2018 and 2019. For example, in the first quarter of 2021, the Company reported past due balances of $94.6 million for active accounts and $11.5 million for closed accounts that were issued a final bill. In comparison, in the first quarter of 2019, the Company had active past due balances of $135.1 million and $19.4 million for closed accounts. Similarly, accounts receivable charge-offs were down in 2020 from the prior two years by as much as $5 million. During the first quarter of 2021, charge-offs were down approximately $7 million lower than the same quarter in 2020. In other words, uncollectible costs are not a problem that require phantom deferrals or special cost recovery mechanisms.

More importantly, simply comparing the 2019 uncollectible expense, which occurred pre-COVID-19, to the $27 million threshold to arrive at deferral amount is fundamentally flawed. This comparison does not show that COVID-19 lockdown increased uncollectible costs, it simply shows that the 2019 uncollectible expense recorded by the Company exceeded the $27 million threshold sent in Case No. U-20642. To allow the Company to recover this difference in costs is in effect an improper recovery of historical uncollectible costs pre-COVID-19. The Commission should not allow such a cost recovery.

Q. WHAT APPROACH DO YOU PROPOSE TO SET UNCOLLECTIBLE EXPENSE FOR THE PROJECTED TEST YEAR?

A. I propose to use the Commission-approved methodology of a three-year average of charge-offs to revenues. The Commission has indicated in several cases that the use of a three-year average ratio of charge-offs to revenues applied to future revenue is the most appropriate way to forecast uncollectible accounts expense. This approach also works for forecasting the uncollectible expense for the 2022 projected test year due to the fact that the COVID-19 lockdown did not increase uncollectible costs in any measurable way when comparing 2020 costs and 2021 trends to prior years.

This is in contrast to the Company's approach of using booked uncollectible expense for three years and then selecting only 2019 as the base amount to build to the 2022 forecast as discussed above. The booked expense for uncollectible accounts can fluctuate from year to year due to a number of reasons including assumptions made by the Company, temporary events, and the adequacy of the reserve account at the outset of any one particular year. Therefore, using booked uncollectible expense, and particularly a single year to estimate future uncollectible expense, as the Company has done in this case, is not wise or appropriate.

Q. WHAT IS YOUR PROJECTED AMOUNT FOR UNCOLLECTIBLE EXPENSE FOR 2022?

A. For 2022, I have forecasted uncollectible accounts expense of $35,877,000 using the three-year historical ratio of net charge-offs to revenue for 2017, 2019, and 2020, as discussed above. Exhibit AG-50 shows the calculation. Line 4 shows the average percentage of 2.5% as the ratio of net charge-offs to revenue for the three-year historical period. This percentage is multiplied by the projected 2022 test year revenues of $1.435 billion on line 5 to derive the forecasted amount of uncollectible expense of $35,877,000 on line 6.

This amount represents a reduction of $4,341,000 from the Company's proposed amount of $40,198,000.

Q. YOUR PROPOSED UNCOLLECTIBLE EXPENSE FOR THE PROJECTED TEST YEAR DOES NOT INCLUDE ANY AMORTIZATION EXPENSE FOR

UNCOLLECTIBLE COSTS DEFERRED BY THE COMPANY. PLEASE EXPLAIN.

A. As discussed above, during 2020 the Company incurred lower uncollectible costs than it did in 2019. Additionally, current accounts receivable past due amounts have been running at lower levels since the second quarter of 2020 than in the prior two years. Therefore, there is no evidence that uncollectible costs have increased to warrant the recording of deferred amounts in a regulatory asset in 2020 or 2021.

I reviewed the $1,111,000 of deferred uncollectible costs recorded by the Company to the regulatory asset account for 2020 due supposedly to the COVID-19 lockdown. To arrive at the deferred amount, the Company estimated increased uncollectible expense beginning in March 2020 and monthly through December 2020. In the schedule provided in response to discovery, there is no explanation, methodology or basis articulated as to how the Company was able to determine soon after the start of the lockdown in March 2020 that it had incurred $1.8 million of incremental uncollectible costs due to the COVID-19 lockdown.[46] The testimony of Company witnesses Johnson and Uzenski is also silent as to how the Company would know that the amount of uncollectible expense calculated by month during 2020 were due to the COVID lockdown. In fact, there is no explanation whatsoever in their testimony as to how the monthly uncollectible amounts were determined. It would take months past March 2020 to determine what the impact, if any, of the lockdown would have been on uncollectible cost. As I have demonstrated in my

[46] Exhibit AG-48 includes DR AGDG-212a and b.

testimony above, all the evidence with past due balances and charge off of past due accounts receivable points toward lower uncollectible costs, not higher.

The deferred costs recorded by the Company in the regulatory asset account were calculated based on inflated projections of uncollectible expense for 2020 and future years against a low threshold of $27.0 million negotiated in the settlement to Case No. U-20642. My testimony above makes this fact abundantly clear. The Company did not suffer any financial loss in 2020 from higher uncollectible costs and is not like to do so in 2021 or 2022.

My conclusion is that no deferral and amortization of deferred uncollectible costs is necessary for 2020 and future years. Therefore, I recommend that the Commission approve an uncollectible accounts expense amount of $35,877,000 for the projected test year without any deferral or amortization of prior year amounts.

Q. IN HIS TESTIMONY COMPANY WITNESS RAJAN TELANG PROPOSES THE IMPLEMENTATION OF AN UNCOLLECTIBLE EXPENSE TRUE-UP MECHANISM. HOW DO YOU RESPOND?

A. The Uncollectible Expense True-Up Mechanism (UETM) is not necessary. On page 13 of his direct testimony, Mr. Telang states that the UETM will ensure that DTE Gas is not harmed by the COVID-driven increase in uncollectible expense, while also providing a safeguard for DTE Gas's customers if uncollectible expense returns to levels less than the forecasted amount that is included in rates.

There are two basic reasons to reject the Company's proposal. First, the premise that uncollectible costs have increased significantly due to COVID-19 is false. The Company may have forecasted a higher expense level for 2020 and future years, and may want to use those amounts to support its argument, but my testimony above proves the opposite. Given that uncollectible costs did not increase in 2020 and are not likely to increase in 2021, there is no need to protect the Company or customers from any excessive costs that are likely to materialize.

Second, trackers such as the UETM remove the incentive for utilities to control costs and in the case of uncollectible costs to take all reasonable steps to collect past due gas bills. If the utility can easily recover higher uncollectible costs through an automatic cost tracking mechanism there is less incentive to pursue collection actions. This is a well understood business principle. As Mr. Telang identified in his testimony, the Commission in prior years had approved a UETM and also other cost tracking mechanisms for DTE Gas and other utilities. However, in more recent years the Commission realized that those mechanisms were no longer necessary or desirable for the reasons I described, and it proceeded to reject them in various rate cases.

In this rate case, I have proposed an uncollectible expense amount of $35.9 million, which is considerably more than the $27 million stated in Case No. U-20642. The $35.9 million amount provides the Company with a sufficient expense level to cushion against any potential increases in uncollectible costs in 2022.

Therefore, I recommend that the Commission reject the Company's proposal to implement the UETM.

Q. ARE THERE RECENT RATE CASE FILINGS THAT SUPPORT YOUR CONCLUSIONS WITH REGARD TO UNCOLLECTIBLE EXPENSE?

A. Yes. Consumers Energy filed a rate case for its electric business in March 2021, which was approximately three weeks after DTE Gas filed this rate case. Consumers used the same historical year of 2019 and projected test year of 2022. In projecting its uncollectible expense for 2022, Consumers used the three-year average of net charge-offs to revenue and applied that ratio to the revenues for the projected test year, as I have done in this rate case for DTE Gas.[47] Furthermore, Consumers did not propose any uncollectible cost deferral in a regulatory asset for 2020 or future years and did not propose a UETM or any similar uncollectible expense true-up mechanism. It would appear that Consumers did not experience an increase in uncollectible costs due to the COVID lockdown in 2020 and is not anticipating an increase in future years.

Also, on March 22, 2021, Michigan Gas Utilities Corporation (MGUC) filed a general rate case for its gas business using the same 2019 historical period and 2022 projected test year. MGUC also used the historical ratio of net charge-offs to revenue to calculate its 2022 forecasted uncollectible expense and did not propose recovery of any deferred uncollectible costs, nor did it propose a mechanism to true-up future uncollectible costs.

[47] MPSC Case No. U-20963, Karen Gaston direct testimony and Exhibit A-85 (KMG-4), page 2.

B. 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 $30.6 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 rates developed by the Company are 2.8% (2020), 2.9% (2021), and 3.0% (2022) as shown on Exhibit A-13, Schedule C12. The use of a "blended rate" inclusive of wage increases has been rejected by the Commission in recent general rate cases.

More importantly, and contradicting some of the Company's testimony in this case, DTE Gas has not experienced across-the-board inflationary 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 2019.[48] It is therefore difficult to understand why the Company would project inflation-related cost increases at an annual rate of 2.8% to 3.0% for 2020, 2021, and 2022.

The Company also has stated in testimony that investments in technology will result in increased operating efficiencies and reduction in O&M costs. These cost savings should offset any inflation. The Company has not provided any evidence that its operations are

[48] Michael Cooper direct testimony at page 56.

facing inflationary cost pressures that it cannot manage in the course of operating its business. It is more than likely, based on historical results, that the proposed $30.6 million in inflationary cost increases will not happen and that the Company can manage its business in a manner that it can offset any such costs. In such a case, the $30.6 million would provide a financial windfall to the Company.

I am aware of the fact 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 in fact 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 $30.6 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.

C. 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 $30.6 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 55.7% weighting), and contractor's costs (a 33.6% weighting). For the remainder of its O&M costs (10.7%) the Company has escalated this component by the CPI rates of 1.3%, 2.3% and 2.6% in 2020, 2021, and 2022 respectively. The result of these calculations is a set of composite or blended projected rates of inflation of 2.8% to 3.0% for all periods as explained above.

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-52 includes a copy of the CPI-Urban index inflation rates from IHS Markit for 2020, 2021, and 2022. These more recent CPI rates are 1.2% for 2020, 2.2% for 2021, and 1.5% for 2022. These rates are lower than the CPI rates utilized by the Company in its projections.

In Exhibit AG-53, I have calculated the inflationary cost increases under this approach. The amount of inflation cost adjustment would be approximately $17.0 million, or $13.6 million below the amount proposed by the Company.

The Commission should not grant any inflationary cost increases above the $17.0 million level. In fact, given the evidence presented above, the Commission should remove the entire $30.6 million of projected inflation increases, which is my primary proposal in this case.

D. Gas Storage, Transmission & Distribution

Q. PLEASE DISCUSS YOUR ADJUSTMENTS TO THE COMPANY'S TEST YEAR O&M EXPENSE FOR GAS STORAGE TRANSMISSION AND DISTRIBUTION OPERATIONS.

A. For the historical 2019 test year, the Company incurred $12.5 million of O&M expense for Gas Storage, $57.9 million for Transmission, and $118.9 million for Distribution operations. The total O&M expense for the three areas was $189.3 million. In comparison, for the projected test year the Company has forecasted a total amount of $236.2 million. Exhibit A-13, Schedules C5.1, C5.2 and C5.3 provide additional information along with the direct testimony of Company witness Mark Johnson who sponsors the O&M expenses for these three operations.

In addition to $17.0 million of inflation cost increases discussed earlier, the Company included $29.9 million of incremental expenses in the projected test year for the three operations above the 2019 base amount. The $29.9 million of additional expense represents a 17% increase over the historical test year expense level. In my testimony below I will address some of the larger expense increases and propose certain adjustments, which are also listed in Exhibit AG-54.

<u>1. ROW Maintenance</u>

Q. **PLEASE EXPLAIN WHAT ADJUSTMENTS YOU PROPOSE FOR ROW MAINTENANCE.**

A. The Company proposes to increase spending for right-of-way (ROW) maintenance by $3.0 million in 2022. On page 17 of his direct testimony, Mr. Mark Johnson discusses the Company's plan to accelerate the clearing of 650 miles of transmission pipeline ROW in 2022 through mechanical brushing and herbicide treatment.

In discovery, the Company was asked to provide the number of miles cleared annually in prior years and to explain why 650 miles need to be cleared all in one year instead of spreading the effort over multiple years. In response, the Company reported that in 2020 and the prior five years, it cleared generally less than 25 miles of ROW per year, with 2016 being the exception at 84 miles. The amount of herbicide spraying also has been very erratic in the past six years, with zero to at most 128 miles (2018) being cleared.

The response also stated that the Company had rethought its plans and was reducing the number of miles planned for mechanical brushing to 500 from 650 and was now planning to apply herbicide to 550 miles of ROW, all still at the same $3.0 million incremental expense for 2022. In its response, the Company also stated that it wanted to clear 550 miles all in one year in order to secure the best unit price and to remediate overgrown transmission pipeline ROW. Exhibit AG-55 includes the Company's discovery response information.

Q. **WHAT IS YOUR ASSESSMENT OF THE COMPANY'S PLANS FOR TRANSMISSION ROW CLEARING.**

A. The Company's plans are not sound and certainly not well thought through. It appears that in prior years, the Company has neglected to perform sufficient transmission pipeline ROW clearing and now wants to perform a one-year surge in 2022. This work should be spread at least over a three-year period. Whether done in one year or over three years, pricing should not be significantly different and perhaps more advantageous if spread over a three-year period because it would provide some work continuity to contractors who will perform this work. Hopefully, the Company will continue some level of elevated ROW clearing in future years past the three-year period to avoid reoccurrence of the problem.

Therefore, I recommend that the Commission approve only an incremental $1.0 million in O&M expense for this item for 2022 and remove the remaining $2.0 million from the Company's forecasted test year expense.[49]

2. TIMP Pipeline Integrity

Q. PLEASE DISCUSS THE COMPANY'S TIMP PIPELINE INTEGRITY EXPENSE FOR THE HISTORICAL AND PROJECTED TEST YEAR.

A. For the historical 2019 period, the Company had expenses of $17.1 million for TIMP Pipeline Integrity.[50] For the projected test year, the Company has forecasted expenses of $19.2 million, which is a $2.1 million increase over 2019. In Case No. U-20642 and specifically on page 14 (lines 16 to 23) of his direct testimony, witness Mark Johnson stated that the Company would be ramping up expenses in this area to get on a "seven-year inspection cycle" and increase the number of miles inspected by ILI.[51] In Exhibit A-13, Schedule C5.2, in Case No. U-20642, the Company forecasted an increase of $8.4 million for TIMP Pipeline Integrity for the projected test year ended September 2021, from the 2018 historical expense of $10.3 million. This should have placed the total expense at more than $18 million for the 12 months ended September 2021.

[49] Company's proposed increase of $3.0 million over three years is $1.0 million per year.
[50] Transmission Integrity Management Program (TIMP).
[51] ILI is a pipeline In Line Inspection electronic tool that provides information on the internal characteristics and integrity of the pipeline inspected.

However, the forecasted ramp up in TIMP Pipeline Integrity expense has not materialized as forecasted. In response to discovery request AGDG-4.128b, the Company reported only $10.3 million of expense in 2020 and 13.5 million for 2021. This is after the Company increased the expense level to $17.1 million in 2019. Exhibit AG-56 includes the discovery response.

The Company has not made a consistent commitment to a higher expense level in order to achieve the 7-year inspection cycle and will likely spend less than it requested in Case No. U-20642. This lack of consistency in spending to achieve the 7-year inspection cycle undermines the Company's credibility. As such, I believe that the best way to forecast future expenses for TIMP Pipeline Integrity is to use a three-year historical average.

Actual expenses in 2018, 2019, and 2020 were $10.3 million, $17.1 million, and $10.3 million, respectively. These amounts average to an annual amount of $12.6 million, which is $6.6 million below the Company's estimate of $19.2 million. Accordingly, I have reduced the Company's forecasted expense for TIMP Pipeline Integrity for the projected test year by $6.6 million as shown in Exhibit AG-54. I recommend that the Commission adopt this lower level of expense.

3. TCARP Transmission Fees

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR TCARP TRANSMISSION FEES FOR THE PROJECTED TEST YEAR.

A. In conjunction with the development of the Traverse City-Alpena Reinforcement Project (TCARP), the Company has contracted with two affiliates, DTE Michigan Lateral Company (DMLC) and Saginaw Bay Pipeline Company (SBPL), for those companies to provide transportation services through their transmission lines. The annual transportation charges forecasted by the Company are $9,839,725 under the proposed transportation agreement with DMLC[52] and $1,747,716 under the proposed transportation agreement with SBPL[53] for a total annual amount of $11,587,441. In footnote 2 in Exhibit A-13, Schedule C5.2, the Company shows a slightly higher amount of $11,625,000 for 2022.

Q. WHAT IS YOUR ASSESSMENT OF THE TRANSPORTATION AGREEMENTS AND THE RELATED FEES FORECASTED FOR 2022?

A. Both DMLC and SBPL have filed applications with the Commission under Act 9 to obtain approval to build facilities and charge new demand charges under the transportation agreement with DTE Gas. The application by DMLC in Case No. U-20894 is currently going through hearings for the determination of adequate construction requirements and fair and reasonable charges under the transportation agreement, among other issues. I filed testimony in that case on behalf of the AG proposing lower transportation demand charges for each of the pipeline segments under the transportation contract. My recommendation is for a total annual demand charge of $5,650,407 instead of the $9,839,725 agreed to between DMLC and DTE Gas. The difference is $4,189,318.

[52] MPSC Case No. U-20894, Steven Richman direct testimony at page 6.
[53] The Application by SBPL in Case No. U-20993 states a monthly demand charge of $145,643 x 12 = $1,747,716.

With regard to the SBPL application filed in Case No. U-20993, SBPL has requested *ex parte* approval by the Commission. As of the date of my testimony, the AG has intervened in the case and has requested that the case be litigated due to concern about the potential impact on costs to be paid by DTE Gas and ultimately its customers. No hearing date has been set yet in this case.

Although it is likely that the Commission may issue an order in both cases before an order is issued in this rate case, the appropriate demand charge that the Commission will approve under each of the transportation contract is unknown at this time. Given the position that the AG has taken in Case No. U-20894 and the recommendation for a lower demand charge, I have removed the $4,189,318 incremental transportation expense from the Company's forecasted O&M expense for the DMLC contract.

With regard to the SBPL transmission fees, until the Commission decides whether to grant *ex parte* approval or schedules the case for contested hearings and issues an order in Case No. U-20993 approving the appropriate demand charge to be billed to DTE Gas under the transportation agreement, it is premature to include any amount in this rate case.

Therefore, I have removed the $1,747,000 of transportation expense for the SBPL transportation contract from the Company's forecasted 2022 O&M expense.

In total, for the two transportation contracts I have removed $5,937,000.

4. MAOP Records Remediation Expense

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED MAOP EXPENSES FOR THE PROJECTED TEST YEAR AND ANY REQUIRED ADJUSTMENTS.

A. On page 19 of his direct testimony, Mr. Johnson discusses federal rules which require the Company to undertake a records review of its pipelines' MAOP to resolve records defects, including reaffirmation of MAOP beginning in 2020 if the Company does not have traceable, verifiable, and completed records. Mr. Johnson states that the Company will begin to undertake records remediation beginning in 2021 and will require $4.9 million of O&M expense in 2021 to perform this task. In response to discovery request AGDG-7.219a, the Company stated that Exhibit A-13, Schedule C5.2, had an error and the $4.9 million for MAOP Records Remediation should have been $5.9 million with zero expense for Records Defect Remediation instead of $1.0 million.[54]

The requirement to remediate MAOP records has been in existence since at least 2012. The new rule issued in October 2019, and effective beginning in 2020, requires reaffirmation of the MAOP and not the start of a records review process. In response to discovery, the Company reported that it incurred no O&M expenses between 2017 and 2020 with minimal amounts in 2015 and 2016, but has now forecasted $4.0 million of expense for 2021 and $5.9 million in 2022. Exhibit AG-57 includes the discovery response.

[54] Exhibit AG-57 includes DR AGDG-7.219a.

As discussed under the Capital Expenditures section of my testimony, the Company is responsible to have complete and accurate records about its pipelines, including records supporting the MAOP. The Company has undertaken capital spending to remediate some of the gaps in its records and has requested recovery of 100% of those costs. In that section of my testimony, I proposed that the Commission only approve recovery of 50% of the proposed capital spending as a fair and reasonable sharing of the remediation costs between the Company and customers. The same holds true here. Customers should not be responsible for 100% of the O&M expense for defects, gaps, and other problems that are the responsibility of the Company. The Company should be held accountable for those problems, even if they go back decades, and should be responsible for at least 50% of the costs to remediate its records.

Therefore, I recommend that the Commission remove 50%, or $2.95 million, of the $5.9 million in O&M expense proposed by the Company for the 2022 test year.

5. Pipeline Safety Management Systems (PSMS)

Q. **THE COMPANY HAS FORECASTED $2.0 MILLION FOR PSMS EXPENSE FOR THE PROJECTED 2022 TEST YEAR. WHAT IS YOUR ASSESSMENT OF THE FORECASTED AMOUNT?**

A. There are a few inconsistencies with the amounts proposed by Mr. Johnson and discussed in his testimony. First, while Mr. Johnson included $2.0 million as an increase in expense in Exhibit A-13, Schedule C5.16, Line 7, between 2019 and 2022, the actual increase is $1.6 million. In discovery, the Company disclosed that it spent $0.4 million in 2019 on this expense item and now expects to spend $2.0 million in 2022.[55] As such, the increase is $1.6 million and not $2.0 million.

Second, on page 17 of his direct testimony in Case U-20642, Mr. Johnson forecasted O&M expense of $0.5 million for 2019, $1.3 million for 2020, and $1.0 million for the 2021 test year, which he characterizes as "…Ongoing program support…." Based on his testimony in that case, it would be expected that $1.0 million of annual expense is an appropriate level for 2022 as well. Furthermore, the Company fell considerably short of its forecasted expense level in 2020, spending only $0.4 million instead of the $1.3 million proposed in Case U-20642.

Based on the inconsistencies and actual spending level discussed above, I recommend that the Commission only allow $1.0 million of O&M expense in this area and remove the remaining $1.0 million of expense.

6. Meter Abnormal Condition Expense

Q. THE COMPANY HAS REQUESTED A $1.5 MILLION INCREASE IN O&M EXPENSES TO REMEDIATE CERTAIN ABNORMAL METERS. WHAT IS YOUR ASSESSMENT OF THE COMPANY REQUEST?

A. Beginning on page 34 of his direct testimony, Mr. Johnson discusses the Company's plans to remediate meters with Abnormal Operating Condition (AOC Meters). This is a condition that may indicate a malfunction of a component or deviation from the normal

[55] See DTE Gas response to discovery request AGDG-4.132a.

operating condition of the meter due to atmospheric corrosion and other reasons. Although Mr. Johnson implies that the Company is implementing a new initiative, AOC meters are not a new phenomenon. They have existed before.

The Company spent $583,000 in 2020 and $471,000 in 2019 to remediate AOC meters with smaller amounts in the previous two years. In discovery, the Company was asked to explain the reason for the higher expense level of approximately $2.0 million in 2022 and to provide the number of meters remediated in prior years, the number forecasted for 2022, and the annual backlog of AOC meters to be remediated.

In response to discovery, the Company could not clearly articulate why it is requesting an increase in the expense level, other than to state that it plans to remediate the existing backlog and other upcoming AOC meters as required by code. This explanation does not provide sufficient information to justify a five-fold increase in expense from 2019 to 2022. Furthermore, the outstanding backlog at the end of each year does not track with the number of AOC meters discovered and remediated each year.[56] The discovery response shows no significant backlog at the end of 2019 or 2020. Therefore, it is difficult, if not impossible, to reconcile the historical activity and spending in this area to the remediation activity and expense amount proposed for 2022.

[56] AG-58 includes DR AGDG-4.135a-c, and AGDG-12.393b.

Due to the lack of adequate justification for the additional expense, I recommend that the Commission only approve the spending level of $0.5 million in 2019 and remove the proposed increase of $1.5 million from the Company's O&M forecast.

Q. WHAT IS THE TOTAL AMOUNT OF EXPENSE ADJUSTMENT THAT YOU PROPOSE FOR STORAGE, TRANSMISSION AND DISTRIBUTION?

A. In total, I propose the Commission approve a reduction in O&M expense for these three operations of approximately $20.0 million.

E. Meter Reading Expense

Q. THE COMPANY HAS FORECASTED $5.1 MILLION OF METER READING EXPENSE FOR THE PROJECTED TEST YEAR. DO YOU AGREE WITH THIS FORECAST?

A. No. In response to discovery the Company reported that it incurred approximately $4.7 million of meter reading expense in the 2019 historical year and a slightly higher amount in 2020. For 2021 and 2022, the Company has forecasted expense of $5.0 million and 5.1 million, respectively. These amounts exclude the allocation of incentive compensation. Exhibit AG-59 includes the information provided in response to discovery request AGDG-4.139a.

The Company was also asked to provide the number of meters that still need to be read manually, as it continues to convert meters to automated meter reading. In response to discovery, the Company reported that in 2019 it read 101,581 meters manually. That number declined to 75,411 in 2020 and is expected to decline further in 2021 and 2022 to a level of 47,000 in 2022. The percent decline between 2019 and 2022 is 54%, and 38% between 2020 and 2022. Exhibit AG-59 includes the number of meters read manually versus those read through automated meter reading. These are the source data from which the numbers and percentages of manually read meters were calculated.

What is apparent from this information is that while the number of manual meter reads is expected to decline significantly, the forecasted meter reading expense is increasing in both 2021 and 2022. This is a significant disconnect between forecasted costs and the underlying activity that should justify those costs. Although it should be expected that as fewer meters remain to be read manually, the cost to read the remaining meters increases due to the increased distance between remaining manually-read meters. However, the lower number of meters to be read manually should result in a net decline in meter reading expense. I also understand that there are some fixed costs with office personnel and automated meter reading functions, but the net result should still be a meter reading expense that declines as opposed to increase in 2022.

To establish a reasonable amount of meter reding expense for 2022, I have taken the rate of decline of 54% in the number of manually read meters from 2019 to 2022 and cut it in half to 27%. This reduction takes into consideration the fact that are certain meter reading fixed costs and also higher costs per meter for those meters remaining to be read manually.

By applying the 27% reduction rate to the 2019 meter reading expense of $4,738,101, I calculated a projected meter reading expense of $3,458,814 for 2022.[57] This amount is $1,637,620 lower than the Company's forecasted amount of $5,096,434. The expense reduction reflects the reduction in manual reads in the projected test year and also provides an incentive to the Company to further reduce meter reading costs including reassessing the level of office staff, fixed costs, and other avoidable costs.

Therefore, I recommend that the Commission adopt the expense amount of $3,458,814 and remove the remaining amount of $1,637,620 from the Company's O&M forecast.

F. Health Care Costs

Q. THE COMPANY HAS FORECASTED THAT ITS ACTIVE EMPLOYEE HEALTH CARE EXPENSES (MEDICAL, DENTAL AND VISION) WILL INCREASE FROM $17.0 MILLION IN 2019 TO $21.4 MILLION IN THE FUTURE TEST YEAR. DO YOU AGREE WITH THIS INCREASE?

A. No. The forecasted increase of health care O&M expense to $21.4 million represents an annualized increase of 8% per year. Mr. Cooper accomplishes this feat by taking a novel, unorthodox approach to forecasting health care costs. First, he determines an average cost per employee of $11,382 for 2019 by adjusting 2015 to 2019 costs through a "constant dollar normalization" process.[58] Second, he escalates the $11,382 cost per employee by national average health care trend rates of 5.7% for 2020, 5.2% for 2021, and 4.7% for

---

[57] $4,738,101 x (1-0.27) = $3,458,814.

[58] Actual costs per employee are escalated by PWC trend rates as shown on Exh. A-13, Sch. C5.9.3

2022.[59] Third, he multiplies the result of his calculations by 2,491 employees. Fourth, he applies a 65% allocation factor to determine the portion of health care costs chargeable to O&M expense.

Q. WHAT IS YOUR ASSESSMENT OF THE CALCULATIONS PERFORMED BY MR. COOPER AND THE RESULTING FORECAST?

A. The problem with Mr. Cooper's analysis and calculations is that the $11,382 constant dollar adjusted cost per employee for 2019 is divorced from reality. This amount is 8.2% higher than the actual cost in 2019 of $10,518. Mr. Cooper is simply compounding inflationary increases on top of inflationary increases over the eight-year period from 2015 to 2022. The Commission should not accept this brazen attempt to inflate forecasted O&M expenses.

Q. HAVE YOU CALCULATED A MORE APPROPRIATE EXPENSE FOR HEALTH CARE FOR THE PROJECTED TEST YEAR?

A. Yes. In Exhibit AG-60, I calculated a forecasted expense of $18.6 million for the projected test year. To arrive at this amount, I used information obtained from Mr. Cooper's Exhibit A-13, Schedule C5.9.3, which has the average cost of health care per employee from 2015 to 2019. The average annualized increase in the average cost per employee is 3% between 2015 and 2019. The 3% average rate of increase already reflects any inflationary increase

[59] Aon health care trend rate of 6.2% reduced to 5.7% (2020), 5.2% (2021) and 4.7% (2022) - Wellness.

in costs year over year as actually experienced and therefore it is not necessary to further inflate it as Mr. Cooper has done.

Using the 3% annual rate of increase and applying it to the actual costs in 2019 and subsequent years, I calculated the 2022 expense at $18.6 million after allocating a portion of the costs to capital expenditures. This is a reasonable forecast of health care expense for the projected test year based on actual cost trends, in contrast with the Company's artificially derived expense of $21.4 million.

I recommend that the Commission approve the $18.6 million of forecasted health care expense for 2022 and remove $2.8 million from the Company's forecasted O&M expense in this case.

G. Supplemental Severance Plan

Q. EXHIBIT A-13, SCHEDULE C5.9 SHOWS $0.7 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 23 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 at retirement. This plan makes up for the difference in the richer retirement benefits for those employees who previously participated in the former MCN Energy Group pension plan versus 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 and it is worth pointing out that companies entering into a merger under similar circumstances typically capitalize this liability at the time of acquisition with an offsetting amount of goodwill. DTE Energy's approach for this benefit was to wait some fifteen years after the acquisition of MCN to begin cost recognition of this benefit item thereby attempting to avoid any "goodwill taint." 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. As mentioned above, 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 $740,000 from the Company proposed O&M expense for the future test year.

H. Customer Service Expenses

Q. PLEASE SUMMARIZE THE O&M EXPENSE FORECASTED BY THE COMPANY FOR THE PROJECTED TEST YEAR FOR CUSTOMER SERVICE ACTIVITIES.

A. Exhibit A-13, Schedule C5.4, shows that the Company incurred $59.0 million of expense in 2019 for Customer Service operations, after certain adjustments, and has forecasted expense of $73.7 million for the projected test year. This amount includes $4.7 million of blended inflation cost increases, as discussed earlier, and an additional $10.0 million of expense increases. Below, I will discuss the two major items that drive the additional $10 million in expense.

1. Merchant Fees

Q. THE COMPANY HAS FORECAST AN INCREASE OF $5.6 MILLION IN CUSTOMER MERCHANT FEES BETWEEN 2019 AND THE FUTURE TEST YEAR. DO YOU AGREE WITH THIS INCREASE?

A. No. Line 6 of Exhibit A-12, Schedule C5.4, shows an increase of approximately $5.6 million in credit card merchant fees between 2019 and 2022. In his direct testimony, Company witness Benjamin Burns provides a brief discussion of merchant fees and sponsors Exhibit A-13, Schedule C5.8 to support the merchant fees of $11.1 million forecasted for 2022. In this exhibit, the Company assumes that merchant fees will continue to increase at an annual rate of 22.4% for residential customers and 32.2% for non-residential customers, based on the three-year rate of growth from 2017 to 2019. The exhibit also shows the reduction in fees pertaining to the limitation as to which non-residential customers can use credit cards to pay their utility bills after 2019.

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

A. The basic problem with the Company's forecast is that it assumes the three-year rate of growth will continue unabated into 2020, 2021, and 2020. As more and more customers pay their gas bill with a credit card there are fewer customers left who will make use of credit cards to pay their gas bills. This is basic logic. The 2020 actual data support this conclusion. In response to discovery, the Company reported that in 2020 it incurred $6,955,000 of merchant fees.[60] In comparison to the amount of $6,887,000 incurred in

[60] Exhibit AG-61 includes DTE Gas responses to Staff Audit Requests TMS-1,1 and TMS-1.2.

2019, merchant fees increased only by 4% between 2019 and 2020. Likely, this decline reflects a tapering off of the additional number of customers paying gas bills with credit cards and also reflects the restriction on non-residential customers beginning in 2020.

Q. WHAT IS YOUR FORECAST OF MERCHANT FEES FOR THE PROJECTED TEST YEAR?

A. With the use of credit cards abating in 2020, I believe the 4% rate of increase in credit card fees is a reasonable rate of increase to use to forecast merchant fees for 2022. By applying the 4% rate to the actual amount in 2020 of $6,955,000 and again for 2022, I calculated merchant fees of $7,523,000 for the projected test year.[61] This amount is $3,586,000 lower than the Company's forecast of $11,109,000.

I recommend that the Commission adopt the forecasted amount of $7,523,000 and remove the remaining $3,586,000 from the Company's forecasted O&M expense.

2. Customer Experience Pay Increase

On page 15 of his testimony, witness Henry Campbell states that O&M expense for the Customer Experience function was forecasted to increase by $3.8 million and provides scant information about the drivers of this expense item, other than a later discussion on page 16 of wage increases for Customer Service Representatives (CSRs).

In response to discovery, the Company divulged that the $3.8 million consists mostly of the addition of 120 CSRs in a surge of personnel additions to address expected customers

---

[61] ($6,955,000 x 1.04 x 1.04 = $7,523,000).

calls for high bills, time of use rate changes, low-income customer assistance, and on-going training and development of employees.[62] The Company did not explain why these are new issues of significant concern that will justify the addition of 120 CSRs.

To the contrary, in her direct testimony, Company witness Angie Pizzuti discusses at length how the new digital tools have given customers access to information on the Company's website and have reduced customer calls. In fact, Ms. Pizzuti proposes millions of dollars of additional spending to permit customers to transact digitally with the Company and further reduce customers calls and CSR employees.

The addition of 120 CSRs is not adequately supported or justified. Therefore, most of the proposed expense increase of $3.8 million needs to be removed. Based on the information provided by the Company in discovery response AGDG-10.347b, included in Exhibit AG-62, the total amount of the forecasted expense increase for 2022 is $11,245,000 for both gas and electric operations. Of this amount, $2,028,000 pertains to CSR special wage increases and the remaining amount of $9,217,000 pertains to the CSR surge of 120 employees and related costs. The amount applicable to the gas business is $3,115,000, based on the allocation percent of 33.8%.

I recommend that the Commission remove the $3,115,000 from the Company's forecasted O&M expense for the projected test year.

[62] Exhibit AG-62 includes DR AGDG-10.347a.

I. Administrative and General Expenses

Q. WHAT ADJUSTMENTS TO THE ADMINISTRATIVE AND GENERAL EXPENSES FOR THE PROJECTED TEST YEAR DO YOU RECOMMEND?

A. Expenses in the Administrative and General area, as shown on Company Exhibit A-13, Schedule C5.6, are forecasted to increase from $106.6 million in the 2019 historical period to $124.1 million in the projected test year, reflecting an increase of $17.5 million or 16.4%. This increase includes (a) $5.0 million for blended inflation cost adjustments; (b) $9.7 million for increased Capital Use Charges billed by DTE Electric; (c) $1.7 million for IT charges, including ClickSoft fees related to the Customer Service area; (d) $0.9 million of increased corporate membership fees; and (e) $0.3 million for higher MGP amortization expense.

In my testimony below I will propose certain adjustments to the Injuries and Damages expense and the Capital Use Charges. I will also discuss and propose disallowances of incentive compensation expense and capitalized amounts as a separate topic.

1. Injuries and Damages Expense

The Company proposed an increase of $2.6 million to the injuries and damages expense from $4.2 million in 2019 to $6.8 million in the projected test year. Exhibit A-13, Schedule C5.6, shows the calculation used by the Company to arrive at the $6.8 million. The Company's forecasted amount is based on the five-average amount from 2015 to 2019. The Schedule C5.6 shows that injuries and damages costs have been trending down since 2015.

In response to discovery, the Company stated that it has taken proactive steps to lower litigation costs and reduce work injuries and lost workdays, among other initiatives. The Company also provided the actual expense of $4,692,230 for 2020. Exhibit AG-64 includes this information.

In Exhibit AG-63, I have recalculated the five-year average from 2016 to 2020 at $5.8 million, which is $1.0 million lower than the Company's forecast. I recommend that the Commission remove the $1.0 million for the Company forecasted 2022 O&M expense.

2. Rents - Capital Use Charges

On line 15 of Exhibit A-13, Schedule C5.6, the Company shows forecasted Rents expense of $47.8 million. This amount represents an increase of $9.7 million, or 25%, over the 2019 historical period. This expense item consists mainly of two types of costs: (1) shared building space by the various DTE Energy subsidiaries, including DTE Gas, and (2) shared IT systems among the Company's businesses. For most of these costs, DTE Electric (DTEE) incurs the expense or capital outlay and then invoices the applicable share of the cost to DTE Gas in the form of Rents or Capital Use Charges. For capital outlays, DTEE calculates the annual depreciation expense and a return on investment, which is billed as a Capital Use Charge to DTE Gas.

2a. Capital Use Charges - Facilities

Q. PLEASE DISCUSS THE AMOUNT OF SHARED COSTS CALCULATED BY THE COMPANY PERTAINING TO BUILDINGS, FURNITURE AND EQUIPMENT FOR THE PROJECTED TEST YEAR.

A. In Exhibit A-13, Schedule C5.15, the Company shows capital expenditures at DTEE for 2020, 2021, and 2022 for projects expected to go into service in those years. The capital expenditure amounts are $24.6 million for 2020, $18.6 million for 2021, and $10.0 million for 2022. The expenditures are primarily for remodeling of office space at the DTE Energy headquarters' building, an outdoor plaza area, the Shelby Service Center, and unspecified future work for $5.0 million in 2022.

In discovery, the Company was asked to explain what work was being done at each location and why this work was necessary at this time given the uncertainty of how many office employees will work remotely and how many will return to their office location at some unknown date in the future. In response, the Company stated that the remodeling work for 2021 and 2022 was being done to upgrade facilities, make the office space more agile, and support future office needs, among other reasons. The Company also stated that although there is uncertainty when DTE will return back to the office, the renovation projects are needed to maintain proper asset health. Exhibit AG-65 includes the Company's discovery responses.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S FORECAST OF SHARED COSTS FOR 2021 AND 2022 FOR BUILDINGS, FURNITURE AND EQUIPMENT?

A. The proposed capital renovations for 2021 and 2022 should be postponed until a later date after the Company decides how many employees will return to the office and its space needs can be better determined. The remodeling projects do not appear necessary at this time. It is not clear what agile office design means and what future office needs the

Company will have. In fact, in response to discovery requested AGDG-7.237b, the Company stated that projects for 2022 on the 23rd and 24th floors of the WCB building have been put on hold due to unknown scope and timing.[63]

In Exhibit A-13, Schedule C5.15, line 17, column (g), the Company has identified a cumulative shared cost to be incurred by DTE Gas for the capital projects in 2020, 2021, and 2022. Assuming that the 2020 projects were initiated before the COVID lockdown and therefore unavoidable, I have accepted those costs. However, as discussed above, the projects for 2021 and 2022 should be postponed to a later date and the related Shared Asset Cost should be removed from this rate case.

Therefore, I recommend that the Commission remove $685,000 of O&M expense from the Company's forecasted amount for 2022.[64]

2b. Capital Use Charges – IT Projects

Q. PLEASE DISCUSS THE SHARED ASSET COSTS PERTAINING TO IT SYSTEMS.

A. There are two components for the IT Shared Asset Costs included in the Capital Use Charges. The first pertains to IT projects for customer service operations sponsored by witness Angie Pizzuti. The second component pertains to customer service, corporate applications, and other IT projects sponsored by witness Jaison Busby. Some of the IT projects for customer service seem to overlap between the testimony of Ms. Pizzuti and

[63] Exhibit AG-65.
[64] Exhibit A-13, Schedule C5.16, line 17, column (g) amount of $928,000 less $243,000 from column (e).

Mr. Busby, which tends to complicate and confuse things. In total, the two witnesses have sponsored 130 projects as listed in Exhibit A-13, Schedule C5.13.1, and Exhibit A-13, Schedule C5.14. In my testimony below, I will discuss 16 of these projects and propose related cost disallowances.

For most of the projects where I will propose cost disallowances, the common theme is that the Company has not adequately justified the need for the project, has not provided sufficient or completed information, or the project should generate sufficient cost savings to pay for itself. In all cases, the Company could not provide a cost/benefit analysis to support the decision that it was economically beneficial to undertake the project and include the related costs in O&M expense as a Capital Use Charge billed from DTEE.

Where the Company has identified potential costs savings in operating expenses or uncollectible accounts expense, the estimated amounts are aspirational with no specific commitment to reduce the Company's revenue requirement in the projected test year or future years. Exhibit AG-66 includes some this information provided by the Company in response to discovery.

2b.(1) Capital Use Charges – Customer Service IT Projects

Q. PLEASE DISCUSS THE CUSTOMER SERVICE IT PROJECTS PROPOSED BY MS. LIZZUTI FOR WHICH YOU ARE PROPOSING COST DISALLOWANCES.

A. On pages 4 through 8 of her direct testimony, Ms. Pizzuti states that between 2019 and 2022 the Company, in concert with DTEE, is proposing $86.3 million of capital expenditures to implement 30 IT projects in support of various customer service programs.

Ms. Pizzuti segregates this total amount into three categories with $14.4 million classified as regulatory compliance, $25.7 million as discretionary IT enhancements, and $46.2 million as discretionary strategic investments. Exhibit A-13, Schedule C5.14, identifies the categories and the projects that comprise those categories.

Underlying most of the capital expenditures is a new initiative by the Company to achieve customer service satisfaction levels equivalent to best in class. In this regard, the Company is not comparing itself with other gas utilities, but instead to large consumer goods and service companies, such as Amazon, Nike, Rocket Mortgage, and Domino's, among others.[65]

Although the goal to be best in class is admirable, the Company does not have the same financial resources to compete at the same level as some of these mega-sized companies. The projects investment of $86.3 million over a four-year period by both DTE Gas and DTEE is a staggering amount. Moreover, the targeted improvements in customer service scores are minimal to justify such a large amount of capital expenditures. For example, in response to discovery, the Company identified an aspirational goal to achieve a 90% level of customer-issue resolution during the first contact with the Company instead of a current level of 83%. Similarly, the Company wants to achieve a 90% customer satisfaction level for interactions between the Company and its customers instead of 83%. These and other goals are aspirational, as are the estimated cost savings the Company has forecasted, meaning that there is no firm target or commitment. In reality, the Company and its

[65] Exhibit AG-67.

affiliates could spend more than $86 million between 2019 and 2022, and most likely even more over subsequent years and still fall short of those customer satisfaction goals and cost savings without any accountability. Exhibit AG-67 includes the Company's goals provided in response to discovery.

In my testimony below, I will identify and discuss the customer service IT projects that I propose be disallowed.

<u>Regulatory Reserve</u> – On pages 18 and 19 of her direct testimony, Ms. Pizzuti requests that capital expenditures reserve be established to address potential IT work that may be needed in the future to comply with Commission orders. In response to discovery, the Company could not identify what projects have been identified other than the Payment Stability Program, which is still being designed. The capital reserve requested is approximately $8.9 million in total between 2020 and 2022. The proposed amounts are basically placeholders for projects that have not yet been identified and in one case not yet fully defined. In recent rate cases, the Commission has rejected the use of placeholder amounts in forecasting future capital expenditures. Therefore, I recommend that the Commission disallow the Shared Asset cost of $632,000 shown on line 11, column (h) of Exhibit A-13, Schedule C5.14.

<u>Treasury Credential on File</u> – On page 21of her direct testimony, Ms. Pizzuti discusses the Credential on File project related to customers' use of credit cards. This project entails approximately $2.1 million in capital expenditures. In response to discovery, the Company stated that the project development has not yet begun and is not scheduled to begin until 2022 with project implementation not yet determined. Exhibit AG-68 includes the discovery response AGDG-9.296c. This project is premature to be included in this rate case. I recommend that the Commission disallow the Shared Asset cost of $84,000 shown on line 12, column (h) of Exhibit A-13, Schedule C5.14.

AA Use Cases – On page 28 of her direct testimony, Ms. Pizzuti discusses the AA Use Cases project, which would entail the use of machine learning to create a score for each customer about the propensity to pay. This project entails $3.0 million in capital expenditures. It is not clear what real benefits this project will yield. Furthermore, in response to discovery, the Company stated that the project development has not yet begun, is not scheduled to begin until 2022, and specific products and services from the system have not yet been identified. Exhibit AG-68 includes the discovery response AGDG-9.299a. This project is premature to be included in this rate case. I recommend that the Commission disallow the Shared Asset cost of $132,000 shown on line 14, column (h) of Exhibit A-13, Schedule C5.14.

Customer Profiles & Preferences – On page 27 of her direct testimony, Ms. Pizzuti discusses the Customer Profiles & Preferences project. With this project the Company wants to collect customers' personal information of a non-billing nature for the Company to potentially better interact with the customer. This project entails approximately $2.9 million in capital expenditures. It is not clear what specific information of a non-billing nature the Company wants to capture and why most customers would want the Company to have such personal information. In response to discovery, the Company admitted that it has not yet determined what additional data it seeks to capture. Exhibit AG-68 includes the discovery response AGDG-9.298a and b. This project is premature to be included in this rate case and should not be a high priority at this time. I recommend that the Commission disallow the Shared Asset cost of $127,000 shown on line 16 and 18, column (h) of Exhibit A-13, Schedule C5.14.

Redesign of SAP Dunning Process (BRF+) – On page 35 of her direct testimony, Ms. Pizzuti discusses the redesign of the dunning process and the rules within the SAP system that drive the Company's bill collection procedures. Apparently, as part of the implementation of the Customer 360 system completed in 2017, the Company decided to modify the rules contained within the SAP system with its own custom procedures. It has now discovered that those custom procedures have created more manual work and it wants to revert to the SAP standard rules. This project entails approximately $2.8 million in capital expenditures.

In response to discovery, the Company provided additional information that make it clear this project is the result of a poorly planned design of the system. Exhibit AG-68 includes the discovery responses AGDG-9.305a-c. Customers should not pay for errors made by the Company during the initial implementation of the collection dunning process. This cost should be entirely the responsibility of the Company. I recommend that the Commission disallow the Shared Asset cost of $232,000 shown on line 27, column (h) of Exhibit A-13, Schedule C5.14.

Construction Management Center – On page 43 of her direct testimony, Ms. Pizzuti discusses the Construction Management Center as a self-service tool for builders and developers to check on the status of their requests for new service attachments. Apparently, after the initial implementation and subsequent changes, the system is still not fully functional and only 16 builders are using it. This project entails approximately $4.8 million in capital expenditures for system improvements.

In response to discovery, the Company stated that due the COVID lockdown and other priorities this project has been put on hold. Furthermore, the Company has not been able to identify any financial benefits emanating from this project. Exhibit AG-68 includes the discovery responses AGDG-9.313a-d. Customers should not pay for a system that is not fully functional, has been put on indefinite hold, and is not economically justified. I recommend that the Commission disallow the Shared Asset cost of $120,000 shown on line 27, column (h) of Exhibit A-13, Schedule C5.14.

IVR Virtual Assistants – On page 45 of her direct testimony, Ms. Pizzuti discusses the IVR Virtual Assistants and Natural Language Processing project as a tool to allow customers to resolve inquiries and process transactions digitally without the need to talk to a Customer Service Representative, thus reducing telephone calls and saving costs. This project entails approximately $3.3 million in capital expenditures.

In response to discovery, the Company stated that, conservatively, it expects to reduce 100,000 calls per year. This should translate to annual cost savings of $575,000 based on the cost per call of $5.75.[66] Exhibit AG-68 includes the discovery responses AGDG-9.315. Given the forecasted annual cost savings, this project should pay for itself. I recommend

[66] Exhibit AG-OM17, DR AGDG-9.316e.

that the Commission disallow the Shared Asset cost of $228,000 shown on line 34, column (h) of Exhibit A-13, Schedule C5.14.

Digital Transactions and Experience Group – On pages 38 to 43 of her direct testimony, Ms. Pizzuti discusses the Digital Experience Group and Digital Transaction projects as initiatives that will accelerate customers' utilization of digital tools and self-service instead of engaging with customer service representatives on the phone, thus reducing phone calls and operating expenses. The two projects entail approximately $17.8 million in capital expenditures over a three-year period.

In response to discovery, the Company stated that it expects to reduce 500,000 calls by 2022 and up to 1.2 million by 2025. This should translate to annual cost savings in excess of $2.5 million in 2022 based on the cost per call of $5.75. Exhibit AG-68 includes the discovery responses AGDG-9.307a and b. Given the forecasted annual cost savings, these projects should pay for themselves. I recommend that the Commission disallow the Shared Asset cost of $1,241,000 shown on lines 30 and 31, column (h) of Exhibit A-13, Schedule C5.14.

Shutoff Protection Redesign – On page 36 of her direct testimony, Ms. Pizzuti discusses the Shutoff Protection Redesign project as a tool to allow customers to extend their bill payment due date and modify the shutoff protection and default rules. The Company stated that it is still working out the proposed shutoff protection rules with the Commission Staff, but expects to achieve up to $6.0 million in uncollectible expense reductions. This project entails approximately $1.7 million in capital expenditures. Although the development of this project is still in the early stages and perhaps premature to include in this rate case, the forecasted annual cost savings should pay for the cost of the project whenever it is implemented. Therefore, I recommend that the Commission disallow the Shared Asset cost of $75,000 shown on line 37, column (h) of Exhibit A-13, Schedule C5.14.

Q. WHAT IS THE TOTAL AMOUNT OF CUSTOMER SERVICE IT SHARED ASSET COSTS THAT YOU PROPOSE THE COMMISSION DISALLOW?

A. In summary, I propose that the Commission disallow $2,871,000 for the 9 projects identified above.

2b.(2) Capital Use Charges – Additional IT Projects

Q. PLEASE DISCUSS THE ADDITIONAL IT PROJECTS PROPOSED BY MR. BUSBY FOR WHICH YOU ARE PROPOSING COST DISALLOWANCES.

A. In Exhibit A-13, Schedule C5.13.1, Mr. Busby identifies about 100 IT projects at DTE Electric with costs to be shared by DTE Gas. The total amount of capital expenditures for this list of projects is approximately $325 million over the four-year period of 2019 to 2022. Some of the projects are of a general corporate nature, and others are either specifically to support customer service operations or for general IT infrastructure.

Although the Company expanded its testimony in this case to discusses specific projects and has filed a 5-year IT plan, a basic problem remains. The Company often cannot provide a cost/benefit analysis to show that its decision to undertake the projects was economically justified. Furthermore, in response to discovery, the Company has refused to provide a complete forecast of the project costs from inception to completion. This refusal to provide complete information prevents a full assessment of the project size and scope and makes it difficult, if not impossible, to accept the narrow presentation of only a portion of the total costs. A sample of the discovery responses reflecting the refusal to provide complete and useful information is included in Exhibit AG-69.

In my testimony below, I will identify and discuss the IT projects that I propose be disallowed.

Success Factors Program and Purchase to Pay – On page 58 of his direct testimony, Mr. Busby briefly describes the Success Factors project. However, his testimony is devoid of any discussion about the Purchase to Pay system. The two projects entail capital expenditures of $15.3 million from 2019 to 2022, and perhaps even more outside this four-year period. These projects have not been adequately justified. Therefore, I recommend that the Commission disallow the Shared Asset costs of $514,000 shown on lines 17 and 19, column (j) of Exhibit A-13, Schedule C5.13.1.

Automated Application Monitoring – On page 81 of his direct testimony, Mr. Busby describes the Automated Application Monitoring as a project to bridge the gap between system monitoring and customer experience on various communications channels in order to determine what level of system performance customers are experiencing. From Mr. Busby's testimony, it is not clear why this information is essential and of what value it will be to the Company and its customers. The project entails capital expenditures of $4.5 million from 2020 to 2022.

In discovery, the Company was asked to provide the total capital expenditures from inception to completion and to explain further what gaps in performance information this system would resolve. In response, the Company provided a reference to a discovery response that has no information about the total cost of the project from inception to completion as requested. The Company also could not explain what gap existed between systems and channels, other than repeating the monitoring function of the proposed system. In response to the request for a cost/benefit analysis, the Company referenced a previous discovery response that does not provide any information on the cost/benefit analysis for this project. Exhibit AG-70 includes discovery responses AGDG-8.275a-c and g received from the Company.

This project has not been adequately justified. Therefore, I recommend that the Commission disallow the Shared Asset cost of $290,000 shown on line 23, column (j) of Exhibit A-13, Schedule C5.13.1.

Customer Legacy Application Health – On pages 83 and 84 of his direct testimony, Mr. Busby describes the Customer Legacy Application Health project as ongoing support and maintenance of non-core billing or self-service systems. From Mr. Busby's testimony, it is not clear why this ongoing support starts in 2021 at $1.5 million and increases to $2.5 million with no capital spending in 2019 and 2020. In total, the project entails capital expenditures of $4.0 million for 2021 and 2022.

In discovery, the Company was asked to provide the total capital expenditures from inception to completion and the components of where the $4.0 million will be spent. In response, the Company did not provide the cost of this project from inception to completion, and although it identified certain areas where the $4.0 million be spent there were no specific dollar amounts assigned to each area. Exhibit AG-70 includes discovery responses AGDG-8.276a-b received from the Company.

The Company has not made a compelling or convincing case that the project is needed and justified. Therefore, I recommend that the Commission disallow the Shared Asset cost of $239,000 shown on line 29, column (j) of Exhibit A-13, Schedule C5.13.1.

Hybris Application Health – On page 85 of his direct testimony, Mr. Busby describes the Hybris Application Health as a project to perform scheduled maintenance, vulnerability management, and minor enhancements. In his testimony, Mr. Busby states that the Hybris system is an e-commerce delivery platform that allows the Company to offer non-metered services to customers. In response to discovery, the Company elaborated further, stating that the services provided are TreeGuard Assurance, Surge Protection and Natural Gas Balance. Exhibit AG-70 includes discovery response AGDG-8.277b showing this information. The project entails capital expenditures of $3.0 million from 2019 to 2021.

This project is not part of the Company's scope of providing natural gas delivery service. Therefore, I recommend that the Commission disallow the Shared Asset cost of $33,000 shown on line 31, column (j) of Exhibit A-13, Schedule C5.13.1.

Cloud Center of Excellence and Private Cloud Transformation – On pages 71 and 79 of his direct testimony, Mr. Busby describes the Cloud Center of Excellence Setup and the

Private Cloud Transformation projects. The first project entails an automated creation of cloud-based instances of software applications. The Company expects its cloud-utilization to grow by as much as 100% and wants to avoid the use of specialized labor for common or basic configurations. The second project involves the expansion of a private cloud platform, which the Company anticipates will increase operational efficiencies.

The Cloud Center of Excellence requires approximately $1.8 million of capital expenditures between 2020 and 2022. The Private Cloud Transformation Setup requires $4.0 million of capital expenditures in 2022 In total, the two projects entail capital expenditures of $5.8 million from 2020 to 2022.

In discovery, the Company was asked to provide the total capital expenditures from inception to completion and provide a copy of the cost/benefit analysis showing these projects were economically justified. The Company did not provide the requested information. Exhibit AG-70 includes discovery responses AGDG-8.274a and f received from the Company.

The Company has not made a sound economic case that the shift to more cloud computing is justified. From the testimony of Mr. Busby, it appears that certain costs savings can be achieved. If this is true, then these projects should be self-funded through avoided capital investments for on-premise systems and by achieving O&M costs savings. Therefore, I recommend that the Commission disallow the Shared Asset costs of $172,000 shown on lines 58 and 104, column (j) of Exhibit A-13, Schedule C5.13.1.

Q. WHAT IS THE TOTAL AMOUNT OF IT SHARED ASSET COSTS THAT YOU PROPOSE THE COMMISSION DISALLOW?

A. In summary, I propose that the Commission disallow $1,248,000 for the 7 IT shared projects identified above.

In total for the 16 shared projects, consisting of both the customer service IT projects and the other IT shared projects, plus the facilities shared costs, I propose a total disallowance of Rents-Capital Use charges of $4,804,000.

J. 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 $18.2 million of employee incentive compensation in O&M expense, which has been included in the projected test year.[67] Based upon the information provided by the Company and included in Exhibit AG-OM22, $2.6 million pertains to the Annual Incentive Plan (AIP), $8.3 million pertains to the Rewarding Employees Plan (REP), and $7.3 million pertains to the Long-Term Incentive Plan (LTIP). I will also point out that 62% of the $18.2 million requested is to recover costs related to the DTE Corporate Services LLC employees (the LLC employees) whose

[67] Page 53 of Michael Cooper testimony shows approximately $17.0 million of O&M expense for incentive compensation. However, in response to Staff Date Request TMS-5.2, the Company reported a final amount of $18.2 million. Exhibit AG-71 includes the response to TMS-5.2 and related schedules.

performance metrics are often related to the performance of DTE Energy (not just DTE Gas).

2020 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, Gas Damage Prevention 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 2020. 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.

2020 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.

__2020 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 2020 represents 20% of the total measures. However, as shown in Exhibit A-19, Schedule I6, 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 represents 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 Gas 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 I6, Mr. Cooper presents a calculation that purports to show that the expected operating and financial cost savings in 2020 of $23.7 million will exceed the incentive plan payments by $6.0 million.

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 55 and 56 of his direct testimony, Mr. Cooper discusses the incentive metrics measuring Financial Performance. His discussion about the Company controlling the increase in O&M costs from 2008 to 2019 below the rate inflation is inconsistent with the proposed increase in O&M costs in this rate case and the request to recover inflationary cost increases of $30.6 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 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, lower employee absenteeism, 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 IS YOUR RECOMMENDATION WITH REGARD TO INCENTIVE PAYMENTS BEING RECOVERED IN CUSTOMER RATES?**

A. Page 2 of Exhibit AG-71 shows the components of the incentive compensation expense that the Company has included in the O&M expense for the projected test year with $12.9 million pertaining to financial measures. For the reasons described above, I recommend that the Commission remove the entire $12.9 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 for DTE Gas, DTE Electric and Consumers Energy.

In that vein, I recommend that the Commission allow recovery of only 20% of the incentive compensation expense that the Company has identified pertaining to operating performance measures. The 20% represents the percentage of performance measures that have been achieved at target level or higher over the past five years from 2016 to 2020. In calculating the incentive compensation expense in this rate case, the Company has assumed that it will achieve the target level for all operating performance measures. The last five years of actual performance results show that the Company was able to achieve target level performance only 20% of the time with certain years as low as 8% and some years as high as 31%. Exhibit AG-72 shows the source data provided by the Company, and the calculation of the level of the annual performance achieved at target or better along with the overall average percentage rate for the five years at the bottom of the schedule.

In the schedule in Exhibit AG-71, the Company calculated $5.3 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 20% of the $5.3 million, or $1.1 million.

Therefore, the Commission should deny recovery of the remaining of the $17.1 million in incentive compensation expense proposed by the Company.

Q. IS THERE A PORTION OF INCENTIVE COMPENSATION THAT THE COMPANY INCLUDED IN CAPITAL ADDITIONS AND RATE BASE, WHICH IS NOT INCLUDED IN THE CHART ON PAGE 53 OF MR. COOPER'S DIRECT TESTIMONY AND THE SCHEDULE ON PAGE 2 OF EXHIBIT AG-71?

A. Yes. The chart on page 53 of Mr. Cooper's direct testimony, as corrected by Exhibit AG-71, only includes the projected incentive compensation pertaining to O&M expense for the projected test year. In addition, each year the Company has allocated and capitalized a portion of both short-term and long-term incentive compensation, which is included in rate base. In Case No. U-20642, the Commission ordered the Company to remove from rate base the portion of incentive compensation that related to financial measured beginning with the year 2019. Pages 4 of Exhibit AG-71 shows this adjustment and the removal of the portion of incentive compensation pertaining to financial measures for capitalized amounts from 2020, 2021, and 2022.

However, the capitalized amounts on pages 4 and 5 do not reflect my proposed disallowance of 80% of the 2022 incentive compensation pertaining to operating measures. Therefore, I recommend that $2,476,000 of the $3,084,000 that the Company seeks to capitalize in 2022 be removed. Exhibit AG-19 includes this adjustment and related reduction to rate base.

K. O&M Expense Summary

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 $89.6 million as discussed above and summarized in the following table. Exhibits AG-51 and AG-50 provide additional details of the areas where I have proposed O&M expense adjustments.

Summary of O&M Expense Reductions	**Amount ($Millions)**
Inflation Expense Adjustment	$ 30.6
Storage Transmission & Distribution	20.0
Meter Reading Expense	1.6
Health Case and Other Benefits	3.5
Credit/Debit Card Fees	3.6
Customer Service Resources	3.1
Uncollectible Accounts Expense	4.3
Employee Incentive Compensation	17.1
Other Expenses	5.8
Total Reduction	**$ 89.6**

IX. 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 $5,405,000. The calculation of this amount is shown in Exhibit AG-19.

I recommend that the Commission reduce the depreciation expense proposed by the Company for the projected test year by $5,405,000.

<u>X. Adjustments To Revenue Deficiency</u>

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

A. Exhibit AG-73 summarizes the adjustments to rate base and operating income. The net result is a revised revenue deficiency of $19.0 million, which is a reduction of $175.8 million from the Company's requested level of $194.8 million.

I recommend the Commission adopt these adjustments and issue an order granting rate relief to the Company in an amount not exceeding $19.0 million.

<u>XI. Rate Design</u>

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 $12.25 to $14.40 per month. Mr. Maroun also proposes to increase the monthly customer service charge for small commercial customers in rate schedule GS-1 from $32.00 to $40.00.

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

A. No. The proposed change from $12.25 to $14.40 per month represents an increase of nearly 18%. 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 25% 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 residential monthly customer charge of $12.25. The monthly service charge was increased $1.00 in 2020 in the Company's last rate case. The Company's proposed monthly charge of $13.90 would result in an annual charge of $173, 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 $13.25.

Similarly, for the GS-1 rate, the Commission should maintain the current monthly charge of $32.00, which was also increased by $1.00 in 2020. If the Commission wishes to increase this customer charge, it should limit the increase to no more than $1, to $33.00, to minimize any hardship on small commercial customers.

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, 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.

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.

Mr. Coppola has also provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking. Additionally, he prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company which was filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.

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

Experience and Qualifications of Sebastian Coppola

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 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.

- **Specific Regulatory Proceedings and Related Experience:**

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in DTE Michigan Lateral Company (DMCL) 2021 Act 9 filing to convert a pipeline and build two interconnections for transportation services to DTE Gas Company in case No. U-20894.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2021 power plant and tree trimming securitization costs in case No. U-21015
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2021 PSCR plan case No. U-20802.
- Filed testimony on behalf of the Michigan Attorney General in (CECo 2019-2020 GCR reconciliation case No. U-20234.
- Filed testimony on behalf of the Maryland Office of Public Counsel in Washington Gas Light Company's 2020 rate Case 9651 on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 Karn 1 & 2 Retirement Cost and Bond Securitization Case U-20889.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Reconciliation in case U-20222.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2020-2021 GCR plan case No. U-20543.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Gas Company (SEMCO) 2020-2021 GCR plan case No. U-20551.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy (CECo) 2020 electric rate Case U-20697 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in in the complaint against Upper Peninsula Power Company's (UPPCO) Revenue Decoupling Mechanism (RDM) in Case No. U-20150.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019 gas rate Case U-20650 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 DTE Gas Company 2019 gas rate Case U-20642 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 DTE Gas 2018-2019 GCR reconciliation Case U-20210.
- Prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company on behalf of the Maryland Office of People's Counsel filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.
- 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 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.

Experience and Qualifications of Sebastian Coppola

- 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 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

**Experience and Qualifications
of Sebastian Coppola**

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 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.

Experience and Qualifications of Sebastian Coppola

- 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.
- 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,

**Experience and Qualifications
of Sebastian Coppola**

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 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.

Experience and Qualifications of Sebastian Coppola

- 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.
- 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,

Experience and Qualifications of Sebastian Coppola

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.
- 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.

Experience and Qualifications
of Sebastian Coppola

- 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.
- 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

Experience and Qualifications
of Sebastian Coppola

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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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 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.

Experience and Qualifications
of Sebastian Coppola

- 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.
- 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.

Experience and Qualifications
of Sebastian Coppola

- 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.

Experience and Qualifications of Sebastian Coppola

- Prepared testimony and assisted Michigan Attorney General in settlement of MGUC 2009-2010 GCR case U-15700.
- 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.

**Experience and Qualifications
of Sebastian Coppola**

- Filed testimony in MichCon financing orders in 1987 and 1988.
- 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.

Corporate Analytics

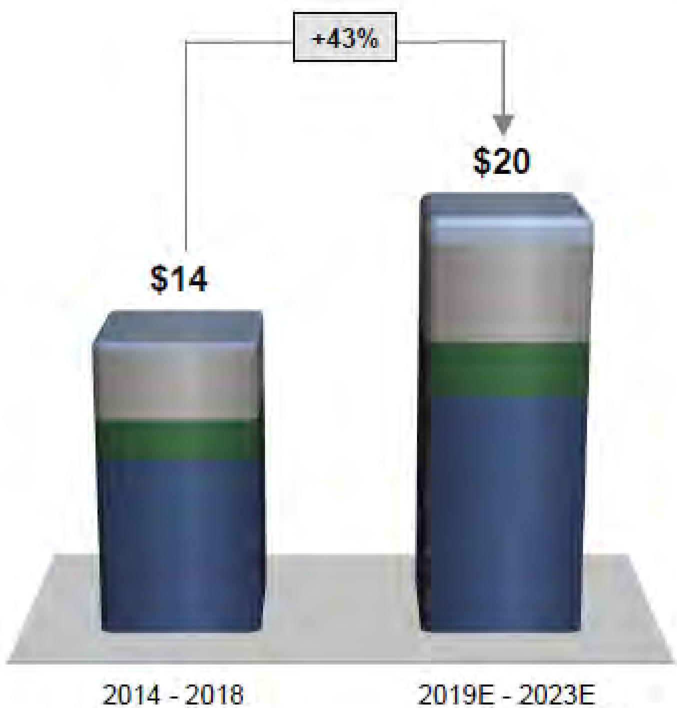

DTE Business Update
October 2, 2019
DTE
DTE

Growth fueled by investment in utility infrastructure and generation along with non-utility opportunities

DTE

(billions)

DTE Investment



Electric $11.3 billion
Distribution infrastructure, cleaner generation, maintenance
7% - 8% operating earnings* growth

Gas $2.5 billion
Base infrastructure, main renewal acceleration
8% - 9% operating earnings* growth

GSP $4.0 - $5.0 billion
Expansions, NEXUS / Link buildouts, acquisitions

P&I $1.0 - $1.4 billion
Industrial energy services, renewable natural gas (RNG)

* Reconciliation of operating earnings (non-GAAP) to reported earnings included in the appendix

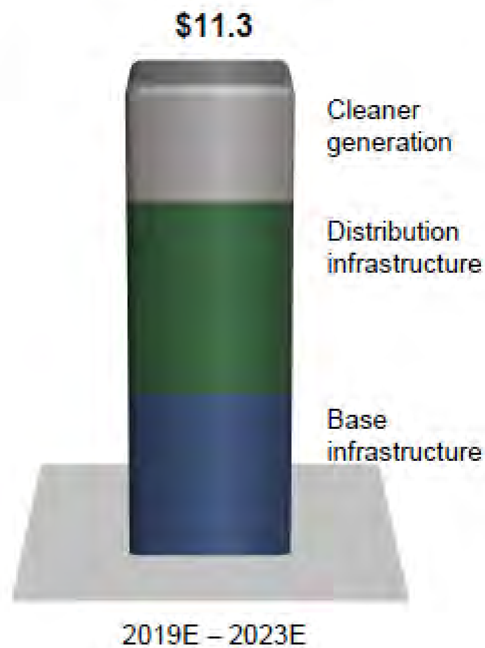
Both utilities increase customer reliability with investment plans over the next 5 years

DTE

(billions)

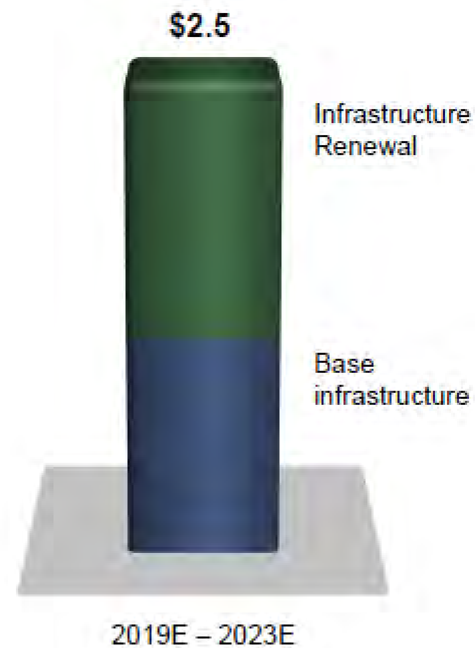
DTE Electric

Targeting 7% - 8% operating earnings growth*



DTE Gas

Targeting 8% - 9% operating earnings growth*

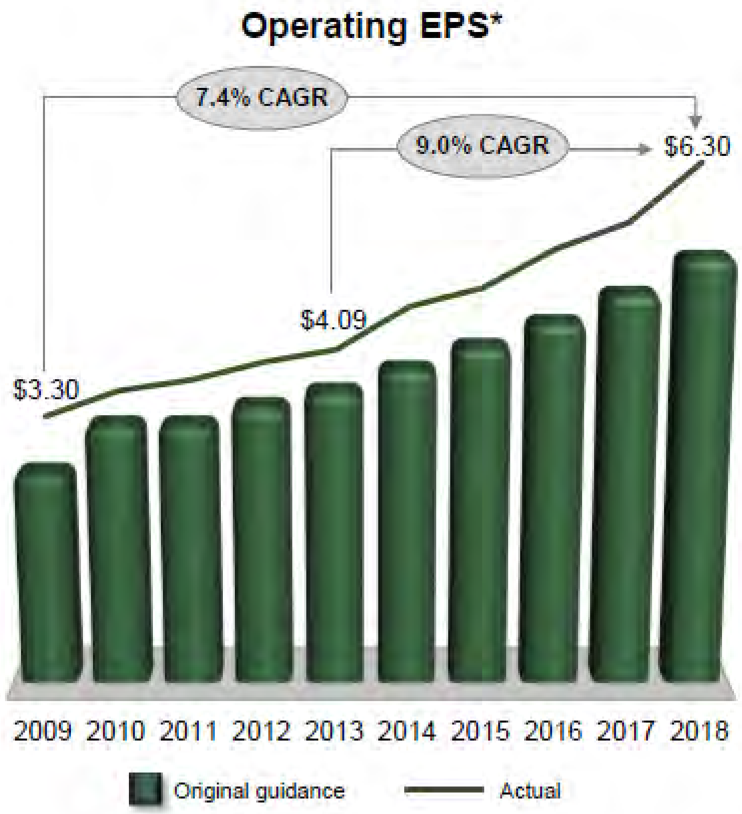


* Reconciliation of operating earnings (non-GAAP) to reported earnings included in the appendix

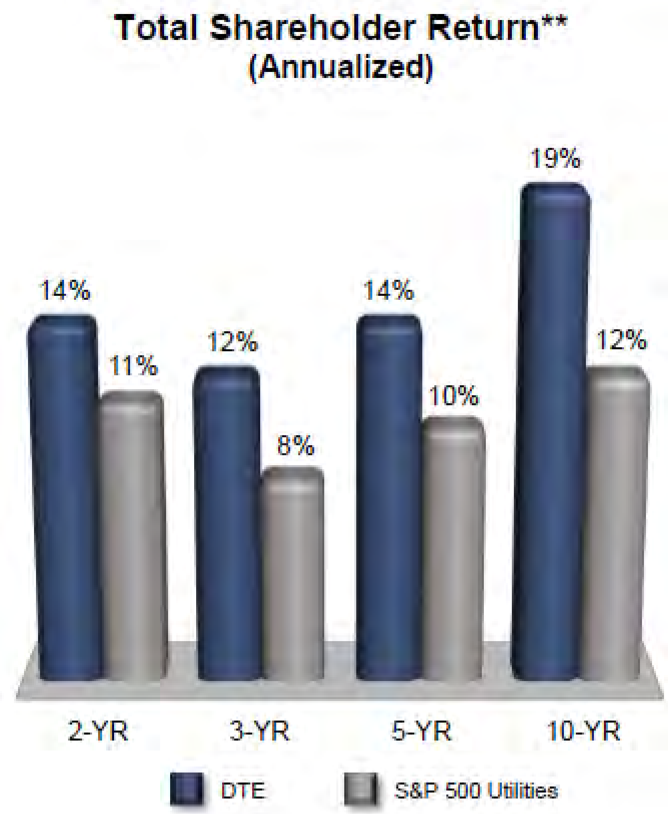
Focus on culture and commitment to customers has delivered strong returns for shareholders

DTE

Decade of exceeding guidance…



…and delivering strong TSR results



* Reconciliation of operating earnings (non-GAAP) to reported earnings included in the appendix
** Source: Bloomberg as of 6/30/2019

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Exhibit AG-2
Case No. U-20940
Date: June 3, 2021
Page 1 of 2

Service Alterations - Cost Disallowance

($000)

Line #		Actual	**Forecasted**		
		2020	**2021**	**2022**	**Total**
1	Number of Units Forecasted		4,255	4,113	
2	Cost Per Unit [1]	$ 3,800	$ 3,800	$ 3,800	
3	Total Capital Expenditures - AG		$ 16,169	$ 15,629	
4	Company Forecasted Cost		18,541	17,838	
5	Disallowance		**$ (2,372)**	**$ (2,209)**	**$ (4,581)**

Source: (1) Page 2 (DR AGDG-3.49)

MPSC Case No.: U-20940
Requestor: AG
Question No.: AGDG-3.49
Respondent: D. Brudzynski
Page: 1 of 1

Question: Refer to page 9, lines 3- 5, of Mr. Brudzynski's direct testimony. Does the Company receive full reimbursement of service alterations requested by customers? Explain your answer. Provide the amount of reimbursements received each year 2015 to 2020, and forecasted for 2021 and 2022, and identify on which exhibit and line number those reimbursements are shown or included.

Answer: No. The CIAC reimbursement is based on project specific costs and revenue generated from project.

See the updated Table 4 Service Alterations from page DGB-16 lines 7-8 of Mr. Brudzynski's direct testimony that include 2020 actuals, as requested:

Service Alterations	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Projected	2022 Projected
Units	3,717	4,070	3,822	4,008	4,329	4,991	4,255	4,113
Capital Spend ($000)	$10,089	$9,330	$12,222	$14,908	$16,521	$18,967	$18,541	$17,838
Cost/Unit	$2,714	$2,292	$3,198	$3,720	$3,816	$3,800	$4,357	$4,337
CIAC ($000s)	($1,699)	($1,655)	($1,562)	($2,054)	($2,100)	($2,300)	($2,046)	($1,935)

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-3.56a
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to page 17, lines 11-16, and page 18, lines 1-4, of Mr. Brudzynski's direct testimony. Please:

a. Identify the impact on cost per unit in 2020 for each of the three reasons.

Answer:

Factor	CPU Increase (2019 to 2020)
Labor and Overheads	$883
Increased PPE	$113
Vehicle Rentals	$33
Total	$1,029

The total increase in the cost per unit of service renewals between 2019 and 2020 for the three components was $1,029. The overall increase in cost per unit of service renewals between 2019 and 2020 was $732 (see response AGDC-3.55a). The $1,029 per unit impact was offset by decreases in other cost per unit component types (materials, etc.).

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-3.56b
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to page 17, lines 11-16, and page 18, lines 1-4, of Mr. Brudzynski's direct testimony. Please:

b. Explain why the Company shifted more labor costs to capital expenditures from O&M expense when the additional labor was not needed in prior years.

Answer: Please refer to response AGCUBDG-1.11 for why DTE Gas shifted O&M resources to capital work. As discussed in the response, the O&M work that was decreased was non-hazardous leak repairs. Non-hazardous leak repair is still critical work, and should not be discontinued going forward despite the temporary deferment in 2020 due to an unprecedented year.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-3.56c
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to page 17, lines 11-16, and page 18, lines 1-4, of Mr. Brudzynski's direct testimony. Please:

c. Provide the additional cost of using internal labor versus contractor labor during 2020.

Answer: As referenced in testimony on page DGB-18, lines 3-4, internal labor replaced contactor labor in some of DTE Gas's territories, primarily in the northern part of our service territory. The cost of those internal service renewals were $5,201 per unit compared to a contractor cost of $4,149 per unit.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AGCUB
Question No.:	AGCUBDG-1.11
Respondent:	D. Brudzynski / M. Johnson
Page:	1 of 1

Question: Refer to testimony of D. G. Brudzynski, p DGB-17:19 – DGB-18:4. Explain why "economic uncertainty surrounding the COVID-19 impact in 2020" caused DTE to shift resource allocation from O&M work to capital work. Further, explain what O&M work was reduced as a result of this shift.

Answer: The COVID-19 pandemic caused an unprecedented economic disruption in Michigan with the implementation of lockdowns, social distancing and other health safety measures as ordered by the Governor. As a result, many small commercial customers had to close their businesses for extended periods of time or operate at severely curtailed capacity during 2020 and into 2021. This unprecedented shutdown of large portions of the economy, created uncertainty for many companies in Michigan including DTE Gas, that when coupled with an unseasonably warmer than normal winter at the start of the year, led to a significant drop in sales volume as discussed by Witness Chapel in his testimony from page GHC-22, line 15 through page GHC-24, line 22.

To mitigate some of this uncertainty, DTE Gas took unprecedented one-time actions to re-prioritize resources from non-emergency O&M work to capital.

The O&M resources that were shifted to routine capital came from non-hazardous distribution leak repairs. Non-hazardous leaks (Grade 3) do not require immediate action and can be monitored and are checked annually to ensure they remain non-hazardous. All hazardous incoming leaks in 2020 were repaired immediately, consistent with DTE Gas procedures. Refer to testimony of Witness M.C. Johnson, p. MCJ-44:1-11.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-3.66
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to page 28, lines 19-21, of Mr. Brudzynski's direct testimony. Please identify the impact on the cost per unit in 2020 for each of the three reasons.

Answer:

Factor	CPU Increase (2019 to 2020)
Labor and Overheads	$834
Increased PPE	$3
Vehicle Rentals	$1
Total	$838

The total increase in the cost per unit of service abandonment between 2019 and 2020 for the three components was $838. The overall increase in cost per unit of service abandonments between 2019 and 2020 was $594 (see response AGDG-3.65). The $838 per unit impact was offset by decreases in other cost per unit component types (materials, etc.).

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-11.358
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to the response to AGDG-3.65. Please explain why the unit cost to complete service abandonments increased by 38% from 2018 to 2019.

Answer: The increase in unit cost for service abandonments was primarily driven by a) an increase in labor unit cost (total labor costs decreased from 2018 to 2019, but fewer units were completed), and b) an increase in outside service costs.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-3.70b
Respondent:	H. Decker
Page:	1 of 1

Question: Refer to Exhibit A-12, Schedule B5.1, page 2. Please:

b. Provide a split of the actual capital expenditures for each year 2015 to 2020 and forecasted 2021-2022 for New Market Attachments on line 13 between Area Expansion Projects and other attachments. Provide also the number of new customer attachments for each category by year 2015-2022, all in Excel.

Answer: Please refer to file attachment U-20940 AGDG-3.70b New Markets Attachments

Attachments: U-20940 AGDG-3.70b New Markets Attachments

DTE Gas Response to data request AGDG-3.70b

AGDG 3.70b

New Markets Attachments ($000)	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast
	2015	2016	2017	2018	2019	2020	2021	2022
Total Capital Expenditures	$ 32,870	$ 27,756	$ 35,865	$ 58,085	$ 62,702	$ 64,953	$ 67,013	$ 68,709
Area Expansion Projects	7,394	5,686	9,821	16,374	14,665	16,979	17,318	17,491
All other	25,476	22,071	26,044	41,710	48,037	47,974	49,695	51,218
Attachments - Total	8,827	8,270	9,504	9,383	9,703	9,820	8,484	9,001
Area Expansion Projects	828	942	942	495	977	942	1,300	1,500
All Other	7,999	7,328	8,562	8,888	8,726	8,878	7,184	7,501

MICHIGAN PUBLIC SERVICE COMMISSION | Exhibit AG-6
DTE Gas Company - Gas Rate Case | Case No. U-20940
Date: June 3, 2021

New Attachments Disallowance

New Markets Attachments ($000)	Actual 2015	Actual 2016	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Forecast 2021	Forecast 2022	Line #
Total Capital Expenditures	$ 32,870	$ 27,756	$ 35,865	$ 58,085	$ 62,702	$ 64,953	$ 67,013	$ 68,709	1
Area Expansion Projects	$ 7,394	$ 5,686	$ 9,821	$ 16,374	$ 14,665	$ 16,979	$ 17,318	$ 17,491	2
All other	$ 25,476	$ 22,071	$ 26,044	$ 41,710	$ 48,037	$ 47,974	$ 49,695	$ 51,218	3
									4
Attachments - Total Units	8,827	8,270	9,504	9,383	9,703	9,820	8,484	9,001	5
Area Expansion Projects	828	942	942	495	977	942	1,300	1,500	6
All Other	7,999	7,328	8,562	8,888	8,726	8,878	7,184	7,501	7
									8
All Other Unit Cost (L. 11/L.7				$ 4,693	$ 5,505	$ 5,404	$ 6,918	$ 6,828	9
									10
Average Unit Cost 2018-2020 (Line 9)						$ 5,200	$ 5,408	$ 5,408	11
									12
2021 and 2022 Units priced at 3-Year average + 4%							$ 38,794	$ 40,565	13
									14
Difference: AG vs. Company Forecast (L. 13 - L. 3)							**$ (10,901)**	**$ (10,653)**	15

Source: 3.70b

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-3.99a
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to page 58, lines 21-23, and page 59, lines 1-10 of Ms. Sandberg's direct testimony. Please:

a. Identify the contractor and on whose behalf it was performing work on Belle Isle.

Answer: The work was being performed by Kiewit on behalf of DTE Electric.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-3.99b
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to page 58, lines 21-23, and page 59, lines 1-10 of Ms. Sandberg's direct testimony. Please:

b. In which year was the $2.5 million capitalized to the Company's plant accounts?

Answer: This amount was capitalized in 2019.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-3.99c
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to page 58, lines 21-23, and page 59, lines 1-10 of Ms. Sandberg's direct testimony. Please:

c. Was the $2.5 million net of any reimbursements received from the contractor, contractor's customer, or insurance proceeds? If yes, provide the amount reducing the Company's cost.

Answer: No.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-3.99d
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to page 58, lines 21-23, and page 59, lines 1-10 of Ms. Sandberg's direct testimony. Please:

d. If the Company did not receive 100% reimbursement of the cost to replace the main, please explain why not.

Answer: The two parties agreed they would share the cost because there were contributing factors on both sides.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-11.376a
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to the response to AGDG-3.99d. Please:
a. Explain what the contributing factors were on the part of DTE Gas.

Answer: As part of Compliance Action CA-00003059_01 (Belle Isle Damage) the identified contributing factors were:

Contributing Factor 1: Although DTE marked their gas main on the island and mainland sides, no markings were provided to indicate the location of the facilities within the river.

Contributing Factor 2: The accuracy of the 1995 as-built for the gas main was solely relied on to determine the location of the main within the river. This drawing did not accurately reflect the actual location of the gas main, as there was supposed to be several feet between the gas main and the bore path for the electric conduit.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-11.376b
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to the response to AGDG-3.99d. Please:
b. Was the cost of $0.2 million for the interim solution capitalized by DTE Gas or expensed?

Answer: The cost for the interim solution was expensed.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-11.376c
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to the response to AGDG-3.99d. Please:
c. What was the total cost to complete the project, including the $0.2 million interim solution, before the sharing of the cost with DTE Electric or its contractor?

Answer: The total cost to complete the project, including the interim solution and prior to cost sharing was ~$2.4M.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-3.68
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to page 33, lines 6-13, of Mr. Brudzynski's direct testimony. Please provide a list of the exposed pipeline projects, other than the Alpena West Branch Drain Line project, with a description of the problem, what needs to be done, why it needs to be done, a timeline from design to in-service date, and the related cost by year for each item.

Answer: Please see below reference to the attachment.

Attachments: *U-20940 AGDG-3.68 2021-Q1 Exposure List for 2021 Rate Case*

DTE Gas Response to data request AGDG-3.68

PIPELINE	EXPOSURE LOCATION	RANK	DESCRIPTION	REMEDIATION METHOD	COST ESTIMATE	IN SERVICE	COMMENT
Austin-Detroit A	Bradley Drain	1	Shallow Pipe	Direct Bury	$1,390,000	2021	Budgeted for 2021
Austin-Detroit B	Bradley Drain	1	Shallow Pipe	Direct Bury	$1,390,000	2021	Budgeted for 2021
Austin-Detroit A	Pine Creek	2	Exposed Pipe	Depends on remediation	Depends on remediation	TBD	Discovered fall of 2020, evaluating possible permanant remediation solutions
Alpena (16)	West Branch Drain	3	Exposed Pipe	HDD	$3,000,000	2022	Budgeted for 2022
Alpena (16)	Cedar River	3	Exposed Pipe	HDD	$2,466,657	2022	Budgeted for 2022
Alpena (16)	AuGres River	3	Exposed Pipe	HDD	$2,000,000	2022	Budgeted for 2022
Mackinaw (6)	Creek	4	Exposed Pipe		TBD		2023 and beyond plan is being developed
Mackinaw (6)	Creek	5	Exposed Pipe		TBD		2023 and beyond plan is being developed
Austin-Muskegon	Wetland area	6	Exposed Pipe		TBD		2023 and beyond plan is being developed
Mackinaw (6)	Drain	7	Exposed Pipe		TBD		2023 and beyond plan is being developed
Mackinaw (6)	Drain	7	Exposed Pipe		TBD		2023 and beyond plan is being developed
Sault Ste. Marie	Beaver Meadow Creek	8	Exposed Pipe		TBD		2023 and beyond plan is being developed
Reed City-Muskegon	John Beem Drain	9	Exposed Pipe		TBD		2023 and beyond plan is being developed
Belding (4)	Wabasis Creek	10	Exposed Pipe		TBD		2023 and beyond plan is being developed

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-11.360
Respondent:	D. Brudzynski / Legal
Page:	1 of 2

Question: Refer to the attachment to the response to AGDG-3.68 and line 18 of Exhibit A-12, Schedule B5.1. After deducting the 5-year average routine transmission capital expenditures of $7,513,000 from the total capital expenditures for 2020, 2021, and 2022 on Schedule B5.1, line 18, as well as deducting the cost of the projects in the attachment to DR 3.68, the following unexplained amounts of $7,500,000, $5,223,000, and $4,827,000 remain for 2020, 2021, and 2022, respectively. Please identify specifically what makes up these remaining amounts for each year.

Answer: The Company objects for the reason that the request is unduly vague in that it inaccurately describes the subject expenditures as unexplained. Without waiving this objection, but subject to it, the Company responds as follows:

As stated in the testimony, the primary drivers to the increase of capital expenditures in routine transmisson plant are exposed pipe projects, mainline valve crossover projects, and the K-line replacement project. The tables below provide the project details:

2020	
Primary Variance Driver	**Cost**
K-Line Pipe Replacement	5,457,000
Cedar Creek (10" Muskegon-Ludington pipeline) Line Lowering	1,917,000
Total	**7,374,000**

2021	
Primary Variance Driver	**Cost**
MLV #C4 Replacement	1,019,000
Replace Valve C3 (30" valve) and it's two Crossover Valves	678,000
MLV #C8 Replacement	2,096,000
MLV #E5 Replacement	341,000
Total	**4,134,000**

2022	
Primary Variance Driver	**Cost**

MPSC Case No.: U-20940
Requestor: AG
Question No.: AGDG-11.360
Respondent: D. Brudzynski / Legal
Page: 2 of 2

Central-Line Lowering-Belding 4in (Wabasis Creek), Reed Muskegon 8in (John Beem Drain), Austin-Muskegon 8in (6 Mile Rd)	1,500,000
MLVC3-replace 30" MLV on the C line, and actuator	500,000
At MLV #8 on A-Line: Replace MLV#8 on the A-Line	600,000
At MLV 8 on C line; do 6 crossover valves and 1 MLV	500,000
Southeast -Regulator replacement -Northwest Gas Station	1,250,000
Total	**4,350,000**

The detailed list of all routine tranmission plant capital projects can be found in exhibit A-12 B5.11 lines 18.1-18.123.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-11.359b
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to the attachment to the response to AGDG-3.68. For each project to be completed in 2021 and 2022, please:

b. What is the length of pipe that is exposed?

Answer:

Bradley Drain is a shallow pipe.	There is no exposed pipe.
West Branch	Approximately 10 feet
Cedar River	Approximately 10 feet
Au Gres	Approximately 10 feet

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-11.359c
Respondent:	D. Brudzynski
Page:	1 of 2

Question: Refer to the attachment to the response to AGDG-3.68. For each project to be completed in 2021 and 2022, please:

c. Provide photographs of the exposed pipe and surrounding area.

Answer: West Branch

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-11.359c
Respondent:	D. Brudzynski
Page:	2 of 2

Au Gres

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-3.75b
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to Exhibit A-12, Schedule B5.5, page 12, pertaining to the Alpena West Branch Drain Line. Please:

b. Explain what has removed the soil cover.

Answer:

Natural meandering and scouring of the West Branch Drain over time has resulted in an exposure of the pipeline within the drain itself. These natural forces have altered the course of the drain to the point where the soil cover has been removed.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-3.75c
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to Exhibit A-12, Schedule B5.5, page 12, pertaining to the Alpena West Branch Drain Line. Please:

c. Why is the Company not replacing the soil cover for the 800 feet with new soil instead of lowering the pipeline at a cost of $4 million?

Answer: For clarification, the pipeline itself is not exposed for 800 feet, only within the drain itself. The 800 feet is required to get a horizontal directional drill profile under the drain that meets the requirements for boring in a 16" transmission line. This method will ensure safe operation for years to come without risk of future exposures in the drain. Adding enough soil to cover the line to meet DTE standards is not feasible, while still keeping the drain functional. Additionally, it will be difficult to ensure this problem does not reoccur in the future. Concrete shielding has been attempted in the past on this same crossing and it has failed over time.

Additional clarification is the cost estimate for this project is $3 million as shown in Exhibit A-12, Schedule B5.5, Page 12.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-11.359d
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to the attachment to the response to AGDG-3.68. For each project to be completed in 2021 and 2022, please:

d. Why must the pipe be removed and replaced by direct burry or HDD?

Answer: Local permits are requiring the pipe to be lowered to up to 5 feet below the bottom of the waterway. The only way to accomplish this is to lower the pipe. An engineering evaluation and review of the optimum approach is conducted on a case by case basis with the direct bury method being preferred as it is typically lower cost. However, if conditions do not allow the direct bury, then a HDD will be performed.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-11.359e
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to the attachment to the response to AGDG-3.68. For each project to be completed in 2021 and 2022, please:

e. Why can't the Company replace the missing soil cover? Provide the cost for this option and explain whether or not the Company explored this option. If no, why not?

Answer: Adding enough soil to cover the line to meet DTE standards is not feasible, while keeping the drain functional. Additionally, it will be difficult to ensure this problem does not reoccur in the future. Concrete shielding has been attempted in the past on similar crossings and it has failed over time. See the picture of West Branch in response AGDG-11.359c above.

Attachments: *None*

MPSC Case No.:	U-20642
Requestor:	Attorney General
Question No.:	AGDG-3.164
Respondent:	A. D. Sandberg
Page:	1 of 1
Partial, Supple, etc:	2nd

Question: Refer to page 42, lines 10-18, of Ms. Sandberg's direct testimony. Please confirm that the $12.4 million comprises the entire cost of the project. If not confirming, please provide the total cost from inception to completion by year and forecasted period in this case.

Answer: The total projected capital expenditure for the Van Born project is $96.0 million spanning from 2020 to 2024. The $12.4 million identified in this proceeding is only part of the total projected capital expenditures from December 31, 2018, the end of the historical test year, through September 30, 2021, the end of the projected test year.

Table below provides the projected capital spend by year for the Van Born Project from inception starting 2020 to projected completion in 2024.

Van Born Project ($ millions)	Total Project Cost	2019	2020	2021	2022	2023	2024
Total Project Capital Expenditures	$96.0	$0.0	$2.0	$14.0	$43.0	$35.0	$2.0

For detailed Van Born project cost for this proceeding, please refer to Exhibit A-12, Schedule B5.3, page 27 of 39

Attachments: None

MPSC Case No.:	U-20642
Requestor:	Attorney General
Question No.:	AGDG-3.162
Respondent:	A. D. Sandberg
Page:	1 of 1
Partial, Supple, etc:	3rd

Question: Refer to page 41 of Ms. Sandberg's direct testimony. Please provide a map of the area of the Van Born system showing the area that impacts 160,000 customers, the location of current pipelines and the proposed pipeline, and show the location of 120,000 customer mitigated and the 40,000 customers at risk of a potential outage.

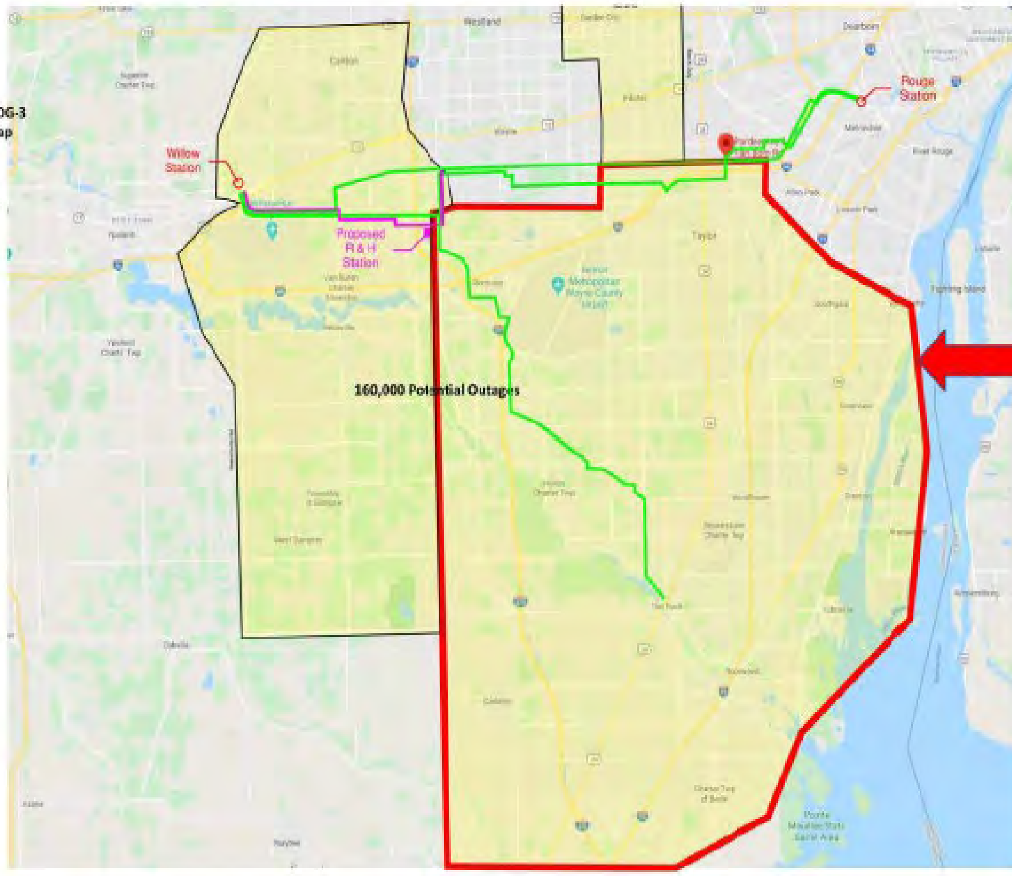
Answer: Please refer to file attachment U-20642 AGDG-3.162 Van Born System Outage Map

Attachments: U-20642 AGDG-3.162 Van Born System Outage Map

Case No. U-20642
Discovery Request: AGDG-3
Respondent: A. D. Sandberg
File Attachment: U-20642 AGDG-3
Van Born Potential Outage Map

EXISTING PIPELINES

PROPOSED PIPELINE



Post Construction
40,000 Potential
Outages

MPSC Case No.:	U-20642
Requestor:	Attorney General
Question No.:	AGDG-3.188
Respondent:	A. D. Sandberg
	L. Abayev
Page:	1 of 1
Partial, Supple, etc:	3rd

Question: Refer to the Van Born project on page 27 of Exhibit A-12, Schedule B5.3. Please explain how another supply line from the same gate station at Willow significantly reduces risk of a supply interruption. Wouldn't a different source of supply provide a better risk mitigation? Explain your answer.

Answer: Currently, Willow Gate Station has flexibility in supply with other interconnecting and transmission pipelines. Willow Gate Station piping configurations will be reviewed and designed to provide redundancy for the proposed Van Born project.

Attachments: None

MPSC Case No.: U-20642
Requestor: Staff
Question No.: STDG-1.19
Respondent: A. D. Sandberg
Page: 1 of 1

Question: Regarding Lines 12-14 on Page 42 of Company witness Alida D. Sandberg, which states in part that:

> "From December 31, 2018, the end of the historical test year, through September 30, 2021, the end of the projected test year, DTE Gas will have incurred $12.4 million of Van Born Project capital expenditures."

Because this project has not yet been submitted before the MPSC for Act 9 certification, please provide a cost estimate for the Van Born Project consistent with what DTE provided in their Act 9 application for the 10" Lincoln-Traverse City Pipeline Loop (U-20640, Exhibit A-5) and the 8" Frankfort Pipeline Loop (U-20641, Exhibit A-5).

Answer:

STDG-1.19 Van Born Pipeline	**Total Project Cost**
Project Cost Breakdown ($000s)	**1/1/2019-9/30/2021**
Land/ROW	$1,600
Material	$1,500
Engineering	$1,850
Construction	$5,383
AFUDC	$292
Contingency	$1,775
Total Project Cost - Van Born	**$12,400**

Attachments: *None*

MPSC Case No.:	U-20642
Requestor:	Attorney General
Question No.:	AGDG-3.163
Respondent:	A. D. Sandberg
Page:	1 of 1
Partial, Supple, etc:	2nd

Question: Refer to page 42, lines 2-5, of Ms. Sandberg's direct testimony. Please identify where the future revenue would come from, how much, and any known leads for potential revenue.

Answer: At this time no future revenue or known leads have been identified related to the project.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-3.93b
Respondent:	A. Sandberg
Page:	1 of 1

Question: Refer to page 42, lines 11-20, of Ms. Sandberg's direct testimony.

b. Is the Company proposing any changes to the project from what was presented in Case U-20642? If yes, identify the changes and explain the reasons.

Answer: The Van Born total projected cost of $96.0 million and the expected in service date of 01/31/24 has not changed from the previous case U-20642.

Presented in case no. U-20642, construction was to begin on 09-01-2022.

In this proceeding, the construction has moved to reflect a change in the intermediate schedule milestones and is expected to begin on 04-01-23.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-11.372a
Respondent:	A. Sandberg
Page:	1 of 1

Question: Refer to the response to AGDG-3.93a and page 18 of Exhibit A-12, Schedule B5.5.

a. Why does the Company need to reduce pressure on the 30" line to 300 psig? What is the cost to reduce the pressure?

Answer: The primary goal of the Van Born Pipeline project is to reduce the potential outage risk by creating system redundancy. This is accomplished by having two parallel lines operating at the same pressure. If an event were to occur on one of the 300 psig pipelines, then gas supply would continue from the other 300 psig pipeline. The cost to reduce the pressure is estimated to be $2.0 million. This cost estimate includes connecting the two pipelines through the installation of new cross-over valves and updating the existing main line valves with remote control capabilities.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-11.372c
Respondent:	A. Sandberg
Page:	1 of 1

Question: Refer to the response to AGDG-3.93a and page 18 of Exhibit A-12, Schedule B5.5.

c. Looking at the schematic on page 18 of Schedule B5.5, explain why a new 24" pipeline needs to be built when the Company already has two other pipelines transporting gas from the Willow Station, the 30" and 36" lines, to the River Rouge station. With these two existing pipelines interconnecting at the River Rouge station, why can't the Company reverse flow on either of the pipelines to serve residential and small commercial customers in case of an emergency and interruption of gas supply on one of the existing lines? Explain fully.

Answer: Based on seasonal demands, the existing pipeline system does not have enough capacity to reverse flow and support the residential and industrial customers in the service territory. The intent of this project is to operate the two existing pipelines in parallel at 300 psig, thus creating system redundancy. Therefore, a new pipeline is required to maintain gas supply for the 540 psig system.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-4.119c
Respondent:	R. Tomina
Page:	1 of 1

Question: Refer to page 34, lines 1-8 of Ms. Tomina's direct testimony. Please:

c. How much did the project cost increase because of the unexpected complexities and project schedule delays?

Answer: Approximately 80% ($3,700,000) of the increases in the project over the original budget are due to the unexpected complexities and schedule delays.

Attachments: None

MPSC Case No.:	U-20642
Requestor:	Attorney General
Question No.:	AGDG-3.180a
Respondent:	A. D. Sandberg
	J. J. Busby
Page:	1 of 1
Partial, Supple, etc:	2nd

Question: Refer to the Clicksoft Field Management project on page 9 of Exhibit A-12, Schedule B5.3. Please:

a. Provide the year when the current Field Service Management was installed.

Answer: The Current Field Service Management software (Service Suite) was installed in 2014.

Attachments: *None*

MPSC Case No.:	U-20642
Requestor:	Attorney General
Question No.:	AGDG-3.180b
Respondent:	A. D. Sandberg
	J. J. Busby
Page:	1 of 1
Partial, Supple, etc:	2nd

Question: Refer to the Clicksoft Field Management project on page 9 of Exhibit A-12, Schedule B5.3. Please:

b. Explain who determined that the current system is at the end of its life and why.

Answer: ABB, the vendor who delivered (Service Suite) determined that the current version is End of Life and they won't support it after the end of 2019.

Attachments: *None*

MPSC Case No.:	U-20642
Requestor:	Attorney General
Question No.:	AGDG-3.180c
Respondent:	A. D. Sandberg
	J. J. Busby
Page:	1 of 1
Partial, Supple, etc:	2nd

Question: Refer to the Clicksoft Field Management project on page 9 of Exhibit A-12, Schedule B5.3. Please:

c. Explain whether or not the current system is still functional.

Answer: The current system is functional with as-is functionality with no more patch upgrades to support the stability and security of the current version. Hence the reliability of the application will not meet business expectations.

Attachments: *none*

MPSC Case No.:	U-20642
Requestor:	Attorney General
Question No.:	AGDG-3.180d
Respondent:	A. D. Sandberg
	J. J. Busby
Page:	1 of 1
Partial, Supple, etc:	2nd

Question: Refer to the Clicksoft Field Management project on page 9 of Exhibit A-12, Schedule B5.3. Please:

d. Explain why it must be retired.

Answer:

- The current version of Service Suite 9.2.1 is End of Life and unsupported since end of 2019.
- Service Suite application requires DTE Gas's capital investments without integration gains and would still require additional investment within the next 5 years to upgrade from On-Premise to align with ABB's Cloud roadmap for Service Suite, equivalent to the cost of going to a new platform now.
- No new purpose-built features for Gas Operations.
- Service Suite is not utilizing cloud capabilities, which increases turnaround time on defects and improvements.
- Service Suite has a long outage window when pushing updates to the field
- Maintaining and supporting multiple platforms will incur additional maintenance and licensing costs.

Attachments: None

MPSC Case No.:	U-20642
Requestor:	Attorney General
Question No.:	AGDG-3.180e
Respondent:	A. D. Sandberg
	J. J. Busby
Page:	1 of 1
Partial, Supple, etc:	2nd

Question: Refer to the Clicksoft Field Management project on page 9 of Exhibit A-12, Schedule B5.3. Please:

e. What cost savings or financial benefits will the new system provide and over what time period?

Answer: DTE Gas is not implementing ClickSoft for financial savings but rather as a requirement for operational functionality and acceptable levels of risk given the end of life status of Service Suite.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-3.84a
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to Exhibit A-12, Schedule B5.5, page 41, pertaining to the Field Service Management (ClickSoft) system. Please:

a. Provide the date the current system was installed and why it is considered end of life, when the EOL will occur, and the date when the Company made the determination to go to a new system.

Answer: The current system was initially implemented in 2007 with an in-service date of April 7, 2007 and was owned by a vendor called Advantex. In 2014, ABB (ASEA Brown Boveri) bought the Advantex software and rebranded it as Service Suite.

ABB communicated that effective December 2019 they would no longer support the product and, so the current system has been deemed end of life as of December 2019. The Company made the determination to go to a new system in May 2018. Please refer to U-20940 Busby Direct Testimony JJB-27 line 15 through JJB-28 line 20 for additional details.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-3.84b
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to Exhibit A-12, Schedule B5.5, page 41, pertaining to the Field Service Management (ClickSoft) system. Please:

b. Confirm that the system still functions as designed. If not confirming, please explain.

Answer: Yes, the current system - Service Suite functions as designed with the base functionalities implemented in 2007 and has not been patched or upgraded since 2014.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-3.84d
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to Exhibit A-12, Schedule B5.5, page 41, pertaining to the Field Service Management (ClickSoft) system. Please:

d. Who has fixed problems and defects during the past three years, the Company IT team or ABB?

Answer: The Company's IT team has been fixing the issues during the past three years and keeping it operational.

Attachments: None

MPSC Case No.:	U-20642
Requestor:	Staff
Question No.:	STDG-9.11B
Respondent:	A. D. Sandberg
	J. J. Busby
Page:	1 of 1
Partial:	2nd

Question: The following questions pertain to the Energy Gas Management Systems (EGMS) Upgrade described in Exhibit A-12, Schedule B5.3, page 11 of 39:

B. How long has the EGMS system been obsolete and unsupported by the vendor?

Answer: The Company objects for the reason that the request is unduly vague and incapable of answer in its present form. Without waiving this objection, but subject to it, to clarify what is meant by "obsolete and unsupported", the current EGMS system is functional and operational. However, DTE Gas is several software versions behind the vendor's current software releases. Vendor support is limited due to the older version of software currently in operation.

Attachments: *None.*

MPSC Case No.:	U-20642
Requestor:	Staff
Question No.:	STDG-9.11C/J. J. Busby
Respondent:	A. D. Sandberg
Page:	1 of 1
Partial:	2nd

Question: The following questions pertain to the Energy Gas Management Systems (EGMS) Upgrade described in Exhibit A-12, Schedule B5.3, page 11 of 39:

C. Please describe why DTE Gas allowed the EGMS system to be obsolete and unsupported by the vendor.

Answer: The Company objects for the reason that the request is unduly vague and incapable of answer in its present form. Without waiving this objection, but subject to it, please see response for question STDG-9.11B

Attachments: *None.*

.

MPSC Case No.:	U-20642
Requestor:	Staff
Question No.:	STDG-9.11D
Respondent:	A. D. Sandberg
	J. J. Busby
	Legal
Page:	1 of 1
Partial:	2nd

Question: The following questions pertain to the Energy Gas Management Systems (EGMS) Upgrade described in Exhibit A-12, Schedule B5.3, page 11 of 39:

D. How has DTE Gas been using the EGMS system since it has been unsupported by the vendor?

Answer: The Company objects for the reason that the request is unduly vague and incapable of answer in its present form. Without waiving this objection, but subject to it, please see response for question STDG-9.11B.

Attachments: *None.*

MPSC Case No.:	U-20642
Requestor:	Staff
Question No.:	STDG-9.11E
Respondent:	A. D. Sandberg
	J. J. Busby
Page:	1 of 1
Partial:	2nd

Question: The following questions pertain to the Energy Gas Management Systems (EGMS) Upgrade described in Exhibit A-12, Schedule B5.3, page 11 of 39:

E. Please describe why the upgrade and addition of servers are necessary for this project.

Answer: It is necessary to replace the existing servers as they are at end of life. In addition, the new EGMS version software requires additional servers to support its operation.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.258a
Respondent:	J. Busby / Legal
Page:	1 of 1

Question: Refer to page 34, lines 8-21 of Mr. Busby's direct testimony. Please:

a. Provide the total cost of this project by year from inception to completion at the DTE level and the portion applicable to the gas business, the electric business, DTE Gas Gathering, and other affiliates.

Answer: DTE Gas objects for the reason that the request is vague and incapable of an answer in its present form. Without waiving this objection, but subject to it, the Company responds as follows:

Exhibit A-12 B5.4, B5.4.1, B5.16 and the corresponding detailed testimony provides all available information on projects from 2019 through 2022. Additionally, workpaper U-20940 JJB WP-01 can be referenced for summary data from 2015 to 2019 .

2020 actuals to date are included in response to 282b. Please note this case introduces a dataset for Gas-IT projects that follow the precedent used in our Electric filings for data presentment.
For the number of units replaced please refer to the response to Q.254e

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.259a
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 35, lines 14-23 of Mr. Busby's direct testimony. Please:
a. Provide the total cost of this project by year from inception to completion at the DTE level and the portion applicable to the gas business, the electric business, DTE Gas Gathering, and other affiliates.

Answer: Please see the response to question 254h.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.259e
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 35, lines 14-23 of Mr. Busby's direct testimony. Please:
e. Provide a copy of the cost/benefit analysis in Excel with formulas intact performed on this project showing a favorable net present value to justify undertaking the project.

Answer: This information is not available in the requested format as DTE's consideration of costs and benefits occur over the processes mentioned in U-20940 Busby Direct Testimony & the DTE Five-Year IT Plan. For cost consideration, please refer to A-12 B5.4, B5.4.1, A-12 B5.16 as well as testimony. For an accompanying analysis of benefits, please use the testimony analysis provided as well as the information in A-12 B5.15 & JJB WP-02.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.260
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 36, lines 3-6 of Mr. Busby's direct testimony. Please explain what you mean by "FERC compliant." Does FERC mandate a set of requirements on how the Company should design or operate its EGMS? If yes, provide a copy of those requirements.

Answer: FERC does not mandate requirements for DTE Gas but does mandate requirements for FERC regulated pipelines. Since DTE Gas non-FERC pipelines interconnect with multiple FERC regulated pipelines, it is necessary for DTE Gas to follow the nomination and confirmation deadline requirements set forth by FERC.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.253
Respondent:	T. Uzenski / J. Busby
Page:	1 of 1

Question: Refer to page 14, lines 5-19 of Mr. Busby's direct testimony. Please explain why these costs are not charged to O&M expense as incurred, given that they are base operating system maintenance costs.

Answer:

Mr.Busby's testimony is describing the overall work related to sustainment. The amounts shown for capital sustainment projects are based on the Company's accounting policy for IT costs. Upgrades and enhancements are capitalized if it is probable that those expenditures will result in significant, additional functionality, the upgrade results in new software designs or a change to part of the existing software design, and a materiality threshold of $10,000 for capitalizing upgrades and enhancements is met. In addition, for the first 60 days subsequent to the in-service date of a software development project, the direct cost of remediating all defects related to the originally planned design can be capitalized.

Attachments: *none*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.254a
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 21, lines 8-13 and page 22, lines 1-10 of Mr. Busby's direct testimony.

a. Is the EOL Gas Device Program a one-time program or a repetitive annual program? Explain your answer.

Answer: The EOL Gas Device Program is a repetitive program undertaken annually to replace network and endpoint devices that are at the end of their serviceable life.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.254d
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 21, lines 8-13 and page 22, lines 1-10 of Mr. Busby's direct testimony.

d. Who established the life expectancy in Table 1? Why is it only for 5 years?

Answer: For EOL Endpoint gas devices, life expectancy is established by Endpoint Engineering team and for the EOL Network gas devices, life expectancy is established by Network Engineering Team

These are derived from industry standards and OEM (Original Equipment Manufacturer) specifications. Please refer to the DTE Five Year IT Plan (Section 6.C.III) for additional details around DTE Gas Assets.

Attachments: None

MPSC Case No.: U-20940
Requestor: AG
Question No.: AGDG-8.254e
Respondent: J. Busby
Page: 1 of 1

Question: Refer to page 21, lines 8-13 and page 22, lines 1-10 of Mr. Busby's direct testimony.

e. Do these devices still function after 5 years? Provide the number of failures experienced in 2019 and 2020 by device type.

Answer: In some EOL replacement instances these devices still mechanically function, but they may no longer meet the business demand requirements of the user(s). They must be able to be upgraded, patched, and able to accept security protocols required to ensure the security of DTE and customer data. Please refer to the DTE Five Year IT Plan (Section 6.C.III) for additional details around DTE Gas Assets.

Please see the table below for the number of devices replaced (unplanned and planned) from 2018 to 2022:

	2018	2019	2020	2021	2022
Network Devices	*	16	28	12	135
Endpoint Devices	1069	1157	1739	335	700

** Data unavailable*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.254f
Respondent:	J. Busby / Legal
Page:	1 of 1

Question: Refer to page 21, lines 8-13 and page 22, lines 1-10 of Mr. Busby's direct testimony.

f. Provide the percentage failure rate at 5 years and 7 years.

Answer: DTE Gas objects for the reason that the request is vague and incapable of answer in its present form as it is unclear what is meant by "percentage failure". Without waiving this objection, but subject to it, the Company answers as follows:

We are unable to provide this data since DTE Gas currently does not track failures based on the device installation date.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.254g
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 21, lines 8-13 and page 22, lines 1-10 of Mr. Busby's direct testimony.

g. Has the Company considered stretching the use of these devices to at least 7 years? If yes, provide a copy of the analysis. If no, why not?

Answer: No. The life expectancy of 5 years is derived from industry standards and OEM (Original Equipment Manufacturer) specifications. Please refer to the DTE Five Year IT Plan (Section 6.C.III) for additional details around DTE Gas Assets.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.254i
Respondent:	J. Busby / Legal
Page:	1 of 1

Question: Refer to page 21, lines 8-13 and page 22, lines 1-10 of Mr. Busby's direct testimony.

i. Provide the reduction in cap ex for 2021 and 2022 if life expectancy was stretched to 7 years.

Answer: DTE Gas objects for the reason that the request is unduly burdensome, overly broad, and calculated to cause unreasonable expense to DTE Gas and its ratepayers.

This data is not available. It is neither a best practice, nor an industry benchmark to stretch the viable life of an asset except when there is established and tested proof indicating we have opportunity to do so. We do not maintain data on arbitrary adjustment. Please see questions 254.d, 254.e and 254.f for a discussion of the overall standard.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.261a
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 43, lines 5-24 of Mr. Busby's direct testimony. Please:

a. Explain what the DTE CleanVision Natural Gas Balance Pilot is about and what it aims to achieve. How much is the cost of this program and where is it included in cost recovery in this rate case? Provide an exhibit and line-item reference.

Answer: DTE CleanVision Natural Gas Balance Pilot is a voluntary program for DTE Gas customers. They can choose to enroll and offset the natural gas emissions of their usage. This provides an affordable and easy solution for gas customers to offset their emissions from their natural gas usage. The program costs associated with this program are not being recovered.

There are, however, foundational systems that support all DTE technology and these require periodic updates the costs associated with the system updates are outlined in the Exhibit A-12 Sch 5.4.1 Line 12

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.261d
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 43, lines 5-24 of Mr. Busby's direct testimony. Please:
d. What will the $800,000 be spent on?

Answer: All costs in this rate case in connection to this program are only for IT costs. These include updates to the Hyrbris system needed for the program and other DTE programs to follow in order for them to show up and be billed on customer bills. For additional details of the IT portion of the implementation in 2020 and 2021 please refer to the U-20940 Busby Direct Testimony (page 43 lines 5 – 24, page 44 lines 1-11).

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-3.70a
Respondent:	D. Brudzynski
Page:	1 of 1

Question: Refer to Exhibit A-12, Schedule B5.1, page 2. Please:

a. Provide the same information for actual 2020 in Excel.

Answer: Please refer to file attachment U-20940 AGDG-3.70a Exh A-12 B5.1 with 2020 actuals

Attachments: U-20940 AGDG-3.70a Exh A-12 B5.1 2020 actuals

Case No: U-20940
Discovery Request: AGDG-3.70a
Respondent: D. Brudzynski
File Attachment: U-20940 AGDG-3.70a Exh A-12 B5.1 with 2020 actuals

Michigan Public Service Commission
DTE Gas Company
Capital Expenditures - Routine Distribution, Transmission, Storage and General
($000) **2020 Actuals**

Case No.: U-20940
Exhibit: A-12
Schedule: B5.1
Witness: D. Brudzynski
Page: 2 of 2

Line No.	(a) Description	(b) Five Year Average 2015-19	(c) Historical 12 mos. ended 12/31/2019	(d) Actuals 12 mos. ending 12/31/2020	(e) Projected Bridge Year 12 mos. ending 12/31/2021	(f) Projected Bridge Year 24 mos. ending 12/31/2021 =col.(d) + col.(e)	(g) Projected Test Year 12 mos. ending 12/31/2022
1	**Routine Capital Requirements**						
2	**Distribution Plant**						
3	Main Renewals	$ 4,002	$ 6,354	$ 3,747	$ 3,673	$ 7,420	$ 3,810
4	Public Improvements	15,882	18,341	24,106	15,636	39,742	16,582
5	Service Abandonments	6,623	7,103	5,127	6,150	11,277	6,168
6	Service Alterations	12,614	16,521	18,896	18,541	37,437	17,838
7	Service Renewals	12,285	13,240	13,490	16,035	29,525	16,096
8	System Reliability	18,935	29,643	19,129	26,745	45,874	30,629
9	Cathodic Protection	4,445	5,282	7,179	5,875	13,054	5,900
10	Communications & Control - Meters	12,325	10,714	19,358	9,078	28,437	12,079
11	Advanced Metering Infrastructure	14,003	4,027	3,693	4,095	7,788	2,129
12	Revenue Protection	3,125	2,648	3,321	3,013	6,334	3,012
13	New Market Attachments	43,455	62,702	64,953	67,013	131,966	68,709
14	Permits and Other Adjustments	788	1,833	551	804	1,356	1,137
15	Sales and Use Tax Settlement 1/	(2,249)	-	-	-	-	-
16	**Total Distribution Plant**	146,233	178,407	183,551	176,659	360,210	184,090
17	**Transmission Plant**						
18	Transmission	7,513	7,413	14,830	15,516	30,346	19,807
19	Sales and Use Tax Settlement 1/	(1,379)	-	-	-	-	-
20	**Total Transmission Plant**	6,134	7,413	14,830	15,516	30,346	19,807
	Storage Plant						
21	Gas Storage	5,811	2,951	3,406	3,960	7,366	3,704
22	Environmental Projects - Storage	306	124	88	433	521	476
23	Compression - Storage	17,461	22,298	11,199	10,330	21,529	18,233
24	**Total Storage Plant**	23,577	25,373	14,694	14,722	29,416	22,413
	General Plant						
25	Structures and Improvements	8,277	13,820	8,701	8,065	16,766	8,045
26	Transportation Vehicles and Equipment	11,561	8,896	9,861	9,214	19,075	10,000
27	Tools and Equipment	1,555	1,648	828	1,162	1,990	1,174
28	Communications and Control Equipment	1,860	2,086	943	1,430	2,373	1,444
29	**Total General Plant**	23,254	26,449	20,332	19,872	40,204	20,664
30	**Total Routine Capital Requirements**	$ 199,198	$ 237,643	$ 233,407	$ 226,769	$ 460,176	$ 246,974

Capital Expenditures (columns c–g); Projected Bridge Year (columns d–f).

1/ Sales and Use Tax Settlement, Page 2 of 2, column (b) line no. 15 and 19, was a one-time tax credit in 2017-18.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company

Exhibit: AG-19
Case No: U-20940
June 3, 2021

Adjustments to Capital Expenditures, Rate Base and Depreciation Expense

($000)

		Capital Expenditure Reductions [1]					Rate Base		
Line	Description (a)	2019 (b)	2020 (c)	2021 (d)	2022 (e)	Total (f)	Reduction (g)	Depreciation Rate [2]	Reduction in Depreciation Expense
1	**Contingency Capita Expenditures**		$ 2,030	$ 6,501	$ 4,503	$ 13,034	$ 10,783	1.55%	$ 167
2	**Distribution Plant:**								
3	Service Alterations			2,372	2,209	4,581	3,477	2.89%	100
4	Service Renewals		1,983	2,292	2,292	6,567	5,421	2.89%	157
5	Service Abandonments		1,568			1,568	1,568	2.89%	45
6	New Market Attachments			19,901	10,653	30,554	25,228	2.89%	729
7	Belle Isle Main Replacement	2,400				2,400	2,400	2.89%	69
8	**Transmission Plant:**								
9	Pipeline Soil Cover Remediation			2,780	8,967	11,747	7,264	1.55%	113
10	Van Born project		964	9,900	22,000	32,864	21,864	1.55%	339
11	East Jefferson Main Replacement			990	14,000	14,990	7,990	1.55%	124
12	Middlebelt Deration Project			1,485		1,485	1,485	1.55%	23
13	Northeast Beltline Project		3,839	786		4,625	4,625	1.55%	72
14	**Gas IT Projects**								
15	Clicksoft system	5	534	4,517	1,757	6,813	5,935	20.00%	1,187
16	EGMS	1,198	1,820	100	150	3,268	3,193	20.00%	639
17	Projects Sustainment	1,217	2,090	1,172	1,600	6,079	5,279	20.00%	1,056
18	BioGreen Program Redesign		400	400		800	800	20.00%	160
19	Field Sketch Enhancements	427	398	300	150	1,275	1,200	20.00%	240
20	**2020 Routine Capital Expenditures Not Spent**		5,195			5,195	5,195	2.89%	150
21	**Incentive Compensation-Capitalized** [3]				2,467	2,467	1,234	2.88%	36
22	Total	$ 5,247	$ 20,821	$ 53,496	$ 70,748	$ 150,312	$ 114,938		$ 5,405
23									
24	**Working Capital** (Exhibit AG-20)						19,700		
25									
26	**Total Rate Base Deduction**						$ 134,638		

Source: (1) See AG witness Coppola Direct Testimony.
(2) Depreciation rates from Exhibit A-13, Schedule C6, page 2.
(3) See Exhibit AG-71. Reflects disallowance of 80% of short-term Incentive payments disallowed per Mr. Coppola's testimony

Line	Description (a)	Millions of Dollars (b)	(bc)	Note or Ref. (d)
1	Working Capital Per Company		$ 1,020.3	1
	Attorney General Changes			
2	Set Customer Accounts Receivable at Historic 2019 Level		(9.0)	2
3	Covid - Uncollectibles Deferral	$ 10.7		3
4	*Amount Removed*	(10.7)	(10.7)	4
5	**Total Change**		**$ (19.7)**	
6	**AG Revised Working Capital Level**		**$ 1,000.6**	
7	**Change in Working Capital**		**$ (19.7)**	

Note 1 Per Company Exhibit A-12, Sched. B-4, page 1, Line 59
Note 2 Per Company Exhibit A-12, Sched. B-4, page 1, Line 9, historic level is $9.0 million lower than projected level.
Note 3 Per Company Exhibit A-12, Sched. B-4, page 1, Line 28.
Note 4 See Coppola testimony in Uncollectible Accounts and Working Capital sections.

MICHIGAN PUBLIC SERVICE COMMISSION **Exhibit AG-20**
DTE Gas Company - Gas Rate Case **Case No. U-20940**
Date: June 3, 2021
Accounts Receivable - % of Revenues

Line	Description	Millions of Dollars 2018	2019	Note or Ref.
	(a)	(b)	(c)	(d)
1	Average Customer Accounts Receivable	$ 235.1	$ 214.1	1
2	Distribution Revenues	$ 1,236.7	$ 1,259.1	2
3	Transportation Revenues	90.1	110.5	2
4	Total	$ 1,326.8	$ 1,369.6	L 2 + L 3
5	**Accounts Receivable - % of Revenue**	**17.7%**	**15.6%**	L 1 / L 4

Conclusion: The fall of Accounts Receivable as a percent of Revenue reflects more rapid collection of amounts owed due to use of credit/debit cards and other factors.

Note 1 Per Company Exhibit A-12, Sched. B-4 in Cases U-20642 and U-20940

Note 2 Per Company Exhibit A-3, Sched. C1 in Cases U-20642 and U-20940

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Exhibit AG-21
Case No. U-20940
Date: June 3, 2021

Recommended Capital Structure & Cost Rates for
Projected Year Ending December 2022 (Millions of Dollars)

Line	Description (a)	Note	Capital Balances (b)	% Permanent Capital (c)	% Total Capital (d)	Cost Rate* (e)	Total Cost (d) x (e) (f)	Conversion Factors* (g)	Pre-Tax Wtd. Cost (f) x (g) (h)
1	Long Term Debt	(A)	$ 2,157.8	50.00%	38.46%	3.97%	1.53%	1.0000	1.53%
2	Preferred Stock			0.00%	0.00%	0.00%	0.00%	1.3550	0.00%
3	Common Equity	(A)	2,157.7	50.00%	38.46%	9.50%	3.65%	1.3550	4.95%
4	Total Permanent Capital	(B)	4,315.5	100.00%	76.92%		5.18%		6.48%
5	Short Term Debt	(B)	194.6		3.47%	0.95%	0.03%	1.0000	0.03%
6	Deferred Income Taxes	(B)	1,100.6		19.62%	0.00%	0.00%	1.0000	0.00%
7	JDITC								
8	Long Term Debt		-		0.00%	0.00%	0.00%	1.0000	0.00%
9	Preferred Stock		-		0.00%	0.00%	0.00%	1.3550	0.00%
10	Common Equity		-		0.00%	0.00%	0.00%	1.3550	0.00%
11	Total JDITC		-						
12	**Total Capitalization & Cost Rates**		$ 5,610.7		100.00%		**5.21%**		**6.51%**

Notes

(A) Line 4 Permanent Capital allocated 50% to Common Equity and 50% to Long-Term Debt--see witness Coppola testimony

(B) Balances Per Company Case - see Exh. A-14, Schedule D2

* All Cost Rates and Conversion Factors based on the Company case except for the Cost of Common Equity (see Exhibit AG-22)

MICHIGAN PUBLIC SERVICE COMMISSION | **Exhibit AG-22**
DTE Gas Company - Gas Rate Case | **Case No. U-20940**
Date: June 3, 2021
Page 1 of 1

Analysis of DTE Gas Cash Flow - Moody's Test
(Actual and Pro-Forma with 50/50 Capital Structure)

		Millions of Dollars					
		Actual 2019 Moody's Cash Flow Ratio			Actual 2018 Moody's Cash Flow Ratio		
Line	Caption	Cash From Operations Pre-Wkg. Cap.	Debt	Ratio (b) / (c)	Funds From Operations (FFO)	Debt	Ratio (e) / (f)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	2019 Actual - See AGDG-6.205 (Case U-20940)	$ 368	$ 1,997	**18.4%**			
	2018 Actual - See AGDG-1.75 (Case U-20642)				$ 337	$ 1,826	**18.5%**
2	Change to 50% Long Term Debt*		91			112	
3a	Earnings Reduct. - (Less Common Equity)**	(9)			(11)		
3b	Earnings Reduct - (Actual ROE% vs Target ROE%)**	(17)	-		-	-	
4	**Pro Forma 2018 w/50% Common Equity (L1+2+3)**	$ 342	$ 2,088	**16.4%**	$ 326	$ 1,938	**16.8%**
5	**Ratings Downgrade Risk*** **			**Below 15%**			**Below 15%**

* Additional Debt to Reduce Common Equity (from Exh. A-4, Sch. D1) from 52.75% (Case U-20940) and 53.75% (Case U-20642)
2019 Adjus Perm. Capital of $3,326M x 2.75% = $91M
2018 Adjus Perm. Capital of $2,975M x 3.75% = $112M

** Line 3a: Line 2 x 9.5% Target ROE
Line 3b: For 2019: Perm. Cap. Of $3.326M x 50% Equity Percentage x 1% ROE Reduction = $17M lower net Income
For 2018: The Company had an earned ROE of 9.5%, so no adjustment is needed.

*** For Moody's, see report dated July 23, 2020 on page 3 under "Factors that could lead to a downgrade". (AGDG-6.202)

MICHIGAN PUBLIC SERVICE COMMISSION **Exhibit AG-23**
DTE Gas Company - Gas Rate Case **Case No. U-20940**
Date: June 3, 2021

Cost Savings -Lower Common Equity
with and without higher Debt Cost - $ in Millions

Line	Description	Capital Balances	% Permenant Capital	% Total Capital	Cost Rate	Conversion Factors	Pre-Tax Wtd. Cost (e) x (f)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
	DTE Gas Recommended Capital Structure*						
1	Long Term Debt	$ 2,075.8	48.10%	37.00%	3.97%	1.0000	1.47%
2	Preferred Stock		0.00%	0.00%	0.00%	1.3550	0.00%
3	Common Equity	2,239.7	51.90%	39.92%	10.25%	1.3550	5.54%
4	Total Permanent Capital	4,315.5	100.00%	76.92%			7.01%
5	Short Term Debt	194.6		3.47%	0.95%	1.0000	0.03%
6	Deferred Income Taxes	1,100.6		19.62%	0.00%	1.0000	0.00%
7	**Total Capitalization & Cost Rate (L1 to 6)**	$ 5,610.7		100.00%			7.04%
	DTE Gas with 50%/50% Capital Structure						
8	Long Term Debt	$ 2,157.8	50.00%	38.46%	3.97%	1.0000	1.53%
9	Preferred Stock		0.00%	0.00%	0.00%	1.3550	0.00%
10	Common Equity	2,157.7	50.00%	38.46%	10.25%	1.3550	5.34%
11	Total Permanent Capital	4,315.5	100.00%	76.92%			6.87%
12	Short Term Debt	194.6		3.47%	0.95%	1.0000	0.03%
13	Deferred Income Taxes	1,100.6		19.62%	0.00%	1.0000	0.00%
14	**Total Capitalization & Cost Rate (L8 to 13)**	$ 5,610.7		100.00%			6.89%

15 BP Savings

Savings -Capital Structure Change

15	Assume no change in Debt Rate	$5.6 Billion in Rate Base x 15 Basis Points	**$ 8.4**
16	Assume 15 BP Increase in Debt Cost (Assumes Moody's A1 rating reset at A2)	Line 15 less (15 BP cost change x $2.2 billion of Long Term Debt)	**$ 5.2** **

* From Company Exhibit A-14, Sched. D2.

** Same week issuances of 30 Yr. debt in 2019 rated A2/A vs. A1/A reflect a 10 to 15 basis points increase due to the ratings difference.
Also, the savings in the first year would approximate $8.4 million but it would decline as more debt is refinanced at higher rates to $5.2 million.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Exhibit AG-24
Case No. U-20940
Date: June 3, 2021

Summary of Cost of Common Equity Analysis

Line	Description (a)	Relative Weighting (b)	Proxy Rates (c)	Note (d)
1	Discounted Cash Flow Approach (DCF)	50.00%	9.40%	1
2	Capital Asset Pricing Model Approach (CAPM)	25.00%	9.14%	2
3	Utility Equity Risk Premium Approach	25.00%	8.55%	3
4	**Weighted Average Cost of Common Equity (Sum of Col. (b) x (c) for Lines 1, 2 and 3)**		**9.12%**	
5	Allowance for Other Risk Factors		0.38%	4
6	**Cost of Common Equity for Rate Case Purposes**		***9.50%***	

Note 1 See Exhibit AG-25
Note 2 See Exhibit AG-26
Note 3 See Exhibit AG-27
Note 4 The Company's service area may pose certain higher risks not present with peer utilities.

Discounted Cash Flow (DCF) Application
(See Equation Below)

Line	Company	Ticker	Average 30 Day High Low Price*	Avg. 2021 & 2022 Ann. Dividend**	Dividend Yield Col. (d)/c	EPS Growth Rate*** Value Line	Analysts p/Yahoo	Average of Col. (f) & (g)	DCF ROE for Each Co. Col. (e) + (h)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Proxy Group								
1	Atmos Energy	ATO	$ 92.04	$ 2.60	2.82%	5.86%	7.00%	6.43%	9.25%
2	New Jersey Resources	NJR	40.19	1.38	3.43%	3.63%	6.00%	4.81%	8.25%
3	NiSource	NI	22.82	0.90	3.94%	NM	4.37%	4.37%	8.31%
4	Northwest Natural Holdings	NWN	50.95	1.93	3.79%	6.15%	3.10%	4.63%	8.41%
5	One Gas	OGS	73.12	2.24	3.06%	6.32%	5.00%	5.66%	8.72%
6	South Jersey Industries	SJI	24.97	1.33	5.33%	9.06%	4.40%	6.73%	12.06%
7	Southwest Gas Holdings	SWX	66.46	2.43	3.66%	9.44%	4.00%	6.72%	10.38%
8	Spire	SR	71.00	2.66	3.75%	6.49%	5.70%	6.10%	9.84%
9	Average				***3.72%***	***6.71%***	***4.95%***	***5.68%***	$\boxed{\textbf{9.40\%}}$
10	High								12.06%
11	Low								8.25%

* Average of High and Low prices per Yahoo from February 18, 2021 to March 31, 2021
** Average of Value Line Projected Dividends for 2021 and 2022 published February 26, 2021 for proxy companies.
*** For Columns (f) and (g) per workpapers
N/M Not Meaningful-Earnings Growth rate exceeding 10%

Equation **R = D/P + g** *Where* **R** = the required return on the equity security; **D** = the next dividend on the security; **P** = the current price of the equity security; **g** = the expected growth rate of earnings

MICHIGAN PUBLIC SERVICE COMMISSION | **Exhibit AG-26**
DTE Gas Company - Gas Rate Case | **Case No. U-20940**
Date: June 3, 2021

Capital Asset Pricing Model Application
(See Equation Below)

Line	Company & Ticker (a)		% Common Equity (b)	Current Beta (B) (c)	Risk Premium (R_p) (d)	Beta x Risk Premium Col. (c) x (d) (e)	2022 Risk Free Rate (R_f) (f)	K_e or 2022 CAPM ROE for Each Co. Cols. (e) + (f) (g)
	Proxy Group							
1	Atmos Energy	ATO	59.1%	0.80	7.25%	5.80%	2.75%	8.55%
2	New Jersey Resources	NJR	47.3%	0.95	7.25%	6.89%	2.75%	9.64%
3	NiSource	NI	33.0%	0.85	7.25%	6.16%	2.75%	8.91%
4	Northwest Natural Holdings	NWN	48.0%	0.80	7.25%	5.80%	2.75%	8.55%
5	One Gas	OGS	59.2%	0.80	7.25%	5.80%	2.75%	8.55%
6	South Jersey Industries	SJI	37.4%	1.05	7.25%	7.61%	2.75%	10.36%
7	Southwest Gas	SWX	48.1%	0.95	7.25%	6.89%	2.75%	9.64%
8	Spire	SR	45.7%	0.85	7.25%	6.16%	2.75%	8.91%
9	**Average**		**47.2%**	**0.88**	**7.25%**	**6.39%**	**2.75%**	***9.14%***
10	High							10.36%
11	Low							8.55%

Sources

Column (b) Per SEC Filings: Average for the four quarters ended December 2020.
Column (c) The Value Line Investment Survey of February 26, 2021 for proxy companies.
Column (d) Reflects the average returns of Large Stocks (12.16%) vs Long Term Gov't Bond Income Returns (4.91%) for the period 1926 to 2020 per the Ibbotson Clasic Year Book.
Column (f) Developed 30 Yr. U. S. Treasury Rate

2021 10 year U. S. Treasury Rate as of April 2021 (US Treasury Website)	1.70%	
2023 10 year U. S. Treasury Rate per AGDG-6.182	2.30%	
Average - indicative of 2022	2.00%	
30 Yr. vs. 10 Yr. Treasury Spread as of March 2021 (AG Workpaper)	0.75%	
Developed 2022 30 Yr. US Treasury Rate	***2.75%***	*To Col. (f) above*

Equation for CAPM $K_e = R_f + (B \times R_p)$

Where K_e = the Cost of Common Equity; R_f = the Risk Free Rate of Return;
B = the Beta or covariance of the stocks price to overall market ; and
R_p = the Expected Risk Premium of the overall market

Utility Equity Risk Premium Approach

Line	Description (a)	Rate Developed (b)	Note (c)
1	Number of Companies in proxy group**	8	
2	Average Rating	A/BBB	1
3	Proj. Test Period Risk Free Rate - 30 Year U. S. Treasury Rate	2.75%	2
4	Corporate Spread Over Treasury Bond Rate	1.80%	3
5	Sub Total (Line 3 + Line 4)	4.55%	
6	Historical Spread - Gas Util. Common Stocks vs. Utility Bonds	4.00%	4
7	**Cost of Common Equity (Line 5 + Line 6)**	8.55%	

1 See Peer Group Ratings Workpaper
2 From CAPM Exhibit of AG (see Column (f) footnote)
3 Average Spread of straight A and straight BBB rated issuers for 10 Mo Ended October 2020 (See WP on Bond Spreads)
4 See WP on Utility Equity Risk Premium

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Energy Gas Company - Gas Rate Case

Peer Group Non-Utility or Non Regulated Operations

Line	Company & Ticker		Percent Common Equity*	Current Beta (*B*)	Utility Business	Non Utility & Non Reg. Business		Measurement Criteria	Col. (d) & (e) Information SEC Form	Period Ending	Page
	(a)		(b)	(c)	(d)	(e)		(f)	(g)	(h)	(i)
	Proxy Group										
1	Atmos Energy	ATO	59.1%	0.80	***65.8%***	***34.2%***	A	Net Income	10-K	Sep. 20	26
2	New Jersey Resources	NJR	47.3%	0.95	***65.4%***	***34.6%***	B	Net Income	10-K	Sep. 20	37
3	NiSource	NI	33.0%	0.85	***99.6%***	***0.4%***		Revenues	10-K	Dec. 20	65
4	Northwest Natural Gas	NWN	48.0%	0.80	***100.0%***	***0.0%***		Revenues	10-K	Dec. 20	Var.
5	One Gas	OGS	59.2%	0.80	***100.0%***	***0.0%***		Revenues	10-K	Dec. 20	5
6	South Jersey Industries	SJI	37.4%	1.05	***59.6%***	***40.4%***	C	Revenues	10-K	Dec. 20	67
7	Southwest Gas	SWX	48.1%	0.95	***68.5%***	***31.5%***	D	Net Income	10-K	Dec. 20	5
8	Spire	SR	45.7%	0.85	***94.4%***	***5.6%***		Revenues	10-K	Sep. 20	36
9	**Average**		47.2%	0.88	***81.7%***	***18.3%***					

* With the exception of Atmos, all of the peer companies carried short term debt at each quarter end in 2020.
No Short-Term Debt is incorporated in the ratios above.

A Pipeline and Storage
B Clean Energy Ventures, Energy Services, Midstream and Home Services
C Gas Transportation and Storage, Midstream, Solar and Land Fill Gas
D Utility Infrastructure Services

MICHIGAN PUBLIC SERVICE COMMISSION **Exhibit AG-29**
DTE Gas Company - Gas Rate Case **Case No. U-20940**
Date: June 3, 2021
Market to Book Equity Ratios **Page 1 of 1**

Line	Company & Ticker		Dec. 31 2020 Mkt. Price p/ Sh.	Dec. 31, 2020 Book Value of Common Equity ($Mil.)	Shares Outstanding (Millions)	Book Value Per Sh.	Market to Book Ratio
	(a)		(b)	(c)	(d)	(e)	(f)
	Proxy Group						
1	Atmos Energy	ATO	95.43	7,213.2	128.2	56.27	1.7
2	New Jersey Resources	NJR	35.55	1,698.2	96.1	17.67	2.0
3	NiSource	NI	22.94	5,752.2	391.8	14.68	1.6
4	Northwest Natural Gas	NWN	45.99	888.7	30.6	29.04	1.6
5	One Gas	OGS	76.77	2,233.3	53.2	41.98	1.8
6	South Jersey Industries	SJI	21.55	1,666.9	100.6	16.57	1.3
7	Southwest Gas	SWX	60.75	2,674.9	57.2	46.76	1.3
8	Spire	SR	64.04	2,344.8	51.7	45.35	1.4
9	**Average**						**1.6**

Col. (b) Price per Share per Yahoo
Col. (c) Per SEC Filings
Col. (d) Per SEC Filings
Col. (e) Equals Col. (c) divided by Col. (d)
Col. (f) Equals Col. (b) divided by Col. (e)

MICHIGAN PUBLIC SERVICE COMMISSION **Exhibit AG-30**

DTE Gas Company - Gas Rate Case **Case No. U-20940**

Date: June 3, 2021

Gas Regulatory Decisions-Authorized ROE's under 10% - 2019 and 2020

Line	Gas Company*	Order Date & Jurisdiction*			ROE Rate from Order* 2019	2020	Parent Company	Foreign,Prvt, Domestic	Long Term Debt Issued Since Rate Order**			
	(a)	(b)			(c)	(d)	(e)	(f)	(g)			
1	Baltimore Gas & Elec.	Jan	4	MD	9.80%		Exelon	D	$1.25Bil	4.10%	10 Yr. Debt	(Mar 2020)
2	Bershire Gas Company	Jan	18	MA	9.70%		Berkshire Hathaway	D	$900M	4.20%	30 Yr. Debt	(Mar 2020)
3	Orange & Rockland	Mar	14	NY	9.00%		Consol. Edison	D	$125M	2.9% & 3.5%	10 & 30 Yr Debt	(Q4 2019)
4	Duke Energy-KY	Mar	27	KY	9.70%		Duke Energy	D	$1.0B	0.9% & 2.5%	5 & 10 Yr. Debt	(Sep 2021)
5	Louiseville Gas & Elec.	Apr	30	KY	9.73%		PPL Corp.	D	$400M	4.25%	30 Yr. Debt	(Apr 2019)
6	Atmos Energy	May	7	KY	9.65%		Atmos Energy	D	$600M	1.50%	10 Yr. Debt	(Mar 2020)
7	Atmos Energy	May	21	TX	9.80%		Atmos Energy	D	$600M	1.50%	10 Yr. Debt	(Mar 2020)
8	Consumers Energy	Sep	4	MI	9.90%		CMS Energy	D	$550M	3.10%	31 Yr. Debt	(Sep 2020)
9	Northern Ill. Gas	Oct	2	IL	9.73%		Southern Company	D	$400M	1.75%	7 Yr. Debt	(Feb 2021)
10	Avista	Oct	8	OR	9.40%		Avista	D	$180M	3.40%	30 Yr. Debt	(Nov 2019)
11	Wash. Gas Light	Oct	15	MD	9.70%		AltaGas	***F***				
12	Northwest Nat. Gas	Oct	21	WA	9.40%		NorthWest Natural Hldgs	D	$150M	3.60%	30 Yr. Debt	(Mar 2020)
13	Piedmont Nat. Gas	Oct	31	NC	9.70%		Duke Energy	D	$1.0Bil	0.9% & 2.5%	5 & 10 Yr. Debt	(Sep 2021)
14	Entergy New Orleans	Nov	7	LA	9.35%		Entergy	D	$1.2Bil	2.8% & 3.8%	10 & 30 Yr Debt	(May 2020)
15	Elizabeth Town Gas	Nov	13	NJ	9.60%		South Jersey Industries	D				
16	Semco Energy Gas	Dec	6	MI	9.87%		AltaGas	***F***				
17	Black Hills Gas	Dec	11	WY	9.40%		Black Hills	D	$400M	1.70%	10 Yr. Debt	(Jun 2020)
18	Baltimore Gas & Elec.	Dec	17	MD	9.75%		Exelon	D	$1.25Bil	4.05%	10 Yr. Debt	(Mar 2020)
19	Interstate Pwr & Light	Dec	18	IA	9.80%		Alliant Energy	D	$400M	2.30%	10 Yr. Debt	(Jun 2020)
20	Columbia Gas-MD	Dec	18	MD	9.80%		NISOURCE	D	$2.0Bil	1.0% &1.7%	5 & 10 Yr Debt	(Aug 2020)
21	Wash. Gas Light	Dec	20	VA	9.80%		AltaGas	***F***				
22	Mountaineer Gas	Dec	21	WV	9.80%		UGI	D	$150M	3.10%	30 Yr. Debt	(Mar 2020)
23	MDU Resources	Jan	15	WY		9.35%	MDU Resources	D				
24	Consolidated Edison NY	Jan	16	NY		8.80%	Consol. Edison	D	$650M	0.65%	3 Yr. Debt	(Nov 2020)
25	Roanoke Gas	Jan	24	VA		9.44%	RGC Resources	D				
26	Cascade Natural Gas	Feb	3	WA		9.40%	MDU Resources	D	$75M	3.3%/3.7%	30/40 Yr Debt (Jun/Oct 2020)	
27	Atmos Energy	Feb	24	KS		9.10%	Atmos Energy	D	$600M	1.50%	10 Yr. Debt	(Mar 2020)
28	**Average For each Period**				**9.65%**							

* Data from Regulatory Research Associates with Summary of All Orders on Page 3

** Per various SEC Filings

MICHIGAN PUBLIC SERVICE COMMISSION **Exhibit AG-30**

DTE Gas Company - Gas Rate Case **Case No. U-20940**

Date: June 3, 2021

Gas Regulatory Decisions-Authorized ROE's under 10% - 2019 and 2020

Line	Gas Company*	Order Date & Jurisdiction*			ROE Rate from Order* 2019	ROE Rate from Order* 2020	Parent Company	Foreign,Prvt, Domestic	Long Term Debt Issued Since Rate Order**			
	(a)	(b)			(c)	(d)	(e)	(f)	(g)			
1	Questar Gas	Feb	25	UT		9.50%	Dominion Energy	D	$1.1 Bil.	1.5% & 3.3%	5 & 20 Yr. Debt	(Mar 2021)
2	Fitchburg Gas & Electric	Feb	28	MA		9.70%	Unitil	D	$27.5M	3.80%	20 Yr. Debt	(Sep 2020)
3	Avista	Mar	25	WA		9.40%	Avista	D	$165M	3.10%	30 Yr. Debt	(Sep 2020)
4	Northern Utilities	Mar	26	ME		9.48%	Unitil	D	$40M	3.80%	20 Yr. Debt	(Sep 2020)
5	Atmos Energy	Apr	21	TX		9.80%	Atmos Energy	D	$600M	1.50%	10Yr. Debt	(Sep 2020)
6	Black Hills Colorado Gas	May	19	CO		9.20%	Black Hills	D	$400M	2.50%	10Yr. Debt	(Jun 2020)
7	Centerpoint Energy Res	Jun	16	TX		9.65%	Centerpoint Energy Res	D	$500M	1.75%	10Yr. Debt	(Sep 2020)
8	Pudget Sound Energy	Jul	8	WA		9.40%	Pudget Hldgs., LLC	***PVT***				
9	Texas Gas Service	Aug	4	TX		9.50%	OneGas	D				
10	DTE Gas	Aug	20	MI		9.90%	DTE Energy	D	$200M	4.40%	60Yr. Debt	(Sep 2020)
11	Questar Gas	Aug	21	WY		9.35%	Dominion Energy	D	$1.1 Bil.	1.5% & 3.3%	5 & 20 Yr. Debt	(Mar 2021)
12	Consumers Energy	Sep	9	MI		9.90%	CMS Energy	D	$400M	3.70%	30 Yr. Debt	(Nov 2020)
13	S. Jersey Gas	Sep	23	NJ		9.60%	South Jersey Industries	D				
14	Southwest Gas	Sep	25	NV		9.25%	Southwest Holdings	D				
15	Southwest Gas	Sep	25	NV		9.25%	Southwest Holdings	D				
16	Eversource Gas of Mass.	Oct	7	MA		9.70%	Alliant Energy	D	$200M	1.40%	5 Yr. Debt	(Nov 2020)
17	Public Service of Co.	Oct	12	CO		9.20%	Xcel Energy	D				
18	Northwest Natural Gas	Oct	20	OR		9.40%	NorthWest Natural Hldgs	D				
19	NSTAR Gas	Oct	21	MA		9.90%	Emera	***F***				
20	Columbia Gas of Maryland	Nov	7	MD		9.60%	NISOURCE	D				
21	Peoples Gas	Nov	19	FL		9.90%	Emera	***F***				
22	NY State Elec. & Gas	Nov	19	NY		8.80%	Avangrid	D				
23	Rochester Gas & Elec	Nov	19	NY		8.80%	Avangrid	D	$200M	1.85%	10 Yr. Debt	(Nov 2020)
24	Madison Gas & Elec	Nov	24	WI		9.80%	MGE Energy	D				
25	Southwest Gas	Dec	9	AZ		9.10%	Southwest Holdings	D				
26	Avista	Dec	10	OR		9.40%	Avista	D				
27	Baltimore Gas & Elec	Dec	16	MD		9.65%	Exelon	D				
28	New Mexico Gas	Dec	16	NM		9.38%	Emera	***F***				
	Average For each Period				**9.65%**	**9.44%**						

* Data from Regulatory Research Associates with Summary of All Orders on Page 3

** Per various SEC Filings

Gas Regulatory Decisions-Authorized ROE's - Summary All 2019-20 Decisions

		Total Year 2019		Total Year 2020	
Line	Caption	# of Orders	Avg. ROE	# of Orders	Avg. ROE
	(a)	(b)	(c)	(d)	(e)
1	**Average Authorized ROE's page 1 and 2**	22	9.65%	33	9.44%
	ROE Orders At 10% or Higher				
2	Wisconsin Cases*	4	10.05%	1	10.00%
3	California Cases**	2	10.12%		
4	Atlanta Gas Light***	1	10.25%		
5	Total Number At 10% +	7		1	
6	Tota/Avg. of All Cases	**29**	**9.76%**	**34**	**9.46%**

* In 2020 the Wisconsin Commission granted a 10% ROE to Wisconsin Power & Light and a 9.8%ROE to Madison Gas & Electric.

** These companies are noted as having "wildfire risk" by Standard & Poor's (see Company Discovery AGDG-6.184-2).
The concern expressed by S&P would naturally be a factor considered by the California Commission as well.

*** New multi-year rates established January 2020 with ROE reduced from 10.75% to 10.25% and capped annual increases.
(Page II-77 of Southern Company Form 10-K filed 2-20-20)

MPSC Case No.:	U-20940
Requestor:	Attorney General
Question No.:	AGDG-6.209b
Respondent:	E. Solomon
Page:	1 of 1

Question: Refer to Exhibit A-17, Schedule G3. Please:

b. Confirm that the equity ratios represent the ratios as a single point in time at the end of December 2019. If not confirming, please explain.

Answer: The equity ratios represent a single point in time and from the fiscal year data for 2019 per S&P Global Market Intelligence. Atmos Energy, New Jersey Natural Gas, Spire Alabama, and Spire Missouri data was as of 9/30/2019, while the rest of the Company's data was as of 12/31/2019.

Attachments: *none*

MPSC Case No.:	U-20940
Requestor:	Attorney General
Question No.:	AGDG-6.209c
Respondent:	E. Solomon
Page:	1 of 1

Question: Refer to Exhibit A-17, Schedule G3. Please:

c. Are the equity ratios shown in this exhibit for each company the same as the equity ratios set by the regulatory commission in those utilities' most recent rate case. If yes, please provide a copy of the analysis and validation performed with supporting documentation.

Answer: The equity ratios shown in the exhibit are using the same methodology the Michigan Public Services Commission would use to calculate an equity ratio.

Attachments: *none*

MPSC Case No.:	U-20940
Requestor:	Attorney General
Question No.:	AGDG-6.209d
Respondent:	E. Solomon
Page:	1 of 1

Question: Refer to Exhibit A-17, Schedule G3. Please:

d. Explain why the Company used different peer companies in Schedule G3 and Schedule G4 of Exhibit A-17.

Answer: Exhibit A-17 Schedule G3 used the same peer group that was used in the ROE analysis. Some of the peer group in the ROE analysis did not have credit ratings from one or both Moody's and S&P. Exhibit A-17 Schedule G4 was based on the American Gas Association largest gas utilities to get a larger sample.

Attachments: none

Exhibit AG-32

CONFIDENTIAL

April 9, 2021

WATER UTILITY INDUSTRY

The Water Utility Industry consists of eight companies that provide water services mostly to residential customers. The group continues to be highly ranked among the 97 industries that are followed by *Value Line*. Much of the appeal of owning these securities has to do with their well-defined earnings and dividend growth prospects. These equities also provide diversification for professional money managers who overseeing funds that must be put invested in regulated utilities.

Due to the small number of equities available here, they trade at high Price/Earnings ratios.

As a group, these stocks have underperformed the S&P 500 Index since the beginning of the year.

Earnings Remain Steady

COVID-19 has not caused any real problems for water utilities. This is due to two main reasons. First, the demand for water is relatively inelastic. Whether GDP is rising or falling substantially, the demand for water will not change much. (Regulators can occasionally impose price increases for emergencies, such as a drought, to reduce usage.) People just have to consume this essential resource. Secondly, because utilities must file petitions with state authorities to change rates, the price of water is typically known for the next year or two. For example, in California, the process is so lengthy that a utility will file well in advance to establish rates for the next three-year period. The end result of this is that companies' level of profitability is very predictable relative to that of other industries. Of course, there is a cost for this as investors must pay a premium for these stocks. Furthermore, because profits here are less volatile, so too is dividend growth. The average increase for water utilities is currently in the range of 5% to 10%.

Industry Fundamentals

Change in this Industry historically doesn't occur overnight. Indeed, the storyline here has been consistent for some time. Following years and years of underinvestment, the nation found itself with an aging water infrastructure that is in poor condition. Many pipelines were installed 50 to 75 years ago. In badly need of replacement, water utilities have been spending heaving to replace old assets. This high level of expenditures will have to be maintained for decades.

Regulation

As we have highlighted in the past, one of the most significant factors in determining the profitability of a utility is the regulatory climate where it operates. Fortunately for the Water Utility Industry, state authorities and water utilities both realize what needs to be done, and are working constructively to address the issues. Regulators agree that the outlays being made to upgrade the country's infrastructure are required, so they are allowing fair return on investment to be made. Having a positive relationship may seem reasonable, but this is not the case for gas and electric utilities. Conflicts are not unusual.

INDUSTRY TIMELINESS: 7 (of 97)

Balance Sheets

Internally generated funds are not sufficient for these entities to cover their capital budgets. As a result, external financing is needed to make up the difference. The trend has been to sell debt rather than issuing new equity. We attribute this primarily to the low interest rates environment that has been prevalent for some time now. Still, on the whole, balance sheets here aren't overleveraged, as Financial Strength ratings average B+ to B++.

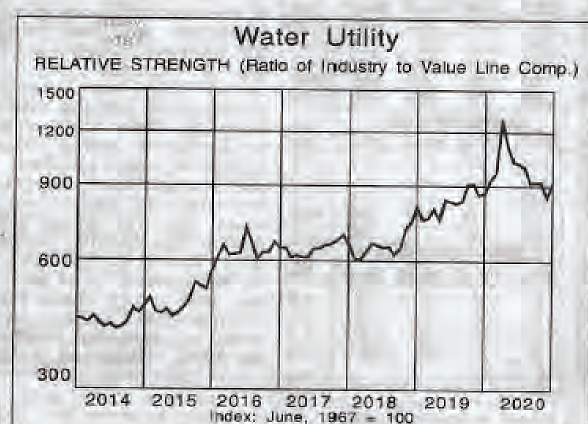
Scarcity

The market capitalization of all the stocks combined in this group total about $47 billion. (For example, Consolidated Edison, a New York-based electric utility has a market cap itself of approximately $25 billion.) Hence, water stocks always seem to be pricey because the demand outstrips supply.

Conclusion

Since the start of this year, the stock of *Middlesex Water* has been the only one out of the seven regulated water utilities to have outperformed the market averages. Still, though there are some timely stocks in the group, none can be considered inexpensive. Rather, the premium investors are willing to pay for these equities has been reduced. Certain Wall Street analysts have attributed the sluggish showing to rising yields on long-term Treasury bonds. Utilities are bought for the income they generate and this makes bonds look more attractive. In our opinion, the Water Utility Industry has not traded like electric and gas utilities for some time. Indeed, the average dividend yield of these equities is lower than the *Value Line* median. It should also be noted, that the typical member of this sector has below-average total return prospects out to 2024-2026. Nevertheless, very conservative accounts may find this a small price to pay for the low volatility and well-defined prospects. As always, we advise subscribers to read each individual report carefully before making any commitments to better understand the potential risk being assumed.

James A. Flood



CALIFORNIA WATER NYSE-CWT

RECENT PRICE 56.17 | P/E RATIO 31.4 (Trailing: 29.0, Median: 24.0) | RELATIVE P/E RATIO 1.43 | DIV'D YLD 1.6% | VALUE LINE 1791

TIMELINESS 1 Raised 3/19/21
SAFETY 3 Lowered 7/27/07
TECHNICAL 2 Lowered 4/9/21
BETA .65 (1.00 = Market)

18-Month Target Price Range
Low-High: $43-$81 | Midpoint (% to Mid): $62 (10%)

2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+15%)	6%
Low	45	(-20%)	-3%

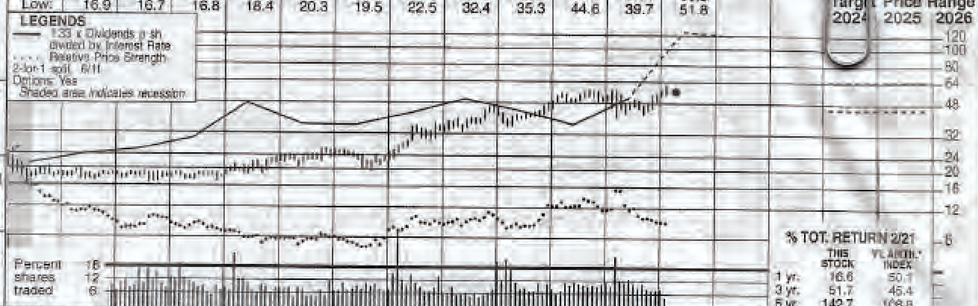
Institutional Decisions

	2Q2020	3Q2020	4Q2020
to Buy	109	101	122
to Sell	107	106	91
Hld's(000)	35580	36492	37534

High:	19.8	19.4	19.3	23.4	26.4	26.0	36.8	46.2	49.1	57.5	57.4	60.5
Low:	16.9	16.7	16.8	18.4	20.3	19.5	22.5	32.4	35.3	44.6	39.7	51.8

LEGENDS
1.33 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 6/11
Options: Yes
Shaded area indicates recession

Target Price Range 2024 2025 2026



% TOT. RETURN 2/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.6	50.1
3 yr.	51.7	45.4
5 yr.	142.7	108.8

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
8.72	8.10	8.88	9.90	10.82	11.05	12.00	13.34	12.23	12.50	12.29	12.70	13.89	14.53	14.72	15.78	16.00	15.95	Revenues per sh	16.30
1.52	1.86	1.56	1.86	1.93	1.93	2.07	2.32	2.21	2.47	2.22	2.34	3.00	3.11	3.14	3.88	3.45	3.55	"Cash Flow" per sh	3.75
.74	.67	.75	.95	.98	.91	.86	1.02	1.02	1.19	.94	1.01	1.40	1.36	1.31	1.97	1.90	2.00	Earnings per sh A	2.25
.57	.58	.58	.59	.59	.60	.62	.63	.64	.65	.67	.69	.72	.75	.79	.85	.92	.98	Div'd Decl'd per sh B ■	1.15
2.01	2.14	1.84	2.41	2.66	2.97	2.83	3.04	2.58	2.76	3.69	4.77	5.40	5.65	5.64	5.93	5.25	5.50	Cap'l Spending per sh	5.85
7.90	9.07	9.25	9.72	10.13	10.45	10.76	11.28	12.54	13.11	13.41	13.75	14.44	15.19	16.07	18.30	18.35	18.25	Book Value per sh C	19.80
36.78	41.31	41.33	41.45	41.53	41.67	41.82	41.98	47.74	47.81	47.88	47.97	48.01	48.07	48.53	50.33	51.00	52.00	Common Shs Outst'g D	53.00
24.9	29.2	26.1	19.6	19.7	20.3	21.3	17.9	20.1	19.7	24.8	29.6	26.9	30.3	39.3	24.9	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	24.0
1.33	1.58	1.39	1.10	1.31	1.29	1.34	1.14	1.13	1.04	1.25	1.55	1.35	1.64	2.09	1.29			Relative P/E Ratio	1.30
3.1%	2.9%	3.0%	3.1%	3.1%	3.2%	3.4%	3.5%	3.1%	2.8%	2.9%	2.3%	1.9%	1.8%	1.5%	1.7%			Avg Ann'l Div'd Yield	2.1%

CAPITAL STRUCTURE as of 12/31/20
Total Debt $1156.2 mill. Due in 5 Yrs $357.0 mill.
LT Debt $781.1 mill. LT Interest $40.0 mill.
(Total interest coverage: 5.2x) (46% of Cap'l)

Pension Assets-12/20 $716.8 mill. Oblig. $833.9 mill.

Pfd Stock None

Common Stock 50,330,000 shs.

MARKET CAP: $2.8 billion (Mid Cap)

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
501.8	560.0	584.1	597.5	588.4	609.4	666.9	698.2	714.6	794.3	815	830	Revenues ($mill) E	865
36.1	42.6	47.3	56.7	45.0	48.7	67.2	65.6	63.1	96.8	97.0	105	Net Profit ($mill)	120
40.5%	37.5%	30.3%	33.0%	36.0%	35.5%	30.1%	24.5%	19.1%	11.1%	21.0%	21.0%	Income Tax Rate	21.0%
7.6%	8.0%	4.3%	2.7%	4.3%	6.1%	3.5%	3.1%	5.8%	3.3%	5.0%	5.0%	AFUDC % to Net Profit	5.0%
51.7%	47.8%	41.6%	40.1%	44.4%	44.6%	42.7%	49.3%	50.2%	45.9%	44.5%	43.5%	Long-Term Debt Ratio	38.0%
48.3%	52.2%	58.4%	59.9%	55.6%	55.4%	57.3%	50.7%	49.8%	54.1%	55.5%	56.5%	Common Equity Ratio	62.0%
931.5	908.2	1024.9	1085.9	1164.4	1191.2	1209.3	1440.2	1566.7	1702.4	1685	1675	Total Capital ($mill)	1700
1381.1	1457.1	1515.8	1590.4	1701.8	1859.3	2048.0	2232.7	2406.4	2550.6	2675	2700	Net Plant ($mill)	2850
5.5%	6.3%	6.0%	6.3%	5.2%	5.5%	7.1%	5.9%	5.5%	7.0%	6.5%	7.0%	Return on Total Cap'l	8.0%
8.0%	9.0%	7.9%	9.1%	7.0%	7.4%	9.7%	9.0%	8.1%	10.5%	10.5%	11.0%	Return on Shr. Equity	11.5%
8.0%	9.0%	7.9%	9.1%	7.0%	7.4%	9.7%	9.0%	8.1%	10.5%	10.5%	11.0%	Return on Com Equity	11.5%
2.3%	3.4%	3.4%	4.1%	2.0%	2.4%	4.7%	4.0%	3.2%	6.0%	5.5%	5.5%	Retained to Com Eq	5.5%
71%	62%	56%	55%	71%	68%	51%	55%	60%	43%	48%	49%	All Div'ds to Net Prof	51%

CURRENT POSITION ($MILL.)	2018	2019	12/31/20
Cash Assets	47.2	42.7	44.6
Other	141.5	142.0	221.4
Current Assets	188.7	184.7	266.0
Accts Payable	95.6	108.5	131.7
Debt Due	170.0	197.0	375.1
Other	55.6	53.2	81.9
Current Liab.	321.2	358.7	588.7

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '24-'26
Revenues	3.5%	4.0%	1.5%
"Cash Flow"	6.0%	8.0%	2.0%
Earnings	5.0%	8.0%	6.5%
Dividends	3.0%	4.0%	6.5%
Book Value	5.0%	5.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) E Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	134.6	174.9	221.3	167.4	698.2
2019	126.1	179.0	232.6	176.9	714.6
2020	125.6	175.5	304.1	189.1	794.3
2021	155	205	255	200	815
2022	160	205	260	205	830

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	d.02	.31	.75	.32	1.36
2019	d.16	.35	.88	.24	1.31
2020	d.42	.11	1.94	.31	1.97
2021	.08	.45	.95	.42	1.90
2022	.10	.45	1.00	.45	2.00

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.18	.18	.18	.18	.72
2018	.1875	.1875	.1875	.1875	.75
2019	.1975	.1975	.1975	.1975	.79
2020	.2125	.2125	.2125	.2125	.85
2021	.230				

BUSINESS: California Water Service Group provides regulated and nonregulated water service to 492,600 customers in 100 communities in the state of California. Accounts for about 94% of total customers. Also operates in Washington, New Mexico, and Hawaii. Main service areas: San Francisco Bay area, Sacramento Valley, Salinas Valley, San Joaquin Valley & parts of Los Angeles. Acquired Rio Grande Corp; West Hawaii Utilities (9/08). Revenue breakdown, '20: residential, 70%; business, 18%; industrial, 4%; public authorities, 5%; other 3%. Off. and dir. own 1% of common stock (4/20 proxy). Has 1,184 employees. Pres. and CEO: Martin A. Kropelnicki. Inc.: DE. Addr.: 1720 North First St., San Jose, CA 95112-4598. Tel.: 408-367-8200. Internet: www.calwatergroup.com.

California Water Service Group reported solid financial results to wrap up 2020. The West Coast water service provider generated revenues of $189 million in the December period, or a 7% annual increase, thanks largely to rate hikes associated with the recently approved general rate case. Meanwhile, fourth-quarter share profits of $0.31, which were also buoyed by benefits from the general rate case decision, specifically higher operating income and lower taxes, logged a healthy 29% advance compared to the year-earlier tally.

California Water is on a buying spree. The company's subsidiary, Hawaii Water Service, announced that it has received approval to acquire the assets of Kapalua Water and Kapalua Waste Treatment Company, which will add roughly 1,000 service connections in the area. In addition, a deal has been inked to purchase the water system assets of Skylanda Mutual Water Company. Pending regulatory approval, the transaction, which would add almost 19,000 service connection in California, is expected to be finalized early next year. Overall, tuck-in acquisitions will probably be a staple in the company's long-term growth strategy.

The company is in the early innings of a massive infrastructure improvement program. Indeed, management is taking an aggressive approach to upgrading and revamping its aging water delivery, transportation, and treatment facilities. For this year, its capital spending budget for infrastructure-related projects is approximately $285 million. Over the pull to 2025, the company is likely to invest upwards of $700 million. Lastly, California Water has already been given the green light by the California Public Utilities Commission to tap the debt and equity markets.

We continue to like this issue for subscribers with a short-term investment horizon. The stock has been raised one notch on our Timeliness Ranking Scale, to 1 (Highest) and, thus is slated to outpace the broader market averages over the coming six to 12 months. On the other hand, buy-and-hold accounts should turn the page, as total return potential out to 2024-2026 is unenticing at recent levels.

Nicholas P. Patrikis — *April 9, 2021*

(A) Basic EPS. Excl. nonrecurring gain (loss): '11, 4¢. Next earnings report due early May.
(B) Dividends historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available.
(C) Incl. intangible assets. In '20 : $27.6 mill., $0.55/sh.
(D) In millions, adjusted for split.
(E) Excludes non-regulated revenues.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	65

VLF*Alert*

Value Line*funds*

4th Quarter 2018

Volume VII, Issue IV

00207257

Mitchell Appel
President
Value Line Funds

Dear Fellow Shareholder,

Thank you for choosing Value Line Funds as a part of your diversified investment portfolio. For over half a century, Value Line Funds has championed sound investment principles and helped thousands of investors accomplish their financial goals with our actively managed family of mutual funds.

We hope you enjoy this edition of the VLFAlert and thank you for your continued support.

Volatility is Not Risk:
Why the Difference is Critical to Long-Term Results

2017 lulled many equity investors into a comfort zone based on historically low volatility. 2018 has been more volatile—with tighter monetary policy and geopolitical and trade policy uncertainty among the drivers of the increase. But volatility levels in 2018 are actually historically normal—even with the bouts of volatility anticipated ahead of the November mid-term elections. But volatility is not risk. And recognizing the difference can be critical to your long-term investment returns.

Defining Our Terms

Volatility is simply the measure of the up and down movements of the market. For example, since 1950, when the Value Line Funds were first established, the average maximum drawdown in the broad U.S. equity market during midterm election years has been -17%, with weakness tending to be concentrated in the pre-election days. However, the good news is that there has been a consistent tendency historically for post-drawdown rallies, averaging +32% in the subsequent year.[1] Volatility? Yes! Uncertainty? Yes! But volatility is only risk if you act during down times—that is, only if you sell. To which the often-invoked quip may well be the most prudent answer: "Don't just do something, sit there."

Risk, on the other hand, is the probability of a permanent loss. You might think of risk as the possibility of having to lower your quality of life in the future.

> **"Volatility is not synonymous of risk but—for those who truly understand it—of wealth."**
>
> *- Francois Rochon**

Recognizing the Difference

Volatility is independent of risk. Too many investors let an investment's short-term price movements, or perceptions of short-term price movements, drive their buying and selling decisions. Too often volatility is regarded as something to be avoided. But since short-term price moves are unknowable and independent of underlying fundamentals and value, such volatility should not be a determinant.

And ALL investments have risk of some kind, including cash and CDs. One just needs to pick the risks that are best to take based on your individual tolerance level, time horizon and financial needs and goals.

As famed investor and Berkshire Hathaway CEO Warren Buffet wrote:

> "Stock prices will always be far more *volatile* than cash-equivalent holdings. *Over the long term*, however, currency-denominated instruments are *riskier* investments — far riskier investments — than widely-diversified stock portfolios that are bought over time and that are owned in a manner invoking only token fees and commissions. **That lesson has not customarily been taught in business schools, where volatility is almost universally used as a proxy for risk. Though this pedagogic assumption makes for easy teaching, it is dead wrong: Volatility is *far* from synonymous with risk.** Popular formulas that equate the two terms lead students, investors and CEOs astray."[2]

> **"Volatility is our friend. Volatility has nothing to do with risk."**
>
> *- Mohnish Pabrai**

(continued on back)

It's a Matter of Time, Not Timing

Most experienced investors do not fear volatility, only unrecoverable loss. But most losses, as measured by a day, a week, a quarter or a year, are recoverable over time. Declines in principal value have historically been temporary. Of course, there are true risks. A company could go totally out of business. An innovation could transform an industry so profoundly to make a once "blue chip" company a relic. A geopolitical event could happen to negate all assumptions. But these occurrences are rare. For the vast majority of investors, maintaining a long-term perspective is the real key to attaining gains over their investing lifetime. Historically, since World War II, the longer you hold stocks, the narrower the range of returns.[3] In other words, even if volatility is a concern, it decreases the longer you hold stocks. It's the old adage: what matters is time in the market, not market timing.

"You can't overlook the volatility, but you don't let it push you around in the market."

*- Boone Pickens**

solutions designed to meet a broad array of investment goals. Whether you are looking for income or long-term capital appreciation, whether you choose to invest in equities, taxabl or tax-exempt fixed income or a hybrid fund of multiple asset classes, you can rely on the solid fundamentals of Value Line Funds.

Value Line Funds Include:
Equity Funds
Premier Growth Fund
Larger Companies Focused Fund
Mid Cap Focused Fund
Small Cap Opportunities Fund
Hybrid Funds
Asset Allocation Fund
Capital Appreciation Fund
Fixed Income Funds
Tax Exempt Fund
Core Bond Fund

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-5.145
Respondent:	G. Chapel
Page:	1 of 1

Question: Refer to page 9, lines 4-18 of Mr. Chapel's direct testimony. Please provide the time period (starting and ending month and year) of the historical customer gas usage used to weather-normalize sales and project test year sales in the forecasting model for each rate class.

Answer: To determine customer behavior as it relates to weather, I analyzed customer usage from August 2018 through July 2020. The referenced part of my testimony, however, discusses the Company's calculation of normal weather in terms of HDDs, not customer behavior. The Company uses 15 years of weather data to determine "normal weather" (presently the average HDDs from 2006-20) and it uses 24 months of monthly billing data to determine customer behavior in relation to weather.

Attachments: None.

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-5.153
Respondent:	G. Chapel
Page:	1 of 1

Question: Refer to page 27, lines 11-17 of Mr. Chapel's direct testimony. Please identify the time period of historical number of customers and gas consumption for commercial customers used in the forecasting model to arrive at the commercial sales forecasts.

Answer: The customer count forecast is based on commercial customer change from August 2017 to July 2020, a three-year period. Gas consumption is analyzed for commercial customers from August 2018 to July 2020, a two-year period.

Attachments: None.

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-5.154
Respondent:	G. Chapel
Page:	1 of 1

Question: Refer to page 30, lines 6-12 of Mr. Chapel's direct testimony. Please identify the time period of historical number of customers and gas consumption for industrial customers used in the forecasting model to arrive at the industrial sales forecasts.

Answer: The customer count forecast is based on industrial customer change from August 2017 to July 2020, a three-year period. Gas consumption is analyzed for industrial customers from August 2018 to July 2020, a two-year period.

Attachments: None.

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-5.146
Respondent:	G. Chapel
Page:	1 of 1

Question: Refer to page 11, lines 22-25, and page 12, lines 6-10 of Mr. Chapel's direct testimony. Please provide a split of the 4.3 Bcf and 1.4 Bcf between EWR and Covid-19 by customer class. Provide the calculations in Excel with formulas intact, supporting data

Answer: Reductions due to EWR were estimated as a 1% reduction of all sales volumes from 2020 to 2021 and a 1.15% reduction of all sales volumes from 2021 to 2022.

For 2021, reductions due to CoVid-19 were estimated as a 2% reduction of Rate A volumes, a 6% reduction of Rate GS-1 volumes, and a 7% reduction of Rate S volumes from their historical base consumptions. For 2022, reductions due to CoVid-19 were estimated as a 1% reduction of Rate A volumes, a 3% reduction of Rate GS-1 volumes, and a 4% reduction of Rate S volumes from their historical base consumptions.

There is one other component of the referenced numbers (4.3 Bcf and 1.4 Bcf) that is not addressed in testimony and that is the issue of non-attachment customer count change. Attachment U-20940 AGDG-5.146 EWR CoVid Customer Count Change Volumes breaks down the components of each of these numbers.

The net volume change (in Bcf) for 2021 is -1.5 for EWR, -4.8 Bcf for CoVid-19, and 2.0 Bcf for non-attachment customer change for a total of -4.3 Bcf. The net volume change (in Bcf) for 2022 is -1.7 for EWR, -2.4 Bcf for CoVid-19, and 2.7 Bcf for non-attachment customer change for a total of -1.4 Bcf.

Attachments: Attachment U-20940 AGDG-5.146 EWR CoVid Customer Count Change Volumes

AGDG-5.146						
	2021				**2022**	
EWR		**2021**		**EWR**		**2022**
	2020 Base	EWR			2021 Base	EWR
RATE A	109,875	(1,099)		RATE A	107,825	(1,240)
RATE 2A I	289	(3)		RATE 2A I	306	(4)
RATE 2A II	4,124	(41)		RATE 2A II	4,008	(46)
RATE GS-1	37,262	(373)		RATE GS-1	36,137	(416)
RATE GS-2	529	(5)		RATE GS-2	1,094	(13)
RATE S	1,501	(15)		RATE S	1,414	(16)
	153,580	(1,536)			150,784	(1,734)
CoViD-19		**2021**		**CoViD-19**		**2022**
	2019 Base	CoVid-19			2019 Base	CoVid-19
RATE A	111,653	(2,233)		RATE A	111,653	(1,117)
RATE 2A I	308	0		RATE 2A I	308	0
RATE 2A II	4,236	0		RATE 2A II	4,236	0
RATE GS-1	41,248	(2,475)		RATE GS-1	41,248	(1,237)
RATE GS-2	942	0		RATE GS-2	942	0
RATE S	1,482	(104)		RATE S	1,482	(59)
	159,870	(4,812)				(2,413)
Non-Attachment				**Non-Attachment**		
Count Changes		**2021**		**Count Changes**		**2022**
		Count Change				Count Change
RATE A		323		RATE A		1,335
RATE 2A I		21		RATE 2A I		(0)
RATE 2A II		(75)		RATE 2A II		(111)
RATE GS-1		1,163		RATE GS-1		1,354
RATE GS-2		570		RATE GS-2		(8)
RATE S		32		RATE S		144
		2,033				2,712

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-5.157d 3rd Supplemental
Respondent:	G. Chapel
Page:	1 of 1

Question: Refer to Exhibit A-15, Schedule E2, page 1. Please provide the following information in Excel. If the historical weather-normalized information is not available by rate schedule, provide it by customer class:

d. Provide the same information in Excel for weather-normalized sales for each year 2014 to 2020 in MMcf. Provide also monthly weather-normalized sales by month for 2019 and 2020, and January and February 2021. Provide all this sales information on a calendar basis including unbilled sales.

Answer: The attachments listed below provide data as discussed via e-mail on May 21,2021 and includes billed sales data from 2014 - 2021 on a total company basis and historical aggregates.

Attachments:
U-20940 AGDG-5.157d Supplemental.xlsx
U-20940 AGDG-5.157d Historical Aggregates.xlsx
U-20940 AGDG-5.157d Billed Sales 2021.xlsx
U-20940 AGDG-5.157d Billed Sales 2020.xlsx
U-20940 AGDG-5.157d Billed Sales 2019.xlsx
U-20940 AGDG-5.157d Billed Sales 2018.xlsx
U-20940 AGDG-5.157d Billed Sales 2017.xlsx
U-20940 AGDG-5.157d Billed Sales 2016.xlsx
U-20940 AGDG-5.157d Billed Sales 2015.xlsx
U-20940 AGDG-5.157d Billed Sales 2014.xlsx

AGDG-5.157

	Sep-Aug	Sep-Aug	Sep-Aug	Sep-Aug	Sep-Aug	May-Apr
Rate A	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Normalized Sales (MMcf)	106,935	108,713	111,153	111,713	109,602	110,915
Average Number of Customers	1,144,561	1,154,235	1,165,546	1,176,299	1,189,798	1,200,661
Normalized Sales per Customer (Mcf)	93.4	94.2	95.4	95.0	92.1	92.4
Weighted Heating Value (Mcf/MMBtu)	1.0460	1.0472	1.0466	1.0531	1.0600	1.0527
Normalized Sales per Customer (Dth)	97.7	98.6	99.8	100.0	97.6	97.2

	Sep-Aug	Sep-Aug	Sep-Aug	Sep-Aug	Sep-Aug	May-Apr
Rate 2A I	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Normalized Sales (MMcf)	370	316	313	325	285	291
Average Number of Customers	1,356	1,327	1,298	1,276	1,297	1,332
Normalized Sales per Customer (Mcf)	273.1	238.4	240.9	254.8	219.5	218.5
Weighted Heating Value (Mcf/MMBtu)	1.0467	1.0472	1.0458	1.0545	1.0596	1.0527
Normalized Sales per Customer (Dth)	285.8	249.6	251.9	268.6	232.5	230.0

	Sep-Aug	Sep-Aug	Sep-Aug	Sep-Aug	Sep-Aug	May-Apr
Rate 2A II	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Normalized Sales (MMcf)	4,861	4,520	4,648	4,149	4,214	4,001
Average Number of Customers	5,669	5,487	5,314	5,211	5,086	5,082
Normalized Sales per Customer (Mcf)	857.5	823.7	874.7	796.2	828.7	787.3
Weighted Heating Value (Mcf/MMBtu)	1.0463	1.0475	1.0466	1.0533	1.0600	1.0526
Normalized Sales per Customer (Dth)	897.1	862.9	915.4	838.6	878.4	828.7

	Sep-Aug	Sep-Aug	Sep-Aug	Sep-Aug	Sep-Aug	May-Apr
Rate GS-1	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Normalized Sales (MMcf)	38,620	40,171	41,654	40,588	38,769	37,425
Average Number of Customers	88,923	89,056	89,179	89,163	89,515	89,867
Normalized Sales per Customer (Mcf)	434.3	451.1	467.1	455.2	433.1	416.4
Weighted Heating Value (Mcf/MMBtu)	1.0461	1.0472	1.0467	1.0532	1.0601	1.0526
Normalized Sales per Customer (Dth)	454.3	472.4	488.9	479.4	459.1	438.3

	Sep-Aug	Sep-Aug	Sep-Aug	Sep-Aug	Sep-Aug	May-Apr
Rate GS-2	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Normalized Sales (MMcf)	316	494	338	528	198	191
Average Number of Customers	51	51	54	51	45	49
Normalized Sales per Customer (Mcf)	6,208.2	9,630.5	6,206.7	10,361.4	4,382.9	3,896.4
Weighted Heating Value (Mcf/MMBtu)	1.0467	1.0484	1.0473	1.0536	1.0597	1.0525
Normalized Sales per Customer (Dth)	6,498.4	10,096.1	6,500.2	10,916.6	4,644.4	4,100.8

	Sep-Aug	Sep-Aug	Sep-Aug	Sep-Aug	Sep-Aug	May-Apr
Rate S	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Normalized Sales (MMcf)	1,226	1,302	1,440	1,375	1,343	1,437
Average Number of Customers	250	233	213	213	218	224
Normalized Sales per Customer (Mcf)	4,900.6	5,586.8	6,749.1	6,453.5	6,169.2	6,407.5
Weighted Heating Value (Mcf/MMBtu)	1.0460	1.0472	1.0465	1.0531	1.0603	1.0525
Normalized Sales per Customer (Dth)	5,126.0	5,850.3	7,062.8	6,796.1	6,541.1	6,743.8

Normalized Sales Change in Trend From Decline in 2020 to Increases in last 12 months April 2021

Rate A

	Sep-Aug 2015-16	Sep-Aug 2016-17	Sep-Aug 2017-18	Sep-Aug 2018-19	Sep-Aug 2019-20	% Change Sept-Aug 2018-19 v. 2019-20	May-Apr 2020-21	% Change Sept-Aug 2019-20 to May-Apr v. 2020-21
Normalized Sales (MMcf)	106,935	108,713	111,153	111,713	109,602	-1.9%	110,915	1.2%
Average Number of Customers	1,144,561	1,154,235	1,165,546	1,176,299	1,189,798		1,200,661	
Normalized Sales per Customer (Mcf)	93.4	94.2	95.4	95.0	92.1		92.4	
Weighted Heating Value (Mcf/MMBtu)	1.0460	1.0472	1.0466	1.0531	1.0600		1.0527	
Normalized Sales per Customer (Dth)	97.7	98.6	99.8	100.0	97.6		97.2	

Rate 2A I

	Sep-Aug 2015-16	Sep-Aug 2016-17	Sep-Aug 2017-18	Sep-Aug 2018-19	Sep-Aug 2019-20		May-Apr 2020-21	
Normalized Sales (MMcf)	370	316	313	325	285		291	
Average Number of Customers	1,356	1,327	1,298	1,276	1,297		1,332	
Normalized Sales per Customer (Mcf)	273.1	238.4	240.9	254.8	219.5		218.5	
Weighted Heating Value (Mcf/MMBtu)	1.0467	1.0472	1.0458	1.0545	1.0596		1.0527	
Normalized Sales per Customer (Dth)	285.8	249.6	251.9	268.6	232.5		230.0	

Rate 2A II

	Sep-Aug 2015-16	Sep-Aug 2016-17	Sep-Aug 2017-18	Sep-Aug 2018-19	Sep-Aug 2019-20		May-Apr 2020-21	
Normalized Sales (MMcf)	4,861	4,520	4,648	4,149	4,214		4,001	
Average Number of Customers	5,669	5,487	5,314	5,211	5,086		5,082	
Normalized Sales per Customer (Mcf)	857.5	823.7	874.7	796.2	828.7		787.3	
Weighted Heating Value (Mcf/MMBtu)	1.0463	1.0475	1.0466	1.0533	1.0600		1.0526	
Normalized Sales per Customer (Dth)	897.1	862.9	915.4	838.6	878.4		828.7	

Rate GS-1

	Sep-Aug 2015-16	Sep-Aug 2016-17	Sep-Aug 2017-18	Sep-Aug 2018-19	Sep-Aug 2019-20		May-Apr 2020-21	
Normalized Sales (MMcf)	38,620	40,171	41,654	40,588	38,769	-4.5%	37,425	-3.5%
Average Number of Customers	88,923	89,056	89,179	89,163	89,515		89,867	
Normalized Sales per Customer (Mcf)	434.3	451.1	467.1	455.2	433.1		416.4	
Weighted Heating Value (Mcf/MMBtu)	1.0461	1.0472	1.0467	1.0532	1.0601		1.0526	
Normalized Sales per Customer (Dth)	454.3	472.4	488.9	479.4	459.1		438.3	

Rate GS-2

	Sep-Aug 2015-16	Sep-Aug 2016-17	Sep-Aug 2017-18	Sep-Aug 2018-19	Sep-Aug 2019-20		May-Apr 2020-21	
Normalized Sales (MMcf)	316	494	338	528	198	-62.4%	191	-3.6%
Average Number of Customers	51	51	54	51	45		49	
Normalized Sales per Customer (Mcf)	6,208.2	9,630.5	6,206.7	10,361.4	4,382.9		3,896.4	
Weighted Heating Value (Mcf/MMBtu)	1.0467	1.0484	1.0473	1.0536	1.0597		1.0525	
Normalized Sales per Customer (Dth)	6,498.4	10,096.1	6,500.2	10,916.6	4,644.4		4,100.8	

Rate S

	Sep-Aug 2015-16	Sep-Aug 2016-17	Sep-Aug 2017-18	Sep-Aug 2018-19	Sep-Aug 2019-20		May-Apr 2020-21	
Normalized Sales (MMcf)	1,226	1,302	1,440	1,375	1,343	-2.3%	1,437	7.0%
Average Number of Customers	250	233	213	213	218		224	
Normalized Sales per Customer (Mcf)	4,900.6	5,586.8	6,749.1	6,453.5	6,169.2		6,407.5	
Weighted Heating Value (Mcf/MMBtu)	1.0460	1.0472	1.0465	1.0531	1.0603		1.0525	
Normalized Sales per Customer (Dth)	5,126.0	5,850.3	7,062.8	6,796.1	6,541.1		6,743.8	

Source: AGDG-5.157

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company

Exhibit AG-39
Case No. U-20940
Date: June 3, 2021

Removal of Covid-19 Sales Reduction and Revenue Impact, plus Other Sales

		Removal of COVID-19 Volume Reduction				
		2021	**2022**	**Total**	**Rate**	
Line #		(MMcf)	(MMcf)	(MMcf)	(Mcf)	**Revenue**
	(a)	(b)	(c)	(d)	(e)	**(f)**
1	Rate A	2,233	1,117	3,350	$ 3.693	$ 12,371,550
2	Rate GS-1	2,475	1,237	3,712	$ 3.491	12,958,221
3	Rate S	104	59	163	$ 2.272	370,336
4	Total Covid-Related	4,812	2,413	7,225		**$ 25,700,107**
5	Shift of EUT customers to Sales			395	$ 3.491	$ 1,379,143
6	**Total Gas Sales Revenue Adjustment**					**$ 27,079,250**

Source: Exhibit A-16,Schedule F3, pages 1-3

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-13.413
Respondent:	G. Chapel
Page:	1 of 1

Question: Refer to the response to AGDG-5.162b. Provide the volume of GS-1 sales calculated by Mr. Chapel's forecasting model for these customers for the projected test year.

Answer: Exhibit A-15, Schedule E1 identifies GS-1 Test Year volumes to be 36,811 MMcf across a GS-1 customer count of 89,545. This works out to be an average annual consumption per customer of 411 Mcf/customer.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-5.162b
Respondent:	G. Chapel/H. Decker
Page:	1 of 1

Question: Refer to page 16, lines 8-14 of Mr. Decker's direct testimony. Please:

b. Confirm that Mr. Chapel has included the remaining 0.4 Bcf of gas sales in his forecast of gas sales for the projected test year as an additional adjustment to the modeled sales forecast. If not confirming, please explain why not.

Answer: In Mr. Chapel's gas sales forecast, any EUT customers that return to sales service are incorporated as an average customer and removed from the EUT customer count. Their specific historic usage is not directly utilized in the forecast. When a customer chooses to move from EUT to sales service, it is often because their volumes have declined, and the sales service becomes the more economical rate for expected usage going forward.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-5.161a
Respondent:	H. Decker
Page:	1 of 1

Question: Refer to Table 2 on page 15 of Mr. Decker's direct testimony. Please:

a. Provide Table 2 with actual volumes for each calendar year 2016 to 2020 in Excel.

Answer: See attachment "U-20940 AGDG-5.161A-01 EUT Power Gen Volumes By Calendar Year".

Attachments: U-20940 AGDG-5.161A-01 EUT Power Gen Volumes By Calendar Year

U-20940 AGDG-5.161A Power Generation Volumes Calendar Year Actual

Case No.: U-20940
Discovery Request: AGDG-5.161A
Witness: H. Decker
Page: 1 of 1

TABLE 2 Power Generation Volumes

12 Month Period	Actual (Bcf)	Variance (Bcf) to 5-yr average	Cooling Degree Days	Variance to 15 yr Avg
Sep '15 ~ Aug '16	58.2	(0.8)	1,191	26%
Sep '16 ~ Aug '17	47.8	(11.2)	902	-5%
Sep '17 ~ Aug '18	60.0	0.9	1,185	25%
Sep '18 ~ Aug '19	59.4	0.3	1,005	6%
Sep '19 ~ Aug '20	69.9	10.8	1,073	14%
5-yr average	59.1			
15 Yr Avg			945	

Calendar Year	Actual (Bcf)
2016	61.9
2017	46.9
2018	61.1
2019	61.3
2020	67.0

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-5.161b
Respondent:	H. Decker
Page:	1 of 1

Question: Refer to Table 2 on page 15 of Mr. Decker's direct testimony. Please:

b. Provide a comparison of the power generation volumes forecasted in Case Nos. U-17999, U-18999, and U-20642 to the actual volumes delivered for the same period in Excel.

Answer: Please see attachment "U-20940 AGDG-5.161B-01 EUT Power Gen Volumes Forecast vs. Actuals".

Attachments: U-20940 AGDG-5.161B-01 EUT Power GenVolumes Forecast Vs. Actuals

Power Generation Forecasted Vs. Actual Volumes for Cases U-17999, U-18999 and U-20642

Case No.: U-20940
Discovery Request: AGDG-5.161B
Witness: H. Decker
Page: 1 of 1

	Projected Period	Projected Period Forecast Volumes (Bcf)	Actual Billed Volumes for Projected Period (Bcf)
U-17999	Nov-16 to Oct-17	33.0	47.2
U-18999	Oct-18 to Sep-19	42.3	59.6
U-20642	Oct-20 to Sep-21	49.5	Incomplete

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-13.412
Respondent:	H. Decker
Page:	1 of 1

Question: Refer to the attachment to response to AGDG-5.161b. Please provide the information under U-20642 for the period October 2020 to April 2021 both actual and forecast.

Answer: As actual billed volumes for April 2021 will not be available until June, below are the billed volumes from October 2020 through March 2021.

	Projected Period	Projected Period Forecast Volumes (Bcf)	Actual Billed Volumes for Projected Period (Bcf)
U-20642	Oct-20 to Mar-21	22.9	24.8

Attachments: None

MICHIGAN PUBLIC SERVICE COMMISSION
DTE GAS COMPANY

Exhibit AG-42
Case No. U-20940
Date: June 3, 2021

Incremental End-User Transportation Volume and Revenue

Line #		Volume in MMcf: Power Generation [1]	Volume in MMcf: Unsupported EUT Losses [2]	Volume in MMcf: Energy Optimization [3]	Total	Rate [4]	Revenue Amount
	(a)	(b)		(c)	(d)	(e)	(f)
1	**Rate Schedule:**						
2	ST		1,175	468	1,643	$ 1.2902	$ 2,119,799
3	LT		1,175	412	1,587	$ 0.7637	1,211,992
4	XLT	577	1,175		1,752	$ 0.5777	1,011,847
5	XXLT	1,170	1,175		2,345	$ 0.1401	328,603
6							
7	**Total volume/Revenue**	1,747	4,700	880	7,327		**$ 4,672,241**
8	Revenue by category	$ 497,035	$ 3,256,748	$ 918,458			$ 4,672,241

Source: (1) Allocation of 1,747 MMcf based on estimate split of 1/3 to XLT and 2/3 to XXLT.
(2) Allocation of 4,700 MMcf based on equal spplit of volumes through all rate schedules.
(3) DTE response to discovery request AGDG-5.178.
(4) Exhibit A-16, Schedule F3, page 4.

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-5.177a
Respondent:	H. Decker
Page:	1 of 1

Question: Refer to Exhibit A-15, Schedule E7, page 1. Please:

a. Expand this schedule to include actual 2020 deliveries Per Company Books and as Billed. Provide in Excel.

Answer: See tab "AGDG-5 Q-177a" in attachment U-20940 AGDG-5.177-01 Expanded Exhibit A-15, Schedule E-7, Page 1

Attachments: U-20940 AGDG-5.177-01 Expanded Exhibit A-15, Schedule E-7, Page 1

Schedule E7

Michigan Public Service Commission
DTE Gas Company
Projected EUT Volumes
Volumes in MMcf

Case No.: U-20940
Exhibit: A-15
Schedule: E7
Witness: H. J. Decker
Page: 1 of 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(h)	(i)	(j)
Line		**Per Company Books**						**Billed**		**12 Months Ended December 2022**	**Change**
No.	**Rate Class**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2019 (1)(2)(3)**	**2020 (1)(2)(3)**	**Projected Volumes**	**(Projected vs 2019 Billed)**
1	ST (1)	18,336	17,331	18,110	18,237	18,017	16,734	18,182	16,687	17,142	
2	LT (1)	21,027	21,223	21,452	22,746	21,965	21,307	22,464	21,437	18,703	
3	XLT (1)	16,381	14,049	15,479	17,771	19,092	22,253	27,684	30,985	28,360	
4	XLT Optional Rate (1)(4)	8,915	8,830	7,080	9,912	8,390	8,977	-	-	-	
5	XXLT (1)	17,283	20,541	21,491	21,287	19,738	17,821	88,428	85,821	82,015	
6	XXLT Optional Rate (1)(2)(3)(5)	11,876	11,952	10,643	13,150	13,278	8,200	-	-	-	
7	SC (1)(3)	39,225	54,541	40,556	51,958	54,937	59,788	-	-	-	
8	Total Volume	133,043	148,467	134,811	155,061	155,417	155,079	156,758	154,930	146,219	(10,539)
9	Year to Year % Variation of Total EUT Market		11.6%	-9.2%	15.0%	0.2%	-0.2%			-6.7%	

(1) Difference in volume per Company Books (Col. (f)) and Billed (Col. (g)) relates to prior period adjustments.
(2) Three Special Contracts have been classified in the applicable rate based on break-even point Per Company Books and Billed 2019 & 2020.
(3) Three Special Contracts have been classified in the applicable rate based on break-even point for the 12 Months Ended December 2022.
(4) Historical period Includes 3 customers in the XLT Optional rate class.
(5) Historical period Includes 1 customer in the XXLT Optional rate class.

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-5.163c
Respondent:	H. Decker
Page:	1 of 1

Question: Refer to page 16, lines 22-25, and page 17, lines 1-7 of Mr. Decker's direct testimony. Please:

c. For the remaining decrease of 4.7 Bcf, provide a copy of the analysis in Excel showing how you arrived at the reduction and on what basis.

Answer: The remaining 4.7 Bcf decrease is the result of the forecasting methodology outlined on page 13, lines 1 through 15 of Mr. Decker's direct testimony. This methodology includes, among other items, recent actuals and discussions with customers. This 4.7 Bcf reduction is the result of a 5.0 Bcf reduction due to recent actuals, offset by a 0.3 Bcf increase due to conversations with customers. Please note this includes over 500 accounts.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-5.160
Respondent:	H. Decker
Page:	1 of 1

Question: Refer to page 12, lines 17-21 of Mr. Decker's direct testimony. Please provide a comparison of the EUT sales forecasted in each of the prior three rate cases No. U- 17999, U-18999, and U-20642 to the actual gas deliveries for the same periods by rate clas

Answer: Please see attachment "U-20940 AGDG-5.160-01 Total EUT Volumes Projected vs. Billed".

Attachments: U-20940 AGDG-5.160-01 Total EUT Volumes Projected vs. Billed

EUT Sales forecasts for cases U-17999, U-18999 & U20642 compared to actual delivered volumes								
Volumes in BCFs							**Case No.:**	U-20940
							Discovery Request:	AGDG-5.160
							Witness:	H. Decker
							Page:	1 of 1
	U-17999			**U-18999**			**U-20642**	
	12 Months Ended October 2017 Projected Volumes	12 Months Ended October 2017 Billed Volumes		12 Months Ended September 2019 Projected Volumes	12 Months Ended September 2019 Billed Volumes		12 Months Ended September 2021 Projected Volumes	12 Months Ended September 2021 Billed Volumes
ST	16.4	17.5		17.5	18.2		17.9	Incomplete
LT	19.0	20.8		20.5	21.7		21.4	Incomplete
XLT	26.6	21.9		24.6	27.9		30.0	Incomplete
XXLT	57.9	74.1		68.5	87.1		76.6	Incomplete
Total Volume	119.9	134.4		131.1	154.9		145.9	Incomplete
SC volumes (incl in XXLT rate class		41.9			53.4			

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-13.411
Respondent:	H. Decker
Page:	1 of 1

Question: Refer to the attachment to the response to AGDG-5.160. Please provide the information under U-20642 for the period October 2020 to April 2021 both actual and forecast.

Answer: As actual billed volumes for April 2021 will not be available until June, below are the billed volumes from October 2020 through March 2021.

	U-20642	
	October 2020- March 2021 Projected Volumes	October 2020- March 2021 Billed Volumes
ST	11.4	10.8
LT	12.8	11.9
XLT	16.4	18.7
XXLT	37.9	37.4
Total Volume	78.5	78.9

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-5.179a
Respondent:	H. Decker
Page:	1 of 1

Question: Refer to Exhibit A-13, Schedule C3.3. Please provide the following information in Excel:

a. Provide the same information for actual revenues for each year 2015 to 2020.

Answer: See attachment U-20940 AGDG-5.179 A-D; Midstream Actuals by Contract

Attachments: U-29040 AGDG-5.179 A-D; Midstream Actuals by Contract

Michigan Public Service Commission
DTE Gas
Transportation & Exchange 2015-2020
Q179a
($000)

Case No.: U-20940
Attachment: AGDG-179
Witness: H. J. Decker

Line No.	(a) Description	(b) Revenues For the Year Ended 2015	(c) Revenues For the Year Ended 2016 [1]	(d) Revenues For the Year Ended 2017	(e) Revenues For the Year Ended 2018	(f) Revenues For the Year Ended 2019	(g) Revenues For the Year Ended 2020	(h) Adjustments to Revenues	(i) Revenues 12 Mos Ended Ended 2022
1	Contract Storage	$ 28,799	$ 30,803	$ 29,370	$ 31,507	$ 32,072	$ 30,944	$ (4,071)	$ 28,001
2	Park & Loan	6,934	7,867	4,498	5,160	1,138	6,539	$ 2,462	3,600
3	Total Midstream Storage Revenue	$ 35,733	$ 38,670	$ 33,868	$ 36,667	$ 33,210	$ 37,483	$ (1,609)	$ 31,601
4									
5									
6	Off-System Transportation	$ 33,115	$ 31,618	$ 30,558	$ 40,919	$ 62,857	$ 61,766	$ (2,495)	$ 60,362
7	Exchange	12,890	9,216	9,985	10,965	12,840	13,470	$ (3,840)	9,000
8	Total Transportation Revenue	$ 46,005	$ 40,834	$ 40,543	$ 51,885	$ 75,697	$ 75,236	$ (6,335)	$ 69,362
9									
10	Total Midstream Revenues	$ 81,738	$ 79,504	$ 74,412	$ 88,552	$ 108,907	$ 112,719	$ (7,944)	$ 100,963

[1] Allocated Storage Revenue of $240,000 sold as a Park.

MICHIGAN PUBLIC SERVICE COMMISSION

DTE Gas Company

Exhibit AG-45
Case No. U-20940
Date: June 3, 2021

Calculation of Incremental Midstream Revenue for Projected Test year
($000)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	**Description**	**Revenues For the Year Ended 2018**	**Revenues For the Year Ended 2019**	**Revenues For the Year Ended 2020**	Average Revenue 2018-2020	**DTE Gas Projected Revenues 12 Mos Ended Ended 2022**	Difference 3-Year **Average** to DTE Forecast	BWEC Revenue	**Incremental Revenue**
1	Contract Storage	**$ 31,507**	**$ 32,072**	**$ 30,944**	$ 31,508	**$ 28,001**	**$ 3,507**		**$ 3,507**
2	Park & Loan	**5,160**	**1,138**	**6,539**	$ 4,279	**3,600**	**$ 679**		**$ 679**
3	Total Midstream Storage Revenue	**$ 36,667**	**$ 33,210**	**$ 37,483**	$ 35,787	**$ 31,601**			
4									
5									
6	Off-System Transportation	**$ 40,919**	**$ 62,857**	**$ 61,766**	$ 55,181	**$ 60,362**	**N/A**		
7	Exchange	**10,965**	**12,840**	**13,470**	$ 12,425	**9,000**	**$ 3,425**	**$ (2,300)**	**$ 1,125**
8	Total Transportation Revenue	**$ 51,885**	**$ 75,697**	**$ 75,236**	$ 67,606	**$ 69,362**			
9									
10	Total Midstream Revenues	**$ 88,552**	**$ 108,907**	**$ 112,719**	$ 103,392	**$ 100,963**			**$ 5,310**

N/A= Based on DTE Gas Forecasted growth.

Source: AGDG-179a

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company

Exhibit AG-46
Case No. U-20940
Date: June 3, 2021

HPP Revenue & Expense 2014 - 2020

	2014	2015	2016	2017	2018	2019	2020	3-Year Growth
HPP Revenue ($MM)	$ 63.3	$ 66.7	$ 70.7	$ 73.4	$ 75.4	$ 82.2	$ 86.6	18%
HPP Operating Expense ($MM)	$ 48.3	$ 48.6	$ 51.7	$ 53.9	$ 59.8	$ 62.2	$ 60.0	11%
Margin	$ 15.00	$ 18.10	$ 19.00	$ 19.50	$ 15.60	$ 20.00	$ 26.60	36%
Average Customers	193,446	199,671	208,424	212,790	210,736	218,629	222,004	4%

Incremental Revenue 2020 vs. 2019 (millions) **$ 6.600**

Source: AGDG-5.173b

MICHIGAN PUBLIC SERVICE COMMISSION
DTE GAS COMPANY

Incremental Revenue - Summary

		Amount	Source
1	Gas Sale Revenue	$ 27,079,250	Exhibit AG-39
2	End-User Transportation Revenue	4,672,241	Exhibit AG-42
3	Midstream Revenue	5,311,000	Exhibit AG-44
4	Appliance Service Program (HPP)	6,600,000	Exhibit AG-46
5	Total	**$ 43,662,491**	

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-13.397
Respondent:	T. Johnson
Page:	1 of 1

Question: Refer to discovery response AGDG-6.212b. Please provide the calculations in Excel with formulas intact and all supporting data showing how you determined that $37.8 million of Uncollectible Expense.

Answer: The $37.8 million was based on 2019 actual uncollectable expense. See attachment U-20940 AGDG-13.397 to 403 UCX Calc "Summary" tab for the calculation of 2019 actual uncollectable expense

Attachments: U-20940 AGDG-13.397 to 403 UCX Calc

DTE Gas					
Uncollectable Expense					
($millions)					
		2018	**2019**	**2020**	**Q1 2021**
	Ending Reserve	31.0	28.1	29.8	38.5
	Less Beginning Reserve	(14.1)	(31.0)	(28.1)	(29.8)
	Less Recoveries	(31.1)	(19.7)	(20.2)	(9.9)
	Plus Write-offs	65.2	57.6	52.0	12.4
	Direct Expense	1.0	2.9	1.6	(0.0)
	Uncollectible Expense	**$52.1**	**$37.8**	**$35.1**	**$11.2**
	Ending Reserve Calculation				
	Accounts Receivable	$251	$225	$201	$263
	Average Reserve Factor (1)	21%	21%	23%	21%
	Reserve	$52	$46	$45	$54
	Estimated Recoveries	($14)	($11)	($10)	($11)
	Deposits Applied	($6)	($7)	($5)	($5)
	Ending Reserve	**$31.0**	**$28.1**	**$29.8**	**$38.5**
	(1) Detail included on support tabs				

MPSC Case No.:	U-20940
Requestor:	Staff
Question No.:	JEU-1.8
Respondent:	T. Johnson
Page:	1 of 1

Question: Has there been a material increase in bad debt or uncollectable accounts in the past 12 months? Or does the Company anticipate that there will be?

Answer: There has not been a material increase in bad debt or uncollectable accounts in the past 12 months; however, actual uncollectable expense of $35 million in 2020 was materially higher than the $27 million currently included in DTE gas rates as part of the settlement agreement in its last general rate case No. U-20642. As referenced in my testimony the historical 3-year average is not indicative of recent collection performance activities which is why we are utilizing the 2019 actual expense for our forecast. However, without continued state and federal assistance as provided in the Coronavirus Aid Relief and Economic Security (CARES) Act and the Coronavirus Response and Relief Supplemental Appropriations Act of 2021 there is the potential that bad debt could materially increase.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	Attorney General
Question No.:	AGDG-6.212a
Respondent:	T. Johnson / T. Uzenski
Page:	1 of 1

Question: Exhibit A-13, Schedule C5.7 related to uncollectible accounts expense shows the inclusion of $2.4 million of expense on line 11 for "Deferred Covid UCX Amortization." Page 34 of witness Uzenski's testimony states that this Deferred Covid Amortization expense relates to estimated costs of $1.1 million for 2020 and $10.8 million for 2021. In this regard, please:

a. Provide a schedule showing how the actual 2020 costs, which were deferred, were calculated in Excel with formulas intact and supporting data. Explain the basis on how these costs were determined.

Answer: The deferred cost in 2020 is based on comparing actual Uncollectible Expense to what was approved in previous base rates starting on March 24. For March through September, the expense in base rates used for comparison is $41.3 million from Case U-18999 and for October through December the expense in base rates used for comparison is $27 million from Case U-20642. Given the partial year of deferrals in 2020, revenue was used to allocate the monthly spread of base rates.

The schedule attached shows the calculation of our assumed 2020 deferral at the time the estimate was prepared of $1.111 million. The calculation of the actual deferral of $1.667 million for 2020 is also shown.

Attachments: U-20940 AGDG-6.212 Deferred UCX Amortization.xls

MPSC Case No.:	U-20940
Requestor:	Attorney General
Question No.:	AGDG-6.212b
Respondent:	T. Johnson / T. Uzenski
Page:	1 of 1

Question: Exhibit A-13, Schedule C5.7 related to uncollectible accounts expense shows the inclusion of $2.4 million of expense on line 11 for "Deferred Covid UCX Amortization." Page 34 of witness Uzenski's testimony states that this Deferred Covid Amortization expense relates to estimated costs of $1.1 million for 2020 and $10.8 million for 2021. In this regard, please:

b. Provide a schedule showing how the forecasted 2021 costs were calculated in Excel with formulas intact and supporting data. Explain the basis on how these costs were determined.

Answer: The deferred cost estimate in 2021 is based on comparing the projected Uncollectible Expense of $37.8 million to the $27.0 million currently approved in base rates.

Attachments: U-20940 AGDG-6.212 Deferred UCX Amortization.xls

U-20940														
AGDG-6.212 a-b														
DTE Gas														
Uncollectible Expense Deferral														
($000)														
							As FILED							
				March (1)	**April-Sept**	**Oct-Dec**	**Total 2020**							
Estimated % of Total for Base Rate Allocation				13.6%	33.2%	25.4%								
UCX in Base Rates (U-18999)	41,226			1,442	13,687									
UCX in Base Rates (U-20642)	27,000					6,855								
Preliminary Uncollectable Expense				3,229	12,725	7,141								
2020 Deferred Expense AS FILED				1,788	(962)	286	1,111							
														Actual
		January	**February**	**March (1)**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total 2020**
DTE Gas Revenue		210,739	179,878	189,890	133,683	106,381	67,562	53,154	52,076	54,407	64,496	111,181	185,756	1,409,203
% of Total for Base Rate Allocation		15.0%	12.8%	13.5%	9.5%	7.5%	4.8%	3.8%	3.7%	3.9%	4.6%	7.9%	13.2%	100%
UCX in Base Rates (U-18999)	41,226			1,434	3,911	3,112	1,977	1,555	1,523	1,592				
UCX in Base Rates (U-20642)	27,000										1,236	2,130	3,559	
Uncollectable Expense				3,229	4,091	3,133	2,133	1,802	450	1,115	866	2,384	4,492	
2020 Actual Deferred Expense				1,796	180	21	156	247	(1,073)	(477)	(370)	253	933	1,667

(1) Per p. 22/36 of U-20757 order from 04/15/2020: Energy utilities under the rate-regulation jurisdiction of the Commission may begin deferring uncollectible, or bad debt, expense incurred starting March 24, 2020 that are in excess of the amount used to set current rates.

		Estimate
		2021
UCX in Base Rates (U-20642)		27,000
Projected 2021 Expense		37,813
Projected 2021 Deferral		10,813

MPSC Case No.:	U-20940
Requestor:	Attorney General
Question No.:	AGDG-6.213a
Respondent:	T. Johnson
Page:	1 of 1

Question: Refer to Exhibit A-13, Schedule C5.7. Please:

a. Provide the net Charge-offs from 2015 to 2020 and the related annual gas sales and transportation revenues for each year in Excel.

Answer: For response, see attachment.

Attachments: U-20940 AGDG-6.213 Net Charge Offs and Aging

Case:	U-20940						
A&D	AGDG-6.213a						
Response to AG Discovery Request #6, Question 213. a							
213							
a.	Provide the net Charge-offs from 2015 to 2020 and the related annual gas sales and transportation revenues for each year in Excel.						
		2015	**2016**	**2017**	**2018**	**2019**	**2020**
	Write-offs (MPSC Page 228A Account 144, Line 3 (f))	52,974,291	42,076,067	34,583,384	54,121,146	57,894,762	53,819,751
	Recoveries (MPSC Page 228A Account 144, Line 4 (f))	(8,226,811)	(9,652,363)	(8,754,369)	(19,869,823)	(19,723,391)	(20,223,013)
	Net Write-offs	44,747,480	32,423,704	25,829,015	34,251,323	38,171,371	33,596,738
	Gas Sales (MPSC Page 300, Line 12)	1,002,012,807	924,936,736	955,184,543	1,034,569,468	1,023,781,293	953,769,657
	Transportation Revenues (MPSC Page 300, Line 17)	302,050,558	304,862,875	298,444,426	322,753,283	329,592,685	331,803,365
	Total	1,304,063,365	1,229,799,611	1,253,628,969	1,357,322,751	1,353,373,978	1,285,573,022

MPSC Case No.:	U-20940
Requestor:	Attorney General
Question No.:	AGDG-6.213b
Respondent:	T. Johnson
Page:	1 of 1

Question: Refer to Exhibit A-13, Schedule C5.7. Please:

b. For 2018 to 2020, and January to March 2021, provide the net charge-offs by month in Excel.

Answer: For response, see attachment.

Attachments: U-20940 AGDG-6.213 Net Charge Offs and Aging

Case: U-20940
A&D AGDG-6.213b

Response to AG Discovery Request #6, Question 213. b

213

b. For 2018 to 2020, and January to March 2021, provide the net charge-offs by month in Excel.

	Total	January	February	March	April	May	June	July	August	September	October	November	December
2018	**Total**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Net Write-offs	34,251,323	2,106,224	2,405,024	1,828,075	1,864,844	1,734,162	1,247,080	4,666,998	2,878,081	4,904,618	3,296,465	3,532,217	3,787,535
2019	**Total**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Net Write-offs	38,171,371	3,149,155	3,511,758	3,042,327	2,898,094	2,282,141	2,384,960	2,994,750	2,716,088	3,528,466	3,513,209	1,784,682	6,365,742
2020	**Total**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Net Write-offs	33,596,738	3,643,445	3,154,918	2,658,888	5,754,785	5,418,431	2,218,278	2,955,147	2,488,606	924,625	1,771,728	1,905,291	702,595
2021	**Total**	**January**	**February**	**March**									
Net Write-offs	2,491,035	(620,968)	1,355,754	1,756,249									

MPSC Case No.:	U-20940
Requestor:	Attorney General
Question No.:	AGDG-6.213c
Respondent:	T. Johnson
Page:	1 of 1

Question: Refer to Exhibit A-13, Schedule C5.7. Please:

c. For each quarter end in 2018, 2019, 2020, and March 21, 2021, provide the accounts receivable aging report in Excel showing total gas accounts receivable and past due amounts by aging period: current, 30 day past due, 60 days past due, etc.

Answer: For response, see attachment.

Attachments: U-20940 AGDG-6.213 Net Charge Offs and Aging

Case: U-20940
A&D AGDG-6.213c

Response to AG Discovery Request #6, Question 213. c

213

c. For each quarter end in 2018, 2019, 2020, and March 21, 2021, provide the accounts receivable aging report in Excel showing total gas accounts receivable and past due amounts by aging period: current, 30 day past due, 60 days past due, etc.

		2018 Q1	2018 Q2	2018 Q3	2018 Q4	2019 Q1	2019 Q2	2019 Q3	2019 Q4	2020 Q1	2020 Q2	2020 Q3	2020 Q4	2021 Q1
Active Arears	**Current**	168,066,564	84,540,241	49,403,396	117,966,260	170,335,016	71,951,840	34,512,538	111,538,416	133,562,585	56,173,334	32,466,184	112,338,424	153,699,549
	01 - 30 Day	47,303,682	33,677,807	16,986,696	28,895,273	45,995,864	25,707,769	10,582,358	23,000,559	35,983,036	21,580,791	8,785,970	18,367,156	36,153,797
	31 - 60 Day	23,643,985	20,308,361	11,529,974	11,258,767	18,817,176	14,206,047	8,660,587	7,574,970	14,571,301	12,589,925	6,075,621	8,717,279	11,951,141
	61 - 90 Day	13,037,773	15,366,939	9,492,787	8,130,155	13,377,531	13,703,764	6,316,221	5,859,319	10,826,839	11,037,183	5,414,733	5,010,958	7,371,066
	Over 90 Day	52,490,282	72,566,033	71,321,040	60,076,284	56,940,155	68,759,297	64,649,680	51,420,743	48,165,867	55,008,476	51,332,292	43,174,930	39,163,397
Final Arears	**Current**	4,080,317	4,815,486	4,574,062	3,633,544	4,645,470	4,707,704	3,211,366	2,706,579	2,220,559	1,739,029	2,638,319	1,722,696	2,766,082
	01 - 30 Day	3,008,980	3,467,934	4,929,218	2,771,934	3,182,550	3,596,665	2,268,470	2,490,573	2,511,094	1,524,212	1,630,913	2,400,779	2,634,961
	31 - 60 Day	2,363,923	3,396,870	3,653,562	3,065,063	2,734,390	3,193,937	2,906,124	2,075,889	2,694,186	1,333,655	1,479,125	1,806,031	2,165,366
	61 - 90 Day	1,762,708	3,351,609	3,224,471	3,553,392	2,448,975	3,344,979	3,587,898	2,776,711	2,217,497	1,803,287	1,218,810	2,295,227	1,229,775
	Over 90 Day	10,110,347	10,960,585	10,319,471	12,133,692	11,007,252	12,609,864	17,512,564	15,233,437	13,230,736	8,000,856	5,188,790	4,708,642	5,478,843
Total		**325,868,560**	**252,451,864**	**185,434,678**	**251,484,364**	**329,484,380**	**221,781,869**	**154,207,807**	**224,677,196**	**265,983,700**	**170,790,749**	**116,230,757**	**200,542,122**	**262,613,977**

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No: U-20940**
DTE Gas Company | **Exhibit: AG-49**
June 3, 2021
Accounts Receivable – Past Due Amounts Calculated by AG at bottom of schedule

Case: U-20940
A&D AGDG-6.213c

Response to AG Discovery Request #6, Question 213. c

213
c. For each quarter end in 2018, 2019, 2020, and March 21, 2021, provide the accounts receivable aging report in Excel showing total gas accounts receivable and past due amounts by aging period: current, 30 day past due, 60 days past due, etc.

		2018 Q1	2018 Q2	2018 Q3	2018 Q4	2019 Q1	2019 Q2	2019 Q3	2019 Q4	2020 Q1	2020 Q2	2020 Q3	2020 Q4	2021 Q1
Active Arears	**Current**	168,066,564	84,540,241	49,403,396	117,966,260	170,335,016	71,951,840	34,512,538	111,538,416	133,562,585	56,173,334	32,466,184	112,338,424	153,699,549
	01 - 30 Day	47,303,682	33,677,807	16,986,696	28,895,273	45,995,864	25,707,769	10,582,358	23,000,559	35,983,036	21,580,791	8,785,970	18,367,156	36,153,797
	31 - 60 Day	23,643,985	20,308,361	11,529,974	11,258,767	18,817,176	14,206,047	8,660,587	7,574,970	14,571,301	12,589,925	6,075,621	8,717,279	11,951,141
	61 - 90 Day	13,037,773	15,366,939	9,492,787	8,130,155	13,377,531	13,703,764	6,316,221	5,859,319	10,826,839	11,037,183	5,414,733	5,010,958	7,371,066
	Over 90 Day	52,490,282	72,566,033	71,321,040	60,076,284	56,940,155	68,759,297	64,649,680	51,420,743	48,165,867	55,008,476	51,332,292	43,174,930	39,163,397
Final Arears	**Current**	4,080,317	4,815,486	4,574,062	3,633,544	4,645,470	4,707,704	3,211,366	2,706,579	2,220,559	1,739,029	2,638,319	1,722,696	2,766,082
	01 - 30 Day	3,008,980	3,467,934	4,929,218	2,771,934	3,182,550	3,596,665	2,268,470	2,490,573	2,511,094	1,524,212	1,630,913	2,400,779	2,634,961
	31 - 60 Day	2,363,923	3,396,870	3,653,562	3,065,063	2,734,390	3,193,937	2,906,124	2,075,889	2,694,186	1,333,655	1,479,125	1,806,031	2,165,366
	61 - 90 Day	1,762,708	3,351,609	3,224,471	3,553,392	2,448,975	3,344,979	3,587,898	2,776,711	2,217,497	1,803,287	1,218,810	2,295,227	1,229,775
	Over 90 Day	10,110,347	10,960,585	10,319,471	12,133,692	11,007,252	12,609,864	17,512,564	15,233,437	13,230,736	8,000,856	5,188,790	4,708,642	5,478,843
Total		**325,868,560**	**252,451,864**	**185,434,678**	**251,484,364**	**329,484,380**	**221,781,869**	**154,207,807**	**224,677,196**	**265,983,700**	**170,790,749**	**116,230,757**	**200,542,122**	**262,613,977**
Active Acctounts - Past Due		136,475,722	141,919,140	109,330,498	108,360,479	135,130,725	122,376,878	90,208,847	87,855,590	109,547,043	100,216,375	71,608,617	75,270,323	94,639,401
Final Bill - Past Due		17,245,957	21,176,998	22,126,722	21,524,081	19,373,168	22,745,446	26,275,056	22,576,611	20,653,513	12,662,011	9,517,637	11,210,679	11,508,945

Uncollectible Accounts Expense
(Thousands of Dollars)

Line	Caption or Description	Net Write-Off Amounts	Net Sales	% Charged Off & AG Projection (b) / (c)	Reference
	(a)	(b)	(c)	(d)	
1	Total Year 2017*	$ 25,829	$ 1,253,629	**2.06%**	Data From AGDG 6.213
2	Total Year 2019*	38,171	1,353,374	**2.82%**	Data From AGDG 6.213
3	Total Year 2020	33,597	1,285,573	**2.61%**	Data From AGDG 6.213
4	Avg. Percentage			**2.50%**	Avg. of Lines 1,2 & 3
5	Projected Test Year Revenues			**$ 1,435,397**	See Note 1 Below
6	Uncollectible Accounts Expense - 2022			**$ 35,857**	Line 4 x Line 5
7	**Uncollectibles per DTE Gas (Ex A-13, Sch. C1, Line 8)**			**40,198**	Ex. A-13, Sch. C1, Line 8
8	***Reduction in O & M Expense for Uncollectibles***			***$ (4,341)***	Line 6 less Line 7

Notes:

* The year 2018 is omitted here and in the Company's analysis due to problems with the Customer 360 System impacting debt collections in 2018.

1 From Company Exhibit A-16, Schedule F2, page 1 of 4, Line 22 which includes 100% of the DTE Gas Proposed Rate Relief Increase.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Exhibit AG-51
Case No. U-20940
Date: June 3, 2021
Page 1 of 1

Other O & M - Excludes Uncollectibles, LAUF & Company Use Gas

Line	Caption (a)	Millions of Dollars: Proposed Changes (b)	Millions of Dollars: Other O & M Level (c)	Reference or Note (d)
1	**Other O & M Per Company Exh. A-13, Sched. C5**		**$ 523.5**	
	AG Proposed Changes			
2	Eliminate Proposed Blended Inflation	$ (30.6)		*
3	Storage, Transmission and Distribution	(20.0)		Ex. AG-54
4	Meter Reading Expense	(1.6)		Testimony
5	Reduce Medical Inflation Rate	(2.8)		Ex. AG-60
6	Eliminate MCN Pension Make-Whole Plan	(0.7)		Testimony
7	Merchant Fee Expenses	(3.6)		Testimony
8	Customer Experience Pay Increases-Offset with Voice/Digital	(3.1)		Testimony
9	Injuries & Damages at 5 Yr. Avg of 2016-2020	(1.0)		Ex. AG-63
10	Reduce Capital Use Charge	(4.8)		Testimony
11	Gas IT Sustainment	0.8		Testimony
12	Reduce Incentive Compensation	(17.1)		Testimony
13	Total Cost Changes	(84.5)	(84.5)	Sum Lines 2 to 12
14	**AG Proposed Other O & M (L1 + L13)**		**$ 439.0**	
15	***Change in Other O & M Expense (L14 less L1)***		***$ (84.5)***	

* From Ex. A-13, Sched. C5, columns (g) + (h) + (i) (See AG-53 for Alternative Approach)

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-7.215c
Respondent:	T. Uzenski
Page:	1 of 1

Question: Regarding the inflation factors shown on Exhibit A-13, Schedule C12, please address the following:

c. Provide a copy of the source document showing the CPI rates on lines 10 and provide a copy of the same report for the latest month available.

Answer: The CPI rate on line 10 of Exhibit A-13, Schedule C12, was sourced from the November 2020 U.S. Economic Outlook by IHS Market. A copy of the same report is being provided for March 2021. See attachments.

Attachments:

U-20940 AGDG-7.215c-001 US Executive Summary Nov 2020 (CPI-U p.17).pdf
U-20940 AGDG-7.215c-002 US Executive Summary Mar 2021 (CPI-U p.17).pdf

IHS Markit®

Executive Summary: US Economic Outlook

March 2021

Forecast at a glance

Base forecast (March 2021) 2021:Q1 - 2025:Q4																		
	Major economic indicators																	
	% ch. from prior quarter, annual rate						% ch. from prior year, or annual average						% ch. from fourth quarter of prior year, or fourth-quarter average					
	2020.3	2020.4	2021.1	2021.2	2021.3	2021.4	2020	2021	2022	2023	2024	2025	2020.4	2021.4	2022.4	2023.4	2024.4	2025.4
Key indicators of real activity																		
Real gross domestic product	33.4	4.1	4.9	7.0	6.8	4.9	-3.5	5.7	4.1	2.3	2.4	2.3	-2.4	5.9	2.9	2.4	2.4	2.3
Contributions to growth (% points):																		
Final sales to domestic purchasers	30.1	4.5	6.4	6.6	5.7	4.5	-2.7	6.0	3.9	2.4	2.6	2.5	-1.5	5.8	2.9	2.4	2.5	2.5
Net exports of goods & services	-3.2	-1.6	-0.9	-0.5	-0.4	-0.4	-0.1	-1.2	0.0	0.2	-0.1	-0.1	-1.1	-0.5	0.2	0.1	-0.1	-0.1
Change in private inventories	6.6	1.1	-0.7	0.8	1.5	0.8	-0.6	0.8	0.3	-0.2	0.0	0.0	0.2	0.6	-0.2	-0.1	0.0	0.0
Major components of real GDP																		
Personal consumption expend.	41.0	2.4	4.7	6.6	7.0	6.1	-3.9	5.9	5.0	3.0	2.8	2.7	-2.6	6.1	3.9	2.8	2.7	2.7
Nonres. fixed investment	22.9	14.0	7.5	5.0	8.7	6.9	-4.0	7.5	6.0	4.5	4.5	4.0	-1.2	7.0	5.1	4.5	4.3	3.8
Residential investment	63.0	35.8	18.9	6.4	-3.8	-7.4	6.0	14.3	-6.3	-5.1	-0.7	-0.1	14.1	3.1	-7.3	-3.4	0.1	-0.8
Change in private inventories *	-3.7	48.0	11.3	54.8	134.6	177.4	-80.9	94.5	156.9	108.9	101.2	94.8	48.0	177.4	126.1	104.6	99.4	93.7
Exports of goods & services	59.6	21.8	6.7	7.9	7.4	9.1	-13.0	7.4	7.0	4.9	4.5	3.9	-11.0	7.8	5.8	4.8	4.3	3.7
Imports of goods & services	93.1	29.6	11.6	9.4	8.3	9.8	-9.3	14.9	5.4	2.4	4.1	4.1	-0.6	9.8	2.7	3.1	4.4	4.0
Gov't consump. & gross invest.	-4.8	-1.1	8.6	6.9	0.2	-0.6	1.1	2.7	0.0	-0.3	0.6	0.7	-0.6	3.7	-0.6	0.2	0.7	0.7
Pvt. housing starts (thous. units)	1432	1588	1602	1612	1545	1488	1396	1562	1379	1262	1256	1275	1588	1488	1321	1252	1265	1266
Light vehicle sales (mil. units)	15.3	16.1	16.1	16.1	16.3	16.4	14.4	16.2	16.5	16.3	16.4	16.5	16.1	16.4	16.4	16.3	16.4	16.5
Industrial production, total	43.3	10.0	9.5	5.7	7.0	5.0	-6.6	7.4	4.1	1.9	2.1	2.0	-4.2	6.8	2.7	1.9	2.0	1.9
Industrial production, mfg	57.5	13.0	8.6	6.6	7.1	4.6	-6.5	8.6	3.5	1.5	2.0	2.0	-2.6	6.7	1.9	1.7	2.0	1.9
Capacity utilization (mfg, %)	70.9	73.2	74.7	75.9	76.8	77.3	70.3	76.2	77.1	76.4	76.1	75.8	73.2	77.3	76.8	76.3	76.0	75.7
Nonfarm payroll employ. (mil.)	140.9	142.6	143.1	145.1	146.6	147.9	142.3	145.6	150.6	153.3	154.9	155.9	142.6	147.9	152.0	153.9	155.4	156.2
Average monthly chg. (thous.)	1342	213	325	777	394	438	-785	483	322	159	116	68	213	438	233	141	90	59
Private nonfarm hours	38.3	10.1	1.9	7.4	4.8	3.7	-6.5	4.9	3.6	1.4	0.9	0.6	-4.9	4.4	2.6	1.0	0.8	0.5
Civilian unemployment rate (%)	8.8	6.7	6.2	5.6	5.2	4.9	8.1	5.5	4.1	3.6	3.5	3.6	6.7	4.9	3.7	3.6	3.5	3.6
Prices, Productivity, & Costs																		
CPI, all items, all urban	4.7	2.4	3.2	1.8	1.4	1.4	1.2	2.2	1.5	2.0	2.2	2.4	1.2	1.9	1.7	2.1	2.3	2.5
CPI excl food & energy, all urban	4.0	1.8	1.0	1.6	2.0	2.0	1.7	1.7	1.9	2.1	2.3	2.4	1.6	1.7	1.9	2.2	2.3	2.5
PCE price index	3.7	1.6	3.4	1.8	1.5	1.6	1.2	2.1	1.5	1.8	2.0	2.2	1.2	2.1	1.6	1.9	2.1	2.3
PCE price excl food & energy	3.4	1.4	2.4	1.8	1.8	1.8	1.4	1.9	1.7	1.9	2.1	2.2	1.4	1.9	1.7	2.0	2.1	2.3
PPI finished goods	6.4	5.0	8.8	2.4	1.6	1.0	-1.3	3.8	1.3	1.8	2.0	2.2	-1.0	3.4	1.4	1.9	2.0	2.3
Compensation per hour	-5.8	1.6	4.5	1.5	0.5	1.1	6.5	2.4	1.8	3.4	4.1	4.3	6.7	1.9	2.5	3.9	4.1	4.4
Output per hour	4.2	-4.2	3.8	1.0	3.2	1.9	2.5	2.0	1.2	1.2	2.0	2.1	2.4	2.5	0.6	1.7	2.0	2.2
Unit labor cost	-9.6	6.0	0.6	0.5	-2.6	-0.8	3.9	0.4	0.6	2.2	2.1	2.1	4.2	-0.6	1.8	2.2	2.1	2.2
CoreLogic house price index **	2.3	3.7	1.7	1.0	1.0	0.9	6.0	7.6	3.7	3.2	2.9	2.7	8.9	4.7	3.5	3.0	2.8	2.7
Price of WTI crude oil ($/barrel)	40.89	42.53	57.70	62.23	59.68	57.59	39.25	59.30	56.88	58.14	59.66	62.39	42.53	57.59	57.64	58.68	60.46	63.72
Price of Brent crude oil ($/barrel)	42.97	44.29	60.68	65.00	62.50	60.58	41.77	62.19	60.17	61.40	62.99	65.78	44.29	60.58	61.00	61.94	63.82	67.13
Selected Financial Variables																		
Federal funds rate (%)	0.09	0.09	0.08	0.08	0.08	0.08	0.38	0.08	0.09	0.10	0.26	0.53	0.09	0.08	0.09	0.11	0.38	0.68
Yield on 10-Yr Treasury Notes (%)	0.65	0.86	1.14	1.44	1.55	1.65	0.89	1.45	1.81	1.99	2.19	2.46	0.86	1.65	1.90	2.03	2.29	2.56
Baa corporate bond yield (%)	3.40	3.36	3.48	3.65	3.82	3.93	3.69	3.72	4.02	4.20	4.39	4.63	3.36	3.93	4.09	4.26	4.48	4.71
Broad trade-wtd US$ (Jan 2006=100)	117.6	114.2	112.4	113.1	113.3	113.8	117.9	113.2	114.0	114.1	114.1	114.3	114.2	113.8	114.1	114.1	114.1	114.3
S&P 500 stock index, period end	3363	3756	3827	3828	3838	3898	3756	3898	4174	4383	4416	4421	3756	3898	4174	4383	4416	4421
S&P 500 stock index, average	3322	3554	3837	3828	3833	3868	3219	3841	4049	4275	4405	4417	3554	3868	4146	4359	4414	4419
Incomes & Related Measures																		
Corporate profits w/ IVA & CCAdj	163.1	-37.1	19.9	47.5	1.8	-6.5	-8.3	12.8	4.6	2.4	3.4	3.6	-10.4	13.9	3.9	3.0	3.4	3.9
Real disposable personal income	-17.4	-10.0	23.7	26.9	-31.8	-3.6	5.8	2.9	-1.9	2.3	2.9	2.8	3.2	0.8	3.2	2.4	2.9	2.8
Personal saving rate (%)	15.7	13.0	16.7	20.3	10.8	8.5	16.1	14.1	8.2	7.6	7.8	7.9	13.0	8.5	8.0	7.6	7.8	7.8
Fed. surplus (unified, FY, bil. $)	-1550	-2292	-4025	-4870	-2136	-1559	-3132	-3331	-1267	-1020	-1088	-1122	-2292	-1559	-1362	-1377	-1403	-1462

* billions of chained 2012 $
** % change, not annualized
Source: IHS Markit

IHS Markit®

Executive Summary: US Economic Outlook

November 2020

Forecast at a glance

Base forecast (November 2020) 2020:Q4 - 2024:Q4

Major economic indicators	% change from prior quarter, annual rate						% change from prior year, or annual average						% change from fourth quarter of prior year, or fourth-quarter average					
	2020.2	2020.3	2020.4	2021.1	2021.2	2021.3	2019	2020	2021	2022	2023	2024	2019.4	2020.4	2021.4	2022.4	2023.4	2024.4
Key indicators of real activity																		
Real gross domestic product	-31.4	33.1	3.7	2.7	1.0	1.9	2.2	-3.6	3.1	2.5	2.5	2.9	2.3	-2.6	1.9	2.8	2.6	3.0
Contributions to growth (% points):																		
Final sales to domestic purchasers	-28.5	29.6	2.9	1.5	1.3	1.5	2.4	-2.9	2.7	1.9	2.2	2.8	2.4	-2.0	1.5	2.1	2.4	3.0
Net exports of goods & services	0.6	-3.1	0.0	0.6	-0.4	0.5	-0.2	0.0	-0.3	0.6	0.2	0.0	0.3	-0.7	0.3	0.6	0.2	-0.1
Change in private inventories	-3.5	6.6	0.8	0.6	0.1	-0.2	0.0	-0.6	0.7	0.0	0.0	0.1	-0.4	0.2	0.1	0.1	0.0	0.1
Major components of real GDP																		
Personal consumption expend.	-33.2	40.7	3.4	1.6	2.2	2.3	2.4	-3.9	3.6	2.2	2.4	2.9	2.5	-2.5	2.1	2.3	2.6	3.0
Nonres. fixed investment	-27.2	20.3	3.1	3.1	0.1	1.0	2.9	-4.8	1.9	3.4	4.6	5.4	1.4	-4.2	1.6	4.5	4.8	5.6
Residential investment	-35.6	59.3	20.0	-4.8	-7.1	-5.2	-1.7	4.8	2.9	-3.1	-1.1	0.4	1.6	10.0	-5.0	-2.1	-0.4	0.9
Change in private inventories *	-287.0	-1.0	41.2	72.5	79.2	69.3	48.5	-81.9	70.1	78.3	81.3	95.2	-1.1	41.2	59.3	90.5	83.3	100.9
Exports of goods & services	-64.4	59.7	12.9	16.9	1.0	10.2	-0.1	-13.4	7.5	8.9	6.6	5.5	0.4	-12.7	9.6	8.3	6.1	5.1
Imports of goods & services	-54.1	91.1	9.3	7.5	3.7	3.9	1.1	-10.4	8.2	2.4	3.7	4.4	-1.9	-5.0	5.1	2.1	3.8	4.7
Gov't consump. & gross invest.	2.5	-4.5	-3.1	1.3	0.7	0.6	2.3	1.0	-0.5	0.4	0.2	0.7	3.0	-1.0	0.7	0.3	0.2	1.0
Pvt. housing starts (thous. units)	1079	1430	1455	1381	1372	1346	1295	1362	1357	1298	1274	1270	1433	1455	1327	1286	1268	1279
Light vehicle sales (mil. units)	11.3	15.3	16.0	15.7	15.7	15.8	17.0	14.4	15.8	15.9	16.0	16.1	16.8	16.0	15.9	15.9	16.0	16.1
Industrial production, total	-42.9	39.8	3.2	1.8	0.1	0.6	0.9	-7.4	1.8	2.6	2.8	3.0	-0.7	-6.4	0.9	3.5	2.7	3.1
Industrial production, mfg	-46.9	53.7	3.9	1.9	-2.0	-1.1	-0.2	-7.4	1.9	1.7	2.5	3.1	-1.2	-5.4	-0.4	3.0	2.5	3.3
Capacity utilization (mfg, %)	63.1	70.3	71.1	71.5	71.1	70.8	75.6	69.6	71.1	71.9	73.1	74.4	75.0	71.1	70.7	72.4	73.6	74.9
Nonfarm payroll employ. (mil.)	133.7	140.8	143.2	145.8	147.1	148.1	150.9	142.4	147.5	151.3	153.4	155.1	151.8	143.2	149.0	152.3	154.0	155.7
Average monthly chg. (thous.)	-4427	1309	780	848	247	360	178	-660	440	258	141	142	210	780	304	193	154	132
Private nonfarm hours	-42.9	36.8	10.6	7.7	3.0	2.8	0.7	-6.7	5.2	2.6	1.2	1.0	0.8	-5.1	3.9	2.2	0.9	1.0
Civilian unemployment rate (%)	13.0	8.8	6.8	6.0	5.8	5.6	3.7	8.1	5.7	4.7	4.4	4.0	3.5	6.8	5.4	4.5	4.3	3.9
Prices, Productivity, & Costs																		
CPI, all items, all urban	-3.5	5.2	2.3	1.6	2.7	2.9	1.8	1.3	2.3	2.6	2.2	2.1	2.0	1.2	2.5	2.5	2.1	2.1
CPI excl food & energy, all urban	-1.6	4.4	2.5	1.9	2.4	2.2	2.2	1.8	2.3	2.3	2.2	2.2	2.3	1.8	2.2	2.2	2.2	2.2
PCE price index	-1.6	3.7	1.7	1.5	2.3	2.3	1.5	1.2	1.9	2.2	2.0	1.9	1.5	1.2	2.1	2.1	1.9	1.9
PCE price excl food & energy	-0.8	3.5	1.9	1.7	2.1	2.0	1.7	1.4	1.9	2.0	1.9	1.9	1.6	1.6	2.0	2.0	1.9	2.0
PPI finished goods	-11.4	7.1	2.0	2.1	3.4	3.8	0.8	-1.4	2.4	3.0	2.2	1.8	0.9	-1.6	3.3	2.6	1.9	1.8
Compensation per hour	20.1	-4.4	-0.2	-0.2	0.2	0.4	3.6	5.9	0.6	1.5	3.1	3.8	3.3	5.8	0.3	2.2	3.6	4.0
Output per hour	10.6	4.9	-5.4	-4.6	-2.4	-1.0	1.7	2.6	-1.6	0.2	1.6	2.3	1.9	2.3	-2.1	1.0	2.0	2.5
Unit labor cost	8.5	-8.9	5.5	4.6	2.7	1.4	1.9	3.3	2.3	1.3	1.5	1.5	1.4	3.4	2.5	1.2	1.6	1.5
CoreLogic house price index **	1.4	3.2	1.9	1.2	0.7	0.7	3.6	5.9	5.8	3.0	3.0	3.0	3.7	8.0	3.5	3.0	3.0	3.0
Price of WTI crude oil ($/barrel)	27.81	40.89	39.78	40.13	41.45	45.46	56.98	38.56	43.91	52.61	56.22	57.37	56.94	39.78	48.61	55.24	56.59	58.02
Price of Brent crude oil ($/barrel)	29.38	42.97	41.20	42.67	44.25	48.33	64.34	41.00	46.73	55.88	57.82	59.38	63.38	41.20	51.67	58.50	58.08	60.35
Selected Financial Variables																		
Federal funds rate (%)	0.06	0.09	0.10	0.10	0.10	0.10	2.16	0.38	0.10	0.10	0.11	0.12	1.64	0.10	0.10	0.10	0.11	0.13
Yield on 10-Yr Treasury Notes (%)	0.69	0.65	0.80	0.88	0.93	0.99	2.14	0.88	0.97	1.24	1.45	1.63	1.79	0.80	1.06	1.34	1.50	1.72
Baa corporate bond yield (%)	3.91	3.32	3.42	3.54	3.57	3.48	4.38	3.63	3.51	3.58	3.84	4.00	3.91	3.42	3.47	3.69	3.90	4.07
Broad trade-wtd US$ (Jan 2006=100)	122.2	117.7	115.6	113.9	111.8	109.9	115.7	118.3	111.1	106.8	106.4	107.1	116.4	115.6	108.6	106.3	106.6	107.4
S&P 500 stock index, period end	3100	3363	3524	3482	3492	3529	3231	3524	3531	3552	3688	3875	3231	3524	3531	3552	3688	3875
S&P 500 stock index, average	2929	3322	3366	3503	3487	3510	2912	3171	3508	3534	3611	3777	3086	3366	3530	3544	3668	3873
Incomes & Related Measures																		
Corporate profits w/ IVA & CCAdj	-35.2	363.3	-69.8	-25.6	2.7	5.9	0.3	-5.3	-12.4	6.0	6.2	7.2	1.3	-14.0	-5.4	7.7	6.3	7.2
Real disposable personal income	46.6	-16.3	-13.6	-5.0	-0.1	0.2	2.2	5.4	-3.9	1.3	2.4	3.1	1.6	2.1	-1.3	2.0	2.8	3.1
Personal saving rate (%)	25.7	15.8	11.9	10.2	9.7	9.2	7.6	15.7	9.4	8.6	8.5	8.7	7.3	11.9	8.6	8.4	8.6	8.7
Fed. surplus (unified, FY, bil. $)	-8003	-1550	-2357	-2233	-705	-1501	-984	-3132	-1699	-1063	-929	-993	-1426	-2357	-1374	-1208	-1309	-1277

* billions of chained 2012 $
** % change, not annualized
Source: IHS Markit

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Exhibit AG-53
Case No. U-20940
Date: June 3, 2021

O & M Reduction - Reduce Inflation Increases to the CPI

		Thousands of Dollars			
Line	Department	Hist. 2019 O & M*	Less Non Inflat. Items**	Inflationary Items	Inflation
	(a)	(b)	(c)	(d)	(e)
1	Natural Gas Storage	$ 12,503	$ -	$ 12,503	
2	Transmission	57,890	-	57,890	
3	Distribution	118,934	-	118,934	
4	Customer Service	59,001	(6,687)	52,314	
5	Marketing	45,375	-	45,375	
6	Admin. & General	106,648	(51,284)	55,364	
7	Pension & Benefits	32,422	(32,422)	-	
8	Total for 2019	$ 432,773	$ (90,393)	$ 342,380	
9	2020 Inflation (1.2% of Line 8)			4,109	$ 4,109 ***
10	Inflation Base - 2020			$ 346,489	
11	2021 Inflation (2.2% of Line 10)			7,623	7,623 ***
12	Inflation Base - 2021			$ 354,111	
13	2021 Inflation (1.5% of Line 12)			5,312	5,312 ***
14	**Cumulative Inflation at 100% of CPI (L9 + L11 + L13)**				**$ 17,043**
15	Inflation per Ex. A-13, Sch. C5, (Col. (g) + (h) + (i))				30,659
16	***Alternative Inflation Elimination (L14 less L15)***				***$ (13,616)***

* Totals per Exhibit A-13, Sched. C5
** Reflects Merchant Fees, Injuries & Damages, MGP Amortization, Rents and all Pensions & Benefits
*** Inflation at Percentages in HIS US Economic Outlook of March 2021, page 4, (see AGDG-7.215c-002)

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Exhibit AG-54
Case No. U-20940
Date: June 3, 2021

Storage, Transmission and Distribution Non-Inflationary Increases*

Line	Caption (a)	Addit. Expense Per Company (b)	AG Changes (c)	AG Revised Addit. Expense (b) - (c) (d)	Explanation or Note (e)
1	Poly Separation Valves	$ 0.4		0.4	
2	Transmission ROW Maintenance	3.0	(2.0)	1.0	Testimony
3	Sub Total	3.4	(2.0)	1.4	
4	Additional Logging Requirements	$ 0.5	$ -	$ 0.5	
5	Pipeline Integrity - TIMP	2.1	(6.6)	(4.5)	Testimony
6	TCARP Transmission Fees	11.6	(5.9)	5.7	Testimony
7	Max. Allowable Operating Pressure (MAOP) Records	5.9	(3.0)	3.0	Testimony
8	Records Management - Mitigation	0.3	-	0.3	
9	Pipeline Safety Management Systems (PSMS)	2.0	(1.0)	1.0	Testimony
10	Quality Assurance	1.0	-	1.0	
11	Cyber security & Nominations Support	0.6	-	0.6	
12	Corrosion CIS, Survey Work and DIMP	1.0	-	1.0	
13	Meter Abnormal Operating Condition	1.5	(1.5)	-	Testimony
	Total Additional Expense	**$ 29.9**	**$ (20.0)**	**$ 10.0**	Sum L 3 to L 13

Note * These are the increases shown in col. (j) of Ex. A-13, Sched. C5.1, C5.2 and C5.3 (also collectively on Ex. A-13, Sch. C5.16), as corrected by DR AGDG-7.219a.

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-4.129a
Respondent:	M. Johnson
Page:	1 of 1

Question: Refer to page 17, lines 20-25 of Mr. Mark Johnson's direct testimony. Please:

a. Explain why an acceleration of mechanical brushing is necessary and why 650 miles is targeted.

Answer: The acceleration of the mechanical brushing in 2022 allows DTE to remediate transmission lines that have become overgrown and build a program that allows DTE to leverage more cost-effective means of maintaining the pipelines moving forward. Mechanical brushing will be performed and followed up by a herbicide spraying program, which lengthens the interval required between more costly mechanical brushing cycles by nearly double. Without this accelerated brushing program DTE will continue to target the worst areas year-to-year and limit our ability to build a more cost effective, comprehensive program for maintaining the pipelines. This larger one time spend will also allow DTE to get a better unit price on mechanical brushing for 2022 based on the volume of work.

After further evaluation and discussions with experts in brushing and spraying programs DTE has optimized the initial 650 miles targeted as follows. Approximately 500 miles of pipeline to be mechanically brushed and approximately 550 miles of pipeline to be sprayed. The spraying mileage is higher to account for lines brushed in prior years that need herbicide follow up. This mileage targeted would account for the pipelines with the most vegetation growth in our system and position DTE with a sustainable program.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-4.129b
Respondent:	M. Johnson
Page:	1 of 1

Question: Refer to page 17, lines 20-25 of Mr. Mark Johnson's direct testimony. Please:

b. Provide the cost and miles cleared or treated each year from 2015 to 2020 actual, and forecasted for 2021 and 2022.

Answer:

	Actuals			
	Brushing		Spraying	
	Spend	Miles	Spend	Miles
2015	$142,611	17	$0	0
2016	$514,508	83.5	$0	0
2017	$161,040	22	$42,106	65
2018	$229,340	14	$137,800	128
2019	$153,000	18	$0	0
2020	$145,000	11.5	$24,000	12
	Forecasted			
2021	$200,000	24	$25,000	20
2022	$2,400,000	500	$600,000	550

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-12.390
Respondent:	M. Johnson
Page:	1 of 1

Question: Refer to the response to AGDG-4.129a. Please explain why the Company decided to increase the miles of ROWs to be brushed to 500 miles in 2022, when only 12 to 84 miles were brushed annually between 2015 and 2021. Why didn't the Company take a more gradual approach to increase the number of miles in 2021 and future years to get to 500 miles over 3 to 5 years?

Answer: DTE Gas believes it is best to implement the increased brushing efforts in 2022 instead of gradually in order to secure the best unit pricing based on volume of work, remediate transmission line ROWs that have become overgrown and implement a program that allows sustained ROW maintenance. Remediation of overgrown transmission line ROWs allows unimpeded and safe access to our rights-of-way for routine pipeline maintenance tasks, integrity assessments and remediation that are performed by DTE Gas employees and contractors.

Attachments: None

MPSC Case No.: U-20940
Requestor: AG
Question No.: AGDG-4.128b
Respondent: M. Johnson
Page: 1 of 1

Question: Refer to page 16, lines 22-25, and page 17, lines 1-9 of Mr. Mark Johnson's direct testimony. Please:

b. Provide the TIMP PI O&M expense for each year 2015 to 2020 actual and forecasted for 2021.

Answer:

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Forecast
TIMP PI O&M $ (,000)	$ 8,453	$ 5,515	$ 5,860	$ 10,327	$ 17,144	$ 10,322	$ 13,517

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-12.389
Respondent:	M. Johnson
Page:	1 of 1

Question: Refer to the response to AGDG-4.128b. Please explain what the amounts in the table represent. The request was for PI O&M expense comparable to the $2.1 million forecasted on page 16, lines 22-25 of your testimony for 2022. Please provide the requested information.

Answer: The amounts in the table represent O&M assessment and remediation costs. The $2.1 million is the O&M known and measurable adjustment for the test year (2022) compared to the historical year (2019).

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-7.219a
Respondent:	M. Johnson
Page:	1 of 1

Question: Refer to witness Mark Johnson's testimony on page 19.

a. Regarding the $4.9 million of expense for MAOP Records remediation, please provide a schedule showing how much the Company has forecasted to be spent on this program in each of the years 2021 to 2025.

Answer:

	2021F	2022F	2023-2025F
Annual MAOP Records Remediation O&M Expense ($M)	$4.0	$6.0	$4.0

There was an error with the adjustments shown in Exhibit U-20940 A-13 Schedule C5.2. The tables below show the original filed and corrected adjustment. There is no change to the overall O&M expense.

Filed Adjustments:

Adjustment	FERC Account	O&M Expense ($M)
MAOP Records Remediation	859	$4.9
Records Defect Remediation	850	$1.0

Corrected Adjustments:

Adjustment	FERC Account	O&M Expense ($M)
MAOP Records Remediation	859	$5.9
Records Defect Remediation	850	$0.0

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-4.135a
Respondent:	M. Johnson
Page:	1 of 1

Question: Refer to page 34, lines 11-25, and page 35, lines 1-7 of Mr. Mark Johnson's direct testimony. Please:

a. Provide the expense for each year 2015 to 2020 actual and forecasted for 2021- 2022 by major component. Provide the amount spent on evaluation versus remediation separately.

Answer:
Meter AOCs are identified through the annual leak survey process. Costs associated with Meter AOC identification roll into the overall leak survey cost and cannot be separated.

Meter AOC remediation costs are not separately tracked and impact numerous areas of the capital and O&M budget. Based on the remediation completions and an estimated average remediation cost of $42, the following table was developed. Meter AOC remediation data prior to 2017 was not migrated to the current customer information system and is therefore not available.

Year	Total O&M Cost ($000)
2015	Data not available
2016	Data not available
2017	$82
2018	$321
2019	$471
2020	$583
2021F	$1,050
2022F	$1,974

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-4.135b
Respondent:	M. Johnson
Page:	1 of 1

Question: Refer to page 34, lines 11-25, and page 35, lines 1-7 of Mr. Mark Johnson's direct testimony. Please:

b. Provide the number of AOC meters identified, remediated, and the backlog, separately, by year for 2015 to 2020 actual and forecasted for 2021-2022.

Answer: Meter AOC remediation data prior to 2017 was not migrated to the current customer information system and is therefore not available.

Year	AOC Meters Identified	AOC Meters Remediated	AOC Backlog
2015	19,495	Data not available	Data not available
2016	12,836	Data not available	Data not available
2017	21,267	1,963	1,963
2018	29,504	7,649	5,686
2019	53,858	11,209	2,018
2020	38,127	13,890	4,223
2021F	30,000	25,000	18,436
2022F	30,000	47,000	35,872

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-4.135c
Respondent:	M. Johnson
Page:	1 of 1

Question: Refer to page 34, lines 11-25, and page 35, lines 1-7 of Mr. Mark Johnson's direct testimony. Please:

c. Explain why an increase in expense is necessary and on what basis.

Answer: DTE Gas plans to remediate the existing backlog and upcoming due AOCs in the service territory. Remediation of AOCs is required by code and ensures that assets are operating as intended and helps mitigate the risk of unintended release of natural gas. This increases the safety and reliability of DTE Gas infrastructure for the public.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-12.393b
Respondent:	M. Johnson
Page:	1 of 1

Question: Refer to the response to AGDG-4.135b. Please: b The AOC Backlog numbers for each year do not track when adding current year meters identified and subtracting meters remediated to the prior year backlog in order to get to the current year backlog. For example, adding 30,000 meters identified in 2020 to the 2019 backlog of 4,223 and subtracting 25,000 meters remediated in 2020 should result in 9,223 meter in backlog at the end of 2020, not 18,436. If there are other items that affect the year end backlog, please identify them.

Answer: The 3 columns provided in 4.135b do not represent data points that can be analyzed as described. The number of times an abnormality was identified (usually corrosion) is listed in the left most column. Once identified those abnormalities need to be either corrected through a remediation within a specified time period or removed from the list if subsequent evaluation determines no correction is needed. The time periods for correction of the AOC range from immediate action required to being corrected within 2 years. The 3rd column represents meter abnormalities that have not been corrected within our expected time period. The 3 columns cannot be evaluated with the math provided in the question above to gauge the total picture.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-4.139a
Respondent:	M. Johnson
Page:	1 of 1

Question: Refer to page 48, lines 11-19 of Mr. Mark Johnson's direct testimony. Please provide the following information in Excel:

a. Provide the meter reading expense recorded on the books of the Company for each year from 2008 to 2020, and the amount forecasted for 2021 and 2022, by major function, activity, and component, i.e., labor to read meters, office support labor, vehicle expense, etc.

Answer: Please see Attachment U-20940-AGDG 4.139a Meter Read Expense 2008-2020.

Attachments: U-20940 AGDG-4.139a Meter Read Expense 2008-2020.

MPS U-20940
Requ AG
Que: AGDG-4.139a
Resp M. Johnson

Meter Reading Expenses 2008-2020 Plus 2021-2022 Forecast

Summary	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021 F	2022 F
ST	5,337,311	5,491,765	4,573,971	3,670,963	2,081,901	2,077,228	2,081,532	1,535,801	1,534,027	1,661,807	1,492,890	1,573,646	1,644,468	1,676,500	1,725,082
OT	367,417	383,853	225,390	292,606	106,187	97,153		63,254	71,710	90,039	86,055	90,861	73,487	74,988	77,161
ContractLabor	171,767	187,533	282,639	340,516	38,253	49,910	32,261	6,746	2,725	1,808	1,873	1,800	3,397	3,466	3,566
Materials	155,944	141,562	226,813	226,044	70,197	65,534	69,158	(51)	49,214	110,155	114,921	91,423	68,278	69,672	71,691
Outside Services	3,646,305	3,838,245	3,392,601	4,226,892	4,924,664	5,319,925	4,571,385	4,090,181	4,518,464	3,299,488	2,619,837	2,874,851	2,803,030	2,860,262	2,943,147
Other Non labor	1,609,250	1,254,177	1,649,803	995,995	622,885	394,170	414,544	306,451	118,278	257,606	102,081	105,520	262,657	268,020	275,787
Subtotal Directs	11,287,994	11,297,135	10,351,216	9,753,016	7,844,087	8,003,920	7,168,879	6,002,381	6,294,417	5,420,903	4,417,657	4,738,101	4,855,317	4,952,908	5,096,434
REP	358,253	491,707	314,780	226,116	182,157	214,108		161,419	145,667	172,821	137,529	155,895	220,640	225,145	231,670
LTIP						34,515		4,649	14,648	15,470	13,131	15,669	15,140	15,449	15,896
Grand Total	**11,646,247**	**11,788,842**	**10,665,996**	**9,979,132**	**8,026,244**	**8,252,543**	**7,168,879**	**6,168,450**	**6,454,732**	**5,609,195**	**4,568,316**	**4,909,665**	**5,091,097**	**5,193,502**	**5,344,000**

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-12.396a
Respondent:	M. Johnson
Page:	1 of 1

Question: Refer to the response to AGDG-4.140.

a. For each of the items identified in the explanation: AMR drive by reads, hard to access non-AMI sites, etc., please provide the number pertaining to the gas business and the number pertaining to the electric business separately for each year 2017-2022.

Answer:

The number of meters read as part of AMR drive-by collection is increasing each year as shown in the table below, and the number of manual reads are generally decreasing each year as depicted below as well. Manual reads reflect hard to access sites, AMI opt-out customers and other special conditions that require a manual read.

Manual (AMR Drive by or Manual Walk Up) Reads							
		2017	**2018**	**2019**	**2020**	**2021**	**2022**
Gas -GRMI (Less Grand Rapids)	AMR	284,846	323,845	330,212	334,090	338,365	338,378
	Manual	38,477	5,677	2,803	2,346	2,113	2,000
Gas - Grand Rapids	AMR	8	70,924	240,091	253,035	258,989	259,992
	Manual	251,765	184,367	18,571	8,195	6,003	5,000
Gas - SEMI	AMR	14,513	14,311	14,991	15,254	16,791	17,500
	Manual	108,276	85,554	68,366	54,950	40,250	30,000
Electric	Manual	90,421	19,186	11,841	9,920	10,295	10,000

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-12.396b
Respondent:	M. Johnson
Page:	1 of 1

Question: Refer to the response to AGDG-4.140. b What is the ST labor cost for?

Answer: ST Labor in AGDG-4.140 refers to Office Staff support and currently one DTE Meter Reader. All other meter readers are part of Outside Services.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-12.396c
Respondent:	M. Johnson
Page:	1 of 1

Question: Refer to the response to AGDG-4.140. c What is included in Other Non-Labor?

Answer: Other Non-Labor is an allocation of miscellaneous corporate service and overhead costs.

Attachments: None

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Exhibit AG-60
Case No. U-20940
Date: June 3, 2021

Medical Expenses -Reduced Inflation Rate
(Thousands of Dollars)

Line	Caption	2015	2016	2017	2018	2019	Reference
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Historic Cost Information						
1	Gross Actual Medical, Dental & Vision	$ 20,637	$ 20,568	$ 25,323	$ 25,825	$ 26,201	Note 1
2	Average Employees	2,202	2,258	2,274	2,377	2,491	Note 1
3	Cost per Employee	$ 9.372	$ 9.109	$ 11.136	$ 10.865	$ 10.518	Note 1
4	Avg. Annualized Cost per Employee Increase			***3.00%***			

Line	Caption	2019	2020	2021	2022	Reference
	Projected Cost Information					
5	Actual 2019 Escalated 3% per Year	26,201	26,987	27,797	28,631	Note 2
6	Less Allocation to Costs Capitalized	(9,216)	(9,493)	(9,777)	(10,071)	Note 3
7	Net Cost in O & M	$ 16,985	$ 17,494	$ 18,019	$ 18,560	Line 5 less Line 6
8	Company Expense Estimate				21,408	Ex. A-13, Sch. C5.9 (L10)
9	***Reduction in Medical Expense and O & M***				***$ (2,848)***	Line 7 less Line 8

Notes
1 From Company Exhibit A-13, Sch. C5.9.3, Lines 1 to 6
2 Actual 2019 Cost with 2020 to 2022 escalated by 3% each year, consistent with 3% observed history on Line 4
3 Reflects 35% allocated to costs capitalized leaving 65% allocated to O & M on Line 7 (See Cooper Testimony, p.19, Line 16)

MPSC Case No.:	U-20940
Requestor:	Staff
Question No.:	TMS-1.1
Respondent:	B. Burns
Page:	1 of 1

Question: Please provide for the next several questions the actual merchant fee information by year for DTE Gas customers since inception of the program, through 2020. Please provide the monthly amounts for 2020.

1. Please provide the projected and actual merchant fee costs by year.

Answer: Please see the charts below.

Merchant Fees (000)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Projected Merchant Fees	*Not available*				$ 3,745	$ 3,095	$ 2,925	$ 4,560	$ 4,410	$ 7,259	$ 7,074
Actual Merchant Fees	$ 1,431	$ 2,226	$ 1,991	$ 2,121	$ 2,826	$ 2,808	$ 3,143	$ 4,188	$ 5,401	$ 6,887	$ 6,955

2020 Gas Merchant Fees (000)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Projected Merchant Fees	$0.596	$0.560	$0.570	$0.604	$0.474	$0.485	$0.501	$0.661	$0.651	$0.660	$0.639	$0.673	$ 7,074
Actual Merchant Fees	$0.616	$0.580	$0.590	$0.625	$0.490	$0.502	$0.518	$0.719	$0.707	$0.605	$0.570	$0.433	$ 6,955

Attachments: N/A

MPSC Case No.: U-20940
Requestor: Staff
Question No.: TMS-1.2
Respondent: B. Burns
Page: 1 of 1

Question: Please provide for the next several questions the actual merchant fee information by year for DTE Gas customers since inception of the program, through 2020. Please provide the monthly amounts for 2020.

2. Please provide the number of customers monthly that pay their utility bill by credit or debit card (please distinguish between the two), broken out between residential and small commercial customers.

Answer: Please see the charts below. The payment data can only be provided on an annual basis and the DTE billing system does not distinguish between credit and debit cards.

Gas Customers	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential	180,636	206,325	255,132	284,042	345,654	410,764	516,166	535,001	600,610	651,868	663,184
Small Commercial	4,840	5,809	7,648	8,887	11,570	14,749	18,538	16,559	19,533	21,383	22,032

Attachments: N/A

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-10.347a
Respondent:	H. Campbell
Page:	1 of 1

Question: Refer to the response to AGDG-7.229a. Please:

a. Identify specifically what the $3.8 million will be spent on, why this increased spending is necessary, and what it will achieve. Provide the calculations in Excel supporting this amount.

Answer: The $3.8 million is comprised of the Customer Service Representative (CSR's) wage increase, increase complement of CSR's and support staff including the respective overhead (benefit allocation) thereof. The wage increase accounts for the $2 an hour raise that was extended to the CSR's in 2020. Secondly, the complement of CSR's will increase by 120. An increase in complement is needed to address the more complex call types such as High Bill, Time of Use (ACPP), Low-income and the associated ongoing training and development needed to sustain operational performance and customer satisfaction. Further, additional administrative and escalation support (Supervisors / Analysts) is needed for the increase in CSR complement.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-10.347b
Respondent:	H. Campbell
Page:	1 of 1

Question: Refer to the response to AGDG-7.229a. Please:

b. Provide the actual costs incurred in 2019 and 2020 in this area, and the amount forecasted for 2021.

Answer: See attachment for response.

Attachments: U-20940 AGDG-10.347b Customer Experience Costs 2019-2021

Case:	U-20940				
Audit and Discovery	AGDG-10.347b				
Witness:	Henry Campbell				
Customer Experience					
Incremental O&M					
		Incremental 2022	**2019**	**2020**	**2021E**
	Customer Representative Wage Increase	$2,028	$0	$1,352	$1,971
	Customer Representative Surge (120)	$4,800	$0	$0	$2,720
	Supervisor / Analyst Support for Surge	$1,440	$0	$0	$816
	Increased Overhead (Benefit) Rate	$2,977	$0	$487	$1,983
	Total Cost	$11,245	$0	$1,839	$7,490
	Gas Allocation %	33.8%		33.8%	33.8%
	Gas Allocation	**$3,801**	**$0**	**$622**	**$2,531**
				Planned 2021	
				Surge Hires	**2021**
				Hire 54 April	$1,620
				Hire 44 July	$880
				Hire 22 October	$220

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Exhibit AG-63
Case No. U-20940
Date: June 3, 2021

Injuries & Damages
(Thousands of Dollars)

Line	Year or Caption (a)	Injuries & Damages (b)	Reference
1	2016	$ 7,817	Ex. A-13, Sch C5.6
2	2017	6,855	Ex. A-13, Sch C5.6
3	2018	5,366	Ex. A-13, Sch C5.6
4	2019	4,201	Ex. A-13, Sch C5.6
5	2020	4,692	AGDG-7.236a
6	5 Year Average	$ 5,786	Average of L 1 to L 5
7	Company Case (per Exh. A-13, Sched. C5.6)	6,824	Ex. A-13, Sch C5.6
8	***Reduction in Injuries & Damages and O & M***	***$ (1,038)***	L 6 less L 7

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-7.236a
Respondent:	T. Uzenski
Page:	1 of 1

Question: Refer to Exhibit A-13, Schedule C5.6, page 2. Please:
a. Provide the actual amount of Injuries and Damages expense for 2020.

Answer: Actual Injuries and Damages expense for 2020 was $4,692,230.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-7.236b
Respondent:	T. Uzenski
Page:	1 of 1

Question: Refer to Exhibit A-13, Schedule C5.6, page 2. Please:

b. Explain the reasons for the downward trend in Injuries and Damages expense from 2015 to 2019 and describe any changes the Company has made to its employee safety programs and other practices and initiatives that have reduced I&D expenses over the five-year period.

Answer: The downward trend is mostly driven by lower costs for case litigation and settlement. The company has implemented safety initiatives such as DART (Days Away Restricted or Transferred) lost workday model tracking, development of life critical standards and assessments, a PSIF (Potentially Serious Injury or Fatality) program, vehicle safety, contractor safety, hazard identification, and targeted safety communications. In addition, the Wellness program has a focus on accident prevention. These initiatives cannot be directly traced to savings on injuries and damages expense.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-7.237b
Respondent:	T. Uzenski
Page:	1 of 2

Question: Refer to Exhibit A-13, Schedule C5.15. Please:

b. For each line item with amounts in 2021 and 2020, please describe what is being done at each location in detail.

Answer: Work has been completed for the 2020 Projects. The expenditures at all locations included mechanical work, fire suppression, fire detection, plumbing, ADA renovation of bathrooms, and sustainable design (LED lighting, low flow faucets, urinals, toilets, recycled materials, recyclable materials). The Beech Street project included a new Security Control center and a renovation of the security office. (Security staff continues to work on site in a traditional manner.) The General Office (GO) Building 7th floor was updated as an agile work space with unassigned offices. Work at the North Area Energy Center in Cass City included re-paving the front parking lot and a renovation of the office spaces, warehouse, garage areas, showers and locker rooms.

<u>2021 Projects</u>

All the projects include mechanical work, fire suppression, fire detection, plumbing, ADA renovation of bathrooms, and sustainable design (LED lighting, low flow faucets, urinals, toilets, recycled materials, recyclable materials).

General Office (GO) Building 8th & 9th Floor: Work started in 1st quarter 2021. The floors will be designed to support our future office needs, agile design, and office consolidation.

Walker Cisler Building (WCB) 4th Floor Refresh: This floor will be renovated to support the relocation of Ann Arbor employees to the Detroit head-quarters.

WCB 5th Floor Refresh: This floor will be renovated to support our future office needs, agile design, and office consolidation.

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-7.237b
Respondent:	T. Uzenski
Page:	2 of 2

WCB 12th Floor: Renovations support our future office needs, agile design, and office consolidation. Work is targeted to be complete in the 2nd quarter of 2021.

WCB 22nd Floor: Renovations support our future office needs, agile design, and office consolidation. Work is targeted to be complete in the 2nd quarter of 2021.

WCB 23rd Floor: Project is on hold. Scope and timing are currently undetermined.

WCB 24th Floor: Project is on hold. Scope and timing are currently undetermined.

Attachments: *none*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-7.237c
Respondent:	T. Uzenski
Page:	1 of 1

Question: Refer to Exhibit A-13, Schedule C5.15. Please:

c. Explain why it is necessary to perform this work at this time, given the uncertainty of how many office employees will work remotely and when employees will return to their previous work location due to the Covid-19 restrictions.

Answer: Although there is uncertainty of when DTE will return back to the office, projects are still needed to maintain proper asset health which provides our employees a safe work environment. These projects include upgrading the fire suppression system, fire detection, plumbing, ADA renovation of bathrooms, and sustainable design (LED lighting, low flow faucets, urinals, toilets, recycled materials, recyclable materials, etc.) Many of these projects bring our facilities up to current building codes.

Also see response to AGCUBDG-1.16. The design for currently open projects has been updated to reflect an anticipated overall reduction in office space and a new style of work environment that will exist after the pandemic. The future workspace will likely include a combination of dedicated office space, shared workspace and virtual offices. In general, updated Company office spaces are expected to be more agile to support a wider range of activities for a hybrid workforce including space for larger group meetings to collaborate and foster teambuilding.

Attachments: *none*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.316c
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 49, lines 9-14 of Ms. Pizzuti's direct testimony. Please:
c. Provide the basis for the 1.2 million reduction in calls. Provide the time period over which the reduction of 1.2 million calls would occur.

Answer: Our aspiration to reduce 1.2 million calls is based on our assessment of the impact of the investments in the Digital and Voice Self-Service channels as described in my testimony (A30 through A43). These call volume reductions are based on our targets for increased self-service engagement and completion rates that will result from the efforts of digital product teams, which includes new web and IVR self-service alternatives across the MIMO, Collection, and Billing transactions.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.316d
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 49, lines 9-14 of Ms. Pizzuti's direct testimony. Please:
d. Provide the total number of calls received by the Company in each of the past two years.

Answer: In 2019, the Company handled 5.13 million calls in the contact center. In 2020, the volume of calls dropped significantly to 4.15 million calls, with 80% of that reduction coming from reductions in Billing, Collection, and MIMO calls stemming from the impacts of the COVID pandemic, which resulted in significantly reduced collection activity and fewer requests for moves in the spring and during the usually heavy college move season.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.316e
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 49, lines 9-14 of Ms. Pizzuti's direct testimony. Please:

e. Provide the calculation of the $7.0 million in O&M savings in Excel with formulas intact, basis, and description explanations of the assumptions made.

Answer: Attached is an Excel file that summarizes the aspirational targets by year for the volume of calls and the associated contact center O&M savings expected from the Digital and Voice Self-Service projects.

Attachments: *U-20940 AGDG-9.316e-01 Call Reduction Summary*

Summary of Call Reductions and Associated Contact Center O&M Savings for 2021-2025

Cost/Call $ 5.75 *Average cost for each incremental call that is deflected from the Contact Center to a self-serve channel*

Year	MIMO Web Call Reductions	MIMO Web Call O&M Savings	Self-Service Call Reductions	Self-Service Call O&M Savings	Total O&M Savings
2021	90,000	$ 517,500	24,000	$ 138,000	$ 655,500
2022	92,000	$ 529,000	160,000	$ 920,000	$ 1,449,000
2023	74,000	$ 425,500	242,000	$ 1,391,500	$ 1,817,000
2024	32,000	$ 184,000	261,000	$ 1,500,750	$ 1,684,750
2025	-	$ -	233,000	$ 1,339,750	$ 1,339,750
Totals	288,000	**$ 1,656,000**	920,000	**5,290,000**	**$ 6,946,000**

MIMO Web Call Reductions
Annual decrease in MIMO calls to the Contact Center resulting from an increased percentage of MIMO orders completed on the Web

Percent Web Completions
2020 - 11% (baseline)
2021 - 21%
2022 - 31%
2023 - 39%
2024 - 42%
2025 - 42%

Self-Service Call Reductions
Annual decrease in calls to the Contact Center resulting from the implementation of new self-service functionality - IVR Virtual Assistants, new Web functionality, NLP, Speech Analytics

Reductions by Transaction (2021-2025)
MIMO - 324,000
Restores - 163,000
Promise to Pay - 119,000
High Bill Inquiries - 313,000
Total = 920,000

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.316f
Respondent:	A. Pizzuti
Page:	1 of 1

Question: f. Refer to page 49, lines 9-14 of Ms. Pizzuti's direct testimony. Please: Provide the amount of the $7.0 million in savings by year and the amount included in the projected test year and identify specifically in which exhibit and line item.

Answer: The savings are not reflected in the projected test year because they are assumed to offset other cost increases not separately identified. They are not included in this filing.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.316g
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 49, lines 9-14 of Ms. Pizzuti's direct testimony. Please:
g. Is the $7.0 million in O&M savings a commitment by the Company to reduce the revenue requirement or simply a target and a goal?

Answer: The $7.0 million in O&M is an aspirational goal by the Company based on its assessment of the opportunity provided through the targeted investments in the Digital and Voice self-service channels.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.287a
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 3, lines 21-25, and page 4, lines 1-7, of Ms. Pizzuti's direct testimony. Please:

a. Identify what the distinctive experiences are and who is providing these experiences that the Company wants to emulate.

Answer: We have identified through our benchmarking six Best-In-Class (BIC) customer experience design attributes that are necessary to deliver Transactional Excellence and provide distinctive levels of service (AMP-8; Figure 4), along with those companies that are recognized as best at incorporating these attributes into the design of their customer experiences.

BIC Design Attributes	Who Does It Best?
1. Simplicity	Rocket Mortgage
2. Convenience	Amazon
3. Interactivity	Nike
4. Desirability	Sephora
5. Seamlessness	Lemonade
6. Accountability	Domino's

Customer expectations have been evolving for years, with more and more of our customers comparing their DTE experiences to the experiences provided by companies such as those identified above. These best practices will inform the manner in which we design our customer interactions to ensure that we are creating distinctive experiences that meet customer expectations.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.293b
Respondent:	A. Pizzuti
Page:	1 of 2

Question: Refer to page 16, lines 6-26, and page 17, lines 1-14 of Ms. Pizzuti's direct testimony. Please:

b. Provide the specific goals and measures that the Company wants to achieve and describe how they compare to current levels.

Answer: As described in my direct testimony, investments in the Customer IT Portfolio are intended to create positive outcomes around three key areas of focus, with aspirational targets established for the associated outcome metrics for both the Customer Experience and Customer Affordability.

1. **Customer Experience –** How successfully we deliver distinctive levels of service will be measured based on the results of ongoing feedback from our customers, with a focus on four key metrics.

Outcome Metric	Description	2020 Actual	Aspiration
First Contact Resolution (FCR)	Percentage of customers who indicate their request was handled on the first contact	83%	90%
Transactional Satisfaction (TSAT)	Percentage of customers who indicate they are satisfied with their most recent experience	83%	90%
Net Promoter Score (NPS)	Difference between percent of customers who view DTE favorability and the percent who views DTE unfavorably	43	55+
MPSC Complaints	Total annual customer MPSC complaints	1,657	< 1,350

2. **Customer Affordability –** In addition to creating distinctive experiences, investments in the Customer IT Portfolio are intended to reduce the cost of service to customers, primarily through a focus on expanding self-service alternatives and reforming the collection experience. Success will be measured against four key metrics.

Outcome Metric	Description	2020 Actual	Aspiration
Self-Service Engagement Rate (%)	Percentage of transactions attempted in a self-service channel	53%	74%
Self-Service Completion Rate (%)	Percent of attempted self-service transactions successfully completed	89%	92%

Outcome Metric	Description	2020 Actual	Aspiration
Call Volume Reductions	Reduction in calls to the contact center versus 2020 baseline	Baseline	1.2 million
Self-Service O&M Savings	Reduction in contact center O&M expense versus 2020	Baseline	$7 million
Customer Arrears (Gas + Electric)	Total amount of Gas + Electric customer past due balances	$168 million	$94 million
UCX Expense (Gas + Electric)	Annual amount of customer past due balance write-offs	$96.7 million	$37.0 million

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.296c
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 21, lines 1-10 of Ms. Pizzuti's direct testimony. Please:
c. What stage in development is the Credential on File system currently and when is the planned implementation date?

Answer: Development of the Credential on File system has not begun yet and isn't scheduled to begin until 2022. The project will be implemented in 2022 with the exact date of implementation to be established pending completion of the final project plan.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.299a
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 28, lines 10-23, and page 29, lines 1-8 of Ms. Pizzuti's direct testimony. Please:

a. Identify what new specific products and services the Company plans to design.

Answer: The proposed capital spend and completion of the analytics model is not scheduled to occur until 2022, and as such we have not yet identified specific products and services that will result from the output and insights that the model will provide.

However, the model will provide insights into yet to be recognized enhancements to our existing offerings, and insight into new offerings currently not contemplated by our billing practice rules.

The Company will work closely with staff to collaborate on any improvements or new product offerings that are identified to ensure alignment on the anticipated customer benefits.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.299b
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 28, lines 10-23, and page 29, lines 1-8 of Ms. Pizzuti's direct testimony. Please:

b. Provide a copy of the cost/benefit analysis that shows this project is financially justified on a net present value basis.

Answer: As stated in my response to AGDG-9.288d, projects in the Customer IT Portfolio are assessed against desired key outcome metrics, and as such this project does not have a documented net present value analysis.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.298a
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 27, lines 21-25, and page 26, lines 1-9 of Ms. Pizzuti's direct testimony. Please:

a. Identify specifically what additional customer information the Company seeks to capture and the source of this information.

Answer: Analysis and identification of what additional data is needed is part of this effort, and will include a complete inventory of all of the currently captured customer information to determine what incremental data is required. The goal is to create personas for customers that will enable the Company to provide, as stated in my direct testimony, "personalized and proactive customer interactions and experiences".

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.298b
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 27, lines 21-25, and page 26, lines 1-9 of Ms. Pizzuti's direct testimony. Please:

b. Provide any evidence that the majority of the customers want the Company to have this non-billing information and what value it will bring to the Company

Answer: As indicated in my direct testimony, customers are comparing their DTE experiences to those of their other service providers, many of whom are using data and data analytics to create targeted communications and personalized experiences for their customers.

Personalization will allow the Company to better understand and service our customer needs. For example, based on personas we could inform a customer about a rate that could better suit their usage, or point them towards programs (e.g. EV) or additional rebates versus the customer having the seek them out on their own.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.298c
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 27, lines 21-25, and page 26, lines 1-9 of Ms. Pizzuti's direct testimony. Please:

c. Provide a copy of the cost/benefit analysis that shows this project is financially justified on a net present value basis.

Answer: As stated in my response to AGDG-9.288d, projects in the Customer IT Portfolio are assessed against desired key outcome metrics, and as such this project does not have a documented net present value analysis.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.305a
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 35, lines 4-14 of Ms. Pizzuti's direct testimony. Please:
a. Explain what the Business Rules Framework entails.

Answer: The Business Rules Framework Plus (BRF+) project re-designs the current customized dunning solution, which did not allow accounts to flow through dunning correctly. It also implements the standard SAP BRF+ rules engine as the sole means by which the dunning collection steps and associated activities are determined, thus ensuring the timely escalation of arrears through the collection strategy.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.305c
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 35, lines 4-14 of Ms. Pizzuti's direct testimony. Please:

c. Why was the SAP CR&P dunning system programmed to model existing DTE processes, which resulted in errors in the treatment and flow of accounts and manual intervention? When was this system implemented?

Answer: The purpose of the C360 project was to align the new SAP with DTE's business rules. The dunning process was no different. Customization was done to incorporate the collection rules for DTE at that time. Whenever possible, the Company attempted to avoid customization but there were processes the standard SAP product could not provide. BRF+ offers customization options the Company requires while still working within the standard SAP framework. April of 2017 was the C360 go live date that included the SAP CR&B dunning process.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.305d
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 35, lines 4-14 of Ms. Pizzuti's direct testimony. Please:

d. Why wasn't the standard SAP CR&B dunning rules engine not implemented initially

Answer: See response to AGDG-9.305c.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.313b
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 43, lines 9-25 of Ms. Pizzuti's direct testimony. Please
b. What financial benefits will this new system bring? How many employee positions will be eliminated?

Answer: As described in my direct testimony, this project is intended to provide builders and developers the ability to schedule their request on-line, to have full visibility into the status of their request, and to cascade this information to their project managers and contractors, providing them with a new and distinctive experience and increased levels of satisfaction.

While over time this will create efficiencies for customers and employees, who will have access to the same information, there is no expectation that this project will eliminate any employee positions.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.313c
Respondent:	A. Pizzuti
Page:	1 of 1

Question: c. Refer to page 43, lines 9-25 of Ms. Pizzuti's direct testimony. Please Provide a copy of the cost/benefit analysis that shows this project is financially justified on a net present value basis.

Answer: As stated in my response to AGDG-9.288d, projects in the Customer IT Portfolio are assessed against desired key outcome metrics, and as such this project does not have a documented net present value analysis.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.313d
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 43, lines 9-25 of Ms. Pizzuti's direct testimony. Please

d. How many new service requests have been done on-line versus other means since the start of the new system? When was this new system implemented?

Answer: As described in my direct testimony, after conceptually tested in a small pilot, the new portal was deployed on September 27, 2019 and further enhanced through the first half of 2020. The new portal was slowly rolled out to 16 builders through the first quarter of 2020 to assess its performance and to identify any defects and necessary enhancements. Due to the impact of the COVID pandemic on Company priorities, the remediation of identified defects and the required enhancements were put on hold, as was the planned expansion of the portal to additional customers. As such, the use of the portal remains limited to these 16 builders.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.315
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 46, lines 5-7 of Ms. Pizzuti's direct testimony. Please provide the basis for the 100,000 reduction in customer calls.

Answer: We estimate Virtual Assistants (VA) will contain between 20-50% of calls based on the complexity of the transaction. Stop transaction is a simpler transaction that generates roughly 200,000 calls to the contact center. We estimate 50% of the calls to be contained, which equates to 100,000 reduction in calls handled by CSR's as we optimize the performance of the VA.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.307a
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 38, lines 1-8 of Ms. Pizzuti's direct testimony. Please:
a. How much can the 70% be reduced with this new system?

Answer: It is our intent to reduce close to 500,000 calls to the Contact Center across the MIMO, Billing and Collections transactions by 2022, and an additional approximately 700,000 calls by 2025 for a total reduction of 1.2 million calls over the next five years.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-9.307b
Respondent:	A. Pizzuti
Page:	1 of 1

Question: Refer to page 38, lines 1-8 of Ms. Pizzuti's direct testimony. Please:
b. Quantify the number of billing inquiries that the Company estimates it can eliminate with this new system and the related cost savings.

Answer: Our intent is to leverage the benefits of the investments referenced on AMP 38, Lines 1-8 of my direct testimony to reduce billing calls by 10-20% over the next 5-years, which would result in 120,000 to 240,000 calls and an associated cost savings of $690,000 to $1.38 million.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.280
Respondent:	J. Busby
Page:	1 of 1

Question: Mr. Busby's direct testimony frequently refers to increased efficiencies and fewer employees that will be needed to perform various tasks as result of implementing the proposed IT projects. Please provide the total number of employee-positions that will be eliminated by the end of 2022. Please also provide the total cost savings that the Company expects to achieve in 2022 or future years as a result of the IT capital expenditures and system implementations proposed by Mr. Busby.

Answer: The goal with technology upgrades/enhancements and automation of currently manual processes is to help us eliminate process waste and increase productivity rather than to reduce employee headcount. This would enable the employees to focus on higher priority efforts.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.257
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 33, lines 4-5 of Mr. Busby's direct testimony. Please provide the number of employee positions and the total cost that can be eliminated in 2022 or in future years as a result of the more streamlined and efficient approach proposed.

Answer: The goal with automation of currently manual processes is to help us eliminate process waste and increase productivity rather than to reduce employee headcount. This would enable the employees to focus on higher priority efforts.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.271a
Respondent:	J. Busby
Page:	1 of 1

Question: Refer page 71, lines 1-20 of Mr. Busby's direct testimony. Please:

a. Provide the total cost for this project by year from inception to completion at the DTE level and the portion applicable to the gas business, the electric business, DTE Gas Gathering, and other affiliates.

Answer: Please see the response to question 254h.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.254h
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 21, lines 8-13 and page 22, lines 1-10 of Mr. Busby's direct testimony.

h. Provide the capital expenditures and number of units in Excel for each year actual 2018 to 2020 and forecasted 2021 to 2020 at the same level of detail as in Table 1.

Answer: Exhibit A-12 B5.4, B5.4.1, B5.16 and the corresponding detailed testimony is the available information on projects from 2019 through 2022. Additionally, workpaper U-20940 JJB WP-01 can be referenced for summary data from 2015 to 2019 .

2020 actuals to date are included in response to 282b. Please note this case introduces a dataset for Gas-IT projects that follow the precedent used in our Electric filings for data presentment.
For the number of units replaced please refer to the response to Q.254e

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.271d
Respondent:	J. Busby
Page:	1 of 1

Question: Refer page 71, lines 1-20 of Mr. Busby's direct testimony. Please:

d. Provide a copy of the cost/benefit analysis in Excel with formulas intact performed on this project showing a favorable net present value to justify undertaking the project.

Answer: Please refer to the response for Q8.265d

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.265d
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 57, lines 23-25, and page 58, of Mr. Busby's direct testimony. Please:

d. Provide a copy of the cost/benefit analysis in Excel with formulas intact performed on the Kronos project and the SuccessFactors projects showing a favorable net present value to justify undertaking the projects.

Answer: This information is not available in the requested format as DTE's consideration of costs and benefits occur over the processes mentioned in my direct testimony & the DTE Five-Year IT Plan. For cost consideration, please refer to A-13 C5.13, C5.13.1, C5.13.2 as well as testimony. For an accompanying analysis of benefits, please use the testimony analysis provided as well as the information in JJB WP-03.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.271b
Respondent:	J. Busby
Page:	1 of 1

Question: Refer page 71, lines 1-20 of Mr. Busby's direct testimony. Please:
b. Identify what the money will be spent on by major component.

Answer: This project is composed of two major components: Cloud Insights and Cloud Management. Cloud insights analyzes usage of cloud instances and provides information to identify cloud instances that are underutilized and can be disabled or scaled down in size and cost. Cloud Management leverages the Cloud Insights data around when cloud instances are being used and automatically disables cloud instances when they are not being used. Cloud Management also automates the initial creation of cloud instances, reducing the labor involved in that activity. The project costs are 50% for Cloud Insights and 50% for Cloud Management.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.271c
Respondent:	J. Busby
Page:	1 of 1

Question: Refer page 71, lines 1-20 of Mr. Busby's direct testimony. Please:

c. Confirm that this project is likely to pay for itself by avoiding current costs incurred for specialized labor and other costs. If not confirming, please explain.

Answer: In time, the elimination of current mentioned costs will result in the opportunity to redeploy funds to our many other competing priorities.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.275a
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 81, lines 6-21, and page 82 of Mr. Busby's direct testimony. Please:

a. Provide the total cost for this project by year from inception to completion at the DTE level and the portion applicable to the gas business, the electric business, DTE Gas Gathering, and other affiliates.

Answer: Please see the response to question 254h.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.254h
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 21, lines 8-13 and page 22, lines 1-10 of Mr. Busby's direct testimony.
h. Provide the capital expenditures and number of units in Excel for each year actual 2018 to 2020 and forecasted 2021 to 2020 at the same level of detail as in Table 1.

Answer: Exhibit A-12 B5.4, B5.4.1, B5.16 and the corresponding detailed testimony is the available information on projects from 2019 through 2022. Additionally, workpaper U-20940 JJB WP-01 can be referenced for summary data from 2015 to 2019 .

2020 actuals to date are included in response to 282b. Please note this case introduces a dataset for Gas-IT projects that follow the precedent used in our Electric filings for data presentment.
For the number of units replaced please refer to the response to Q.254e

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.275c
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 81, lines 6-21, and page 82 of Mr. Busby's direct testimony. Please:

c. Identify the gap between the system and the channels.

Answer: This project will enable monitoring for the interactions between the billing system and the Customers/Customer Representatives as well as for interactions between the billing system and other systems/applications.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.275g
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 81, lines 6-21, and page 82 of Mr. Busby's direct testimony. Please:

g. Provide a copy of the cost/benefit analysis in Excel with formulas intact performed on this project showing a favorable net present value to justify undertaking the project.

Answer: Please refer to the response for Q.265d

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.276a
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 83, lines 22-25, and page 84 of Mr. Busby's direct testimony. Please:

a. Provide the total cost for this project by year from inception to completion at the DTE level and the portion applicable to the gas business, the electric business, DTE Gas Gathering, and other affiliates.

Answer: Please see the response to question 254h.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.276b
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 83, lines 22-25, and page 84 of Mr. Busby's direct testimony. Please:

b. Explain what the money will be spent on by major component.

Answer: $4.0 million for ongoing support and maintenance of legacy applications over 24-months ending December 31, 2022. Agency Web Site (AGW), Interactive Voice Recognition (IVR), old billing systems in read only mode (CSB, KCS) and Enterprise Service Bus (ESB) are some of the important system that fall in this category.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.276c
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 83, lines 22-25, and page 84 of Mr. Busby's direct testimony. Please:

c. Explain why these costs are not included in O&M expense if the project entails system support and maintenance.

Answer: These are capital costs that support enhancements for extending existing capabilities that are not covered by system support and maintenance.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.277b
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 85, lines 1-18 of Mr. Busby's direct testimony. Please:
b. Identify the non-metered products that the Company is offering currently and others that it plans to offer in the future that require the Hybris Application.

Answer: The Hybris Application supports the following non-metered Products: TreeGuard Assurance, Surge Protection, and Natural Gas Balance.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.274a
Respondent:	J. Busby
Page:	1 of 1

Question: Refer page 79, lines 4-79, and page 80, lines 1-11 of Mr. Busby's direct testimony. Please:

a. Provide the total cost for this project by year from inception to completion at the DTE level and the portion applicable to the gas business, the electric business, DTE Gas Gathering, and other affiliates.

Answer: Please see the response to question 254h.

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.274c
Respondent:	J. Busby
Page:	1 of 1

Question: Refer page 79, lines 4-79, and page 80, lines 1-11 of Mr. Busby's direct testimony. Please:

c. Explain how the Company Private Cloud differs for other on-premise systems at the Company Data Centers.

Answer: DTE's current on premise systems are primarily based on virtualization technologies and platforms (VMWare). Virtualization technologies enable application consolidation on less hardware but provides a limited management toolset. Human intervention or heavy investment in third party scripting toolsets are required to achieve automation and eliminate manual tasks. DTE's private cloud implementation is implemented using a computing platform that combines automation and management capabilities in one vendor toolset that is more 'turnkey'.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.274d
Respondent:	J. Busby
Page:	1 of 1

Question: Refer page 79, lines 4-79, and page 80, lines 1-11 of Mr. Busby's direct testimony. Please:

d. Why is it essential for the Company to be at the leading edge of vendor technology instead of waiting until the technology is proven and mature, and prices decline.

Answer: This is a mischaracterization of the information presented in testimony and is not in context.

On page 79, line 15, the testimony indicates that private cloud use has been active for a considerable time in this market and became noticeably an increasingly common by 2015. Now, in 2021, the Company is looking to leverage tested technology that has become market-leading. Please see page 79 line 11 through page 80 line 8 for enumerated benefits of DTE joining its peers in the adoption of this proven technology.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.274f
Respondent:	J. Busby
Page:	1 of 1

Question: Refer page 79, lines 4-79, and page 80, lines 1-11 of Mr. Busby's direct testimony. Please:
f. Provide a copy of the cost/benefit analysis in Excel with formulas intact performed on this project showing a favorable net present value to justify undertaking the project.

Answer: Please refer to the response for Q.265d

Attachments: *None*

MPSC Case No.:	U-20940
Requestor:	AG
Question No.:	AGDG-8.265d
Respondent:	J. Busby
Page:	1 of 1

Question: Refer to page 57, lines 23-25, and page 58, of Mr. Busby's direct testimony. Please:

d. Provide a copy of the cost/benefit analysis in Excel with formulas intact performed on the Kronos project and the SuccessFactors projects showing a favorable net present value to justify undertaking the projects.

Answer: This information is not available in the requested format as DTE's consideration of costs and benefits occur over the processes mentioned in my direct testimony & the DTE Five-Year IT Plan. For cost consideration, please refer to A-13 C5.13, C5.13.1, C5.13.2 as well as testimony. For an accompanying analysis of benefits, please use the testimony analysis provided as well as the information in JJB WP-03.

Attachments: None

MPSC Case No.:	U-20940
Requestor:	T. McMillan-Sepkoski
Question No.:	TMS-5.2
Respondent:	M. Cooper/T. Uzenski
Page:	1 of 1

Question: Please fill in the attached Excel spreadsheet concerning Capitalized and O&M Expense Incentive Compensation included in the rate base revenue requirement.

Answer: See attached file. Page 1 provides the capital and O&M incentives included in the projected test period for LTIP, AIP and REP financial and operating measures at DTE Gas and their share of DTE LLC.

Attachments: *U-20940 TMS-5.2 Capitalized-O&M IC Worksheet.xls*

MICHIGAN PUBLIC SERVICE COMMISSION
Regulated Energy Division
Co: DTE Gas Company
Case No: U-20940
Amounts in $000's

Case No. U-20940
Audit Request: TMS-5.2
Date Received: 3/31/2021
Respondents: T. M. Uzenski, M. C. Cooper
Page: 1 of 4

CAPITALIZED INCENTIVE COMPENSATION EXPENSE
Estimated Projected Average Rate Base Impact
Projected Test Period December 31, 2022

	LTIP Performance Shares	LTIP Restricted Stock	AIP	REP	TOTAL	FERC Account (see page 4 of this attachment) Utility Plant (Acct 101,107)	Accum Depr. (Acct 108)	Net Utility Plant
FINANCIAL								
DTE Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DTE LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OPERATING								
DTE Gas	$ -	$ -	$ 618	$ 4,409	$ 5,027	$ 5,280	$ (253)	$ 5,027
DTE LLC	$ -	$ -	$ 1,522	$ 2,800	$ 4,321	$ 4,550	$ (228)	$ 4,321
	$ -	$ -	$ 2,140	$ 7,208	$ 9,348	$ 9,829	$ (481)	$ 9,348
TOTAL								
DTE Gas	$ -	$ -	$ 618	$ 4,409	$ 5,027	$ 5,280	$ (253)	$ 5,027
DTE LLC	$ -	$ -	$ 1,522	$ 2,800	$ 4,321	$ 4,550	$ (228)	$ 4,321
	$ -	$ -	$ 2,140	$ 7,208	$ 9,348	$ 9,829	$ (481)	$ 9,348

Effective with U-20642 Rate Order, incentives tied to financial measures cannot be capitalized. Above represents cumulative incentives tied to operating measures in rate base for 2019-22.

O&M INCENTIVE COMPENSATION EXPENSE*
Projected Test Period 12 Months Ended December 2022

	LTIP Performance Shares	LTIP Restricted Stock	AIP	REP	TOTAL
FINANCIAL					
DTE Gas	$ 2,138	$ 217	$ 297	$ 2,185	4,839
DTE LLC	$ 4,024	$ 943	$ 979	$ 2,108	8,053
	$ 6,162	$ 1,160	$ 1,277	$ 4,293	$ 12,892
OPERATING					
DTE Gas	$ -	$ -	$ 243	$ 1,784	2,027
DTE LLC	$ -	$ -	$ 1,034	$ 2,225	3,259
	$ -	$ -	$ 1,277	$ 4,009	$ 5,286
TOTAL					
DTE Gas	$ 2,138	$ 217	$ 540	$ 3,969	6,865
DTE LLC	$ 4,024	$ 943	$ 2,013	$ 4,333	11,312
	$ 6,162	$ 1,160	$ 2,553	$ 8,302	$ 18,178

*FERC account classification is provided on page 2 of this attachment.

MICHIGAN PUBLIC SERVICE COMMISSION
Regulated Energy Division
Co: DTE Gas Company
Case No: U-20940
Amounts in $000's

Case No. U-20940
Audit Request: TMS-5.2
Date Received: 3/31/2021
Respondent: T. M. Uzenski, M. C. Cooper
Page: 2 of 4

O&M INCENTIVE COMPENSATION EXPENSE
Reconciliation of Actual Incentives to Projected Test Period
with Estimated FERC Account classification

							Ratemaking Adjustments and Eliminations								*Projected 12 Mo. Ending 12/31/2022*	
	FERC Account Classification	Actuals Booked 12 Mo Ended 12/31/2019	Eliminate Top 5 O&M	Normalize to 100% payout	Mark to Market Normalization	Previously Capitalized	Eliminate Top 5 Capital	Eliminate EWR Program	Subtotal Adjustments 12/31/2019	Normalized 12 Mo Ended 12/31/2019	Inflation 2020 2.8%	Inflation 2021 2.9%	Inflation 2022 3.0%	Projected 12 Mo Ending 12/31/2022	*LTIP Performance Shares*	*LTIP Restricted Stock*
LTIP																
Financial Measures																
DTE Gas	Storage (814-837)	101							-	101	3	3	3	110	*99*	*10*
	Transmission (850-867)	327							-	327	9	10	10	356	*323*	*33*
	Distribution (870-894)	1,326							-	1,326	37	40	42	1,445	*1,312*	*133*
	Sales (912)	144							-	144	4	4	5	156	*142*	*14*
	Customer Accts/Svcs (901-910)	-						(6)	(6)	(6)	(0)	(0)	(0)	(7)	*(6)*	*(1)*
	Admin & General (920)*	-	-	-	(598)	870	-	-	272	272	8	8	9	296	*269*	*27*
	Subtotal DTE Gas	1,897	-	-	(598)	870	-	(6)	265	2,162	61	64	69	2,356	*2,138*	*217*
DTE LLC	Customer Accts/Svcs (901-910)	50						(14)	(14)	37	1	1	1	40	*32*	*8*
	Admin & General (920)*	5,508	(2,072)	-	(267)	2,224	(871)	-	(986)	4,522	127	135	143	4,926	*3,991*	*935*
	Subtotal DTE LLC	5,558	(2,072)	-	(267)	2,224	(871)	(14)	(1,000)	4,558	128	136	145	4,966	*4,024*	*943*
	Total LTIP	7,455	(2,072)	-	(866)	3,094	(871)	(20)	(735)	6,720	188	200	213	7,322	*6,162*	*1,160*
AIP/REP															*Financial*	*Financial*
Financial Measures															*AIP*	*REP*
DTE Gas	Storage (814-837)	74							-	74	2	2	2	81	*10*	*71*
	Transmission (850-867)	242							-	242	7	7	8	263	*32*	*232*
	Distribution (870-894)	846							-	846	24	25	27	922	*110*	*812*
	Sales (912)	96							-	96	3	3	3	104	*12*	*92*
	Customer Accts/Svcs (901-910)							(6)	(6)	(6)	(0)	(0)	(0)	(6)	*(1)*	*(6)*
	Admin & General (920)*	-	-	(14)	-	1,041	-	-	1,027	1,027	29	31	33	1,119	*134*	*985*
	Subtotal DTE Gas	1,258	-	(14)	-	1,041	-	(6)	1,021	2,279	64	68	72	2,483	*297*	*2,185*
DTE LLC	Customer Accts/Svcs (901-910)	1,306						(20)	(20)	1,287	36	38	41	1,402	*445*	*957*
	Admin & General (920)*	1,051	(221)	(129)	-	938	(93)	-	496	1,547	43	46	49	1,686	*535*	*1,151*
	Subtotal DTE LLC	2,357	(221)	(129)	-	938	(93)	(20)	477	2,834	79	84	90	3,087	*979*	*2,108*
	Total AIP/REP-Financial	3,615	(221)	(143)	-	1,980	(93)	(26)	1,498	5,112	143	152	162	5,570	*1,277*	*4,293*
AIP/REP															*Operating*	*Operating*
Operating Measures															*AIP*	*REP*
DTE Gas	Storage (814-837)	111							-	111	3	3	4	121	*14*	*106*
	Transmission (850-867)	362							-	362	10	11	11	395	*47*	*348*
	Distribution (870-894)	1,269							-	1,269	36	38	40	1,383	*166*	*1,217*
	Sales (912)	144							-	144	4	4	5	157	*19*	*138*
	Customer Accts/Svcs (901-910)	-						(5)	(5)	(5)	(0)	(0)	(0)	(5)	*(1)*	*(5)*
	Admin & General (920)*	-	-	(21)	-	-	-	-	(21)	(21)	(1)	(1)	(1)	(23)	*(3)*	*(20)*
	Subtotal DTE Gas	1,886	-	(21)	-	-	-	(5)	(26)	1,860	52	55	59	2,027	*243*	*1,784*
DTE LLC	Customer Accts/Svcs (901-910)	1,959						(21)	(21)	1,939	54	58	62	2,112	*670*	*1,442*
	Admin & General (920)*	1,576	(331)	(193)	-	139	(139)	-	(524)	1,053	29	31	33	1,147	*364*	*783*
	Subtotal DTE LLC	3,536	(331)	(193)	-	139	(139)	(21)	(544)	2,991	84	89	95	3,259	*1,034*	*2,225*
	Total AIP/REP-Operating	5,422	(331)	(214)	-	139	(139)	(25)	(571)	4,851	136	145	154	5,286	*1,277*	*4,009*
	Grand Total Incentives	16,491	(2,624)	(357)	(866)	5,213	(1,104)	(71)	192	16,684	467	497	529	18,178		
			A	B	B	C	A	D		E						

Crosscheck to page 1

LTIP Performance Shares	LTIP Restricted Stock	LTIP Total	Check
$ 2,138	$ 217	$ 2,356	$ 0
$ 4,024	$ 943	$ 4,966	$ (0)
6,162	1,160	7,322	0
-	-		
Financial AIP	Financial REP	AIP/REP Total	Check
$ 297	$ 2,185	$ 2,483	$ 0
$ 979	$ 2,108	$ 3,087	$ (0)
1,277	4,293	5,570	(0)
-	-		
Operating AIP	Operating REP	AIP/REP Total	Check
$ 243	$ 1,784	$ 2,027	$ 0
$ 1,034	$ 2,225	$ 3,259	$ (0)
1,277	4,009	5,286	(0)
-	-		
		18,178	$ (0)

Reconciliation to Exhibit A-13, C5.6, Page 1

A= footnote 1	(3,727)
B = footnote 2	(1,223)
C = footnote 2	5,213

Reconciliation to Exhibit A-3 C17

A-3 C17	16,754	
EWR elim	(71)	D = within Cust Service normalization A-13 C5.4
Rounding	1	
TMS-5.3	16,684	E = normalized 2019

*Historical ratemaking normalization and elimination adjustments are made to account 920 for simplicity, except for EWR elimination which is Customer Accounts (901-910).

MICHIGAN PUBLIC SERVICE COMMISSION
Regulated Energy Division
Co: DTE Gas Company
Case No: U-20940
Amounts in $000's

Case No. U-20940
Audit Request: TMS-5.2
Date Received: 3/31/2021
Respondent: T. M. Uzenski, M. C. Cooper
Page: 3 of 4

CAPITALIZED INCENTIVE COMPENSATION EXPENSE
TIED TO OPERATING MEASURES ONLY
Annual Capitalized Incentives (2019 Estimated Actual and 2020-22 Projected)

	2019 Actual			Estimated 2020-22 Projected (based on normalized 2019 plus inflation)								
	Actuals Booked 12 Mo Ended 12/31/2019	Disallowed Financial Measures 1/	**Est. Actual 12 Mo Ended 12/31/2019**	Actuals Booked 12 Mo Ended 12/31/2019	Normalize to 100% payout	Mark to Market Normalization	Financial measures now expense 2/	Subtotal Adjustments	Normalized 12 Mo Ended 12/31/2019	**Inflated 12 Mo Ended 12/31/2020** 2.8%	**Inflated 12 Mo Ended 12/31/2021** 2.9%	**Inflated 12 Mo Ended 12/31/2022** 3.0%
DTE GAS												
LTIP Performance Shares	$ 1,191	$ (1,191)	$ -	$ 1,191		(401)	$ (790)	(1,191)	$ -	$ -	$ -	$ -
LTIP Restricted Stock	$ 80	$ (80)	$ -	$ 80			$ (80)	(80)	$ -	$ -	$ -	$ -
AIP	$ 348	$ (200)	$ 148	$ 348	$ (30)		$ (127)	(157)	$ 191	$ 196	$ 202	$ 208
REP	$ 2,286	$ (1,263)	$ 1,023	$ 2,286	$ -	$ -	$ (914)	(914)	$ 1,371	$ 1,410	$ 1,451	$ 1,494
	$ 3,904	$ (2,733)	$ 1,171	$ 3,904	$ (30)	$ (401)	$ (1,911)	$ (2,342)	$ 1,562	$ 1,606	$ 1,652	$ 1,702
DTE LLC												
LTIP Performance Shares	$ 1,850	$ (1,850)	$ -	$ 1,850		(112)	$ (1,737)	(1,850)	$ -	$ -	$ -	$ -
LTIP Restricted Stock	$ 487	$ (487)	$ -	$ 487			$ (487)	(487)	$ -	$ -	$ -	$ -
AIP	$ 1,048	$ (514)	$ 534	$ 1,048	$ (135)		$ (504)	(640)	$ 408	$ 420	$ 432	$ 445
REP	$ 1,433	$ (753)	$ 680	$ 1,433	$ -	$ -	$ (573)	(573)	$ 860	$ 884	$ 910	$ 937
	$ 4,818	$ (3,604)	$ 1,214	$ 4,818	$ (135)	$ (112)	$ (3,302)	$ (3,550)	$ 1,268	$ 1,304	$ 1,341	$ 1,382
TOTAL												
LTIP Performance Shares	$ 3,040	$ (3,040)	$ -	$ 3,040	$ -	$ (513)	$ (2,527)	$ (3,040)	$ -	$ -	$ -	$ -
LTIP Restricted Stock	$ 567	$ (567)	$ -	$ 567	$ -	$ -	$ (567)	$ (567)	$ -	$ -	$ -	$ -
AIP	$ 1,396	$ (714)	$ 681	$ 1,396	$ (165)	$ -	$ (632)	$ (797)	$ 599	$ 616	$ 634	$ 653
REP	$ 3,719	$ (2,016)	$ 1,703	$ 3,719	$ -	$ -	$ (1,487)	$ (1,487)	$ 2,231	$ 2,294	$ 2,360	$ 2,431
	$ 8,722	$ (6,337)	**$ 2,384**	$ 8,722	$ (165)	$ (513)	$ (5,213)	$ (5,892)	$ 2,830	**$ 2,909**	**$ 2,994**	**$ 3,084**

1/ Disallowed rate base included on Exhibit A-4, Schedule B4.2, column (n), line 3 = $11,033 ($4,685 + $6,337 for 2018 and 2019, respectively)

2/ Reclassified to O&M. Normalized 2019 AIP/REP assumes measures will be based on 40% financial and 60% operating.

MICHIGAN PUBLIC SERVICE COMMISSION
Regulated Energy Division
Co: DTE Gas Company
Case No: U-20940
Amounts in $000's

Case No. U-20940
Audit Request: TMS-5.2
Date Received: 3/31/2021
Respondent: T. M. Uzenski, M. C. Cooper
Page: 4 of 4

CAPITALIZED INCENTIVE COMPENSATION EXPENSE
TIED TO OPERATING MEASURES ONLY
Estimated Impact on Projected Average Rate Base 12/31/2022
with FERC Account Classification

		Est. Actual Balance 12/31/2019	Projected Balance 12/31/2020	Projected Balance 12/31/2021	Projected Balance 12/31/2022	Projected Average Rate Base 12/31/2022
Gas Plant Account 101						
DTE Gas	AIP	$ 148	$ 344	$ 545	$ 753	$ 649
	REP	$ 1,023	$ 2,433	$ 3,883	$ 5,377	$ 4,630
	Total DTE Gas	$ 1,171	$ 2,777	$ 4,429	$ 6,131	$ 5,280
DTE LLC	AIP	$ 534	$ 953	$ 1,385	$ 1,830	$ 1,608
	REP	$ 680	$ 1,564	$ 2,473	$ 3,410	$ 2,942
	Total DTE LLC	$ 1,214	$ 2,517	$ 3,859	$ 5,240	$ 4,550
Total Plant Account 101		**$ 2,384**	**$ 5,294**	**$ 8,288**	**$ 11,371**	**$ 9,829**
Accum Depr 108						
DTE Gas	AIP	$ (2)	$ (9)	$ (22)	$ (41)	$ (31)
	REP	$ (15)	$ (64)	$ (155)	$ (288)	$ (222)
	Total DTE Gas	$ (17)	$ (74)	$ (177)	$ (329)	$ (253)
DTE LLC	AIP	$ (8)	$ (29)	$ (63)	$ (109)	$ (86)
	REP	$ (10)	$ (42)	$ (100)	$ (185)	$ (142)
	Total DTE LLC	$ (17)	$ (71)	$ (163)	$ (294)	$ (228)
Total Accum Depr Account 108		**$ (34)**	**$ (145)**	**$ (340)**	**$ (623)**	**$ (481)**
Net Plant						
DTE Gas	AIP	$ 146	$ 335	$ 523	$ 713	$ 618
	REP	$ 1,008	$ 2,368	$ 3,728	$ 5,089	$ 4,409
	Total DTE Gas	$ 1,154	$ 2,703	$ 4,252	$ 5,802	$ 5,027
DTE LLC	AIP	$ 526	$ 924	$ 1,323	$ 1,721	$ 1,522
	REP	$ 670	$ 1,522	$ 2,373	$ 3,226	$ 2,800
	Total DTE LLC	$ 1,196	$ 2,446	$ 3,696	$ 4,947	$ 4,321
Total Net Plant		**$ 2,350**	**$ 5,149**	**$ 7,948**	**$ 10,748**	**$ 9,348**

Annual Capital Expenditures & Depreciation Expense

		Est. Actual CY 2019	Projected CY 2020	Projected CY 2021	Projected CY 2022
Incentives Capitalized (TMS-5.3 page 3)					
DTE Gas	AIP	$ 148	$ 196	$ 202	$ 208
	REP	$ 1,023	$ 1,410	$ 1,451	$ 1,494
	Total DTE Gas	$ 1,171	$ 1,606	$ 1,652	$ 1,702
DTE LLC	AIP	$ 534	$ 420	$ 432	$ 445
	REP	$ 680	$ 884	$ 910	$ 937
	Total DTE LLC	$ 1,214	$ 1,304	$ 1,341	$ 1,382
Total Incentives Capitalized		**$ 2,384**	**$ 2,909**	**$ 2,994**	**$ 3,084**
Depreciation Expense					
DTE Gas	AIP	$ 2	$ 7	$ 13	$ 19
	REP	$ 15	$ 50	$ 91	$ 133
	Total DTE Gas	$ 17	$ 57	$ 104	$ 152
DTE LLC	AIP	$ 8	$ 21	$ 34	$ 46
	REP	$ 10	$ 32	$ 58	$ 85
	Total DTE LLC	$ 17	$ 54	$ 92	$ 131
Total Depreciation Expense		**$ 34**	**$ 110**	**$ 195**	**$ 283**
Composite Depr Rate (WP TMU-10)		2.88%	2.88%	2.88%	2.88%

AIP and REP Operating Measure Results - DTE Gas

			Performance Results [1]									
			AIP					REP				
Line No.	Category	Measure	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020
1	**Customer Satisfaction**											
2		Customer Satisfaction Index	0.0%	175.0%	0.0%	80.1%	0.0%	0.0%	150.0%	0.0%	86.8%	0.0%
3												
4		Customer Satisfaction										
5		Improvement Program (DPMO)	0.0%	103.0%	0.0%	96.9%	175.0%	0.0%	102.0%	0.0%	97.9%	150.0%
6												
7		Customer Satisfaction										
8		Improvement Program (+1PMO)	NA	NA	56.2%	0.0%	0.0%	NA	NA	70.8%	0.0%	0.0%
9												
10		MPSC Customer Complaints	101.0%	0.0%	0.0%	36.5%	175.0%	100.7%	0.0%	0.0%	57.7%	150.0%
11												
12	**Employee Engagement**											
13		DTE Gas Employee Engagement-Gallup	115.0%	90.6%	108.7%	117.3%	57.1%	NA	NA	NA	NA	NA
14												
15		DTE Gas OSHA Recordable										
16		Incident Rate	175.0%	96.7%	126.8%	36.7%	175.0%	150.0%	97.8%	117.9%	57.8%	150.0%
17												
18		DTE Gas OSHA DART Rate	175.0%	0.0%	175.0%	0.0%	131.3%	150.0%	0.0%	150.0%	0.0%	120.8%
19												
20		National Safety Council Barometer Survey	NA	156.3%	NA	137.5%	NA	NA	NA	NA	NA	NA
21												
22	**Operating Excellence**											
23		Gas Distribution System Improvement	175.0%	165.9%	175.0%	175.0%	0.0%	150.0%	143.9%	150.0%	150.0%	0.0%
24												
25		Gas Distribution Response Time	49.0%	118.8%	76.0%	55.7%	160.0%	66.0%	112.5%	84.0%	70.5%	140.0%
26												
27		Lost and Unaccounted for Gas	175.0%	0.0%	0.0%	0.0%	25.0%	150.0%	0.0%	0.0%	0.0%	50.0%
28												
29		Gas Compression Reliability	137.5%	175.0%	175.0%	149.5%	175.0%	125.0%	150.0%	150.0%	133.0%	150.0%
30												
31		Gas Damage Prevention Effectiveness	0.0%	0.0%	0.0%	175.0%	60.6%	0.0%	0.0%	0.0%	150.0%	73.8%
32												
33		Gas Transmission Reliability	175.0%	175.0%	175.0%	NA	NA	150.0%	150.0%	150.0%	NA	NA
34												
35		Meter Assembly Check Backlog	NA	NA	NA	94.3%	118.2%	NA	NA	NA	96.2%	112.1%
36												
37		Less than Threshold	3	4	5	3	3	3	4	5	3	3
38		Between Threshold and Less Than Target	1	2	2	6	3	1	1	2	6	2
39		Target	0	0	0	0	0	0	0	0	0	0
40		Between Target and Maximum	3	4	2	3	3	2	3	1	1	3
41		Maximum	5	3	4	2	4	5	3	4	2	4
42			12	13	13	14	13	11	11	12	12	12
43												
44		Sum	12.78	12.56	10.68	11.55	12.52	10.42	9.06	8.73	9.00	10.97
45												
46		Number of Measures	12	13	13	14	13	11	11	12	12	12
47												
48		Average	106.5%	96.6%	82.1%	82.5%	96.3%	94.7%	82.4%	72.7%	75.0%	91.4%
49												
50	**Performance Measures Achieved at Target or Better**											
51		**Number of Measures**	**3**	**4**	**2**	**3**	**3**	**2**	**3**	**1**	**1**	**3**
52		**Percentage of Total Operating Measures**	**25%**	**31%**	**15%**	**21%**	**23%**	**18%**	**27%**	**8%**	**8%**	**25%**
53		(Line 51 / Line 46)										
54		**Five Year Average Percentage Achieved at Target Level or Better**										**20.3%**

Source: (1) AGDG-7.243

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company

Exhibit AG-73
Case No. U-20940
Date: June 3, 2021

Computation of Revenue Deficiency for Projected Test Year Ending December 2022

($000)

Line	Description (a)	Company Filed Amount (b)	AG Recommended Adjustments (c)	Revised Amount (d)
1	Rate Base [1]	$ 5,610,642	$ (134,638)	$ 5,476,004
2	Rate of Return	5.59%	-0.38%	5.21%
3	Income Required	$ 313,781	$ (28,481)	$ 285,300
4	Adjusted Net Operating Income [2]	169,973	101,312	271,285
5	Income Deficiency (Sufficiency)	$ 143,808	$ (129,793)	$ 14,015
6	Revenue Multiplier	1.3547	1.3547	1.3547
7	**Revenue Deficiency (Sufficiency)**	**$ 194,817**	**$ (175,831)**	**$ 18,986**

[1] Rate Base Adjustments Exhibit AG-20

[2] AG adjustments to Operating Income: Increase (Decrease)

			Source
Revenue		$ 43,662	Exhibit AG-47
O&M Expenses		$ 84,500	Exhibit AG-51
Uncollectible Accounts Expense		$ 4,341	Exhibit AG-50
Depreciation Expense		$ 5,405	Exhibit AG-19
Total		$ 137,908	
Effective Tax Rate (1-1/1.3547)	26.18%		
Taxes		(36,108)	
Interest Synchronization on Capital Adjustments		(487)	RevDef-WP1
Adjusted Net Operating Income		$ 101,312	

PROOF OF SERVICE - U-20940

The undersigned certifies that a copy of the ***Attorney General's Testimony and Exhibits of Sebastian Coppola*** was served upon the parties listed below by e-mailing the same to them at their respective e-mail addresses on the 3rd day of June 2021.

Joel King Digitally signed by Joel King
Date: 2021.06.03 19:55:07
-04'00'

Joel B. King

MPSC Staff:
Michael Orris
Heather Durian
Daniel Sonneveldt
Lori Mayabb
Monica Stephens
orrism@michigan.gov
durianh@michigan.gov
sonneveldtd@michigan.gov
mayabbl@michigan.gov
stephensm11@michigan.gov

ALJ:
Hon. Sally Wallace
Wallaces2@michigan.gov

Attorney General of Michigan:
Joel King
Kingj38@michigan.gov
ag-enra-spec-lit@michigan.gov

Sebastian Coppola
sebcoppola@corplytics.com

Douglas Jester
djester@5lakesenergy.com

MPLP/RESA:
Jennifer Heston
jheston@fraserlawfirm.com

ABATE:
Stephen Campbell
Michael Pattwell
scampbell@clarkhill.com
mpattwell@clarkhill.com

Vicinity Energy:
Arthur LeVasseur
levasseur@fischerfranklin.com

DTE Energy Company:
Paula Johnson-Bacon
David Maquera
Andrea Hayden
Lauren Donofrio
Jon Christinidis
Paula.bacon@dteenergy.com
David.maquera@dteenergy.com
Andrea.hayden@dteenergy.com
Lauren.donofrio@dteenergy.com
Jon.christinidis@dteenergy.com
mpscfilings@dteenergy.com

Energy Michigan Inc.:
Tim Lundgren
Laura Chappelle
Justin Ooms
tjlundgren@varnumlaw.com
lachappelle@varnumlaw.com
jkooms@varnumlaw.com

Detroit Thermal:
Arthur LeVasseur
Steve Manz
levasseur@fischerfranklin.com
smanz@ETAmail.com

CUB:
John Liskey
john@liskeypllc.com

Dearborn Industrial Generation LLC:
Sean Gallagher
sean@legalspg.com

RCG:
Don Keskey
Brian Coyer
donkeskey@publiclawresourcecenter.com
bwcoyer@publiclawresourcecenter.com