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STATE OF MICHIGAN  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application  
of CONSUMERS ENERGY COMPANY for  
authority to increase its rates  
for the distribution of natural  
gas and for other relief.

Case No. U-21806

VOLUME III

\*\* PUBLIC \*\*

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CROSS-EXAMINATION

Proceedings held via Microsoft Teams in  
the above-entitled matter before James M. Varchetti,  
Administrative Law Judge with MOAHR, for the Michigan  
Public Service Commission, Lansing, Michigan, on Friday,  
May 30, 2025, at 9:05 a.m.

APPEARANCES:

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Consumers Energy Company

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On behalf of Consumers Energy Company

(Appearances continued)

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6 On behalf of Michigan Public Service Commission Staff

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14 On behalf of Michigan Environmental Council and  
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23 On behalf of Citizens Utility Board of Michigan (CUB)  
and Michigan Environmental Council

24  
25 (Appearances continued)

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8           Lansing, Michigan 48933  
9           On behalf of Michigan State University (MSU) and  
            Lansing Board of Water and Light (LBWL)

10  
11          REPORTED BY: Dawn M. Houghton, CSR-3071

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A-80	Summary of Actual & Projected O&M Expenses, Gas Engineering and Supply	346	541	
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Friday, May 30, 2025

9:05 AM Eastern

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(Hearing resumes following adjournment of Thursday,  
May 29, 2025)

JUDGE VARCHETTI: We're now on the record. Good morning, everyone. We are back on the record again in Case U-21806 captioned in the matter of the application of Consumers Energy Company for authority to increase its rates for the distribution of natural gas and for other relief.

Today is the day and time scheduled for the second day of cross-examination in this case. My name is James Varchetti. I'm the Administrative Law Judge with the Michigan Office of Administrative Hearings and Rules that has been assigned to be the presiding officer in this matter. I'll note that we're holding this hearing as a video conference via the Microsoft Teams platform.

I'd like to start by asking the attorneys present to place their appearances on the record, starting with counsel for Consumers Energy.

MR. GENSCH: Yes. Good morning, Your Honor. Gary Gensch on behalf of Consumers Energy Company. Also appearing is Bret Totoraitis, Anne Uitvlugt, Spencer

1 Sattler, Evan Keimach, and Mark Ruszkiewicz.

2 JUDGE VARCHETTI: Thank you. And good  
3 morning, Mr. Gensch.

4 Next, who's appearing today on behalf  
5 of the Commission Staff?

6 MS. STIRLING: Good morning, Your  
7 Honor. Anna Stirling on behalf of the Michigan Public  
8 Service Commission Staff. Also appearing as attorneys of  
9 record in this case are Alena Clark, Michael Orris, and  
10 Amit Singh.

11 JUDGE VARCHETTI: Thank you. And good  
12 morning.

13 Next, who's appearing today on behalf  
14 of the Attorney General?

15 MS. GILL: Good morning, Your Honor.  
16 Celeste Gill on behalf of Attorney General Dana Nessel.

17 JUDGE VARCHETTI: Thank you. And good  
18 morning.

19 Next, who is appearing today on behalf  
20 of the Retail Energy Supply Association?

21 I am hearing no one, so we will move  
22 on.

23 Who is appearing today on behalf of the  
24 Michigan Environmental Council and Sierra Club?

25 MR. BZDOK: Good morning, Your Honor.

1 Christopher Bzdok on behalf of the Michigan Environmental  
2 Council, along with Holly Hillyer on behalf of the  
3 Michigan Environmental Council, and Nihal Shrinath on  
4 behalf of Sierra Club, and myself on behalf of Sierra  
5 Club, and I'll defer to Ms. Hillyer for the rest.

6 JUDGE VARCHETTI: Thank you. And good  
7 morning.

8 And who is appearing today on behalf of  
9 the Citizens Utility Board?

10 MS. HILLYER: Good morning, Your Honor.  
11 Holly Hillyer appearing on behalf of the Citizens Utility  
12 Board of Michigan.

13 JUDGE VARCHETTI: Thank you. Good  
14 morning.

15 And who is appearing today on behalf of  
16 the Association of Businesses Advocating for Tariff  
17 Equity?

18 MR. CAMPBELL: Good morning, Your  
19 Honor. Steve Campbell, Clark Hill, PLC, on behalf of the  
20 Association of Businesses Advocating Tariff Equity.

21 JUDGE VARCHETTI: Thank you. And good  
22 morning.

23 Who is appearing today on behalf of the  
24 Lansing Board of Water and Light and Michigan State  
25 University?

1 MR. VACANTE: Good morning. Joe  
2 Vacante with Dickinson Wright appearing on behalf of the  
3 Michigan State University and Lansing Board of Water and  
4 Light.

5 JUDGE VARCHETTI: Thank you. And good  
6 morning.

7 And who is appearing today on behalf of  
8 Energy Michigan?

9 I am not hearing anyone, so I will move  
10 on.

11 And who is appearing today on behalf of  
12 the group of organizations known as The Clean Energy  
13 Organizations?

14 I'm not hearing anyone, so I will move  
15 on.

16 Do we have any other appearances or is  
17 there anyone that I missed?

18 I am not hearing anyone so I assume  
19 that we have everyone.

20 All right. So like I mentioned, this  
21 is date and time scheduled for the second day of  
22 cross-examination in this case.

23 My understanding is that there is one  
24 witness to be crossed today, and since that is the case, I  
25 would like to turn over -- turn over the floor to you,

1 Mr. Gensch, and you can call the first witness.

2 MR. GENSCH: Thank you, Your Honor.

3 Consumers Energy calls Kristine A. Pascarello.

4 THE REPORTER: Would you raise your  
5 right hand, please.

6 Do you solemnly swear the testimony you  
7 will give in this matter will be the truth, the whole  
8 truth, and nothing but the truth, so help you God?

9 MS. PASCARELLO: I do.

10 KRISTINE A. PASCARELLO,

11 HAVING BEEN CALLED BY THE COMPANY AND SWORN:

12 DIRECT EXAMINATION

13 BY MR. GENSCH:

14 Q. Ms. Pascarello, would you please state your full name for  
15 the record.

16 A. Kristine Pascarello.

17 Q. And by whom are you employed?

18 A. Consumers Energy.

19 Q. And what is your job title with Consumers Energy?

20 A. Senior gas -- senior strategy manager and gas strategy.

21 Q. And did you cause to be prepared a document entitled  
22 direct testimony of Kristine A. Pascarello on behalf of  
23 Consumers Energy which consists of a cover page and 87  
24 pages of questions and answers?

25 A. Yes.

1 Q. And did you also cause to be prepared a document entitled  
2 rebuttal testimony of Kristine A. Pascarello on behalf of  
3 Consumers Energy which consists of a cover page and 36  
4 pages of questions and answers?

5 A. Yes.

6 Q. Are there any changes that you wish to make at this time  
7 to any of your testimony?

8 A. No.

9 Q. And is this the testimony you are adopting as your own  
10 today?

11 A. Yes.

12 Q. Did you also cause to be prepared a number of exhibits  
13 associated with your testimony?

14 A. Yes.

15 Q. Are those exhibits marked as Exhibits A-80, A-81, A-12  
16 Schedule B-5.8, A-82, A-83, A-84, A-85, and A-138 through  
17 A-142?

18 A. Yes.

19 Q. Do you have any changes that you wish to make today to any  
20 of those exhibits?

21 A. No.

22 MR. GENSCH: At this time, Your Honor,  
23 the Company moves to bind in the direct and rebuttal  
24 testimony of Kristine A. Pascarello, and for the admission  
25 at the end of cross-examination of the identified

1 exhibits.

2 JUDGE VARCHETTI: Thank you. Are there  
3 any objections to the binding in of Ms. Pascarello's  
4 direct or rebuttal testimony?

5 I am hearing none, so the direct and  
6 rebuttal testimony of Ms. Pascarello will be bound into  
7 the record.

8 (Direct and Rebuttal Testimony bound in)

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STATE OF MICHIGAN  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of )  
**CONSUMERS ENERGY COMPANY** )  
for authority to increase its rates for the )  
distribution of natural gas and for other relief. )  
\_\_\_\_\_ )

Case No. U-21806

**DIRECT TESTIMONY**  
**OF**  
**KRISTINE A. PASCARELLO**  
**ON BEHALF OF**  
**CONSUMERS ENERGY COMPANY**

December 2024

KRISTINE A. PASCARELLO  
U-21806 DIRECT TESTIMONY

1 **Q. Please state your name and business address.**

2 A. My name is Kristine A. Pascarello, and my business address is 1945 West Parnall Road,  
3 Jackson, Michigan 49201.

4 **Q. By whom are you employed?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”).

6 **Q. What is your current position with Consumers Energy?**

7 A. I am a Senior Strategy Manager in the Gas Strategy department within Gas Engineering  
8 and Supply. I have held this position since July 2019.

9 **Q. What are your responsibilities as Senior Strategy Manager?**

10 A. I perform the asset lifecycle oversight, guidance, and leadership of the Natural Gas  
11 Delivery Plan (“NGDP”) development, implementation, recovery, and verification of  
12 results focused on the Distribution assets.

13 **Q. What other relevant experience do you have?**

14 A. I have worked for Consumers Energy for 25 years. I have been a Senior Strategy Manager  
15 in Gas Engineering and Supply since 2019. I have also served the Company as a Project  
16 Manager, Deployment Lead, Senior Engineer Lead, and Engineer. Prior to becoming a  
17 Senior Strategy Manager, I spent 10 years on the Smart Energy Advanced Metering  
18 Infrastructure (“AMI”) and Gas Automated Meter Reading (“AMR”) project teams where  
19 I was responsible for leading field implementation activities required to install electric  
20 smart meters and gas communication modules. This involved business process redesign  
21 and system requirements definition, working with a wide variety of stakeholders including  
22 customers, municipalities, and various Company departments such as Field Operations,  
23 Supply Chain, Customer Contact Center, Rates, Damage Claims, and Security, and

KRISTINE A. PASCARELLO  
U-21806 DIRECT TESTIMONY

1 successfully implementing new technology while delivering a high-quality customer  
2 experience. I was also the contract administrator and Company supervisor for the meter  
3 installation vendor. Before joining the AMI/AMR projects, I was in the Gas Engineering  
4 department. I was the Gas Measurement Lead for 2.5 years, the Electrical, Instrumentation,  
5 and Controls (“EI&C”) Lead for 5 years, and a General/Senior Engineer for 2.5 years. As  
6 the Gas Measurement Lead, I led the Measurement Center of Excellence, was responsible  
7 for Lost and Unaccounted for Gas (“LAUF”) projects including the development of  
8 standardized gas measurement processes, and the monitoring of LAUF, including  
9 implementation of Flow-Cal gas measurement software. During my 7.5 years as the EI&C  
10 Lead/Engineer, I was responsible for project management and electrical design of the  
11 Company’s natural gas facilities, including managing the Gas Transmission and  
12 Distribution Supervisory Control and Data Acquisition (“SCADA”) system designs and  
13 installations. Prior to joining Consumers Energy, I worked as an Electrical Engineer at  
14 Dart Container for four years where I was responsible for machine control design,  
15 including PLC programming and variable frequency drives. I started my career as an  
16 Electrical Engineer at Florida United Engineers, where I was a contract Electrical Engineer  
17 for Florida Power & Light specializing in generation power distribution processes and  
18 power plant control/alarm designs for seven years. I have a total of 36 years of experience,  
19 with 32 years in the utility industry.

20 **Q. Are you a member of any professional societies or trade associations?**

21 A. Yes. I am currently a member of the Engineering Society of Detroit. I am also a certified  
22 Project Manager through the Project Management Institute (“PMI”). I have represented  
23 the Company at the American Gas Association (“AGA”) where I served as a Distribution

KRISTINE A. PASCARELLO  
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1 Measurement Committee (“DMC”) officer, chaired the AMI/AMR subcommittee, and  
2 delivered presentations during conferences. I have also served on the American National  
3 Standards Institute (“ANSI”) B109 working committee.

4 **Q. What is your formal educational experience?**

5 A. I graduated from Lake Superior State University with a Bachelor of Science degree in  
6 Electrical Engineering Technology. I graduated with an Associate of Science degree in  
7 Electronics from Lansing Community College. I also hold Master and Associate  
8 Certificates in Project Management from George Washington University, and Gas  
9 Measurement Fundamentals Certification from the Gas Certification Institute. In addition,  
10 I passed the Fundamentals of Engineering exam in 2004.

11 **Q. Have you previously testified before the Michigan Public Service Commission**  
12 **(“MPSC” or the “Commission”)?**

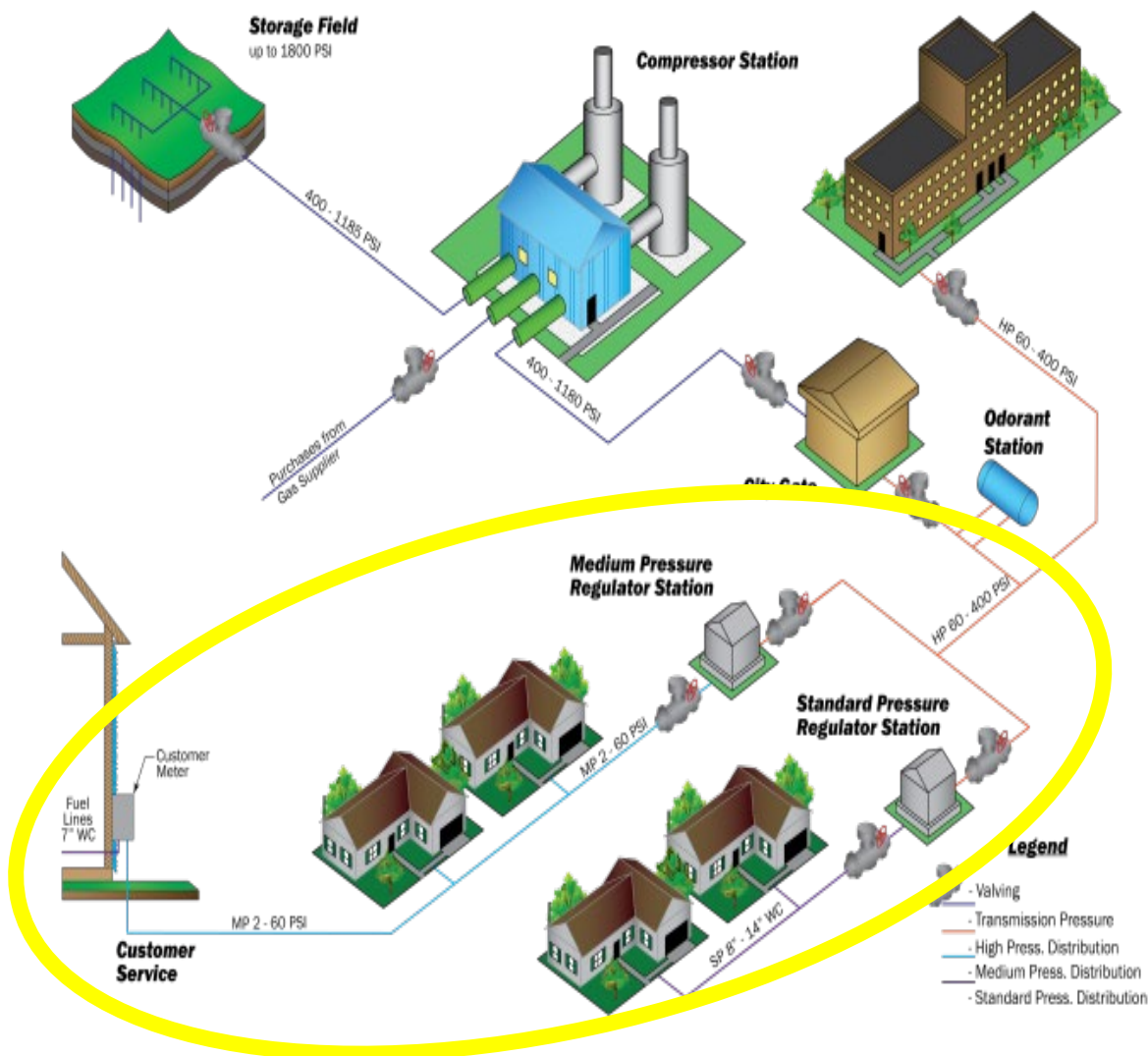
13 A. Yes, I testified in Case Nos. U-20893, U-21148, U-21308, and U-21490.

14 **Q. What is the purpose of your direct testimony?**

15 A. The purpose of my direct testimony is to explain the Company’s request for rate relief as  
16 it relates to Gas Engineering and Supply (“GE&S”) Operating and Maintenance (“O&M”)   
17 expenses, and certain gas distribution capital investments that are intended to keep the  
18 system safe and reliable while providing affordable and clean energy to customers. The  
19 Company’s sustainable and equitable approach to gas distribution investment benefits all  
20 customers, including our more vulnerable populations, with cleaner and safer  
21 infrastructure. This includes engineering, strategy, and gas supply for this system as well  
22 as gas control of the transmission system. The distribution assets are the portion of the  
23 Company system that receives the gas at the outlet of the Company’s city gates and delivers

KRISTINE A. PASCARELLO  
U-21806 DIRECT TESTIMONY

1 the gas to customers, a portion of which is monitored by Gas Control. In the diagram  
2 below, these assets are inside the yellow highlighted section.



3 These expenditures are primarily related to the operation of the Company's gas mains,  
4 services, and meters downstream of the city gates. These investments will ensure the  
5 continued safe delivery of gas through this system to customers.

6 I have divided my direct testimony into two parts: (i) a description of the O&M  
7 expenses related to the Company's GE&S department; and (ii) a description of the  
8 Company's gas distribution capital expenditures that I am sponsoring for 2023, 2024, the

KRISTINE A. PASCARELLO  
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1 10 months ending October 31, 2025, and for the projected test year 12 months ending  
2 October 31, 2026. My direct testimony covers the capital cost for the Material Condition  
3 and Gas Operations Other programs. The remaining capital programs for Distribution are  
4 sponsored by Company witness Lincoln D. Warriner.

5 **Q. How does your direct testimony relate to the NGDP presented by Company witness**  
6 **Neal P. Dreisig?**

7 A. Mr. Dreisig's direct testimony discusses the Company's NGDP. My direct testimony  
8 contains elements that support the objectives of the NGDP: providing gas supply that is  
9 safe, reliable, affordable, and clean. The GE&S department is responsible for the  
10 engineering, design, strategy, project management, construction support, and gas supply  
11 and control associated with execution of the NGDP. The distribution capital programs  
12 represented in my direct testimony work toward achieving the NGDP's objectives of  
13 eliminating vintage materials and leaks, as well as providing safe and reliable service.

14 **Q. Are you sponsoring any exhibits?**

15 A. Yes. I am sponsoring the following exhibits:

16	Exhibit A-80 (KAP-1)	Summary of Actual & Projected 17 O&M Expenses, Gas Engineering 18 and Supply;
19	Exhibit A-81 (KAP-2)	Detailed Summary of Actual & 20 Projected O&M Expenses, Gas 21 Engineering and Supply;
22	Exhibit A-12 (KAP-3)	Schedule B-5.8 Projected Capital Expenditures, 23 Distribution Plant – Material 24 Condition and Gas Operations Other, 25 Summary of Actual & Projected Gas 26 and Common Capital Expenditures;

KRISTINE A. PASCARELLO  
U-21806 DIRECT TESTIMONY

1	Exhibit A-82 (KAP-4)	Actual & Projected Gas Capital
2		Expenditures - Material Condition
3		Program;
4	Exhibit A-83 (KAP-5)	Actual & Projected Gas & Common
5		Capital Expenditures - Gas
6		Operations Other Program;
7	Exhibit A-84 (KAP-6)	Detailed Summary of Actual and
8		Projected Capital Expenses –
9		Enhanced Infrastructure
10		Replacement Program;
11	Exhibit A-85 (KAP-7)	Projected Capital Expenditures -
12		Distribution Plant - Material
13		Condition and Gas Operations Other,
14		Summary of Actual & Projected Gas
15		and Common Capital Expenditures.

16 **Q. Were these exhibits prepared by you or under your direction and supervision?**

17 A. Yes.

18 **Q. Please summarize your direct testimony.**

19 A. First, I will address the reasonable and necessary O&M expenses for the Company's GE&S  
20 department, which are described on Exhibit A-80 (KAP-1). The total O&M expenses were  
21 \$16,014,000 in 2023; and are projected to be \$20,694,000 for 2024; \$22,530,000 for 2025;  
22 and \$22,195,000 for the test year 12 months ending October 31, 2026, as set forth on this  
23 exhibit on line 5, columns (b) through (e).

24 Second, my direct testimony also represents certain Gas Distribution capital  
25 investments through October 31, 2026, which are described on Exhibit A-12 (KAP-3),  
26 Schedule B-5.8. The total Gas Distribution capital expenditures represented by this direct  
27 testimony were \$274,046,000 in 2023 and are projected to be \$301,775,000 for 2024;  
28 \$313,809,000 for the 10 months ending October 31, 2025; and \$402,755,000 for the

KRISTINE A. PASCARELLO  
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1 projected test year 12 months ending October 31, 2026; as set forth on this exhibit on line 3,  
2 columns (b), (c), (d), and (f), respectively.

3 **Q. Were there any organization changes impacting GE&S for this case?**

4 A. Yes. Company reorganizations in 2024 have restructured certain departments to better  
5 align with strategic goals. The following changes occurred in 2024.

- 6 • Effective May 1, 2024, the Company reorganized the Quality Lean office to  
7 enhance collaboration, alignment, and accelerate the maturity of the CE Way.  
8 This reorganization resulted in the formation of three teams within the Quality  
9 Lean Office: Design and Strategy, Industrial Engineering, and the Quality  
10 Improvement Center of Excellence. A total of 63 co-workers were impacted by  
11 this change, with 31 of them being assigned to the Gas Quality Lean team.
- 12 • Effective May 31, 2024, the Gas Compression & Storage technicians  
13 transitioned from Gas Compression Operations to the GE&S Gas Engineering  
14 - Transmission department joining the Measurement, Regulation and Controls  
15 (“MR&C”) team. The 2023 historical and 2024 January through May O&M  
16 expenses of \$346,131 and \$129,292, respectively, for the Gas Compression &  
17 Storage technicians are included in Company Witness Timothy K. Joyce’s  
18 Exhibit-72 (TKJ-1), line 1. The projected June through December 2024 expense  
19 of \$196,544 and projected future O&M expenses are included within the Gas  
20 Engineering - Transmission expenses shown on Exhibit-81 (KAP-2), line 3.
- 21 • Effective August 1, 2024, the Enterprise Corrective Action Program (“ECAP”)  
22 department was moved into the Quality Lean Office. The historical 2023 O&M  
23 expenses for this department were \$207,865 and are split between GE&S  
24 (\$53,555) and Gas Operations (\$154,310) due to the 2023 reorganization  
25 described later in this testimony. The 2024 projected O&M expenses for the  
26 ECAP department are \$116,133 and are included within Exhibit-81 (KAP-2)  
27 with the January through July 2024 O&M expenses of \$64,461 represented in  
28 line 13. The August through December 2024 O&M expenses of \$51,672 and  
29 projected future O&M expenses are included in the Project Management and  
30 Quality Lean Office expenses shown on line 1.
- 31 • Effective August 1, 2024, the Operational Technology (“OT”) Gas SCADA  
32 team responsible for gas SCADA development, including operations and 24/7  
33 support, transitioned to Gas Management Services joining the Gas Control team  
34 from the IT&S-OT Critical Applications team. This change will streamline the  
35 interface between Gas SCADA and 24/7 gas control operational needs and  
36 improve support of construction activities. The 2023 historical and January  
37 through July 2024 O&M expenses of \$68,992 and \$31,948, respectively for the  
38 OT Gas SCADA team are included in Company Witness Stacy H. Baker’s  
39 Exhibit-17 (SHB-1), line 1. The projected O&M expense of \$24,000 for August

KRISTINE A. PASCARELLO  
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1 through December 2024 and projected future O&M expenses are included in  
2 the Gas Management Services expenses on Exhibit-81 (KAP-2), line 15.

3 **Q. How has the Company projected its O&M expenses for 2024, 2025, and the test year**  
4 **12 months ending October 31, 2026?**

5 A. The Company has projected its O&M expenses to meet customer service and safety  
6 requirements. This projection considers several factors, including annual merit increases  
7 for the GE&S department, Company reorganizations, and specific program expenses  
8 necessary to ensure customer safety, meet regulatory requirements, and provide reliable  
9 service to customers. The Company started with the historic 2023 O&M expenses, which  
10 include GE&S personnel assigned to the department for the full year. In 2023, a  
11 reorganization of the Gas Operations Compliance and Controls (“OCC”) department added  
12 new personnel to the GE&S department. However, these new staff members are only  
13 partially included in the GE&S historic expenses. As part of the 2023 Company  
14 reorganization, the Damage Claims/Prevention, ECAP, and Advanced Methane Detection  
15 (“AMD”) personnel were added to GE&S. Due to this reorganization, the January through  
16 August 2023 historical O&M expenses for these departments are included in Company  
17 witness James P. Pnacek’s Exhibit A-89 (JPP-4), page 3, line 1, Compliance and Controls  
18 and the September through December 2023 expenses are included in Exhibit A-81  
19 (KAP-2). To project the O&M expenses accurately, the full-year salaries and expenses for  
20 the new staff members added during the reorganization were used to account for the full-  
21 year impact of the additional staffing from the reorganization. The Company then applied  
22 merit increases to labor, keeping non-labor expenses flat unless specific new expenses,  
23 such as software licensing, were added, to the historic 2023 O&M expenses. The projected  
24 expenses reflect the full-year costs of the reorganized staffing levels, ensuring a

KRISTINE A. PASCARELLO  
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1 comprehensive projection for 2024, 2025, and the test year ending October 31, 2026. The  
2 test year projections are included in Exhibit A-81 (KAP-2). Lastly, the projection  
3 methodologies vary among the different O&M programs and are described within each  
4 respective section later in this direct testimony.

5 **Q. Please describe the methodology used to project the Company's Gas Distribution**  
6 **capital expenditures for the years 2024 through the 12 months ending October 31,**  
7 **2026.**

8 A. The projected capital expenditures for this period are based on projected costs for  
9 individual projects and programs, using historical costs and adjusting for market conditions  
10 impacting areas such as materials and outside services, necessary to ensure customer  
11 safety, meet regulatory requirements, and provide reliable service to customers. The  
12 projection methodology is based on the monthly cash flow average percentage, using the  
13 three-year historical period of 2021 through 2023.

14 **GAS ENGINEERING AND SUPPLY DEPARTMENT O&M EXPENSES**

15 **Q. Please explain the source of the 2023 actual O&M expenses for the GE&S department**  
16 **expenses shown on Exhibit A-80 (KAP-1), line 5.**

17 A. The 2023 actual O&M expense amount of \$16,014,000 for the GE&S department was  
18 taken from Consumers Energy's internal reporting records. This total amount includes  
19 both labor and non-labor O&M expenses for this department, and the labor, material,  
20 contractor, non-labor overheads, and other non-labor expenses are detailed on Exhibit  
21 A-81 (KAP-2), pages 1 through 4. The 2023 level of expense allowed the Company to  
22 provide the engineering and support needed to serve 1.8 million natural gas customers and  
23 complete reasonable and necessary investments in 2023. The projected expenses for 2024  
24 are \$20,694,000; for 2025 are \$22,530,000; and for the test year 12 months ending

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1 October 31, 2026, are \$22,195,000 as shown on Exhibit A-80 (KAP-1), line 5, columns  
2 (c), (d), and (e), respectively. The calculation of expenses in the test year of this case is  
3 further described below.

4 **Q. Please explain the derivation of the GE&S department O&M expenses for the test**  
5 **year as shown on Exhibit A-80 (KAP-1), line 5, column (e).**

6 A. First, the Company has projected expenses for engineering and supply personnel, including  
7 departmental changes resulting from Company reorganizations described earlier in my  
8 testimony, to implement the investment in the gas system replacement as described in the  
9 NGDP. These changes result in a net increase of 27 GE&S staff members for 2024, with  
10 the total staffing levels for 2023, 2024, 2025, 2026, and the test year ending October 31,  
11 2026, being 588, 615, 615, 615, and 615, respectively. Each department within GE&S  
12 analyzed the work activities and factored in productivity improvements to determine the  
13 necessary number of employees. The analysis helps determine the appropriate percentage  
14 of capital and O&M expenses for each department. The O&M percentage for each  
15 department is applied to the total department projected expenses to derive the O&M portion  
16 shown in Exhibit A-80 (KAP-1) and detailed in Exhibit A-81 (KAP-2). This staff will be  
17 responsible for engineering planning, engineering design, permitting, and construction  
18 support for the gas system enhancements as well as gas compliance, geospatial  
19 management, strategy, damage claims/prevention, enterprise corrective action, gas control,  
20 supply, transport and customer choice, and system and operations planning.

21 Second, the Company also has projected O&M expenses for the Storage Integrity  
22 Management Program (“SIMP”), the AMD Program, and the Geospatial Inventory and

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1 Modeling Program. The details of these programs and the associated O&M expenses are  
2 described later in this testimony.

3 The resulting projected costs for the 12 months ending October 31, 2026 are  
4 \$22,195,000, and can be found on Exhibit A-81 (KAP-2), page 4, line 16,  
5 column (e). These expense levels for the GE&S department will allow the Company to  
6 meet customer service, deliverability, and safety requirements in the test year.

7 **Q. Are there any Employee Incentive Compensation Program (“EICP”) O&M expense**  
8 **dollars included in your exhibits?**

9 A. No, there are not. The direct testimony and exhibits of Company witness Amy M. Conrad  
10 contain the EICP O&M expense dollars.

11 **Q. Please briefly describe each of the departments within GE&S, as listed on Exhibit**  
12 **A-81 (KAP-2).**

13 A. GE&S is described in four major departments:

- 14 • Gas Project Management and Quality Lean Office;
- 15 • Gas Asset Management – Consists of Gas Engineering - Distribution, Gas  
16 Engineering – Transmission, Gas Engineering Asset Planning, System  
17 Integrity, which includes SIMP, and Gas Compression Engineering;
- 18 • Gas Engineering Support – Consists of Gas Strategy, Gas Regulatory and  
19 Compliance, which includes the AMD Program, Geospatial Management and  
20 Data Quality, which includes the Geospatial Inventory and Modeling Program,  
21 Damage Claims/Prevention, and Engineering Management; and
- 22 • Gas Management Services.

23 **Q. Please briefly describe pages 5 through 7 of Exhibit A-81 (KAP-2).**

24 A. Pages 5 through 7 of Exhibit A-81 (KAP-2) is provided to present the amounts of the O&M  
25 expenses I am sponsoring. Column (b) shows the historical O&M expense and column (j)  
26 is the projected test year O&M expense. Column (i) represents the increase (or decrease)

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1 in O&M expenses. The expenses that I am supporting are based upon the expenses  
2 necessary to comply with regulations and improve system safety as described for the  
3 programs below and have not been projected utilizing inflation factors.

4 **Q. Please describe the activities of the Gas Project Management and Quality Lean**  
5 **departments.**

6 A. Gas Project Management provides project oversight and management for certain programs  
7 and projects that are required by the business or directly for a customer. These programs  
8 and projects are usually large or complex in nature and require project management  
9 methodology to ensure predictable results. The Gas Project Management team includes  
10 Company-employed and contract project managers who oversee projects and ensure that  
11 each project meets the intended scope, schedule, and cost projection.

12 The Quality Lean department is responsible for the Company's quality  
13 management system. This department establishes and maintains standards, processes,  
14 procedures, and policies that ensure both Company and regulatory requirements are  
15 consistently met. Key responsibilities include developing and implementing standards,  
16 processes, procedures, and policies, supporting overall business efficiency by reducing  
17 waste and errors, and enhancing customer satisfaction by addressing potential or identified  
18 non-conformances. This department facilitates activities involved in evaluating and  
19 improving enterprise-wide processes through Value Stream Assessments. These  
20 assessments help identify continuous improvement opportunities, which are then addressed  
21 using the CE Way Lean Toolbox. In August 2024, the ECAP was integrated into the  
22 Quality Lean organization. Initiated at Consumers Energy in 2020, ECAP is an  
23 enterprise-wide issue management and compliance program designed to support safe and

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1 excellent operations. The structured platform and methodology allow for transparency in  
2 reporting issues, identifying trends, and closing compliance and safety gaps through  
3 corrective actions and controls, based upon associated risk thresholds. ECAP's  
4 functionality for managing processes and performance, as well as analyzing data, focuses  
5 risk reduction efforts, informs operational business decisions, and promotes the integrity  
6 and deliverability of the energy infrastructure. Starting in 2022, ECAP supported  
7 stakeholders in Gas Operations and Engineering to maintain adherence to GSMS standards  
8 established in American Petroleum Institute Recommended Practice ("API RP") 1173.  
9 ECAP is responsible for the management of an integrated safety assurance approach to  
10 proactively sustain and assess the needs of the Company's operational compliance  
11 performance. The program implements a common process and technology that fully  
12 integrates corrective and preventative action ("CAPA") management. CAPA is a  
13 fundamental tool in the Company's quality management systems to support the elimination  
14 or prevention of non-conformances and that process is supported by a strong problem-  
15 solving structure. This organizational change will enable continued strengthening in the  
16 use of the CE Way and bring together the quality management platform which is the  
17 Company's system of record for documenting potential or identified non-conformances.

18 The projected O&M expenses for Gas Project Management is \$1,132,000 and the  
19 Quality Lean department is \$2,020,000 for the 12 months ending October 31, 2026, totaling  
20 \$3,152,000, as shown on Exhibit A-81 (KAP-2), page 1, line 1, and consists of the O&M  
21 portion of the salaries and expenses for project managers, performance managers, and their  
22 Company-employed and contracted support staff. The increase from 2023 historic year is  
23 due to the 2024 Company reorganizations of the Quality Lean department in May and the

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1 ECAP team in August as described earlier in my testimony. The support staff for Gas  
2 Project Management ensures project schedules are produced, tracks project expenses,  
3 provides construction oversight and inspection, and ensures appropriate resources are  
4 available for the project. The Quality Lean staff ensures quality management  
5 implementation in planning and execution of work.

6 **Q. What operating sections are included in the Gas Asset Management department?**

7 A. The Gas Asset Management department consists of all engineering and technical support  
8 for planning, designing, performing risk assessment, and construction support of the  
9 transmission mainlines, distribution mains, storage laterals and wells, service lines, meter  
10 installations, regulating stations, compressor stations, and other infrastructure involved in  
11 delivering natural gas to customers safely and reliably. Gas Asset Management consists of  
12 five sub departments that I will describe more fully below. They are:

- 13 • Gas Engineering – Distribution;
- 14 • Gas Engineering – Transmission;
- 15 • Gas Engineering Asset Planning;
- 16 • System Integrity; and
- 17 • Gas Compression Engineering.

18 The employees within Gas Asset Management provide gas engineering and asset planning  
19 for the compression, storage, transmission, and distribution pipelines, large metering,  
20 regulation, and measurement assets, along with directing compliance-related programs  
21 such as System Integrity, supporting the Company objectives of supplying safe, reliable,  
22 affordable, and clean energy to customers. Gas Asset Management provides necessary  
23 expertise and services in the areas of distribution and transmission system risk,

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1 engineering, and technical design standards, performs system load studies, and initiates  
2 augmentation projects to ensure the capacity of the gas distribution system can meet  
3 projected customer demands. Additionally, this area provides the technical expertise and  
4 coordination for public infrastructure projects initiated by third parties, such as cities,  
5 Michigan Department of Transportation (“DOT”), and large new industrial customers. Gas  
6 Asset Management includes System Integrity, which implements the SIMP, and is  
7 responsible for the storage wells and pipelines within the storage fields. Gas Compression  
8 Engineering is also a part of Gas Asset Management and is responsible for engineering of  
9 the Company’s compressor station assets. The salaries and expenses of all the Gas Asset  
10 Management teams described above and the expenses for the SIMP for the 12 months  
11 ending October 31, 2026, are represented on Exhibit A-81 (KAP-2), pages 1 and 2, lines 2  
12 through 7.

13 **Q. Please describe the activities of the Gas Engineering - Distribution department.**

14 A. The Gas Engineering - Distribution department consists of four sections. First, the  
15 Distribution Pipeline Engineering team is responsible for the design of all new and  
16 replacement gas mains and services across the Company’s distribution system including  
17 customer requested service work. Second, the Gas System Engineering team is responsible  
18 for emergent engineering projects and operational support across the Company’s  
19 distribution system. Third, the Design Quality and Contracts team is responsible for  
20 ensuring consistent and high-quality designs through review and coaching for the design  
21 technicians in Distribution Pipeline Engineering. The Design Quality and Contracts team  
22 also works on process development and technology improvement projects to make design  
23 teams more efficient. Additionally, this team owns the contracts for any outside

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1 engineering services needed to support the Distribution Engineering team. Fourth, the  
2 Distribution Engineering Services team is responsible for field support and field GPS data  
3 collection on installed gas distribution assets. The projected O&M expenses for the Gas  
4 Engineering – Distribution department for the 12 months ending October 31, 2026 is  
5 \$730,000, as shown on Exhibit A-81 (KAP-2), page 1, line 2, and consists of the O&M  
6 portion of the salaries and expenses for engineers, designers, analysts, and other support  
7 staff needed to meet the design and planning needs of the NGDP.

8 **Q. Please describe the activities of the Gas Engineering - Transmission department.**

9 A. The Gas Engineering - Transmission department contains two sections. First, the  
10 Transmission Pipeline Engineering section is responsible for the engineering and design of  
11 the Company's transmission and storage pipeline facilities and supports the following  
12 transmission pipeline capital programs: Asset Relocation-Transmission, Deliverability  
13 Base Pipeline, Maximum Allowable Operating Pressure ("MAOP") Pipeline, MAOP  
14 Transmission (O&M), and Transmission Enhancements for Deliverability & Integrity  
15 ("TED-I"). The Transmission Engineering employees have responsibility for improving  
16 the pipeline system and ensuring compliance with applicable regulations. The second  
17 section is the MR&C team. MR&C is responsible for the engineering, design, and  
18 technical support of the Company's regulator stations, city gates, odorizers, and large  
19 customer meters through the following capital programs: Transmission City Gates,  
20 Distribution Regulator Stations, MAOP Metering & Regulation, and Deliverability Based  
21 Field Measurement. As described above, the Gas Compression & Storage technicians have  
22 been integrated into the MR&C team. The technicians are essential for maintaining the  
23 efficiency and safety of the gas system, ensuring smooth operations and quick responses

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1 to any issues that arise. This team performs critical work in monitoring, maintaining, and  
2 installing equipment in the gas system. Key duties include performing SCADA  
3 hardware/software monitoring, equipment inspections, configuration and commissioning  
4 of new equipment, providing technical support to Gas Operations staff, and ensuring work  
5 complies with policies, procedures, relevant safety standards, and regulations. My  
6 testimony covers the labor and expense costs for staffing of the Gas Engineering -  
7 Transmission department. The capital programs described above are sponsored by  
8 Company witness Michael P. Griffin. The projected O&M expenses for the Gas  
9 Engineering – Transmission department for the 12 months ending October 31, 2026 is  
10 \$2,387,000, as shown on Exhibit A-81 (KAP-2), page 1, line 3, and consists of the O&M  
11 portion of the salaries and expenses for engineers, designers, analysts, technicians, and  
12 other support staff needed to meet the design and planning needs of the NGDP and the  
13 O&M expense for the purchase of odorant. The increase from 2023 historic year is due to  
14 the 2024 Company reorganization which moved the Gas Compression and Storage  
15 technicians to the MR&C team as described earlier in my testimony.

16 **Q. Please describe the activities of the Gas Engineering Asset Planning department.**

17 A. Gas Engineering Asset Planning is responsible for the development of long-range  
18 engineering programs, such as Gas Enhanced Infrastructure Replacement Program  
19 (“EIRP”) and Vintage Service Replacement (“VSR”), as well as coordination of annual  
20 projects across engineering organizations. Gas Engineering Asset Planning partners with  
21 Gas Operations and Gas Distribution Engineering to develop long-range projects. In  
22 addition, Gas Engineering Asset Planning partners with Gas Strategy to develop the  
23 NGDP. Gas Engineering Asset Planning is responsible for securing Right-of-Way permits

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1 for current Gas Distribution construction projects and works to negotiate favorable  
2 permitting requirements for future work. Gas Engineering Asset Planning is responsible  
3 for aligning project schedules and outages across asset classes, such as transmission and  
4 distribution, to create efficiencies and reduce the impact on customers. Gas Engineering  
5 Asset Planning is also responsible for the engineering and coordination of the Asset  
6 Relocation – Civic Program, as well as Distribution – Augment and Distribution –  
7 Compliance Base. The projected O&M expenses for the Gas Engineering Asset Planning  
8 department for the 12 months ending October 31, 2026, is \$396,000 as shown on Exhibit  
9 A-81 (KAP-2), page 1, line 4, and consists of the O&M portion of the salaries and expenses  
10 for engineers, designers, analysts, and other support staff needed to complete the necessary  
11 engineering planning and permitting of projects outlined in the NGDP.

12 **Q. Please describe the activities of the System Integrity department.**

13 A. System Integrity is responsible for the integrity management programs for the Company.  
14 This includes the following programs: Transmission Integrity Management Program  
15 (“TIMP”), Distribution Integrity Management Program (“DIMP”), and SIMP. These  
16 programs ensure the integrity of the Transmission, Distribution, and Storage Assets. My  
17 testimony covers the labor and expense costs for staffing of the System Integrity  
18 department and the O&M expenses for the SIMP. The other System Integrity programs  
19 described above are sponsored by Company witnesses Griffin and Joyce. The projected  
20 O&M expenses for the System Integrity department for the 12 months ending October 31,  
21 2026 is \$3,789,000, as shown on Exhibit A-81 (KAP-2), page 2, line 5, and consists of the  
22 O&M portion of the salaries and expenses for engineers, designers, analysts, and other  
23 support staff needed to meet the design and planning needs of the NGDP including the

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1 implementation of the Transmission and Storage Probabilistic Risk Models and meeting  
2 compliance requirements of the Company's integrity management programs. The increase  
3 in O&M expenses from historical year 2023 is attributed to a departmental reassessment  
4 of work activities. This reassessment identified a rise in O&M inspections and remediation  
5 activities specifically related to integrity work. These activities are essential for  
6 maintaining the safety, reliability, and efficiency of operations, ensuring compliance with  
7 regulatory standards, and addressing any identified issues promptly.

8 In addition to the System Integrity staffing requirements, the SIMP was created in  
9 response to a new Pipeline and Hazardous Materials Safety Administration ("PHMSA")  
10 final rule issued on February 12, 2020. The SIMP O&M expenses for the 12 months ending  
11 October 31, 2026 is \$2,129,000, as shown on Exhibit A-81 (KAP-2), page 2, line 7.

12 **Q. What is the basis for determining the \$2,129,000 in SIMP O&M expenses in the test**  
13 **year 12 months ending October 31, 2026 for this program?**

14 A. On December 9, 2016, PHMSA issued an Interim Final Rule ("IFR") titled "Pipeline  
15 Safety: Safety of Underground Natural Gas Storage Facilities." This IFR included a new  
16 Rule 192.12 Underground Natural Gas Storage Facilities ("UNGSF") and was enacted as  
17 a congressionally mandated response to the natural gas leak incident at the Aliso Canyon  
18 facility on October 23, 2015. Rule 192.12 became effective January 18, 2017, and was  
19 incorporated by reference in the consensus document API RP 1171: Functional Integrity  
20 of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. On  
21 February 12, 2020, PHMSA issued a Final Rule reinforcing its minimum safety standards  
22 for underground natural gas storage facilities and including additional requirements and  
23 clarifications. The effective date of this Final Rule was March 13, 2020.

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As a result, Consumers Energy has developed the SIMP to comply with the federal regulations. The Company owns and operates 808 gas storage wells that fall under the scope of SIMP. The SIMP has several O&M components necessary to execute the program shown below in Table 1. The O&M components address the expenses required for the well plugging program, atmospheric corrosion protection (painting) of rehabilitated wells, risk reduction, annular pressure remediation, well re-assessment, and gas storage field analysis. The projected O&M costs for the SIMP in the test year total \$2,129,000.

**Table 1: SIMP O&M Program Components and Expenses**

	12 Mos Ending Dec 31, 2023	Projected 12 Mos Ending Dec 31, 2024	Projected 12 Mos Ending Dec 31, 2025	Projected 12 Mos Ending Dec 31, 2026	Projected 12 Mos Ending Sept 30, 2026
<b>Storage Integrity Management Program ("SIMP") (\$000)</b>	<b>\$630</b>	<b>\$1,956</b>	<b>\$2,881</b>	<b>\$2,555</b>	<b>\$2,129</b>
a) Plugged Well Monitoring	\$22	\$60	\$24	\$53	\$40
Units: # of CE Plugged Wells	85	82	56	125	93
Units: # of 3rd Party Plugged Wells	0	82	0	0	0
b) Atmospheric Corrosion Protection (Painting) of Rehabilitated Wells	\$126	\$80	\$111	\$19	\$14
Units: # of Wells Painted	25	13	16	4	2
c) Risk Reduction	\$184	\$690	\$1,520	\$1,520	\$1,138
Units: # of Farm Taps	30	31	75	75	60
Units: # of Storage Fields: Storage Lateral/Well Line (pipeline)	1	4	4	4	3
d) Annular Pressure Remediation	\$94	\$63	\$143	\$148	\$123
Units: # of Wells (Assumes 15 Wells will require MIT's, 5 with wellhead seal replacements, remaining repacking of seals, includes labor costs for testing and repairs. Hanger replacements, tubing and/or packer replacements not included)	13	8	15	15	13
e) Well Re-assessment	\$48	\$898	\$983	\$712	\$712
Units: # of Wells	0	105	108	79	79
f) Gas Storage Field Analysis	\$158	\$165	\$100	\$103	\$102
Units: # of Storage Fields	1	2	1	1	1

**Q. Please describe the plugged well monitoring portion of the SIMP funding requirements.**

**A.** To comply with PHMSA Regulation 192.12 and API RP 1171, Consumers Energy has created a program to perform baseline assessment of well integrity as part of the Well Rehabilitation Program sponsored by Company witness Joyce. For all plugged wells within the storage reservoir boundary, the Company must further comply with plugged well monitoring requirements including the 390 plugged wells owned by the Company and the 740 plugged wells owned by other operators or producers. The monitoring of plugged

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1 wells includes visual and instrumented observation of the plugged well sites for any  
2 indication of methane leaks, changes in nearby observation well pressures, changes in  
3 annulus pressures of nearby facility wells, gas loss reported through the gas inventory  
4 verification process, and abnormally high gas production reported. The instrumented field  
5 monitoring will include 93 Company owned plugged wells in the test year. The average  
6 cost to monitor a Company owned plugged well is \$259 and to monitor a plugged well  
7 owned by other operators or producers is \$456. Additional costs associated with Third  
8 Party Plugged wells is due to the Company needing the ability to access property that it  
9 currently does not have rights to as the plugged wells that require instrumented monitoring  
10 were not owned or operated by the Company. In the test year, only plugged wells owned  
11 by the Company will be monitored. The O&M costs associated with the well plugging  
12 portion of the SIMP in the test year total \$39,956 and are based on historical cost of  
13 performing monitoring.

14 **Q. Please describe the well rehabilitation atmospheric corrosion portion of the SIMP**  
15 **funding requirements.**

16 A. The well rehabilitation portion of the SIMP performs baseline assessment and remediation  
17 of Consumers Energy's natural gas storage wells. The O&M funding requirement is for  
18 painting of above-grade equipment associated with the rehabilitated wells to provide  
19 atmospheric corrosion protection upon completion of the assessment and remediation of a  
20 well where an asset is not intended to be retired or replaced. The projected cost is derived  
21 from the configuration of the well for applied corrosion control measures such as paint  
22 applied by contractors and inspection to ensure applied coatings meet the application

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1 specifications. The O&M costs associated with the well rehabilitation atmospheric  
2 corrosion portion of the SIMP for the projected test year totals \$13,875.

3 **Q. Please describe the risk reduction portion of the SIMP funding requirements.**

4 A. The risk reduction portion of SIMP is to address facilities and piping that have compliance  
5 and safety risks associated with them. These facilities are associated with the storage  
6 system and include sections of the storage pipelines, well lines, and farm tap setups that  
7 fall outside of the ability to replace as a part of the capital SIMP programs due to being  
8 typically short sections of pipe or fittings installed as part of the original installation. The  
9 risk reduction portion will be used to investigate, evaluate, replace, or retire facilities to  
10 reduce risk on the storage system. The projected cost addresses risk on the system that  
11 does not fall into other areas of SIMP and includes approximately 75 farm tap facilities,  
12 short sections of transmission piping, and well lines. The costs include records validation,  
13 field research and physical verification, piping and equipment upgrades, replacements,  
14 repairs, and other associated charges. The O&M costs associated with the risk reduction  
15 portion of the SIMP for the projected test year is \$1,137,826.

16 **Q. Please describe the gas storage annular pressure diagnostics and remediation portion  
17 of the SIMP funding requirements.**

18 A. The annular pressure diagnostics and remediation portion of SIMP is the cost of diagnosing  
19 and remediating wells that have annular pressures trending toward or exceeding threshold  
20 pressures. Annular pressure is monitored as part of SIMP and is a method to ensure  
21 integrity of the wells. Annular pressure outside of and trending toward threshold limits  
22 can indicate a loss of mechanical integrity or other failure requiring intervention. The  
23 diagnostic and repair funds are estimated based on historical spend, which typically

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1 requires testing, diagnosing, and repacking or replacement of wellhead seals. The O&M  
2 costs associated with the annular pressure diagnostics and remediation portion of the SIMP  
3 for the projected test year totals \$122,641.

4 **Q. Please describe the well re-assessment portion of the SIMP funding requirements.**

5 A. The well re-assessment portion of SIMP is initiated seven years after the initial baseline  
6 assessment has occurred, in accordance with PHMSA Regulation 192.12 and API RP 1171.  
7 The well re-assessment portion of SIMP started in 2024. The wells that were baseline  
8 assessed in 2018 will be re-assessed in 2025, and wells baseline assessed in 2019 will be  
9 re-assessed in 2026. The re-assessment will consist of well logging and Mechanical  
10 Integrity Testing (“MIT”) of the subject wells based on the configuration of each well and  
11 well history and includes any remedial and necessary actions. There is a total of 79 wells  
12 to be re-assessed in 2026, and all of them will be inspected and will incur costs in the test  
13 year. The O&M costs associated with the well re-assessment portion of the SIMP for the  
14 projected test year totals \$712,452.

15 **Q. Please describe the gas storage field analysis portion of the SIMP funding**  
16 **requirements.**

17 A. The gas storage field analysis portion of the SIMP is an analysis used to model the storage  
18 system deliverability, considerate of all SIMP programs, and other related integrity  
19 programs. The purpose of the analysis is to better model the capability and needs of the  
20 existing storage system to enable right-sizing of the system and necessary equipment  
21 upgrades, including but not limited to well deliverability, field deliverability, pipeline  
22 replacements/retirements, liquid separation, and gas conditioning equipment. The analysis  
23 will support system risk reduction through optimization by matching existing and future

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1 system needs with the capabilities and future capabilities of the gas storage system. The  
2 gas storage field analysis portion of the SIMP for the projected test year totals \$102,250.

3 **Q. Please describe the activities of the Gas Compression Engineering department.**

4 A. Gas Compression Engineering is responsible for the engineering, design, and technical  
5 support of the Company's compressor station assets. This team is also responsible for asset  
6 planning for all capital investments within the existing compression fleet. These capital  
7 investments are sponsored by Company witness Joyce. The increase in O&M expenses  
8 from historical year 2023 is attributed to additional labor required to perform a process  
9 hazard analysis of Northville Compressor Station that will occur in the test year of this  
10 case. The projected O&M expenses for the Gas Compression Engineering department for  
11 the 12 months ending October 31, 2026 is \$1,015,000, as shown on Exhibit A-81 (KAP-2),  
12 page 2, line 6, and consists of the O&M portion of the salaries and expenses for engineers,  
13 designers, analysts, and other support staff needed to meet the design and planning needs  
14 of the NGDP.

15 **Q. What operating sections are included in Gas Engineering Support?**

16 A. Gas Engineering Support consists of five departments which I will describe more fully  
17 below. They are:

- 18 • Gas Strategy;
- 19 • Gas Regulatory and Compliance;
- 20 • Geospatial Management and Data Quality (which includes the Geospatial  
21 Inventory and Modeling Program);
- 22 • Damage Claims/Prevention; and
- 23 • Engineering Management.

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1 **Q. Please describe the activities of the Gas Strategy department.**

2 A. Gas Strategy provides asset strategy, business support, financial analysis, and business  
3 performance measurement for the Company's compression, storage, transmission, and  
4 distribution facilities. This department is responsible for the development, implementation,  
5 and support of the long-term strategy for the natural gas system, and the development of  
6 the NGDP. This department ensures the overall goals and outcomes developed in the  
7 NGDP align with the Company's strategy. Gas Strategy includes the individuals  
8 responsible for ensuring that financial analysis aligns with the portfolio planning services,  
9 including long-term financial planning and long-term strategy. The projected O&M  
10 expenses for the Gas Strategy department for the 12 months ending October 31, 2026 is  
11 \$89,000, as shown on Exhibit A-81 (KAP-2), page 2, line 8, and consists of the O&M  
12 portion of the salaries and expenses for strategy managers and analysts needed to support  
13 the financial analysis and business performance measurements necessary to ensure  
14 implementation of the NGDP as well as the long-term strategy development for the natural  
15 gas system.

16 **Q. Please describe the activities of the Gas Regulatory and Compliance department.**

17 A. Gas Regulatory and Compliance interfaces with the MPSC Gas Safety Staff and the Federal  
18 Office of Pipeline Safety on regulatory compliance matters. This includes regulatory  
19 audits, inspection activities, gas standards work, and submission of periodic and incident  
20 reports in accordance with both federal and state requirements. Gas Regulatory and  
21 Compliance supports compliance-related programs and documents, including  
22 Transmission Integrity Management, Distribution Integrity Management, Gas Operations  
23 Procedures, Public Awareness, and Damage Prevention. Effective September 1, 2023, the

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1 AMD team was integrated into the Gas Regulatory and Compliance department from the  
2 Operations Compliance and Controls department. The Gas Regulatory and Compliance  
3 department is managing the Company's implementation of the API RP 1173 – Pipeline  
4 Safety Management Systems which is the Company's Gas Safety Management System  
5 ("GSMS") and the AMD Program. The salaries and expenses associated with the Gas  
6 Regulatory and Compliance department for the 12 months ending October 31, 2026 is  
7 \$1,272,000 as shown on Exhibit A-81 (KAP-2), page 3, line 9. The 2023 historic expenses  
8 for this department, shown on Exhibit A-81 (KAP-2), page 3, column b, line 9, includes  
9 the September through December 2023 addition of the AMD team. The January through  
10 August 2023 historic expenses for the AMD team are included in Company witness  
11 Pnacek's Exhibit A-89 (JPP-4), page 1, line 1, Compliance and Controls. The projected  
12 O&M expenses include the full-year salaries and expenses for the AMD team added during  
13 the 2023 Company reorganization, reflecting the full-year impact of the additional staffing  
14 as described earlier in my testimony.

15 **Q. Please describe the activities of the Geospatial Management and Data Quality**  
16 **department.**

17 A. The Geospatial Management and Data Quality department is responsible for creating and  
18 maintaining the Geospatial Information Systems ("GIS") & Service Information  
19 Management System ("SIMS") databases for gas distribution, transmission, storage,  
20 service, and regulation systems, and for supporting strategic and operating capacity  
21 planning, performance, asset management, and regulatory reporting requirements.

22 The Geospatial Management and Data Quality department also supports the  
23 Company's gas technical records, working closely with operations and engineering teams

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1 to store, protect, retrieve, and, when appropriate, destroy records according to operational  
2 and regulatory requirements. In alignment with the above scope, the team has dedicated  
3 roles to manage system administration of Consumers Energy's Gas Engineering Content  
4 Management software. The O&M expenses for the Geospatial Management and Data  
5 Quality department for the 12 months ending October 31, 2026 is \$645,000, as shown on  
6 Exhibit A-81 (KAP-2), page 3, line 10, and consists of the O&M portion of the salaries and  
7 expenses of managers and their Company-employed and contracted staff needed to support  
8 the increased asset records management to meet the compliance workload driven by the  
9 NGDP, and to ensure Company records are compliant and current, enabling employees and  
10 other end users to have comprehensive access to current and accurate mapping and correct  
11 information in a timely and cost-effective manner, all contributing to increased pipeline  
12 safety.

13 Additionally, this department is responsible for the Geospatial Inventory and  
14 Modeling Program, which includes the Gas Compliance Code Program – Service  
15 Information Mapping System (“GCCP - SIMS”) project, and the Utility Network  
16 implementation. The O&M expenses for the Geospatial Inventory and Modeling Program  
17 within the Geospatial Management and Data Quality department for the 12 months ending  
18 October 31, 2026 is \$518,000, as shown on Exhibit A-81 (KAP-2), page 3, line 11.

19 **Q. What is the basis for determining the \$518,000 of projected O&M expenses in the test**  
20 **year 12 months ending October 31, 2026 for the Geospatial Inventory and Modeling**  
21 **Program?**

22 A. The Geospatial Inventory and Modeling Program includes the GCCP - SIMS project and  
23 the Utility Network project. This program was created to modernize and transform the

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1 Company's GIS records and systems. This program has both a capital and O&M  
2 component. The projected capital expenditures and project benefits are described in further  
3 detail in the Gas Operations Other Program later in my testimony. The migration of gas  
4 service information to GIS is projected to be complete in early 2025. There are no  
5 projected expenses for the SIMS project in the test year of this case. The O&M expenses  
6 for the Utility Network project is \$518,000 in the test year 12 months ending October 31,  
7 2026. The projected costs for the GCCP - SIMS project was determined based on  
8 information provided to the Company in response to a Request for Proposal that was  
9 performed with several vendors in 2017, along with contracts put in place in 2022. The  
10 projected costs are updated annually as more work is defined and developed for the future  
11 state of the end-to-end solution. Total Utility Network transformation costs were estimated  
12 through an assessment performed in 2019 and 2020 in collaboration with Esri Professional  
13 Services ("Esri"). Esri prepared a high-level Utility Network migration strategy through a  
14 series of workshops in which the Company's business requirements, processes, and  
15 technical infrastructure were assessed to determine the scale and complexity of the  
16 migration. Upon completion of the workshops, Esri provided the Company with a written  
17 planning strategy along with a project schedule and cost estimate. In 2022 and 2023, the  
18 Company executed a Request for Proposal to further develop a business plan. The  
19 Company's current and future state was assessed along with performing a GIS data analysis  
20 to aid in further refining the projected costs, resource requirements, project timeline, and  
21 overall transformation strategy. The Company executed a Request for Proposal in 2024 to  
22 identify a qualified bidder to oversee, coordinate, and execute the modernization of the  
23 Company's existing Gas & Land Geospatial and corporate ArcGIS Enterprise platforms to

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1 the Utility Network (UN) data models hosted on Microsoft Azure. Due to the high level of  
2 impact and complexity of the change to people, processes, and technology, the Gas Utility  
3 Network transformation is planned to be complete in 2026.

4 **Q. Please describe the activities of the Damage Prevention and Claims department.**

5 A. Effective September 1, 2023, the Damage Prevention and Claims department was  
6 integrated into the Gas Engineering and Supply department from the Gas Operations  
7 Compliance and Controls department. The Damage Prevention and Claims department  
8 provides oversight of the Company's staking and locating of underground facilities in  
9 accordance with 811 MISS DIG regulations. This includes the Company's Gas Public  
10 Awareness Program. The O&M expenses for the Damage Prevention and Claims  
11 department for the 12 months ending October 31, 2026 is \$1,231,000, as shown on Exhibit  
12 A-81 (KAP-2), page 3, line 12, and consists of the O&M portion of the salaries and  
13 expenses for roles needed to support damage prevention/claims activities and liaison with  
14 external agencies and excavators, and the public promoting of education and awareness to  
15 proactively prevent and reduce third-party damages. The 2023 historic year expenses for  
16 this department shown on page 3, column (b), line 12 of the exhibit, represent expenses  
17 from September through December 2023. The January through August 2023 historic year  
18 expenses are included in Company witness Pnacek's Exhibit A-89 (JPP-4), page 1, line 1,  
19 Compliance and Controls. The projected O&M expenses include the full-year salaries and  
20 expenses, and software licensing expenses, for the Damage Prevention and Claims team  
21 added during the 2023 Company reorganization, reflecting the full-year impact of the  
22 additional staffing as described earlier in my testimony.

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1 **Q. Please describe Engineering Management.**

2 A. The Engineering Management department includes the O&M expenses associated with the  
3 roles of the Vice President of Engineering and Supply and their support staff. The expenses  
4 include the O&M portion of salaries and associated expenses needed to support a range of  
5 critical responsibilities, including oversight of:

- 6 • Engineering of the Company's natural gas system distribution, transmission,  
7 storage, and compression assets;
- 8 • Procurement and supply of natural gas;
- 9 • Strategic planning;
- 10 • Budgeting and financial management;
- 11 • Setting performance goals, providing professional development opportunities,  
12 and fostering a collaborative and innovative work environment; and
- 13 • Ensuring all operations comply with federal, state, and local regulations.

14 These responsibilities ensure safe, efficient, and reliable delivery of natural gas to  
15 customers. The O&M expenses for the Engineering Management department for the  
16 12 months ending October 31, 2026 is \$46,000, as shown on Exhibit A-81 (KAP-2),  
17 page 4, line 14.

18 **Q. What operating sections are included in Gas Management Services?**

19 A. Gas Management Services is responsible for four major functions:

- 20 • Gas Control;
- 21 • Gas System and Operations Planning;
- 22 • Gas Supply; and
- 23 • Gas Transportation, Customer Choice, and Measurement.

24 Gas Control is responsible for:

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- 1 • The centralized Gas Control Room operation, which monitors and controls the  
2 gas transmission system and monitors key points on the distribution system on  
3 a 24/7 basis, following PHMSA Title 49 CFR 192.631 (control room  
4 management);
- 5 • Monitoring scheduled third-party pipeline supply;
- 6 • Dispatching compression and storage assets to ensure customer supply is met  
7 within the Transmission system's design limits and monitoring portions of the  
8 Distribution system; and
- 9 • Gas SCADA development, including operations and 24/7 support.

Gas System and Operations Planning is responsible for:

- 10 • Transmission and storage capacity studies;
- 11 • Facility and operational improvements to meet changing supply and customer  
12 loads;
- 13 • Reporting operational data;
- 14 • Assisting in development of business cases for major system modifications  
15 related to the Company's gas transmission, storage, and compression system;
- 16 • The preparation of natural gas supply and storage dispatch plans;
- 17 • The coordination of the Gas Cost Recovery ("GCR") plan and GCR  
18 Reconciliation with the Company's operational plans; and
- Administration of interconnect agreements.

19 The Gas Supply section is responsible for:

- 20 • Obtaining reliable and reasonably priced gas supply for the Company's GCR  
21 or Sales customers;
- 22 • Negotiation and administration of all related gas supplier, transportation, and  
23 Buy/Sell agreements, and Asset Management contracts; and
- 24 • Tracking and projecting the cost of gas and related inventory valuations, Gas  
25 Supply coordinates the gas purchase planning related to GCR plans and  
26 reconciliations.

27 The Gas Transportation and Measurement section is responsible for:

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- 1 • The management of the Company’s Gas Customer Choice (“GCC”) Program,  
2 including preparation of required deliveries for GCC Suppliers, and monthly  
3 GCC remittance statements and annual reconciliations;
- 4 • The daily management of the gas transportation activity at the Company,  
5 including the daily balancing and confirmation of gas nominations and gas  
6 transportation contract administration; and
- 7 • The preparation of the Gas Control Operations Summary and various internal  
8 and external reports, all of which make up the foundation of volumetric  
9 accounting on the Company’s gas transmission and storage system.

10 The salaries and expenses associated with the Gas Management Services department for  
11 the 12 months ending October 31, 2026 is \$4,796,000, as shown on Exhibit A-81 (KAP-2),  
12 page 4, line 15, and consists of the O&M portion of the salaries and expenses for engineers  
13 and gas control staff needed for outage coordination, scheduling, and system planning  
14 activities necessary to support the capital, O&M, system control, and system analytics  
15 plans in the NGDP. The projected O&M expenses include the full-year salaries and  
16 expenses, and software licensing expenses, for the OT Gas SCADA team added during the  
17 2024 Company reorganization, reflecting the full-year impact of the additional staffing as  
18 described earlier in my testimony.

**GAS DISTRIBUTION CAPITAL EXPENDITURES**

19  
20 **Q. Please describe the Company’s projections of capital expenditures for Gas**  
21 **Distribution – Material Condition and Gas Operations Other.**

22 A. As shown on Exhibit A-12 (KAP-3), Schedule B-5.8, the Gas Distribution capital  
23 expenditures I am sponsoring were \$274,046,000 in 2023, and are projected to be  
24 \$301,775,000 in 2024; \$313,809,000 for the 10 months ending October 31, 2025; and  
25 \$402,755,000 for the 12 months ending October 31, 2026, as set forth on this exhibit on  
26 line 3, columns (b), (c), (d), and (f), respectively. These projections are based upon the

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1 necessary requirements to meet the Company's objectives of operating a system that is  
2 safe, reliable, affordable, and clean.

3 **Q. Please list the major programs within the Gas Distribution capital expenditures.**

4 A. The major programs, as shown on Exhibit A-12 (KAP-3), Schedule B-5.8, and Exhibit  
5 A-12 (LDW-1), Schedule B-5.9, are:

- 6 • New Business;
- 7 • Asset Relocation;
- 8 • Regulatory Compliance;
- 9 • Material Condition;
- 10 • Capacity/Deliverability; and
- 11 • Gas Operations Other.

12 Several of these major programs have a gas distribution and a gas transmission component  
13 to them. My direct testimony represents only the gas distribution portion of the Material  
14 Condition and Gas Operations Other programs. The direct testimony of Company witness  
15 Warriner represents the gas distribution portion of the remaining programs listed above.  
16 The direct testimony of Company witnesses Griffin and Joyce represent additional  
17 components of the gas transmission system as well as distribution regulating stations,  
18 compression, and storage systems.

19 **Q. Have you included contingency costs in the capital expenditures you are sponsoring?**

20 A. No, there are not any contingency costs included in the capital expenditures.

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1       **1. Material Condition**

2       **Q. Please describe the capital expenditures relating to the Material Condition Program**  
3       **set forth on Exhibit A-12 (KAP-3), Schedule B-5.8, line 1.**

4       A. Material Condition Program expenditures are used to improve the natural gas distribution  
5       system integrity, reduce service interruptions impacting customers, and replace leaking and  
6       vintage gas distribution facilities. Reducing the number of leaks improves reliability,  
7       reduces methane emissions to the atmosphere, and enhances public safety. The  
8       expenditures in this program include the EIRP, the VSR Program, and system  
9       enhancements that are prioritized by risk to improve safety and gain operational  
10      efficiencies through replacement of lower performing gas distribution assets.

11             The expenditures in this program also include capital replacements due to leaks and  
12      system damages, represented by the Material Condition Renewals Program, as well as  
13      emergent gas service and main replacement projects driven by conditions observed in the  
14      field, represented by the Material Condition Non-Modeled Program, and business customer  
15      capital meter and meter stand replacements represented by the Commercial and Industrial  
16      Meters Program. The projects and expenditures for these five programs are described in  
17      more detail below. As shown on Exhibit A-12 (KAP-3), Schedule B-5.8, line 1, the capital  
18      expenditures for these five programs were \$266,297,000 in 2023, and are projected to be  
19      \$285,681,000 in 2024; \$301,865,000 for the 10 months ending October 31, 2025; and  
20      \$385,665,000 for the test year 12 months ending October 31, 2026, as set forth on this  
21      exhibit on line 1, columns (b), (c), (d), and (f), respectively. The expenditures for the  
22      Material Condition Program are further detailed in Exhibit A-82 (KAP-4).

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1 **Q. Please describe the EIRP.**

2 A. Beginning in 2012, the Company implemented the EIRP to ensure continued customer  
3 safety and reliable system operation as part of the DIMP. The EIRP replaces the  
4 Company's highest risk materials as classified by PHMSA, including all cast iron, wrought  
5 iron, Threaded and Coupled ("T&C"), oxyacetylene welded, copper, and bare steel  
6 distribution main with more reliable, lower maintenance plastic and steel main, and  
7 replaces (in the case of older metallic materials) or ties-over (plastic) services to the new  
8 main.

9 The program scope includes the following:

- 10 • Replacement of all cast iron main;
- 11 • Replacement of all bare, oxyacetylene welded, T&C, Xtrube, and cathodically  
12 unprotected steel main;
- 13 • Replacement of all copper main;
- 14 • Replacement of metallic service materials associated with the main replacement  
15 projects;
- 16 • Replacement of approximately 100 miles of transmission pipeline located in  
17 high consequence areas and transmission pipelines operated on the Distribution  
18 System;
- 19 • Replacement of approximately 70 miles of low frequency electric resistance  
20 weld pipe in the Company's Transmission and Storage fields; and
- 21 • As included in the Company's NGDP, elimination of the standard pressure  
22 system which includes replacement of approximately 105 miles of pipe that is  
23 not covered in the vintage main miles and 68 miles of plastic to be converted  
24 from standard pressure (SP) to medium pressure (MP). The Company intends  
25 to complete this work and include it as part of planned EIRP work.

26 In addition to safety and reliability improvements, replacement of cast iron piping  
27 will enable the reduction and eventual elimination of the standard pressure system,  
28 allowing these areas to operate at higher, more efficient pressures while lowering gas

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1 losses, reducing the potential for water infiltration, and reducing greenhouse emissions.  
2 Upgrades to more efficient pressures may require modifications to regulator facilities under  
3 this program. Eliminating standard pressure also allows for the elimination of certain  
4 regulating stations that feed the standard pressure system, which lowers operating costs for  
5 those systems.

6 EIRP projects are selected by the gas engineering teams using a risk model that  
7 assesses the risks and threats of each pipe segment, according to the Company's DIMP.  
8 The risk model helps prioritize system replacements to eliminate the highest risk  
9 distribution pipe first, to maximize the system risk reduction in any given year. The  
10 Company uses this risk-based approach, combined with subject matter expert input, to  
11 select EIRP replacement projects that eliminate vintage mains and standard pressure  
12 systems. The EIRP investment ensures reliability and the safety of customers and the  
13 public. The well-planned, thoughtful execution of the EIRP is a more cost-effective  
14 approach than being forced into replacement under emergent conditions. The Company  
15 continues to evaluate the risks to the distribution system along with the overall timeframe  
16 projected to replace higher risk pipe.

17 **Q. Please describe the progress of the EIRP.**

18 A. Since the EIRP began in 2012 through the calendar year ended 2023, the program has  
19 retired 794 miles of the vintage gas pipe identified for replacement as shown in Table 2.  
20 In addition to the EIRP, other programs, like Asset Relocation – Civic Improvement and  
21 Material Condition Non-Modeled, also eliminate vintage pipe. In any given year, the  
22 number of miles retired for each material will vary based on the mix of investment between  
23 steel and plastic projects. The Company uses a risk model to optimize the investment to

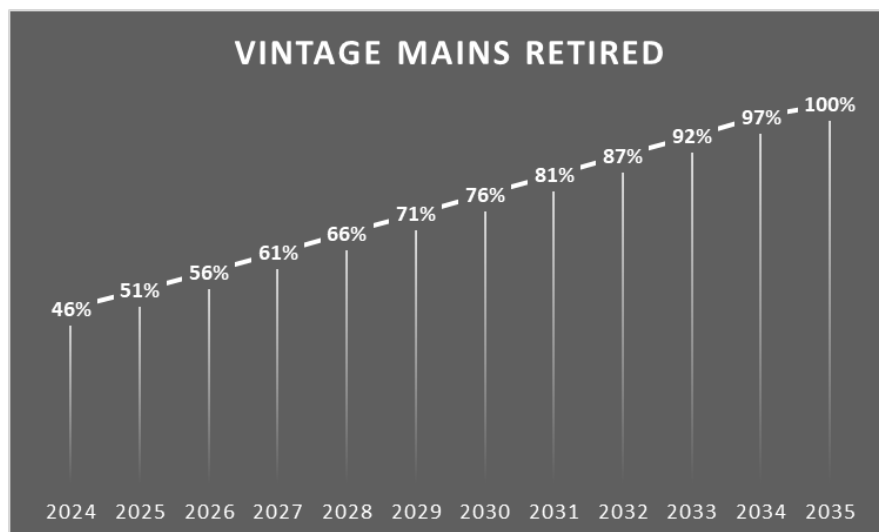
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1 eliminate higher risk gas mains first. At the end of calendar year 2023, the status for each  
2 of the main types is detailed as follows:

- 3 • Copper main – Eliminated the last known copper main segments in 2018;
- 4 • Xtrube main – Eliminated the last known Xtrube main segments in 2018;
- 5 • Cast iron main – Eliminated 286.7 of 580.0 miles by the EIRP through  
6 12/31/2023;
- 7 • Wrought iron main – Eliminated 5.3 of 21.6 miles by the EIRP through  
8 12/31/2023;
- 9 • Bare steel main (including oxyacetylene welded bare steel) – Eliminated 286.3  
10 of 1033.4 miles by the EIRP through 12/31/2023; and
- 11 • T&C main – Eliminated 148.8 of 1061.7 miles by the EIRP through 12/31/2023.

12 As described in the NGDP, completing the EIRP by 2035 enhances safety and reliability  
13 while also balancing affordability. This balance is achieved by managing costs and  
14 prioritizing investments that provide the greatest benefit to customers without extending  
15 the overall project duration and associated costs, ultimately minimizing the cost impact to  
16 customers. The EIRP is currently planned to be completed by the end of 2035, reducing  
17 vintage main miles by approximately 5% per year.

**Figure 1: Vintage Main Replacement Pace 2024 - 2035**



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1 See Table 2 below for a summary of pipe retired each year by the EIRP Program  
2 and the cumulative pipe retired by other programs.

**Table 2: Miles of EIRP Main Pipe Retired by Year**

MILES OF EIRP CLASSIFIED MAIN PIPE REPLACED BY YEAR									
PIPE TYPE:	Miles of Pipe by Pipe Type in EIRP Program Scope	EIRP Actual (2012 -2020) <sup>1</sup>	EIRP 2021 Actuals <sup>1</sup>	EIRP 2022 Actuals <sup>1</sup>	EIRP 2023 Actuals <sup>1</sup>		Cumulative EIRP Retired as of 12/31/23 <sup>1</sup>	Estimated Cumulative Retired by Other Programs as of 12/31/23	Est. Miles Remaining as of 12/31/23
TOTAL:	2869.2	499.7	119.1	84.3	91.1		794.1	401.0	1,674.1
Cast Iron	580	180.4	50.6	23.0	32.7		286.7	101.8	191.5
Bare Steel	1033.4	161.8	46.4	56.1	22.0		286.3	129.8	617.3
Threaded & Coupled	1061.7	100.1	14.9	4.2	29.7		148.8	163.0	749.9
Wrought Iron	21.6	4.7	0.4	0.0	0.2		5.3	5.8	10.5
X-trube	0.9	0.9	0.0	0.0	0.0		0.9	0.0	0.0
Copper	1.6	0.6	0.0	0.0	0.0		0.6	0.5	0.0
Coated & Wrapped on Standard Pressure <sup>3</sup>	108.35	(34.2)	1.2	2.2	3.2		(27.6)		
TOD	100	12.8	6.7	1.1	6.5		27.1		
IFERW	70	38.4	0.0	0.0	0.0		38.4		
<b>Additional Pipe Replacement:</b>									
Plastic <sup>2</sup>		10.1	3.2	6.6	9.8		29.7		
Coated & Wrapped <sup>2</sup>		83.5	12.4	39.5	25.2		160.6		
<b>Notes:</b>									
	1) Does not include miles of EIRP pipe type that were replaced as part of other programs like Civic Improvement or Emergent CE Initiated.								
	2) It is necessary to replace some coated and wrapped steel and plastic pipe as part of EIRP projects due to the configuration of the system, project constructability code 3 condition, but coated and wrapped and plastic are not EIRP targeted pipe type.								
	3) Coated & Wrapped steel pipe on standard pressure does qualify under EIRP while Coated & Wrapped steel pipe on medium pressure does not qualify under EIRP								

3 In 2023, the Company completed 13 projects using the grid approach, which plans for and  
4 constructs large scale EIRP projects (typically 15 to 25 miles of distribution pipeline).  
5 Opportunities to use the grid approach for future projects are decreasing due to the location  
6 of higher risk pipe. A shift back to more segment projects will begin in 2025. The  
7 Company will continue to apply efficiencies achieved through prior years (described later  
8 in this testimony) to mitigate unit costs.

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1 **Q. Please explain the difference between replaced or retired pipe and installed pipe for**  
2 **the EIRP and why cost is based on installed pipe.**

3 A. Replaced or retired pipe refers to the amount of vintage pipe existing on the Company's  
4 gas system prior to EIRP project construction that will be replaced by newly installed pipe  
5 and retired (abandoned in place) upon completion of the EIRP project construction. Miles  
6 of replaced or retired pipe by the EIRP is included in Table 2 above and as part of the  
7 Company's annual performance report filings. Installed pipe refers to the amount of new  
8 pipe that is added to the Company's gas system to replace the vintage material pipe being  
9 retired upon completion of the EIRP project construction. The EIRP project cost is based  
10 on installed pipe, as the EIRP project activities are related to the planning, design, and  
11 construction for the new pipe installation. There is a small amount of construction time  
12 related to the retirement activity to safely cut and cap the old vintage pipe to retire the pipe  
13 (abandon in place). The Company charges 2% of EIRP project cost to cost of removal  
14 ("COR") to cover the cost related to the retirement activities, which is included in the  
15 Company's depreciation rate cases, and not included as part of the EIRP project cost in this  
16 testimony. The EIRP project costs provided in this testimony are without COR and related  
17 to the project planning, design, construction, and other activities to support the new pipe  
18 installation.

19 **Q. What were the results of the 2023 EIRP projects?**

20 A. In 2023, the Company constructed 13 EIRP projects using the grid approach, and one  
21 Steel/TOD project. See Table 3 below for a summary of the scope of the 2023 EIRP project  
22 work completed.

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**Table 3: 2023 EIRP Program Completed Project Work**

<b>Project Type</b>	<b># Projects</b>	<b>Installed Pipe (miles)</b>	<b>Service Counts</b>
Grid Projects	13	102.3	8,649
Segment Projects	0	0	0
Steel/TOD Projects	1	6.6	0
<b>Total</b>	<b>14</b>	<b>108.9</b>	<b>8,649</b>

1 As shown in Exhibit A-84 (KAP-6), the 2023 EIRP spend was \$181.9 million. Program  
2 costs include previous year project carryover expenses, current year project expenditures,  
3 and future year project expenditures. The previous year project carryover expenses include  
4 activities such as pipe installation, pipe retirement, and surface restoration that could not  
5 be completed during the prior construction year. In addition to new pipe installation, the  
6 current year project expenditures include activities, such as standard pressure system  
7 conversions and meter move outs, which have no attributed miles or service counts but  
8 contribute cost to the cost-per-mile calculation. However, these activities are necessary for  
9 project completion. The future year project expenditures include activities such as  
10 engineering, survey, and construction mobilization that must be completed prior to the start  
11 of construction. Like standard pressure system conversions and meter move-outs, these  
12 necessary activities result in additional project expenditures with no associated installed  
13 miles, increasing the total EIRP average cost per mile each year. As shown in Exhibit A-84  
14 (KAP-6), a total of 108.9 miles were installed in 2023. Of the program expenditures of  
15 \$181.9 million, \$176.6 million was spent on 2023 projects with carry-over and future year  
16 expenditures amounting to \$5.4 million. This results in an overall cost of \$1.67 million per  
17 mile. For 2023 plastic pipe installation, the regional per-mile expenditures were  
18 \$2.3 million, \$1.4 million, and \$1.5 million for the Southwest, Northeast, and Southeast

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1 regions, respectively, resulting in a weighted average of \$1.63 million per mile. The higher  
2 per mile expenditures in the Southwest region was due to a large quantity of standard  
3 pressure conversion work in the Lansing area. For the steel project completed in 2023, the  
4 per-mile cost was \$1.55 million. The lower steel cost-per-mile was primarily due to the  
5 project's rural location, which made construction less difficult and did not require  
6 significant pre- or post-construction activities.

7 **Q. What factors influence the installed cost per mile for EIRP distribution projects?**

8 A. There are many factors that can influence the installed cost per mile of EIRP distribution  
9 projects. When looking at unit cost data, it is important to consider these factors to help  
10 understand the complexity and variability of costs incurred in performing the project work.  
11 Some of the key factors to consider are listed below.

- 12 • Location – The urban density of the area where a project is executed has a  
13 significant influence on the cost of that project. Some of the differences  
14 include:
  - 15 – Rural projects – Little or no hard surface (sidewalks), few obstacles in the  
16 ground, typically lower permitting costs and requirements;
  - 17 – Suburban projects – Mostly residential and some commercial services,  
18 moderate hard surface with potential for installation under sidewalks or  
19 streets, moderate traffic control and safety services cost, low to moderate  
20 obstacles in the ground (other service provider wires, pipes, etc.), moderate  
21 permitting cost and number of requirements;
  - 22 – Urban projects – Commercial and residential buildings and services,  
23 significant hard surface requiring installation under sidewalks and streets,  
24 high traffic control and safety services cost, high obstacles in the ground  
25 (other service provider wires, pipes, etc.), moderate to high permitting cost  
26 and number of requirements; and
  - 27 – Inner city projects – Buildings and commercial services, significant hard  
28 surface requiring installation under sidewalks and streets, high traffic  
29 control and safety services cost, significant obstacles in the ground (other  
30 service provider wires, pipes, etc.), high permitting costs and number of  
31 requirements.

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- 1 • Number of associated services – The average number of services to be renewed  
2 with the installed main is a significant driver of project cost, as every service  
3 renewal requires material and labor time, and contributes to the required support  
4 services needed for a project (such as sewer locates, hydrovac excavation,  
5 aggregates, and soft and hard surface restoration). A project with 50 services  
6 per mile will contribute less cost related to service renewals than a project with  
7 100 services per mile.
- 8 – Additional considerations include if the services are long side (crossing the  
9 road from the installed main location) or short side (same side of the road  
10 as the installed main), the number of services on a project that are tie-over  
11 (connecting a previously installed plastic service line to the new installed  
12 main) versus renewal (replacing vintage service pipe), and whether a service  
13 is residential or commercial (requires a different meter and larger service  
14 pipe diameter than residential).
- 15 – Completion of long side services typically takes longer and costs more than  
16 short side, renewals typically take longer and cost more than tie-overs, and  
17 commercial services typically take longer and cost more than residential  
18 services.
- 19 – Commercial services require more costly equipment and material, a higher  
20 skilled employee, and more coordination with the business owner.
- 21 – Exhibit A-84 (KAP-6) provides data on services worked on through the  
22 EIRP Program for 2018 - 2023 and a projection of 2024 through 2026 sorted  
23 by Michigan regional locations where the work is located (SW is primarily  
24 the Jackson, Lansing, Kalamazoo areas; NE is primarily the Flint, Saginaw,  
25 Midland, and Bay City areas; and SE is primarily the Royal Oak, Macomb,  
26 Livonia areas).
- 27 • Pipe type – High pressure (“HP”) steel segment and Transmission Operated by  
28 Distribution (“TOD”) pipe installation is significantly more complex and  
29 expensive than plastic pipe installation. In addition, pipe being retired may  
30 cause cost variations as well. For example, steel pipe may require end caps and  
31 pressure control fittings to be installed before retiring, whereas cast iron  
32 requires less resources to retire.
- 33 • Pipe size – As the size of installed pipe increases, the cost of material, labor,  
34 and associated supporting services also increase due to additional time, and in  
35 some cases, higher skilled labor, required to install the larger size pipe.
- 36 – The most common main pipe size installed on EIRP projects is 2-inch  
37 plastic; however, a large amount of 4-inch and 6-inch plastic is also  
38 installed.

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- 1                   – For larger plastic pipe, typically 8-inch and larger (but also some 6-inch),  
2                   the pipe to be installed is not in coil form (typically 500 ft in length) but is  
3                   in individual segments or “sticks” (typically 40 ft). This requires more  
4                   fusing time for these lengths as well as a more complex fusing process and  
5                   equipment (hydraulic fusing).
- 6                   – Steel pipe size installed varies based on the design requirements of the  
7                   project and is typically 10-inch or larger.
- Tables 4 and 5 below provide data on the feet of pipe installed through the  
                  EIRP Program for the years 2017 through 2023.

**Table 4: EIRP Feet of Pipe Installed by Size, Type, Year**

Year/ Size	2"P	4"P	6"P	8-12"P	2-6"S	8"S	10"S	12"S	16"S	Total
2017	344,644	44,231	11,768	3,231	700	0	0	225	0	<b>404,799</b>
2018	195,527	25,216	30,939	2	129	0	10,057	546	16,685	<b>279,101</b>
2019	192,783	32,619	32,535	1,526	386	0	8,121	12	0	<b>267,982</b>
2020	303,001	34,612	18,831	3,572	0	4,127	7,637	4,371	0	<b>376,151</b>
2021	698,773	44,554	52,279	10,620	922	428	100	22,426	0	<b>830,102</b>
2022	699,278	62,528	76,995	9,360	1,283	6,503	2	0	0	<b>855,949</b>
2023	446,536	32,497	55,590	5,624	13	28	74	34,833	0	<b>575,195</b>
<b>Total</b>	<b>2,880,542</b>	<b>276,257</b>	<b>278,937</b>	<b>33,935</b>	<b>3,433</b>	<b>11,086</b>	<b>25,991</b>	<b>62,413</b>	<b>16,685</b>	<b>3,589,279</b>

**Table 5: EIRP % of Pipe Installed by Size, Type, Year**

Year/ Size	2"P	4"P	6"P	8-12"P	2-6"S	8"S	10"S	12"S	16"S	Total
2017	85.1%	10.9%	2.9%	0.8%	0.2%	0.0%	0.0%	0.1%	0.0%	<b>100.0%</b>
2018	70.1%	9.0%	11.1%	0.0%	0.0%	0.0%	3.6%	0.2%	6.0%	<b>100.0%</b>
2019	71.9%	12.2%	12.1%	0.6%	0.1%	0.0%	3.0%	0.0%	0.0%	<b>100.0%</b>
2020	80.6%	9.2%	5.0%	0.9%	0.0%	1.1%	2.0%	1.2%	0.0%	<b>100.0%</b>
2021	84.2%	5.4%	6.3%	1.3%	0.1%	0.1%	0.0%	2.7%	0.0%	<b>100.0%</b>
2022	81.7%	7.3%	9.0%	1.1%	0.1%	0.8%	0.0%	0.0%	0.0%	<b>100.0%</b>
2023	77.6%	5.6%	9.7%	1.0%	0.0%	0.0%	0.0%	6.1%	0.0%	<b>100.0%</b>
<b>Total</b>	<b>80.3%</b>	<b>7.7%</b>	<b>7.8%</b>	<b>0.9%</b>	<b>0.1%</b>	<b>0.3%</b>	<b>0.7%</b>	<b>1.7%</b>	<b>0.5%</b>	<b>100.0%</b>

- 8                   • Permitting requirements – These vary from community to community and have  
9                   the potential to significantly impact project costs. Municipalities have  
10                  expanded the scope of permitting requirements, moving to more specific  
11                  permitting (by address / premises), permitting fees have increased, and the more  
12                  detailed requirements result in increased cost to projects. Also, some  
13                  communities have placed permit conditions that require dual mains be installed  
14                  on projects, resulting in significant increases to the cost of those projects.
- 15                  • Time of year – Challenging weather conditions in the winter, spring, and late  
16                  fall (such as cold, snow, thunderstorms, heavy wind and rain, and poor ground  
17                  conditions) can slow production and lead to increased project cost.  
18                  Additionally, to reduce customer outages during critical heating seasons, the  
19                  Company transitions into “winter operations” typically in early November  
20                  (temperature dependent), which requires customer appointment and presence to

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1 perform the work. This adds costs as it can require labor resources to work  
2 during non-regular time, resulting in overtime and premium time.

- 3
- 4 • Standard pressure conversions - A standard pressure conversion is a cost-saving  
5 measure used by the Company during standard pressure replacement projects.  
6 When there is existing plastic pipe within the project area, the Company  
7 assesses whether these can be converted to medium pressure instead of being  
8 replaced. If the existing plastic pipes are still within their usable life cycle,  
9 converting them is more economical than installing new plastic pipes. Although  
10 this conversion work increases the cost-per-mile of a project, since it doesn't  
11 involve laying new pipes, it ultimately reduces overall costs by avoiding the  
need for all-new plastic piping.

12 Some additional drivers of costs include:

- 13
- 14 • Sewer location services – As with all utilities, Consumers Energy locates  
15 underground facilities in advance of construction work. Locating sewer mains,  
16 laterals, and services helps to protect those facilities from damage such as  
17 cross-bores and leaves customer sewer lines intact. Sewer locating services are  
18 contracted to third-party vendors for this work and are primarily performed for  
the location of sewer mains at the onset of the program.
  - 19 • Dual main installation - Some communities have placed conditions in the  
20 permits for projects that require the Company to install main on both sides of  
21 the road when replacing and retiring the existing vintage main, which  
22 historically was only required to be installed on one side of the road. This  
23 requirement in effect doubles the footage of main pipe installation for a project,  
24 increasing the cost of materials, labor, and the supporting services for the  
25 project.
  - 26 • Cross bore inspections – This work helps ensure that Company Gas facilities  
27 were not installed through sewer lines or other utilities while using horizontal  
28 directional drilling pipe installation techniques. Given the potential risk with  
29 cross bores, the Company is inspecting for them after construction work is  
30 completed (though all other underground facilities are now being located and  
31 marked) to ensure public safety, which is adding to costs.

32 **Q. Will all the remaining EIRP Program work be completed using the grid approach?**

33 A. No. It will always be necessary to have certain project work completed using the segment  
34 project approach. The grid approach can be used in areas where the Company has a high  
35 concentration of EIRP vintage main distribution pipe to be replaced, allowing for the  
36 design and planning of large projects. As EIRP work is completed in the high concentration

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1 areas, it will be necessary to complete the replacement of vintage main distribution pipe in  
2 areas where the Company only has a small amount of EIRP pipe to replace. The Company  
3 also considers pipe risk in its planning and project selection criteria, which will result in  
4 some amount of segment projects to be completed each year based on risk selection. The  
5 Company is also replacing HP steel pipe and TOD pipe as part of the EIRP, and that work  
6 is planned as segment projects. For the test year of November 1, 2025 through October 31,  
7 2026, a significant amount of the planned project work to be completed by the EIRP will  
8 be using the segment project approach and that is the basis for the Company's current test  
9 year cost projection.

10 **Q. Is the Company planning to complete high pressure steel and other pipe replacement**  
11 **work within the EIRP Program?**

12 **A.** Yes. The Company plans to complete HP steel and TOD steel pipe projects in 2024, 2025,  
13 and 2026. In 2024, the GVL1 segment project includes 7 miles, and the MAC3 segment  
14 project contains 1.24 miles of HP steel pipe installation. In 2025 and 2026, the Company  
15 is planning several projects with varying lengths of HP steel pipe replacement, totaling  
16 21.5 miles and 14.1 miles, respectively. See Table 6 below for a summary of the 2024 to  
17 2026 EIRP steel project work planned. A listing of the specific projects is included in  
18 workpaper WP-KAP-3.

**Table 6: 2024 – 2026 EIRP HP/Steel Project Miles**

	<b># Projects</b>	<b>Southwest</b>	<b>Northeast</b>	<b>Southeast</b>	<b>Total Miles</b>
2024	2	7.04	0	1.20	8.24
2025	12	4.5	16	1	21.5
2026	8	10.5	2.5	1.1	14.1

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1 **Q. Has the Company taken actions to improve the cost per mile in the EIRP since the**  
2 **filing of Case No. U-21308?**

3 A. Yes, the Company has implemented changes expected to mitigate the cost-per-mile for  
4 EIRP projects. The Company has taken the following actions:

- 5 • Engineering design timing – the Company has advanced the engineering design  
6 process so that EIRP project designs are completed the year prior to  
7 construction. This provides partnering teams such as Supply Chain, Permitting,  
8 and Operations more time to focus on planning the execution phase of the  
9 project, including materials management, sequencing of the construction  
10 phases, aligning workforce resources, arranging outside services, and other  
11 activities.
- 12 • Engineering designs – the Engineering team has implemented design  
13 checkpoints at thirty, sixty, and ninety percent completion milestones. The  
14 checkpoints provide opportunities for analysis, evaluation, and feedback by  
15 stakeholders, allowing the Engineering team to alter designs, if necessary,  
16 throughout the design process.
- 17 • Distribution Engineering Services – created a dedicated team to support field  
18 resources in construction planning, collecting asset information, making design  
19 adjustments, and completing as-built records. This provides real-time input and  
20 adjustments with engineering resources to increase efficiency and reduce unit  
21 costs.
- 22 • Redistributed Company headquarters for the Gas Construction Workforce – the  
23 Company has redistributed the Gas Construction headquarters to move the  
24 workforce closer to the projects based on the updated work plans. This allows  
25 the workforce to be repositioned closer to the worksite, thereby reducing travel  
26 and other related costs. In 2022, travel and lodging costs totaled \$1.8 million.  
27 In 2023, these costs were reduced to \$480,416, saving over \$1.3 million. For  
28 2024, travel and lodging costs are projected to be \$690,422, which is a projected  
29 savings of \$1.1 million compared to 2022 levels. The new headquarters will be  
30 used for the remainder of the EIRP, with a projected annual savings of  
31 \$1 million in travel and lodging from 2022 levels. The facilities' projected total  
32 cost is \$11 million, but the projected savings in travel and lodging of  
33 \$13 million results in an overall savings of \$2 million. Information on the  
34 additional EIRP Company headquarters can be found in the testimony and  
35 exhibits of Company witness Quentin A. Guinn.
- 36 • Gas Construction workforce stabilization – the workforce capacity is enhancing  
37 due to stability in the project layout, ability to pre-plan the work because of  
38 earlier designs, and productivity learnings from the EIRP grids.

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1 **Q. What cost per mile is the Company currently projecting for the EIRP projects?**

2 A. As shown in Exhibit A-84 (KAP-6),

3 For SP/MP projects (plastic pipe):

- 4 • 2023: The overall project cost-per-mile for installed plastic pipe was  
5 \$1,625,519.
- 6 • 2024: The projected overall cost-per-mile is \$1,353,912 for installed plastic  
7 pipe. This is based on regional costs of \$1,306,077 (Southwest), \$1,382,187  
8 (Northeast), and \$1,365,542 (Southeast).
- 9 • 2025: The overall projected cost-per-mile is \$1,357,800, with no escalation in  
10 projected regional cost-per-mile due to process improvements.
- 11 • 2026: To account for anticipated increases such as inflation, supply chain, and  
12 labor cost, a 3% increase is applied to 2025 regional cost-per-mile, resulting in  
13 a projected overall cost-per-mile of \$1,404,251, which is still less than the 2023  
14 actual cost per mile.

15 For HP steel/TOD projects (steel pipe):

- 16 • 2024: The projected cost-per-mile is \$1.98 million for the GVL1 project and  
17 \$4.56 million for the MAC3 project.
- 18 • 2025: The cost-per-mile is projected at \$3.8 million, based on the average of  
19 the cost-per-mile from 2018 to 2023 steel projects.
- 20 • 2026: To account for anticipated increases such as inflation, supply chain, and  
21 labor cost, a 3% increase is applied to 2025 cost-per-mile, resulting in a  
22 projected cost-per-mile of \$3.91 million.

23 **Q. What is the Company's projected EIRP cost for the test year 12 months ending**  
24 **October 31, 2026?**

25 A. The capital expenditures for EIRP were \$181,926,631 in 2023 and are projected to be  
26 \$195,587,000 for 2024; \$207,322,000 for the 10 months ending October 31, 2025; and  
27 \$251,372,000 for the test year 12 months ending October 31, 2026. The costs for the EIRP  
28 are set forth on Exhibit A-82 (KAP-4), line 1. As shown below in Table 7, the test year  
29 projects 149.0 installed miles and renewal of 9,175 services.

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1 **Q. How many miles of distribution main installation and associated services does the**  
2 **Company plan to complete for the \$251.4 million investment for the test year?**

3 A. The referenced \$251.4 million supports the annual installed mileage required to ensure  
4 program completion by 2035. The Company prepares its estimates and projections based  
5 on calendar years running from January 1 through December 31. For the test year of  
6 November 1, 2025, through October 31, 2026, the Company combined a prorated  
7 projection for two months of 2025 and a prorated projection for the ten months of 2026 to  
8 provide the projected miles installed and service figures. The projection methodology is  
9 based on the monthly cash flow average percentage, using the three-year historical period  
10 of 2021 through 2023. The derivation of the test year projection is 17% of the 2025  
11 projection and 83% of the 2026 projection.

- 12 • The Company's projection for the calendar year 2025 includes 142.0 miles of main  
13 installation and 12,528 associated services. There are 12 HP Steel/TOD segment  
14 projects for 21.5 miles. The remaining 2025 projects include an additional 120.5 miles  
15 of plastic pipe installation.
- 16 • The Company's projection for the calendar year 2026 includes 150.3 miles of main  
17 installation and 11,903 associated services. There are eight HP Steel/TOD segment  
18 projects for 14.1 miles. The remaining 2026 projects include an additional 136.2 miles  
19 of plastic pipe installation.
- 20 • While total miles and services are subject to final project designs and construction  
21 schedule, based on the current projections the test year is estimated to include  
22 approximately 149.0 miles of main installation and 9,175 associated services.
- 23 • Table 7 below provides a summary for the years 2023 through 2026 and the test year.

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**Table 7: EIRP 2023-2026 Scope and Cost**

Year	Actual	Projected	Projected	Projected	Projected	Projected
	2023	2024	2025	2026	10 months 1/1/25- 10/31/25	Test Year 11/1/25 – 10/31/26
<b>Installed Pipe (Miles) <sup>1</sup></b>	108.9	134.6	142.0	150.3	117.6	149.0
<b>Service Counts <sup>1</sup></b>	8,649	12,114	12,528	11,903	8,748	9,175
<b>Capital Cost (\$Millions) <sup>2</sup></b>	\$181.9	\$195.6	\$250.3	\$251.6	\$207.3	\$251.4

**1** Includes total figures for all EIRP Program pipe installation and service counts for a year

**2** Includes total EIRP capital spend without COR (cost of removal) for a year

1 **Q. Please highlight the customer benefits of the vintage main distribution pipe and**  
2 **services replacement.**

3 A. Major gas utilities throughout the country are embarking or undergoing major replacement  
4 projects, and some utilities are undertaking these projects under urgent timeframes due to  
5 incidents on their systems. The well-planned, thoughtful execution of the EIRP is a more  
6 cost-effective approach than being forced into replacement under emergent conditions for  
7 several reasons including:

- 8 • **Cost Control:** Planned replacements allow for better budgeting and cost  
9 management. The Company can negotiate better prices for equipment and  
10 services, avoiding the premium costs often associated with emergency  
11 procurements.
- 12 • **Minimized Downtime:** Scheduled replacements can be coordinated to minimize  
13 operational and customer disruptions. In contrast, emergent replacements often  
14 result in unexpected downtime, which can be costly in terms of lost productivity  
15 and potential extended customer outages.
- 16 • **Resource Allocation:** With a planned approach, the Company can allocate  
17 resources more efficiently, ensuring that skilled personnel and necessary tools

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1 are available when needed. Emergencies often require pulling resources from  
2 other projects.

- 3 • Risk Management: Proactive planning helps identify potential issues before  
4 they become critical, reducing the risk of catastrophic failures that can be far  
5 more expensive to address.

6 By taking a proactive approach, the Company can avoid the high costs and operational  
7 disruptions associated with emergency replacements. This leads to more efficient and  
8 cost-effective operations while minimizing the impact of service disruptions to customers.  
9 The Company continues to evaluate the risks to the distribution system along with the  
10 overall timeframe projected to replace higher risk pipe. Through December 31, 2023, the  
11 Company has replaced 794 miles of high-risk pipe identified for replacement through the  
12 EIRP, including 287 miles of cast iron and nearly 96,850 services replaced and retired to  
13 improve reliability and customer safety.

14 **Q. Does the Company expect to meet the spending and installed miles requirements for**  
15 **EIRP from the Case No. U-21308 settlement agreement?**

16 A. Yes, the settlement agreement from Case No. U-21308 included spending at \$214 million  
17 and 110.8 miles of main replacement in the EIRP for the 12 months ending September 30,  
18 2024. The Company completed 126.1 miles of main replacement for \$197.6 million and  
19 had facilities expenditures of \$6 million, totaling \$203.6 million for the 12 months ending  
20 September 30, 2024.

21 **Q. What is the purpose of the Material Condition Non-Modeled Program?**

22 A. The projects in the Material Condition Non-Modeled Program are Company-initiated  
23 replacements to address emergent issues that must be resolved to comply with regulations  
24 or to ensure public and/or employee safety, and to target certain assets which may not rank

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1 as highly in the Company's risk modeling but whose replacements offer operational  
2 advantages to the Company and customers. Projects include issues associated with:

- 3 (i) Emergent Replacements / Leak Mitigation (i.e. main or service replacements  
4 due to active gas main damages, leaks, or temporary repairs that need to be  
5 resolved within the year);
- 6 (ii) Safety situations (i.e. saddle tee replacements);
- 7 (iii) Cathodic issues (i.e. cathodic shorts and atmospheric corrosion);
- 8 (iv) Company-initiated work to resolve standards discrepancies or customer  
9 issues (i.e. obsolete fittings or materials); and
- 10 (v) Projects based on operational improvements that may not be represented  
11 effectively in risk model results (and therefore are not EIRP projects).

12 The combination of these items results in hundreds of small replacements annually that are  
13 emergent in nature. The Company's capital expenditures for this program were  
14 \$38,516,000 in 2023 and are projected to be \$38,256,000 for the year 2024; \$36,358,000  
15 for the 10 months ending October 31, 2025; and \$56,206,000 for the test year 12 months  
16 ending October 31, 2026. The costs for the Material Condition Non-Modeled Program are  
17 set forth on Exhibit A-82 (KAP-4), line 2, and are further detailed later in this direct  
18 testimony. The increase in the capital expenditures for this program in the test year is due  
19 to the wrought iron replacement and HP waterway crossing initiatives described below  
20 which have projected expenditures of \$5 million each in the test year. In addition, the  
21 program is increasing projected capital expenditures in Company-initiated work for leak  
22 mitigation at \$4 million and 5,500 obsolete residential meter replacements at \$3.7 million.  
23 Additional details on leaks and obsolete meters are included below in the Material  
24 Condition Renewals program. Projects completed under the Non-Modeled program are  
25 listed in the Non-Modeled program database and are designed by Distribution Engineering.

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1 Projects that are initiated in the field and handled immediately by field personnel are  
2 included in the Material Condition Renewals program.

3 **Q. What is the impact of the NGDP on the Material Condition Non-Modeled Program?**

4 A. The objectives outlined in the NGDP moves the Company toward finalizing EIRP project  
5 areas earlier to complete design, and align with affected municipalities and stakeholders,  
6 increasing the overall timeline allowed for design and construction planning. While this is  
7 beneficial overall, and will positively impact the Company's EIRP, it reduces the flexibility  
8 of the EIRP to add projects to address emergent issues on the system. This approach allows  
9 for a balanced mix of EIRP and Non-Modeled work to continue with the long-term plan  
10 and address system issues as they arise. Therefore, the Company is expecting a sustained  
11 level of Material Condition Non-Modeled spending to address emergent issues for the test  
12 year. Even though vintage infrastructure is being replaced, what remains continues to  
13 deteriorate. In the long-term, enough vintage material will be replaced to allow for  
14 reductions in this program, but with the EIRP ending in 2035, the Company expects that  
15 reduction to occur beyond the test year in this case.

16 **Q. Please describe the importance of replacing the Company's standard pressure system  
17 through projects in the Material Condition Non-Modeled Program.**

18 A. The Company's standard pressure system, also called utilization or low-pressure system,  
19 is made up primarily of cast iron main. In most instances, cast iron main was installed  
20 from the early 1900s through the 1920s. Due to the vintage and the construction method  
21 used when the cast iron gas mains were installed, the joints between each segment of main  
22 will leak if the pressure is too high. These same connection points allow water to infiltrate

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1 the gas main when the pressures in the ground are higher than the pressure of the gas inside  
2 the gas main. This causes customer interruptions and other operating problems.

3           Within a standard pressure system, some meters have a regulator on them but not  
4 all do, meaning that if an overpressure situation were to occur on the gas main, there is not  
5 a device at each home or business preventing that higher pressure from reaching the  
6 customer's equipment. There are several areas of the state where there are very few miles  
7 of cast iron main remaining in that area or system. Replacing these sections allows the  
8 operating pressure in that entire area to be increased, ensuring that the benefits of the new  
9 system, such as improved safety and reliability, are equitably distributed across all  
10 communities, particularly those disproportionately affected by past infrastructure issues.  
11 Additionally, with elimination of the standard pressure system, each home or business will  
12 also now have a regulator installed, ensuring a consistent delivery pressure, and reducing  
13 the risk of higher pressures entering the premise. In 2023, the Company completed the  
14 elimination of the Plymouth cast iron system. This was the last cast iron system within the  
15 Livonia headquarter area. Eliminating this standard pressure system will ensure a higher  
16 level of reliability for the customers in the area. Customers will benefit from a higher level  
17 of reliability with no water infiltration, and improved safety due to regulated meters and  
18 elimination of these vintage, more leak-prone facilities.

19 **Q. Are there additional standard pressure replacements in the Company's future plans**  
20 **for the Material Condition Non-Modeled Program?**

21 A. Not at this time, however, the Company will continue to evaluate risks across the gas  
22 system and prioritize as necessary, which may result in additional standard pressure  
23 replacement projects.

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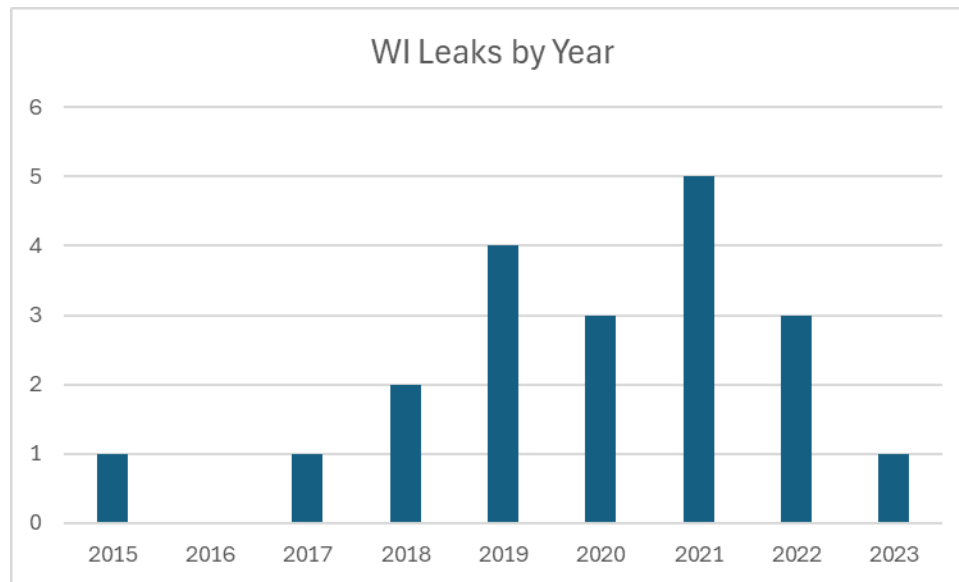
1 **Q. Please describe the importance of replacing the Company's wrought iron gas main in**  
2 **the Material Condition Non-Modeled Program.**

3 A. Wrought iron gas main was generally installed in the 1920s and 1930s. The annual DOT  
4 report combines cast iron and wrought iron together in a single line item, which indicates  
5 similar treatment and characteristics in the gas industry. Cast iron mains are only operated  
6 at low pressures, specifically less than 1 psig. Wrought iron mains, however, are part of  
7 the Company's medium pressure system, with MAOPs of up to 60 psig. Due to the way  
8 wrought iron was manufactured, its material properties are inconsistent and contains  
9 inclusions of lower quality materials. Therefore, it is not possible to choose a welding  
10 procedure that ensures the quality of the finished weld is adequate for use on the gas  
11 system. This leaves the Company with limited options for coupling or compression-style  
12 fittings when a leak or damage occurs on the wrought iron system, none of which are  
13 considered permanent repairs by the manufacturers of those fittings. The other alternative  
14 is replacement of the leaking main on an emergent basis.

15           Additionally, the Company experienced an increasing number of leaks on the  
16 wrought iron system in 2018 through 2022, which is impactful given the inability to make  
17 a permanent repair.

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**Figure 2: Wrought Iron Pipeline Leaks Found 2015 – 2023**



1 With only 12 total miles of wrought iron left on the entire system, it is prudent to  
2 prioritize the replacement of these 12 miles and eliminate this issue from the system  
3 altogether. Most of this material (11 miles) is found in the smaller cities west and south of  
4 Kalamazoo, but there are small pockets in other areas of the state that make up the  
5 remaining mile. The Company plans to replace the wrought iron mains, and any  
6 intermingled other vintage material mains, under the Material Condition Non-Modeled  
7 Program over the next four years.

8 **Q. Please describe the Line 1010 project in the Material Condition Non-Modeled**  
9 **Program.**

10 A. Line 1010 is a 1950s era pipeline that was purchased by the Company from another utility.  
11 In 2020, PSHMA issued a rule adjustment to traceable, verifiable, and complete (“TVC”) records for pressure test documentation. Pipeline segments installed prior to test record  
12 requirements implemented in 1970 were previously “grandfathered,” or exempt, from  
13 original construction pressure test documentation requirements and allowed to operate at  
14

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1 the highest actual operating pressure observed between 1965 and 1970. The updated 2020  
2 rule limited this exemption to pipelines operating below 30% of the specified minimum  
3 yield strength (or “SMYS”). As a result, the Company must reconfirm the MAOP for all  
4 pre-1970 pipelines operating above 30% SMYS. Additional details on the PHMSA TVC  
5 compliance standards are included in the MAOP – Distribution projects section of  
6 Company witness Warriner’s testimony. The Line 1010 project is included in the Material  
7 Condition Non-Modeled program because it was started in 2021, prior to the establishment  
8 of the other MAOP projects discussed in the testimony of Company witness Warriner. The  
9 Company attempted to locate the original Line 1010 pressure test records, but when this  
10 line was built in 1951, there was no code requirement to maintain the records. The  
11 Company plans to replace sections of Line 1010, which will remove them from the TIMP  
12 cycle. Between 2021 and 2026, various segments of Line 1010 will be replaced or retired  
13 to establish a TVC record bringing this pipeline into compliance with the new PHMSA  
14 rule. The various projects will retire approximately 79,000 feet of existing main. The  
15 Company plans to install approximately 27,400 feet of new 12” steel HP main. The  
16 Company will also convert three services from high pressure to medium pressure.  
17 Additionally, the Company will install a 200-foot bypass near the Coolidge City Gate. The  
18 projected total cost to replace/retire the Line 1010 pipeline is \$38,000,000, with  
19 \$10,300,000 projected for 2024, \$14,900,000 projected for 2025, and \$12,800,000  
20 projected for 2026. Any new main installed as part of this project section will not operate  
21 at a pressure that creates a hoop stress greater than 20% of the specified minimum yield  
22 strength of the pipe, meaning it will not need to be inspected every six years as part of  
23 TIMP. The decision to replace the pipeline was made after exploring the option to

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1 repressure test the existing pipeline. A cost and risk analysis were completed, and it was  
2 found that it was not feasible to retest all of Line 1010 while serving the customers on the  
3 system. There is a level of impracticality and risk that is not reflected in the cost estimate  
4 for re-testing a distribution line of this length, especially when it comes to the customer  
5 meter stands. To test a segment, it is necessary to isolate each meter, and for HP customers,  
6 each HP regulator stand. These customers would be without gas for the duration of the test  
7 prep, the actual test, and the reinstatement of that section of pipe. Test durations could  
8 vary from several hours to several days based on multiple factors including the length of  
9 pipe being tested and the type of testing required. Additionally, the testing would have to  
10 be performed in rolling segments, which would require additional work to be able to isolate  
11 individual test segments.

12 **Q. Please describe the HP Waterway initiative in the Material Condition Non-Modeled**  
13 **Program.**

14 A. On April 5, 2023, at approximately 9:30 pm, Consumers Energy customers experienced an  
15 interruption affecting approximately 4,500 customers around Hastings, MI. The cause of  
16 the interruption was a HP distribution gas main that broke where the pipeline crossed the  
17 Thornapple River. Although the pipeline was originally designed and installed in  
18 compliance with standards of the time, the flow of the river current appeared to have  
19 undermined the gas main, leaving it “elevated” in the waterway, with approximately 1.5 -  
20 2 feet of open water between the pipe and the riverbed it was originally installed beneath.  
21 This elevated crossing allowed debris and water flow to exert unintended structural stresses  
22 on the pipeline, which led to an overload condition during flooding and caused a failure at  
23 a girth weld. An evaluation of the distribution system’s GIS mapping overlaid with state

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1 hydrologic data, identified 442 total potential HP water crossings. Those 442 crossings  
2 have been evaluated by reviewing records and standards and performing field visits to  
3 validate/augment the data. The Company's risk models have been updated with the results  
4 and 15 additional pipe segments were identified as exposed or visible in a flowing  
5 waterway. A replacement plan has been created to remediate these over the next three  
6 years (2025-2027).

7 **Q. Please describe the Material Condition Commercial/Industrial Meters Program.**

8 A. The Material Condition Commercial/Industrial Meters Program includes the replacement  
9 of several commercial and industrial meter stands due to corrosion of the stand, obsolete  
10 regulation equipment, or excessive maintenance requirements. Replacement of obsolete  
11 equipment that the Company can no longer acquire parts for is prudent to ensure reliability  
12 for these large customers. Replacement of the stands that have excessive corrosion  
13 developing or excessive maintenance requirements is reasonable for both safety and  
14 reliability for that customer. These replacements are prioritized each year through  
15 collaboration between the Gas Commercial and Industrial Service team within Gas  
16 Operations, and the Metering and Regulation Engineering team within Gas Asset  
17 Management.

18 **Q. Can you please explain the expenditures in the Material Condition Commercial/  
19 Industrial Meters Program?**

20 A. In 2023, \$1,863,000 was spent to complete the Lansing Board of Water and Light project  
21 in addition to the replacement of four meter stands for other customers at a cost of  
22 \$821,000. The projection is to replace nine stands in 2024 and thirteen additional in 2025.  
23 The Company's capital expenditures for this program were \$2,684,000 in 2023 and are

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1 projected to be \$1,300,000 for 2024; \$1,634,000 for the 10 months ending October 31,  
2 2025; and \$2,391,000 for the test year 12 months ending October 31, 2026, respectively.  
3 The costs for the Material Condition Commercial/Industrial Meters Program are set forth  
4 on Exhibit A-82 (KAP-4), line 5.

5 **Q. Can you explain the purpose of the Material Condition Renewals Program?**

6 A. The Material Condition Renewals Program is part of a Company initiative to reduce  
7 actionable leaks through full-service replacement versus repair or reclassification of leaks.  
8 The distinction between the Material Condition Non-Modeled Program and the Material  
9 Condition Renewals Program is that the decision to renew the facility is done by field  
10 personnel on an immediate, emergent basis in the Material Condition Renewals Program.  
11 The program orders are created and completed in the field, are not contained within the  
12 Non-Modeled program database, and are directly related to active gas leaks on gas main  
13 and/or services. The capital expenditures for the Material Condition Renewals Program  
14 were \$31,816,000 in 2023 and are projected to be \$31,872,000 for 2024; \$30,666,000 for  
15 the 10 months ending October 31, 2025; and \$33,182,000 for the test year 12 months  
16 ending October 31, 2026, respectively. The historical and projected expenditures are  
17 detailed on Exhibit A-82 (KAP-4), line 3.

18 **Q. Can you please explain the expenditures in the Material Condition Renewals**  
19 **Program?**

20 A. The Material Condition Renewals Program focuses on addressing urgent issues that arise  
21 in the field, ensuring compliance with regulations and maintaining safety for both the  
22 public and employees. The capital expenditures, shown below in Table 8, in this program

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1 are allocated to projects that are initiated as a response to these emergent issues. The  
2 program is divided into four main areas:

- 3 • Leak Renewals - Main: This involves replacing main pipelines that have  
4 developed leaks.
- 5 • Leak Renewals - Services: This covers the replacement of service lines that are  
6 leaking.
- 7 • Leak Renewals – Meter Stands: This area focuses on renewing meter stands  
8 that have leaks.
- 9 • Damages: This includes field-initiated repairs and replacements due to  
10 discovered damages.

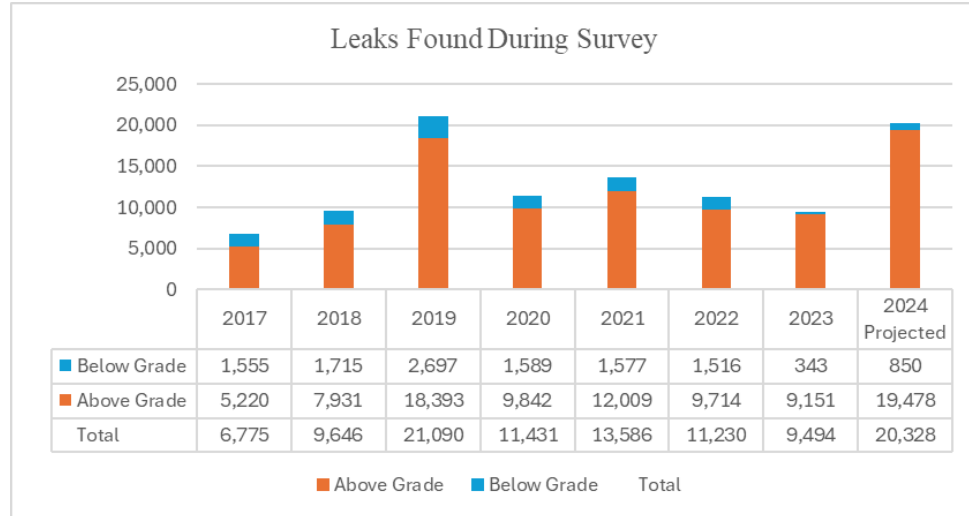
**Table 8: Material Condition Renewals Expenditures**

	Historical Year 12 Mos Ended 12/31/2023	Projected 12 Mos Ending 12/31/2024	Projected 10 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026
(\$000)				
<b>Leak Renew Main</b>	\$ 7,157	\$ 2,007	\$ 3,679	\$ 4,328
<b>Leak Renew Service</b>	\$ 13,866	\$ 15,170	\$ 11,806	\$ 13,889
<b>Leak Renew Mtr/Stand</b>	\$ 1,745	\$ 2,107	\$ 1,015	\$ 1,195
<b>Damages</b>	\$ 9,047	\$ 12,589	\$ 14,165	\$ 13,770
<b>Total</b>	<b>\$ 31,816</b>	<b>\$ 31,872</b>	<b>\$ 30,666</b>	<b>\$ 33,182</b>

11 Each of these areas ensures that the infrastructure remains safe and compliant with  
12 necessary regulations. Most new leaks are found during Leak Survey. Each year different  
13 sections of the system are inspected, which drives fluctuations in the number of leaks found  
14 annually. The historical and projected number of leaks found during Leak Survey is  
15 summarized in Figure 3.

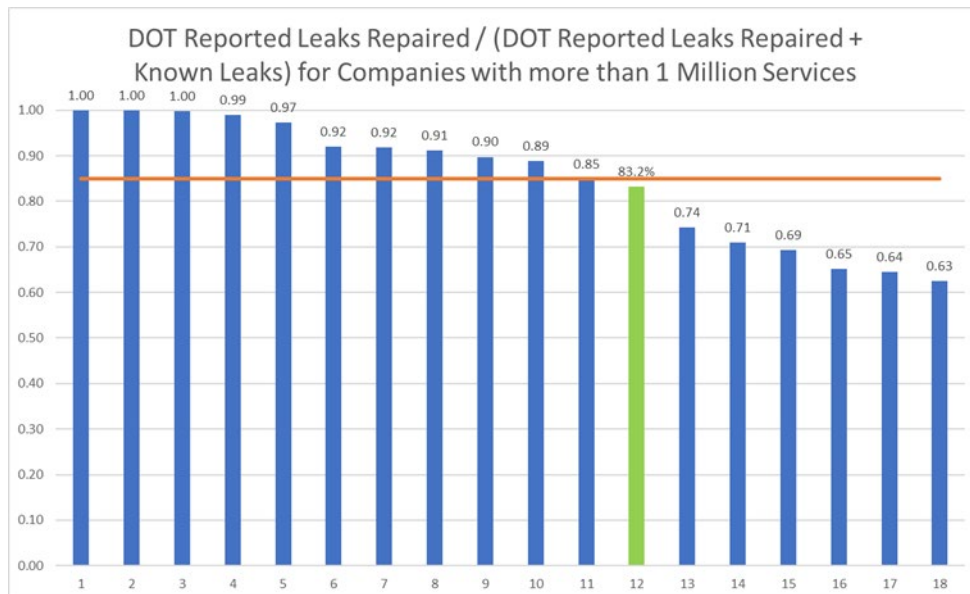
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**Figure 3: Total Number of Leaks Found During Leak Survey**



1 Additionally, Figure 4 below depicts a comparison of the percentage of leaks repaired for  
 2 similarly sized gas companies, those with more than 1 million customers, and is based on  
 3 the annual Federal DOT report information. This graph depicts the ratio of leaks repaired  
 4 to the sum of leaks repaired and open leaks at year end for companies with vintage main  
 5 as part of their system.

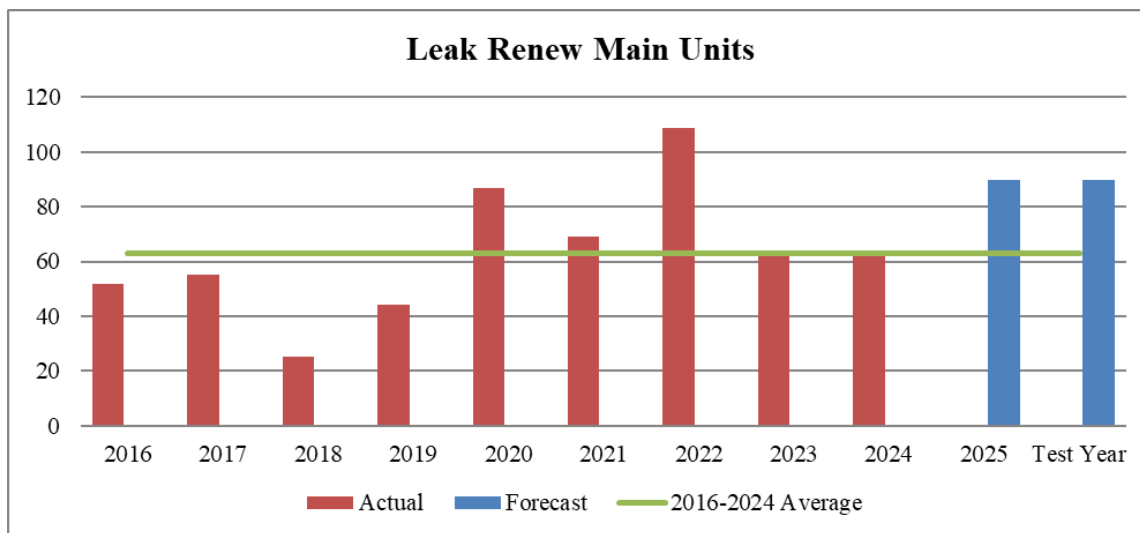
**Figure 4: Industry Comparison of Leaks Repaired to Total Leaks**



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1 Consumers Energy is represented in green (column 12) and had a performance rate of  
 2 83.2% as of December 2023, which is below the industry average of 85%. Based on the  
 3 benchmark data shown in Figure 4, the Company aims to reach the first quartile, which  
 4 will enhance system integrity and public safety. To achieve this, the Company will continue  
 5 to replace leaking metallic services and mains rather than repair them. This approach  
 6 prevents future leaks on the same service or main and reduces methane emissions. This  
 7 replacement work will reduce the number of leaks being managed by the Company at any  
 8 given point in time, eliminating the need for repeat repairs on previously leaked services  
 9 or mains. The Company plans to eliminate Grade 2 leaks by January 2026 and will continue  
 10 to reduce Grade 3 leaks through the test year. Figures 5 through 7 illustrate the historical  
 11 and projected unit counts for gas main, service, and meter stand replacements.

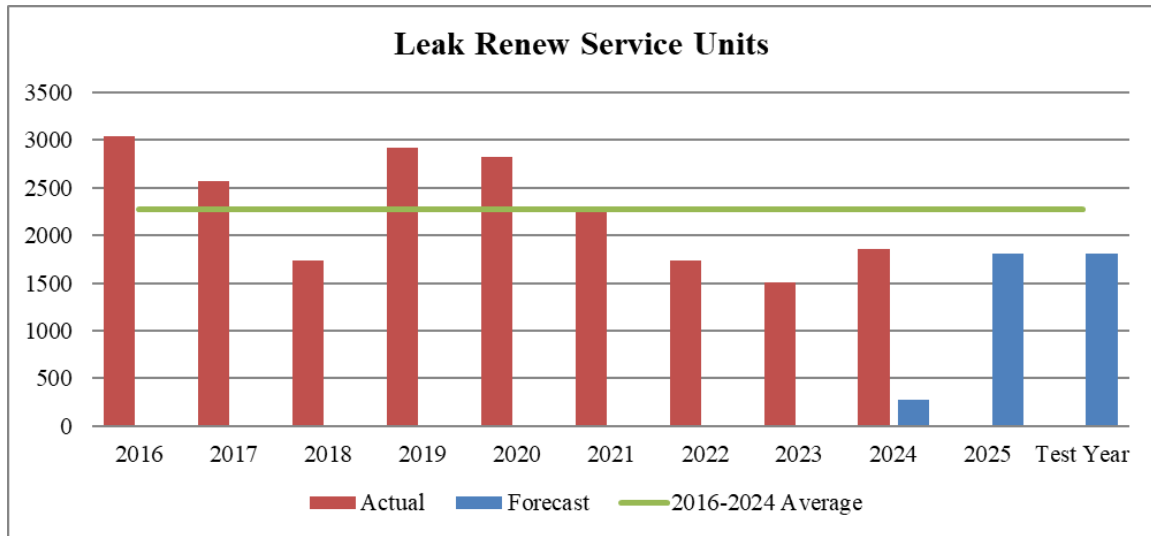
**Figure 5: Gas Main Renewal Projects**



Leak Renew Main	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Test Year
<b>Actual</b>	52	55	25	44	87	69	109	62	62		
<b>Projected</b>										90	90
<b>Actual Cost (\$000)</b>	\$ 930	\$1,119	\$ 377	\$2,405	\$5,590	\$4,522	\$3,065	\$7,157	\$2,007		
<b>Projected Cost (\$000)</b>										\$4,328	\$ 4,328

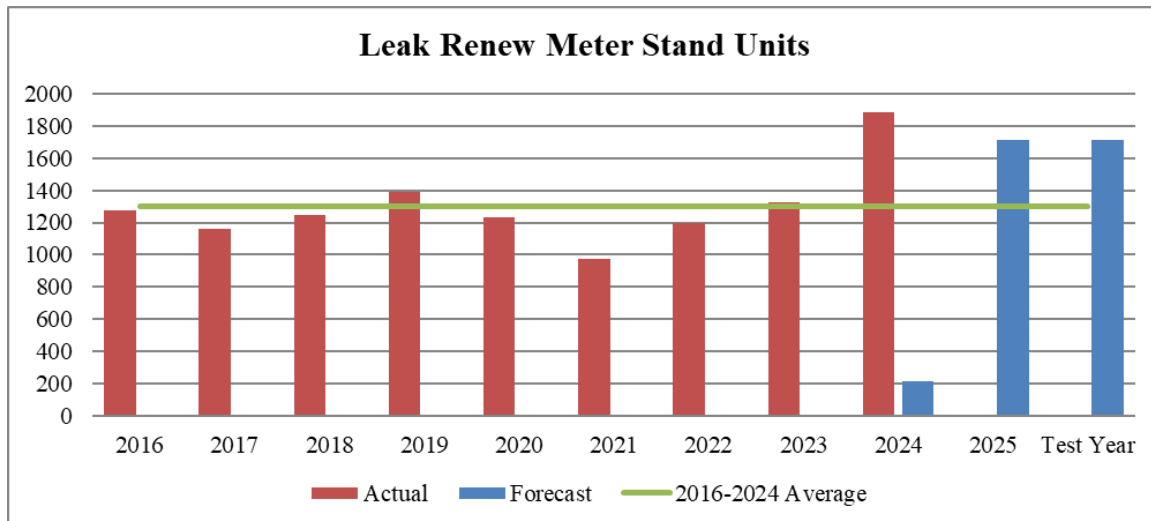
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Figure 6: Gas Service Renewal Projects



Leak Renew Service	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Test Year
Actual	3,043	2,571	1,740	2,918	2,824	2,302	1,732	1,512	1,859		
Projected									270	2,030	2,030
Actual Cost (\$000)	\$ 11,765	\$ 11,250	\$ 10,226	\$ 19,657	\$ 22,788	\$ 21,537	\$ 16,040	\$ 13,866			
Projected Cost (\$000)									\$ 15,170	\$ 13,889	\$ 13,889

Figure 7: Gas Meter Stand Renewal Projects



Leak Renew Mtr/Stand	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Test Year
Actual	1,274	1,163	1,246	1,393	1,231	974	1,195	1,325	1,881		
Projected									216	1,715	1,715
Actual Cost (\$000)	\$ 334	\$ 349	\$ 474	\$ 723	\$ 788	\$ 740	\$ 1,027	\$ 1,745			
Projected Cost (\$000)									\$ 2,107	\$ 1,195	\$ 1,195

1 This program includes funding within the Damages category to replace obsolete regulated  
2 meter stands. The Customer Metering section of the NGDP explains that the sole-sourced

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1 Regulated Meter (“RM”) residential gas meter was discontinued in 2021. This meter type  
2 is the most common in Consumers Energy’s gas system. As the Company’s RM inventory  
3 decreases, it will be necessary to replace RM meter stands with industry-standard  
4 top-connect meter stands due to the different connection methods of each type of meter.  
5 These new stands will feature a temperature-compensated top-connect gas meter and a  
6 separate pressure regulator. To meet meter exchange requirements and minimize extended  
7 customer outages during emergent meter exchanges, the Company will continue  
8 converting meter stands in 2024. The projected cost for rebuilding 20,000 meter stands is  
9 \$12 million.

10 **Q. Please describe the anticipated requirements to comply with Leak Detection and**  
11 **Repair regulations (“LDAR”).**

12 A. The Company is reviewing a PHMSA Notice of Proposed Rule Making (“NPRM”) issued  
13 on May 4, 2023, titled Gas Pipeline Leak Detection and Repair<sup>1</sup>. The publication outlines  
14 proposed revisions to numerous rules in the Minimum Federal Safety Standards for  
15 Pipelines, including Rule 192.723 and Rule 192.763 requirements for advanced leak  
16 detection equipment, enhanced leak detection practices, increased leak survey frequency,  
17 and defined repair timing for all leaks, which could increase spending in the future.  
18 Additional information on the proposed rulemaking is included in the direct testimony of  
19 Company witness Pnacek. The Company expects the rule to be published by January 2025,

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<sup>1</sup> PHMSA NPRM on Gas Pipeline Leak Detection and Repair publication:  
<https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2023-05/Gas%20Pipeline%20Leak%20Detection%20and%20Repair%20NPRM%20-%20May%202023.pdf>

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1 with an anticipated effective date six months later. Full compliance with these requirements  
2 is expected in January 2028.

3 **Q. Please describe PHMSA's LDAR requirements the Company is expecting to be**  
4 **required to comply with during the test year.**

5 A. For grade 2 leaks known to exist on or before July 2025, repairs must be completed within  
6 one year from the publication of the final rule, expected by January 2026. For grade 3 leaks  
7 known to exist on or before the effective date of the rule, repairs must be completed within  
8 three years from the publication of the final rule, expected by January 2028. In addition,  
9 for gas transmission, any leak in High Consequence Area ("HCA"), Class 3, or Class 4  
10 location known to exist by the effective date of this rule, repairs must be completed within  
11 one year from the publication of the final rule, expected by January 2026.

12 **Q. Please describe the Company's plan to comply with the Leak Backlog requirements**  
13 **of the proposed rule?**

14 A. The Company is aware of the compliance timeline proposed for this regulation but is not  
15 requesting full compliance funding for capital expenditures related to the LDAR rule in  
16 this case. The Company is seeking funding to address the known leak elimination  
17 requirements of the rule. This is due to the benefits to public safety and the desire to reduce  
18 risk. The Company plans to eliminate the backlog of known leaks at an accelerated rate,  
19 regardless of when the LDAR rule is published. An additional \$1,510,000 in capital  
20 expenditures is included in this case to address the anticipated leak backlog for the test  
21 year. Since the Final Rule has not yet been published and substantive changes could affect  
22 these projected expenditures, the Company is requesting the Commission approve the  
23 ability to defer any test year revenue requirement of capital expenditures resulting from the

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1 final rule that exceed the requested funding in this case. The regulation is anticipated to be  
2 published shortly after this case filing.

3 **Q. What impact does the NGDP have on the Material Condition Renewals Program?**

4 A. As outlined above, the Company is targeting the replacement of leaking facilities through  
5 the Material Condition Renewals Program to ensure a safe and reliable gas system. These  
6 efforts, combined with the planned replacement of vintage facilities through the NGDP,  
7 Asset Relocation – Civic Improvement, and other Material Condition programs will result  
8 in a reduction in the number of leaks on the Company’s system, leading to a reduction of  
9 methane emissions and an improvement to public safety. Replacing these facilities when  
10 responding to the leak that has occurred prevents a return trip for future additional leaks on  
11 the same vintage facility and works in conjunction with the goals of the NGDP to eliminate  
12 vintage materials. Facilities replaced under the Material Condition Renewals Program will  
13 not need to be replaced again through the EIRP or VSR Program. As stated above, in  
14 relation to other programs, the Company needs to achieve a sufficient level of replacement  
15 before the number of leaks found is expected to decrease. As more vintage facilities are  
16 replaced, the Company expects to be able to reduce expenditures in the Material Condition  
17 Renewals Program as well.

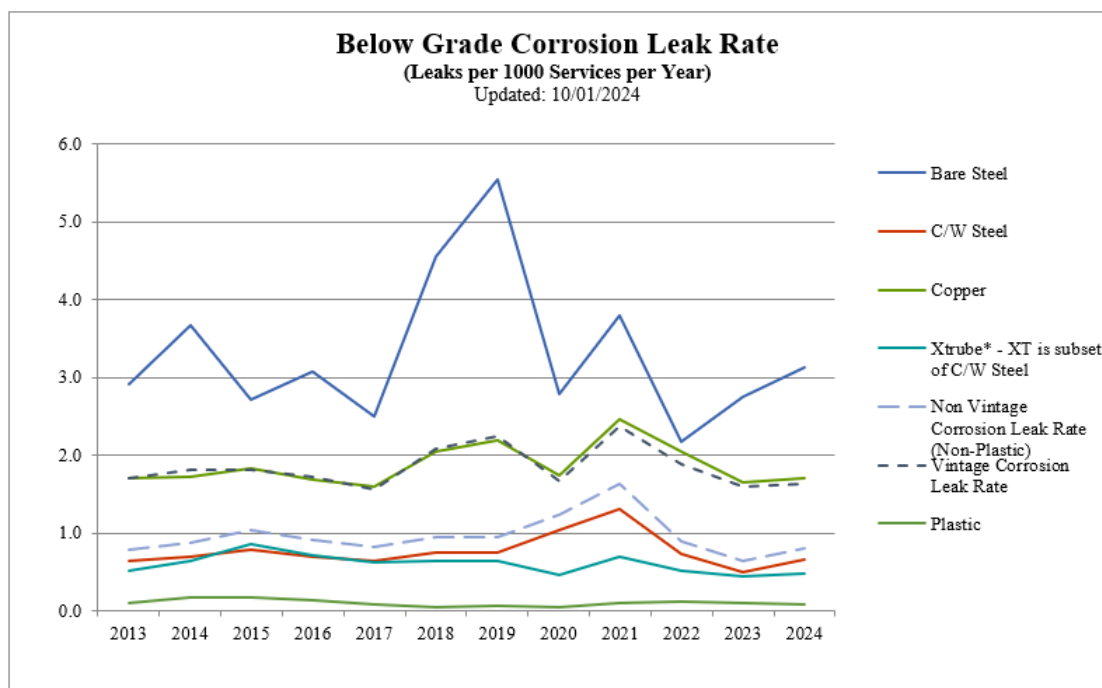
18 **Q. Please describe the VSR Program.**

19 A. The VSR Program began in 2017 and is a comprehensive approach to replacing all the  
20 Company’s copper and bare steel vintage service materials, along with services for which  
21 the material type is unknown. The Company’s goal is to programmatically replace all these  
22 service pipe types not replaced under the EIRP Distribution, Material Condition Renewals,  
23 Material Condition Non-Modeled, and Asset Relocation programs. These vintage service

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1 materials have a higher corrosion leak rate than current materials. Copper services make  
2 up approximately 85.4% of all vintage services. Figure 8 below demonstrates the corrosion  
3 leak rate on bare steel and copper services, compared to that of coated and wrapped steel  
4 and Xtrube steel services, as well as the average leak rate for vintage and non-vintage  
5 services:

**Figure 8: Below Grade Corrosion Leak Rate (As of 10/1/2024)**



6 **Q. Should the duration of the VSR Program be aligned with the timeline of the EIRP?**

7 A. There are operational advantages to aligning the VSR Program timeline with the EIRP, as  
8 discussed further below. Aligning the overall program duration with the EIRP also allows  
9 the Company to exclude any services that are on a vintage (EIRP-type) gas main in the  
10 proactive VSR Program, because those services will be replaced when the EIRP replaces  
11 the gas main. To prioritize replacement within this timeframe, the Company will target  
12 those services outlined below with the highest potential for future leaks. The Company

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1 will continue to monitor leak, age, and soil information and will adjust future vintage  
2 service replacement plans if the data demonstrates additional trends.

3 The VSR Program classifies vintage services into four categories- “In-Grid VSR,”  
4 “Proactive In-Grid VSR,” “Proactive Out-of-Grid VSR,” and “Other Programs.” When a  
5 vintage service is connected to a vintage EIRP main gas distribution pipe that is being  
6 replaced, and construction crews working on the EIRP project upgrade the service(s) along  
7 with the main, the program classifies these services as In-Grid VSRs. The VSR Program  
8 proactively replaces vintage services that are not included as part of a gas distribution main  
9 pipe replacement. When these vintage material services are replaced within an EIRP  
10 project geographic footprint, they are known as Proactive-In Grid VSRs. When these  
11 vintage material services are located outside of the planned geographic footprint of an EIRP  
12 project and the service replacement is not completed with a gas distribution main pipe  
13 replacement, they are known as Proactive Out-of-Grid VSRs. Vintage services are also  
14 replaced through other programs, including Material Condition Renewals, Material  
15 Condition Non-Modeled, Asset Relocation programs, and others. These vintage service  
16 replacements are classified as Other Programs.

17 **Q. How does the Company determine the order in which proactive vintage services will**  
18 **be replaced?**

19 A. Risk and location are the primary factors that determine prioritization. For VSRs selected  
20 through 2024, the Company used a manual analysis process that examines the leak rate  
21 along with other factors such as soil conditions and material age, of each distribution  
22 service material to prioritize replacement in accordance with the Company’s DIMP.  
23 Starting with 2025 VSRs, the Company has transitioned from the manual process to

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1 running the analysis in the Distribution Risk Analysis Model (“DRAM”). The DRAM was  
2 implemented in 2019, and is used primarily to analyze distribution pipelines, which  
3 supports the identification of EIRP projects. The Company has gained enough experience  
4 using the DRAM to apply the model to services as well. This aligns our approach to an  
5 industry standard model and will create efficiency within our engineering team.

6 **Q. Does the approach for prioritizing EIRP work impact the selection process for vintage  
7 services?**

8 A. The EIRP approach plans for the replacement of all vintage services within the EIRP  
9 project’s geographic footprint, allowing the Company to gain efficiency in the field. This  
10 approach enables the Company to eliminate all vintage distribution facilities in the project  
11 footprint in one trip, which reduces impacts to customers and municipalities. However,  
12 not all vintage services fall within an EIRP project where there is vintage main, and thus  
13 the Company still requires a risk-based selection process to prioritize these services.

14 For 2025 and 2026, the Company plans to replace 7,366 and 8,535 total vintage  
15 services, respectively. A breakdown of these services is described below.

- 16 • In-Grid: The Company’s forecast includes the replacement of 2,672 vintage  
17 services in 2025 and 2,122 vintage services in 2026 from In-Grid as part of the  
18 EIRP project work. The costs of these VSRs will be charged to the EIRP  
19 Program.
- 20 • Proactive In-Grid: The Company will also proactively replace vintage services  
21 within the projects targeted by the EIRP that are not connected to a vintage main  
22 pipeline. These projects will be selected for replacement based on the risk  
23 associated with the gas main in that area, but once a project is selected, all  
24 vintage facilities in that area will be replaced. For 2025 and 2026, the Company  
25 expects the selected EIRP projects to contain approximately 994 and 1,413  
26 proactive vintage services, respectively. As these services are not connected to  
27 a vintage main, the costs for these VSRs will be charged to the VSR Program.
- 28 • Proactive Out-of-Grid: For 2025 and 2026, there are a total of 3,200 and 4,500  
29 vintage services, respectively, that do not fall within an EIRP project, and

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1 therefore would not be prioritized in the EIRP. The costs for these VSRs will  
2 be charged to the VSR Program.

- 3 • Other Programs: For 2025 and 2026, the Company is forecasting 500 vintage  
4 service replacements each year from Other Programs.

5 **Q. How many services will be replaced under the VSR Program?**

6 A. As of December 31, 2023, the Company has removed approximately 69,000 vintage  
7 services. At the start of 2024 there were 112,157 vintage services remaining on the  
8 Consumers Energy gas system. Table 9 below outlines the actual vintage services  
9 replacement figures as well as the projections for 2024, 2025, and 2026, including the test  
10 year.

11 The Company will continue to replace vintage services as part of EIRP Distribution,  
12 Material Condition Renewals, Material Condition Non-Modeled, and Asset Relocation  
13 programs. This combined approach will continue to eliminate the highest risk services on  
14 the Company's distribution system, which increases safety for customers and the public.  
15 Additionally, eliminating the highest risk vintage services will reduce the number of future  
16 gas leaks on those services and reduce greenhouse gas emissions. This approach is  
17 consistent with the Company's DIMP plan, and per that plan, will be monitored regularly  
18 for effectiveness.

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**Table 9: Vintage Services Replacements**

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Projected 2024	Projected 2025	Projected 2026	Projected 12 Mos Ending 10/31/2026
<b>VSR Program Units</b>	6,307	9,381	5,571	5,456	5,056	2,176	1,228	2,875	4,194	5,913	5,827
<b>VSR Unit Cost</b>	\$5,322	\$6,037	\$7,260	\$7,848	\$6,518	\$7,888	\$9,246	\$6,493	\$6,671	\$7,389	\$7,296
<b>VSR Program Spend (\$000)</b>	\$33,564	\$56,634	\$40,443	\$42,818	\$32,955	\$17,165	\$11,354	\$18,666	\$27,978	\$43,689	\$42,513
<b>EIRP/Other Programs</b>	5,169	4,042	4,064	4,291	5,245	8,235	3,576	3,476	3,172	2,622	2,677
<b>Total Services Replaced</b>	11,476	13,423	9,635	9,747	10,301	10,411	4,804	6,351	7,366	8,535	8,504
<b>Total Services Remaining</b>	170,478	157,055	147,420	137,673	127,372	116,961	112,157	105,806	98,440	89,905	81,401

1           The capital expenditures for the VSR Program were \$11,354,000 in 2023 and are  
2 projected to be \$18,666,000 for 2024; \$25,885,000 for the 10 months ending October 31,  
3 2025; and \$42,513,000 for the test year 12 months ending October 31, 2026, respectively.

4           The historical and projected expenditures are detailed on Exhibit A-82 (KAP-4), line 4.

5 **Q. Does the replacement of aging pipeline facilities through the Material Condition**  
6 **programs have the potential to reduce emissions into the atmosphere?**

7 **A.** Yes. By replacing aging materials with the potential for increased leak rates, the Company  
8 is reducing the future methane emissions into the atmosphere.

9 **2. Gas Operations Other**

10 **Q. Please list the programs within Gas Operations Other capital expenditures.**

11 **A.** The five programs, as shown on Exhibit A-83 (KAP-5), page 1, are:

- 12           • Routine Computer and Equipment;
- 13           • Tools;
- 14           • Land and Right of Way (“ROW”);
- 15           • Compliance and Controls; and
- 16           • Geospatial Inventory and Modeling Program.

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1 **Q. Please describe the capital expenditures relating to the Gas Operations Other**  
2 **Program as shown on Exhibit A-12 (KAP-3), Schedule B-5.8, line 2.**

3 A. The Gas Operations Other Program expenditures were \$7,750,000 for the year 2023; and  
4 are projected to be \$16,094,000 for 2024; 11,943,000 for the 10 months ending October 31,  
5 2025; and \$17,090,000 for the test year ending October 31, 2026, as set forth on Exhibit  
6 A-12 (KAP-3), Schedule B-5.8, line 2, columns (b), (c), (d), and (f), respectively. The Gas  
7 Operations Other Program includes the following programs:

- 8 • Routine Computer and Equipment: Computer equipment includes printers,  
9 plotters, and other technical equipment. Desktop and laptop computers for  
10 existing employees are not included in this program as they are purchased  
11 through the Information Technology (“IT”) department.
  - 12 – The Routine Computer and Equipment Program expenditures were  
13 \$300,000 for the year 2023; and are projected to be \$50,000 for 2024;  
14 \$5,000 for the 10 months ending October 31, 2025; and \$50,000 for the test  
15 year ending October 31, 2026, as detailed on Exhibit A-83 (KAP-5), line 1.
- 16 • Tools: Tools for field employees are purchased as part of this program. The  
17 purchase of new tools will replace tools that are worn, broken, or outdated.  
18 Tools purchased due to safety issues that come up throughout the year that meet  
19 capitalization criteria are also part of this program. The program also includes  
20 ergonomic tools that will prevent or lower the risk of employee injury.
  - 21 – As described in the Material Condition Renewals Program section earlier in  
22 my testimony, the PHMSA issued NPRM – Gas Pipeline Leak Detection  
23 and Repair which proposes new Rule 192.763 to require that leak surveys  
24 be performed using advanced technology and practices consistent with the  
25 proposed Advanced Leak Detection Program (“ALDP”) performance  
26 standard. The proposed new rule will impact the leak detection tools  
27 purchased for employees when implemented, which the Company expects  
28 will occur within the test year of this case. However, since full compliance  
29 with the LDAR requirements is expected in January 2028, the Company has  
30 not included additional tool costs for complying with the new rule in this  
31 case.
  - 32 – The Tools program expenditures were \$5,613,000 for the year 2023; and  
33 are projected to be \$4,510,000 for 2024; \$2,472,000 for the ten months  
34 ending October 31, 2025; and \$4,510,000 for the test year ending  
35 October 31, 2026, as detailed on Exhibit A-83 (KAP-5), line 2.

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- 1 • Land and ROW: This program includes costs associated with Land and ROW  
2 specialists supporting gas distribution projects. The Land and ROW program  
3 expenditures were \$1,622,000 for the year 2023; and are projected to be  
4 \$831,000 for 2024; \$701,000 for the 10 months ending October 31, 2025; and  
5 \$849,000 for the test year ending October 31, 2026, as detailed on Exhibit A-83  
6 (KAP-5), line 3.
- 7 • Compliance and Controls Projects: These investments are made up of four  
8 projects as listed in Table 10 below. The Compliance and Controls program  
9 expenditures were \$214,000 for the year 2023; and are projected to be  
10 \$4,875,000 for 2024; \$447,000 for the 10 months ending October 31, 2025; and  
11 \$4,168,000 for the test year ending October 31, 2026, as detailed on Exhibit  
12 A-83 (KAP-5), line 4.
- 13 • Geospatial Inventory and Modeling Program: I will further describe this  
14 program later in my testimony. The description of how the projections were  
15 developed for this program are included in the O&M section of my testimony.  
16 The Geospatial Inventory and Modeling program expenditures were \$0 for the  
17 year 2023; and are projected to be \$5,828,000 for 2024; \$8,319,000 for the 10  
18 months ending October 31, 2025; and \$7,513,000 for the test year ending  
19 October 31, 2026, as detailed on Exhibit A-83 (KAP-5), line 5.

20 **Q. Please describe the capital projections for the Compliance and Controls projects.**

21 A. These investments are made up of five projects with the capital projections as listed in  
22 Table 10 below.

**Table 10: Compliance and Controls Project Detail**

(\$000)	2023 Actual	2024 Projected	2025 Projected	2026 Projected	12 months ending 10/2026
Advanced Methane Detection	\$0	\$4,650	\$265	\$3,181	\$3,181
Enterprise Contractor Oversight Dashboard	\$21	\$3	\$15	\$0	\$0
Enterprise Corrective Action Plan - Gas	\$49	\$204	\$200	\$0	\$33
Damage Prevention and MISS DIG	\$59	\$18	\$0	\$954	\$954
Other	\$86	\$0	\$0	\$0	\$0
<b>Total Compliance and Controls</b>	<b>\$214</b>	<b>\$4,875</b>	<b>\$480</b>	<b>\$4,135</b>	<b>\$4,168</b>

23 **Q. Please describe Advanced Methane Detection.**

24 A. AMD is technology designed to identify methane leaks with exceptional precision. Unlike  
25 traditional leak detection equipment that measures methane in parts per million (ppm),  
26 AMD can detect methane in parts per billion (ppb). This heightened sensitivity allows for

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1 the identification of even the smallest leaks. Additionally, AMD technology offers several  
2 advanced features including:

- 3 • Emission Rates: AMD can measure the rate at which methane is being  
4 emitted.
- 5 • Breadcrumbing: This feature helps in tracking the path of methane emissions.
- 6 • Geospatial Locations: AMD provides precise geospatial data of potential  
7 methane indications.
- 8 • Time-Stamped Datalogging: All data is logged with timestamps, providing a  
9 detailed record of methane emissions over time.

10 These capabilities make AMD a powerful tool for monitoring and managing methane  
11 emissions more effectively than traditional methods.

12 **Q. How will this technology improve the Company's capability to find leaks on the**  
13 **system?**

14 A. This technology enables the Company to find and prioritize the higher risk leaks to improve  
15 public safety. Leveraging risk-based prioritization and algorithms, the Company has  
16 implemented a Super Emitter Program, which identifies the largest methane emitting leaks  
17 on its gas distribution system for investigation and escalated remediation. AMD is also  
18 proving to be seven times more effective at locating below ground leaks, leading to  
19 enhanced public safety.

20 **Q. Please explain the benefit to the customer delivered through the AMD.**

21 A. AMD offers several key benefits to customers including:

- 22 • Enhanced Safety: By improving the Company's ability to detect and pinpoint  
23 leaks more accurately, AMD helps prioritize the remediation of high-risk leaks.  
24 This leads to a safer environment for customers.
- 25 • Risk-based Prioritization: The addition of emissions rate data allows the  
26 Company to assess and address leaks based on their potential risk, ensuring that  
27 the most significant leaks are dealt with first.

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- 1 • Increased Detection Sensitivity: With its heightened sensitivity, AMD can  
2 detect methane emissions more effectively, leading to better classification and  
3 remediation of leaks.
- 4 • Support for Environmental Goals: AMD aids the Company in its goal of  
5 achieving net zero methane emissions by identifying and quantifying large  
6 emission sources. This enables targeted and efficient remediation efforts.

7 Overall, AMD enhances the Company's ability to manage methane emissions, contributing  
8 to improved public safety and environmental sustainability.

9 **Q. What solution is the Company implementing?**

10 A. The Company is currently using a third-party vendor to develop its AMD capabilities. This  
11 decision was made after careful consideration of industry offerings, and peer-to-peer  
12 conversations and communications with utilities across the United States. The vendor is  
13 known as an industry leader in Ring-Down Spectroscopy and has many years of experience  
14 deploying this technology to solve gas utility problems, such as leak survey and emission  
15 quantification. This expertise has assisted the Company's deployment of AMD in a  
16 thoughtful and progressive way to lower risk and increase safety for customers.

17 **Q. Did the Company consider other industry offerings and equipment for comparison  
18 and testing of outputs?**

19 A. Yes, other options were evaluated for both capabilities and costs. The Company evaluated  
20 an option that it ultimately eliminated due to the cost of that solution exceeding the  
21 estimated cost to operate the selected units, which are installed in vehicles dedicated to  
22 methane detection. Another option that detects methane and ethane using a "Middle  
23 InfraRed Analyzer" instead of a "Ring-Down" sensor was not selected as it was newer to  
24 the market and there was little industry information available, particularly for large-scale  
25 implementation. The Company will periodically review the industry and market for AMD  
26 best practices and technologies.

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1 **Q. How is Consumers Energy planning on implementing this technology?**

2 A. Consumers Energy planned a two-phased AMD implementation, with methane emission,  
3 risk modeling, and super emitter work activities planned as part of Phase 1. Phase 2 of the  
4 AMD technology implementation looks to use AMD for compliance-based leak survey,  
5 and as a result of the higher quality data, analytics and algorithms can modernize and enable  
6 risk-based leak surveys. This phase will be supported by the GCCP - SIMS Conversion  
7 project described in the Geospatial Inventory and Modeling section later in my testimony.

8 **Q. Please explain the learnings from Phase 1.**

9 A. The Company conducted several case studies during Phase 1 to learn the technology and  
10 identify areas of value beyond compliance leak survey. Below are learnings from these  
11 studies.

- 12 • **Emission Quantification:** Emissions Quantification is a drive mode that is  
13 used to measure emissions based on the flow rate of indications to quantify  
14 distribution system methane emissions as well as individual indications. In  
15 2024, the Company will survey 50% of the gas distribution system to measure  
16 emissions and plans to survey 100% of the gas distribution system annually  
17 starting in 2025.
- 18 • **Source Discrimination:** It was determined that source discriminations work  
19 with AMD devices to assist in pinpointing hard-to-locate leaks or to rule out  
20 bio-gas methane that could produce false positives through current leak survey  
21 methodologies.
- 22 • **Pre/Post Construction drives:** The Company was able to drive  
23 pre-construction collecting data to determine the emissions being released and  
24 then drive again after construction to determine whether the replacement  
25 projects reduced emissions.
- 26 • **Super Emitter Survey:** While surveying in Emissions Quantification mode  
27 (explained above), the Company identifies specific indications with high flow  
28 rates, called super emitters. Most recently, in 2024, Consumers Energy is  
29 specifically targeting indications with flow rates at 30 standard cubic feet per  
30 hour (SCFH) or greater. These indications are investigated and, if confirmed,  
31 escalated for remediation regardless of the leak survey schedule. In the  
32 Company's studies, it was determined that Super emitters account for only 1.8%  
33 of the indications detected, but account for 17.6% of the total emissions.

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1 **Q. Please explain the transition from Phase 1 to Phase 2.**

2 A. In addition to the Phase 1 studies cited above, compliance leak survey testing was  
3 performed in parallel with current methodologies to prepare for Phase 2, and to determine  
4 differences in output and quality, while also identifying needed changes in standards and  
5 practices for future implementation. Traditional leak survey inspectors walked each  
6 location as the unit drove the same area, followed up by investigation of any suspected  
7 leaks, and then compared the data. On average, AMD found one indicator of a possible  
8 leak for every mile of distribution main investigated. In 2023, the Company entered  
9 Phase 2 to further develop AMD capabilities for performing compliance leak survey. In  
10 this phase, the Company will continue to refine its detection capabilities with more parallel  
11 testing and procedure refinement through 2024 to ensure it is focusing its investigations on  
12 true gradable leaks. The new AMD application hardware and software will be  
13 complemented by current asset management, work management, and analytics platforms -  
14 including the GIS; Inspection Manager; Systems, Applications, and Products (“SAP”);  
15 Service Suite; and Distribution Risk Analysis Model.

16 **Q. Please further explain the planned implementation for Phase 2.**

17 A. In 2023, AMD was used to inspect sections that were due for compliance while traditional  
18 leak survey inspectors continued their normal walking survey to get a baseline. In 2024,  
19 AMD procedures were refined and adjusted to scale up its use for compliance leak survey  
20 implementation. Other supporting technology projects will also be developed. The goal is  
21 to operationalize AMD more fully. A full-scale rollout is planned for 2026, where AMD  
22 will become the primary method for compliance leak surveys. The Company is  
23 transitioning from an asset-based to a grid-based leak survey program. This change will

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1 enable AMD to efficiently scale compliance leak surveys by coordinating all distribution  
2 asset surveys within a specific area simultaneously. This transition project is slated to begin  
3 in the 2025 compliance leak survey season. Traditional leak survey will be used for those  
4 areas not part of the AMD schedule in these years to fulfill any compliance leak survey  
5 requirements. Additionally, the Company will continue the Phase 1 emission surveys,  
6 super emitter, and pre-post construction surveys. This approach aims to enhance the  
7 efficiency and effectiveness of leak detection and compliance surveys, leveraging AMD's  
8 advanced capabilities.

9 **Q. How will the Company's procedures be updated when a potential leak is found by**  
10 **AMD?**

11 A. Leak indications are generated by the AMD technology after multiple nights of surveying  
12 each asset in a survey area, usually over three separate nights, which is the recommended  
13 number of drives to ensure comprehensive coverage. The collected data is sent for analysis  
14 and at the conclusion of the final drive, the leak detection team generates reports and  
15 schedules investigations. Qualified individuals will then walk all mains and services,  
16 including meter sets, within and 50 feet beyond the AMD-generated search area to  
17 investigate the potential leaks. If leaks are found, the qualified investigator follows existing  
18 leak response and reporting guidelines to address and document the issue.

19 **Q. What costs are associated with Phase 1 testing and Phase 2 rollout?**

20 A. Table 11 below provides the capital investment and O&M expenses for the AMD Program.  
21 The 2021 and 2022 actual amounts were for Phase 1 units and testing. The 2024 capital  
22 costs are associated with the purchase of three additional units. The O&M expenses will  
23 continue to be license fees and costs associated with performing AMD surveys and studies.

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**Table 11: AMD Actual and Projected Costs**

	2021 Actual	2022 Actual	2023 Actual	2024 Projected	2025 Projected	2026 Projected	Total
O&M	\$122,874	\$102,706	\$188,561	\$452,204	\$572,508	\$572,508	\$2,011,361
Capital	\$2,400,000	\$4,635,000	\$-	\$4,650,000	\$265,000	\$3,181,000	\$15,131,000

1 **Q. Is the Company expecting to see an increase in leaks and associated leak repairs using**  
2 **this new technology?**

3 A. Yes, the Company does anticipate an increase in the detection and repair of leaks with the  
4 implementation of AMD technology. AMD has proven to be seven times more effective at  
5 finding below ground leaks and 5% more effective at detecting above ground leaks  
6 compared to traditional methods. The technology's heightened sensitivity allows for more  
7 precise detection of potential leaks. By providing exact search areas, AMD minimizes the  
8 chances of human error during leak detection. These improvements mean that more leaks  
9 are likely to be identified and repaired, enhancing overall safety and system integrity.  
10 However, it is important to note that these results are based on a limited sample size and  
11 may evolve as the program expands into compliance leak surveys.

12 **Q. Does Consumers Energy's AMD deployment support any regulatory requirements**  
13 **not already discussed?**

14 A. Yes. The PHMSA Advisory Bulletin 2021-0050 requires pipeline facility operators to  
15 update their inspection and maintenance plans to address the elimination of hazardous leaks  
16 and minimization of releases of natural gas. Additionally, as described in the Material  
17 Condition Renewals Program section earlier in my testimony, PHMSA issued NPRM –  
18 Gas Pipeline Leak Detection and Repair which proposed new Rule 192.763 to require that  
19 leak surveys be performed using advanced technology and practices consistent with the  
20 proposed ALDP performance standard. The Company is currently reviewing the proposed

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1 new rule and expects it to be issued within the test year of this case. The Company has  
2 built its AMD Program to further its leak and methane detecting capabilities in accordance  
3 with this and other laws, codes, and guidelines. Regardless of regulations, the Company is  
4 committed to its AMD program due to the clear public safety and emissions reduction  
5 benefits.

6 **Q. Please describe how the implementation of AMD impacts Consumers Energy's stated**  
7 **goals in the NGDP.**

8 A. AMD is described in the NGDP under the technology investments and supports the  
9 Company's stated goal to provide a safe, affordable, reliable, and clean natural gas system  
10 for Michigan. The implementation of this technology also supports the Company's GSMS  
11 as it is part of the recommended practice to evaluate new platforms that can further enhance  
12 the Company's capabilities in alignment with API RP 1173, which provides, "11.2 –  
13 *Management shall also periodically evaluate new technology that may enhance pipeline*  
14 *safety.*"

15 **Q. Please describe the Enterprise Corrective Action Program.**

16 A. The ECAP was initiated at Consumers Energy in 2020 as an enterprise-wide issue  
17 management and compliance program supporting safe and excellent operations. The  
18 structured platform and methodology allow for transparency in reporting issues,  
19 identifying trends, and closing compliance and safety gaps through corrective actions and  
20 controls, based upon associated risk thresholds. ECAP's functionality for managing  
21 processes and performance, as well as analyzing data, focuses risk reduction efforts,  
22 informs operational business decisions, and promotes the integrity and deliverability of the  
23 energy infrastructure. Starting in 2022, ECAP supported stakeholders in Gas Operations,

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1 Engineering, and Regulatory maintaining adherence to GSMS standards established in API  
2 RP 1173.

3 **Q. What costs are associated with the ECAP implementation?**

4 A. ECAP will use a phased implementation approach:

- 5 • Phase 1 (Go Live 2022) – Gas Operations, Regulatory, and Engineering;
- 6 • Phase 2 (Go Live 2023) – Electric Operations and Engineering;
- 7 • Phase 3 (Go Live 2024) – Generation Operations and Electric Supply  
8 Engineering; and
- 9 • Phase 4 (Go Live 2025) – Corporate Safety and Health (Gas, Electric, and  
10 Generation).

11 The actual and projected capital expenditures included in this case represent the gas portion  
12 of ECAP only.

**Table 12: ECAP Actual and Projected Capital Costs**

2021 Actual	\$ 1,226,304	Vendor software to acquire licensing, service, and project support to implement ECAP's system of record into the Enterprise
2022 Actual	\$ 1,204,618	ECAP expense was \$126,333 for the closeout of Phase 1 project implementation. Additionally, \$1,078,285 was expensed in the Computer and Equipment program to advance the purchase of the Environmental Health and Safety Suite of software related to Phase 4 of the project.
2023 Actual	\$ 48,971	Statement of work execution for the Phase 4 project of ECAP in 2024
2024 Projected	\$ 204,000	Projected expenses for ECAP platform modifications to support Phase 4
2025 Projected	\$ 200,000	Projected expenses for ECAP project closeout

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1 **Q. Please describe the Irth Solutions software within Damage Prevention and Miss DIG.**

2 A. The Irth Solutions software is a damage prevention and 811 ticket management solution  
3 used by the Company to report and document daily ticket volume and response as well as  
4 field proactive and re-active work.

5 **Q. Please describe the Irth Software funding requirements.**

6 A. The Irth software subscription includes Utilisphere fixed subscription fees, as well as  
7 additional features such as photo artificial intelligence (“AI”) and augmented reality  
8 (“AR”). This software leverages the latest technology to ensure the safety, resiliency, and  
9 reliability of critical network infrastructure. The projected funding will cover the next  
10 5-year subscription term from 2026 to 2030. This includes:

- 11 • Utilisphere fixed subscription fees;
- 12 • Annual 100,000 additional tickets;
- 13 • New capabilities of photo AI for staking and locating audits, supporting quality  
14 assurance; and
- 15 • New capabilities of AR to enable visual field representation of underground  
16 assets, aiding Damage Prevention field activities and quality assurance  
17 processes.

18 The total expenditure for the 5-year subscription term is \$1.6 million. Based on ticket  
19 volume, the gas portion of this expenditure is \$954,000.

20 **Q. Please highlight the benefits of the Irth software.**

21 A. The Irth software provides the following benefits:

- 22 • Provides analytics and reporting on ticket volume, responses, and timeliness.
- 23 • Provides a calculating risk analysis on each excavator working near Company  
24 facilities which maximizes team effectiveness.
- 25 • Tracks and records all program work being completed by field teams.

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- Acts as a backup ticket management solution supporting the timeliness procedure.
- The addition of photo AI and AR functionality to further increase the Company's ability to maximize productivity.
- Supports the Company's overall damage prevention and public safety program.

**Q. Please describe the GCCP – SIMS project funding requirements within the Geospatial Inventory and Modeling Program.**

A. The GCCP – SIMS project will convert and migrate the SIMS gas service asset data into the gas distribution GIS and reconfigure application and technical integrations, creating a single system of record for both gas service and distribution asset records. This program includes O&M and capital funding requirements as shown in Table 13 and is projecting project completion in late 2024/early 2025. There are no O&M or capital funding requirements for GCCP-SIMS in the test year for this case.

**Table 13: GCCP - SIMS Actual and Projected Costs**

GCCP-SIMS								
	2017 - 2021 Actual	2022 Actual	2023 Actual	2024 Projected	2025 Projected	2026 Projected	Project Total	Test Year
O&M	\$ 1,808,185	\$ 564,455	\$ 2,306,199	\$ 3,134,724	\$ -	\$ -	\$ 7,813,563	\$ -
Capital	\$ 3,345,625	\$ -	\$ -	\$ 2,939,740	\$ -	\$ -	\$ 6,285,365	\$ -

The existing gas service records have no spatial data, and the database is limited in its ability to store all required service attributes, which create inaccuracies in U.S. DOT reporting, System Planning gas load analysis, and Distribution Risk Models. Tabular data is manually linked between the SIMS and the GIS, which causes incomplete and inconsistent data. Gas data must be queried from two independent systems and pieced together to get a complete picture of the distribution network, which limits the Company's ability for data analytics, creates operational complexities, adds risk to damage prevention efforts, and increases response time during safety emergencies. The existing systems use

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1 vastly different data formats and technologies for maintaining and accessing this data,  
2 therefore creating two overlapping and sometimes conflicting systems of record. The  
3 project will provide value by:

- 4 (1) Establishing a single gas distribution system of record within GIS that  
5 represents the gas distribution main and services from the customer's meter  
6 stand to the city gate;
- 7 (2) Creating an enhanced GIS connectivity model with spatial placement of gas  
8 services over an ortho-photo grid, which is essentially digital imagery of an  
9 aerial photograph;
- 10 (3) Improving the ability to identify data gaps and inconsistencies systematically;
- 11 (4) Strengthening the data required to support advanced risk analysis; and
- 12 (5) Creating the foundation required to enable future asset maintenance tools,  
13 including tools that allow the Company to track gas distribution assets, and to  
14 develop GPS leak survey routes to facilities.

15 Without this support, there is increased safety risk associated with the inability to provide  
16 accurate and real-time data to end users to support planned and emergent operational  
17 activities, incident response, and predictive analysis that requires more accurate data  
18 analytics to support compliance reports.

19 **Q. Please describe the Utility Network project and its funding requirements within the**  
20 **Geospatial Inventory and Modeling Program.**

21 A. The Utility Network project will transform the Company's current GIS platform to the Esri  
22 Utility Network Model, and establish a unified gas transmission, distribution, and stations  
23 data model in support of optimizing the core engineering and operational processes,  
24 technologies, and data. This project is an important part of the Company's GSMS and will  
25 support continuous improvement for data gathering processes governed by the Risk  
26 Management element of the GSMS. This program requires both capital and O&M funding  
27 as shown in Table 14. For the Utility Network project, the O&M projected expense is

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1 \$518,408 and the projected capital expenditure is \$7,513,271 for the test year 12 months  
2 ending October 31, 2026.

**Table 14: Utility Network Actual and Projected Costs**

Utility Network							
	2022 Actual	2023 Actual	2024 Projected	2025 Projected	2026 Projected	Project Total	Test Year
O&M	\$ -	\$ 352,679	\$ 722,781	\$ 1,837,426	\$ 196,068	\$ 3,108,954	\$ 518,408
Capital	\$ -	\$ -	\$ 2,888,200	\$10,970,367	\$ 4,865,563	\$18,724,130	\$ 7,513,271

3 The growing business requirements for advanced analytics and business challenges  
4 presented from regulatory mandates and requirements to support a strong pipeline safety  
5 management system necessitate geospatial insight on a more granular asset level than what  
6 is currently available. Managing the distribution and transmission data in different models  
7 continues to be a challenge. The Company's current GIS platform will become  
8 unsupported as Esri's product development focus is shifting to the components that support  
9 the ArcGIS Utility Network Management extension, ArcGIS Enterprise, and ArcGIS Pro.  
10 Esri's development team has taken the existing core technology of ArcMap and the  
11 geometric network for managing gas and electric networks to the limits of its capabilities  
12 and will no longer build additional functionality. Esri utility solution partners, including  
13 several currently in use at the Company, are also moving their product lines away from the  
14 geometric network and will soon only support their solutions on the Utility Network. The  
15 project adds the following value:

- 16 (1) Mitigates risks associated with product support end of life;
- 17 (2) Enables detailed asset management and location-based analytics to bring  
18 clearer understanding around the assets that support energy delivery;
- 19 (3) Enables real-time GIS with ArcGIS Event Server (via ArcGIS Enterprise);
- 20 (4) Increases productivity through use of shortcuts, templates, and streamlined  
21 workflows within the software;

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- 1 (5) Provides extensive, out-of-the-box tracing tools;
- 2 (6) Provides 3D visualization functionality;
- 3 (7) Enables users with editing tools, giving them guidance at every step of the  
4 process for developing workflows and enforcing stronger data integrity;
- 5 (8) Continues to support the concept of long transactions, enabling users to create  
6 future changes to the network model that go into effect after a certain time;
- 7 (9) Offers views of the up-to-date network in a map or schematic diagram with  
8 the ability to quickly toggle back and forth between them; and
- 9 (10) Enables archiving and historical snapshots to view the state of the gas network  
10 over time.

11 All these capabilities will result in greater insight and efficiency that improves the safety  
12 and delivery to customers in Michigan.

13 **Q. Please describe Exhibit A-85 (KAP-7).**

14 A. Exhibit A-85 (KAP-7), in accordance with Attachment 11 to the filing requirements  
15 prescribed in Case No. U-18238, provides the variances in the capital program amounts for  
16 the distribution programs that I am sponsoring compared with the Company's most recent  
17 general gas rate case, Case No. U-21490.

18 **Q. Can you explain why columns (c), (d), (e), and (f) of Exhibit A-85 (KAP-7) do not  
19 contain any data with the exception of the EIRP?**

20 A. The information for column (c), the "Last Rate Case Approved Spending Plan Case No.  
21 U-21490," cannot be provided because Case No. U-21490 resulted in a settlement  
22 agreement that did not state approved capital spending amounts for the programs I am  
23 representing except for the EIRP. Thus, column (c), the "Last Approved Spending Plan"  
24 cannot be calculated for most programs. Since there is no data to display in column (c) for  
25 these programs, the information for columns (e) and (f), which seek information  
26 concerning the variances from (c), cannot be completed. As for the information for

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1 column (d), the “Actual Spending in the Test Year,” cannot be completed as the test year  
2 in Case No. U-21490, which was the 12 months ending September 30, 2025, is a time  
3 period that has yet to transpire as of the filing of this case.

4 **Q. Please summarize your direct testimony.**

5 A. My direct testimony describes the GE&S O&M expenses and capital investments required  
6 to operate a gas distribution system that is safe and reliable. The projections included in  
7 this testimony are needed to meet customer capacity demand and regulatory requirements,  
8 modernize the system, and protect public safety. The Company’s NGDP will work to  
9 enhance the Company’s gas distribution system and offer additional opportunities for  
10 collaboration with municipal partners. Through the implementation of the NGDP and the  
11 execution of the projects outlined in my direct testimony above, investments that are both  
12 reasonable and necessary, the Company can provide a safe, reliable, affordable, and clean  
13 gas delivery system for its customers.

14 **Q. Does this conclude your direct testimony?**

15 A. Yes, it does.

STATE OF MICHIGAN  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of )  
**CONSUMERS ENERGY COMPANY** )  
for authority to increase its rates for the )  
distribution of natural gas and for other relief. )  
\_\_\_\_\_ )

Case No. U-21806

**REBUTTAL TESTIMONY**  
**OF**  
**KRISTINE A. PASCARELLO**  
**ON BEHALF OF**  
**CONSUMERS ENERGY COMPANY**

May 2025

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1 **Q. Please state your name and business address.**

2 A. My name is Kristine A. Pascarello, and my business address is 1945 West Parnall Road,  
3 Jackson, Michigan 49201.

4 **Q. Are you the same Kristine A. Pascarello that testified previously in this case?**

5 A. Yes.

6 **Q. What is the purpose of your rebuttal testimony?**

7 A. The purpose of my rebuttal testimony is to address the capital reductions proposed by  
8 Michigan Public Service Commission (“MPSC” or the “Commission”) Staff (“Staff”)  
9 witness Cynthia L. Creisher and the requested regulatory deferral mechanism for the Leak  
10 Detection and Repair program proposed by Staff witness Jacob G. Martus. Additionally,  
11 I will address the capital expenditure reductions for the Material Condition and Gas  
12 Operations Other programs proposed by Attorney General witness Sebastian Coppola,  
13 Association of Businesses Advocating Tariff Equity (“ABATE”) witness Colin T.  
14 Fitzhenry, Citizens Utility Board of Michigan (“CUB”) witness Ram Veerapaneni,  
15 Michigan Environmental Council (“MEC”) and Sierra Club (“SC”) (collectively, “MEC”)  
16 witness Dr. Sol deLeon. I will also provide rebuttal testimony concerning proposed  
17 reductions to Consumers Energy Company’s (“Consumers Energy” or the “Company”)  
18 projected Gas Engineering and Supply Operating and Maintenance (“O&M”) expenses  
19 recommended by Attorney General witness Coppola and CUB witness Veerapaneni.

20 **Q. Are you sponsoring any exhibits with your direct testimony?**

21 A. Yes. I am sponsoring the following exhibits:

22 Exhibit A-138 (KAP-8) Discovery Response U21806-AG-CE-0431,  
23 Attachment 1;

24 Exhibit A-139 (KAP-9) Discovery Response U21806-AG-CE-0426;

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1 Exhibit A-140 (KAP-10) Audit Response U21806-SA-CE-0388;

2 Exhibit A-141 (KAP-11) Discovery Response U21806-MNSC-CE-0075,  
3 Attachment 2; and

4 Exhibit A-142 (KAP-12) EIRP Project List Detail.

5 **I. STAFF WITNESS CREISHER**

6 **1. Material Condition – EIRP**

7 **Q. Please summarize Staff witness Creisher’s recommendation regarding the Enhanced**  
8 **Infrastructure Replacement Program (“EIRP”).**

9 A. On page 8 of her direct testimony, Staff witness Creisher states that Staff generally supports  
10 the Company’s proposed capital expenditures for the EIRP and the plan to reduce  
11 approximately 5% of vintage main per year, targeting program completion by 2035.  
12 Ms. Creisher also describes the Company’s progress since Case No. U-21490, in reducing  
13 the cost per mile for plastic main pipe installation and encourages the Company to continue  
14 implementing measures to manage costs.

15 **Q. While Staff is generally supportive of the Company’s projected capital expenditures**  
16 **for EIRP, are you recommending any adjustments to the Company’s filed**  
17 **projections?**

18 A. Yes, I am. The Company discovered an error in the forecasted miles for the Northeast  
19 region caused by a feet to miles conversion error in the 2025 program year. This correction  
20 was included as an attachment to discovery response U21806-AG-CE-0431 and is provided  
21 as Exhibit A-138 (KAP-8). The corrected capital expenditures are \$247,018,590 in the  
22 2025 program year, with \$204,611,703 in the 10 months ending October 31, 2025, and  
23 \$250,809,975 in the test year ending October 31, 2026. This results in reductions of

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1 \$3,272,223 for the 2025 program year, which are made up of \$2,710,465 for the 10 months  
2 ending October 31, 2025, and \$561,759 for the test year ending October 31, 2026.

3 **2. Material Condition - Non-Modeled**

4 **Q. Please summarize Staff witness Creisher’s recommendation regarding the Material**  
5 **Condition Non Modeled (“MCNM”) program.**

6 A. Beginning on page 8 of her direct testimony, Ms. Creisher summarizes the Company’s  
7 proposed capital expenditures for the MCNM program, which includes replacement  
8 projects to address emergent issues. She states that Staff does not support the proposed  
9 level of capital expenditure, based on preliminary actual costs for the Line 1010 project  
10 that the Company provided, which is included as Staff Exhibit S-22.1 and Exhibit S-22.2.

11 **Q. In Exhibit S-22.0, Ms. Creisher shows a recommended reduction in the Company’s**  
12 **proposed MCNM expenditures of \$4,054,000 for the 10 months ending October 31,**  
13 **2025, and \$3,500,000 for the test year 12 months ending October 31, 2026. Do you**  
14 **agree with the recommendation?**

15 A. Yes, I do. The reduction is based on Company provided adjustments to the Line 1010  
16 project based on updated project estimates.

17 **3. Compliance and Controls**

18 **Q. Please summarize Staff witness Creisher’s recommendation regarding the**  
19 **Compliance and Controls – Advanced Methane Detection (“AMD”) project.**

20 A. Beginning on page 10 of her direct testimony, Ms. Creisher summarizes the various  
21 projects which are included in the Compliance and Controls program and projected  
22 expenditures referencing Table 10 on page 73 of my direct testimony. She continues that  
23 Staff does not support the proposed level of capital expenditures, noting that the Company

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1 no longer projects to spend \$265,000 on the AMD project in 2025 as provided in the  
2 Company's response to Attorney General's Discovery Request U21806-AG-CE-0422,  
3 which is included as Staff Exhibit S-22.3. On page 11 of her direct testimony, Ms. Creisher  
4 recommends capital expenditures in Compliance and Controls be reduced to \$182,000 for  
5 the 10 months ending October 31, 2025. Additionally, Ms. Creisher provides information  
6 that an incorrect capital expenditure reduction of \$295,000 was provided for Staff's  
7 revenue deficiency calculation. The impacts of this adjustment are not fully reflected in  
8 the testimony and exhibits of other Staff witnesses or in the Staff's revenue deficiency  
9 supported by Staff witness Robert F. Nichols II and will be adjusted in Staff's brief.

10 **Q. In Exhibit S-22.0, Ms. Creisher shows Staff recommended reduction in the**  
11 **Company's proposed Compliance and Controls expenditures of \$265,000 for the**  
12 **10 months ending October 31, 2025. Do you agree with the recommendation?**

13 A. Yes, I do. The reduction is based on the Company provided adjustments to the AMD  
14 project expenditures.

15 **Q. Are there any other adjustments that should be made to the Compliance and Controls**  
16 **projects shown in Table 10 on page 73 of your direct testimony?**

17 A. Yes, there is an adjustment required for the Damage Prevention and Miss Dig capital  
18 expenditure. As described on page 82 of my direct testimony, at the time of filing this case,  
19 the Company projected \$954,000 for the Irth Solutions software used for damage  
20 prevention and 811 ticket management. As provided in discovery response U21806-AG-  
21 CE-0426, included as Exhibit A-139 (KAP-9), the Company has determined that only a  
22 portion of the software cost will be capitalized. The gas portion of the software cost has  
23 been reduced to \$829,082, with \$195,000 as capital and \$634,082 as O&M. This change

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1 will reduce the capital test year amount shown in Exhibit A-83 (KAP-5), line 4, from  
2 \$4,168,000 to \$3,409,000 and increase the O&M test year amount shown in Exhibit A-81  
3 (KAP-2), line 12, from \$1,231,000 to \$1,865,082.

4 **II. STAFF WITNESS MARTUS**

5 **Q. Please summarize Staff witness Martus' recommendation regarding the Leak**  
6 **Detection and Repair ("LDAR").**

7 A. Beginning on page 4, Staff witness Martus' direct testimony discusses the Company's  
8 requested regulatory deferral mechanism for the LDAR rule and its intention to comply  
9 once published. He acknowledges the Company's plan to repair all known grade 2 and  
10 grade 3 leaks (Leak Backlog) regardless of the rules publication and the proposed  
11 \$1,510,000 in capital expenditure detailed in Exhibit S-17.2. On page 5, Mr. Martus states  
12 that Staff supports repairs for safety and finds the cost reasonable, regardless of the LDAR  
13 rule publication. On page 6, he includes that Staff does not support the regulatory deferral  
14 mechanism for LDAR due to an executive order issued in January 2025, making the rule's  
15 publication unlikely during the requested deferral period.

16 **Q. Do you agree with Staff witness Martus' recommendation?**

17 A. Yes, I do.

18 **III. ATTORNEY GENERAL WITNESS COPPOLA**

19 **1. Material Condition EIRP**

20 **Q. Please summarize Attorney General witness Coppola's recommendation regarding**  
21 **the EIRP.**

22 A. Beginning on page 38 of his direct testimony, Attorney General witness Coppola discusses  
23 the history and changes in the EIRP. Beginning on page 39, line 16, Mr. Coppola

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1 summarizes the 13 years of the EIRP historical installation and expenditures. On page 40,  
2 he provides additional information regarding the Transmission Operated by Distribution  
3 (“TOD”) pipe installation. Mr. Coppola incorrectly calculates on line 11 that the Company  
4 has replaced 33.4 miles of TOD pipe with 58.3 miles of new main. The 58.3 miles of new  
5 steel main installed includes both TOD and high pressure (“HP”) steel projects, which are  
6 also included in the totals and cost per mile calculations on page 39 of his direct testimony.  
7 After expressing his concerns regarding the growth of the EIRP and the project  
8 expenditure, beginning on page 40 of his direct testimony, Mr. Coppola describes two  
9 concerns regarding the capital spending plans for 2025 and 2026.

- 10 1. Uncertainty about seven EIRP projects scheduled for 2026 being completed in  
11 the test year based on the status of engineering design; and
- 12 2. Projected expenditures for 2025 and 2026 reaching a new peak level  
13 representing a 38% increase in less than three years. Mr. Coppola states on  
14 page 42 of his direct testimony that the Company is not meeting its commitment  
15 to refrain from spending, citing the settlement agreement in Case No. U-21490.

16 On page 43 of his direct testimony, Mr. Coppola recommends a maximum spending cap  
17 of \$197 million for the 12 months ending October 2026, with future spending levels  
18 adjusted for the Consumer Price Index (“CPI”) rate of inflation. He acknowledges that the  
19 proposed spending cap will reduce the number of miles the Company plans to retire and  
20 install. However, he argues that the spending cap would incentivize the Company to reduce  
21 the cost per mile and reduce competition for limited resources. He suggests a three-to-five-  
22 year extension of the program as a reasonable trade-off to balance against customer  
23 affordability concerns.

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1 **Q. How do you respond to Mr. Coppola’s characterization of the “increasing spending**  
2 **trend” in EIRP?**

3 A. The capital expenditures I am sponsoring are important to replace aged at-risk pipe  
4 intended to improve safety and reliability. The Company continues to look for additional  
5 cost reduction opportunities such as those described in my direct testimony on page 46. As  
6 shown in Exhibit A-138 (KAP-8) on lines 41 and 51, these opportunities resulted in the  
7 2024 actual cost per mile to be \$216,500 less than the 2023 actual cost per mile. Also, as  
8 stated in my direct testimony and shown in Exhibit A-138 (KAP-8), the Company is not  
9 projecting the regional cost per mile of plastic pipe for 2025 or 2026 above 2023 levels.  
10 The Company has made progress toward reducing the cost per mile for plastic main  
11 installation in the the EIRP. Reducing vintage main by 5% per year is a prudent and  
12 reasonable approach to enhancing safety and reliability. This strategy mitigates risks  
13 associated with aging infrastructure and ensures compliance with modern safety standards.  
14 It also improves the overall reliability of the gas distribution system and reduces  
15 maintenance costs. Systematically replacing older pipelines can prevent hazardous  
16 incidents, ensure a stable gas supply, and achieve long-term benefits.

17 **Q. On page 45 of his direct testimony, Attorney General witness Coppola states that the**  
18 **Company has not provided evidence that the planned increase in spending is tied to**  
19 **any increase in safety risks. How do you respond?**

20 A. While Attorney General witness Coppola asserts that most high-risk mains and services  
21 should have been replaced through the Company’s risk-based approach over the past  
22 12 years, it is crucial to recognize that the Company still has over 1,400 miles of vintage  
23 mains that have continued to age during this period. Despite the downward trend in gas

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1 leak data, the presence of these aging pipelines poses ongoing risks to safety and reliability.  
2 As shown in Figure 20 of the Company's Natural Gas Delivery Plan ("NGDP"), Exhibit  
3 A-42 (NPD-1), many of these pipelines were installed in the 1950s or earlier. The  
4 Company provided several examples in discovery, included in Exhibit AG-9, of recent  
5 system incidents that have occurred. Vintage mains, particularly those installed before  
6 modern construction standards, are more susceptible to leaks, breaks, and other failures  
7 due to material degradation and outdated manufacturing practices. The continued aging of  
8 these pipelines necessitates a proactive replacement strategy to mitigate potential hazards  
9 and ensure the long-term integrity of the gas distribution system. Therefore, the assertion  
10 that most high-risk mains have been replaced does not account for the substantial volume  
11 of remaining vintage mains that still require attention to maintain safety and reliability.

12 **Q. On page 45 of his direct testimony, Mr. Coppola recommends the disallowance of**  
13 **\$84,889,000 from the Company's forecasted capital expenditures for the projected**  
14 **test year and recommends establishing a spending budget for the EIRP of**  
15 **\$197 million to be adjusted for the CPI rate of inflation in future years. Do you agree**  
16 **with the recommendation?**

17 A. No, I do not. First, I will address the seven projects which Mr. Coppola expresses  
18 uncertainty about being ready for construction in the test year, recommending a  
19 disallowance of \$84,889,000. These projects are progressing through the design process  
20 during 2025 and have activities aligned with projects scheduled for construction in 2026.  
21 There is no reason to believe that these projects will not be constructed as planned, at the  
22 projected expenditures, in the test year. Company engineers manage projects for the  
23 upcoming year, which include pre-engineering tasks such as order creation, design

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1 commencement, environmental reviews, and ordering long lead-time materials. Following  
2 this, they coordinate with gas control to determine the optimal timing for project execution  
3 based on other ongoing projects and system demands, finalizing the construction schedule.  
4 Company engineering follows a prudent and standard cadence prior to construction. All  
5 seven of the identified projects are on track for construction in the test year as planned.  
6 The seven projects are identified in a table on page 41 of Mr. Coppola's testimony and are  
7 included below.

Line # Page 3 Exh. A-82	EIRP Project Description	Projected Test Year Capex
17	SAG4 - Ph 1,2,3	17,749
18	BCY2 - Ph 2	7,344
19	ALM2 - Ph 1,7,8	9,303
20	ALM5 - Ph 2 Line 1070g	4,713
23	ROK10 - Ph 1,2,3,4,5,6	15,423
24	ROK7 - Ph 4,5,6,7,8	23,625
25	KAL3 - Ph 8,9,10	6,732
	Total	\$ 84,889

8 As seen in the project descriptions, the proposed projects are individual phases of larger  
9 EIRP projects. If these phases are not constructed as planned, it could be detrimental to the  
10 cohesion of the larger project, including impacts on construction sequencing due to each  
11 phase typically designed to build upon the previous one, and wasted resources in  
12 permitting, planning, and initiating each phase. If essential phases are skipped, it can  
13 introduce new risks or exacerbate existing ones within the remaining vintage pipe and can  
14 result in delays in project deliverables such as tie-ins and service replacements. Therefore,  
15 Mr. Coppola's recommendation that these projects are too premature to include in the rate  
16 base should be rejected by the Commission, and the Company's projection for these

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1 projects should be approved. The Commission should approve the funding for these  
2 projects to allow the Company to move forward with the projects and their associated  
3 benefits.

4 **Q. How do you respond to Mr. Coppola's recommendation regarding implementation of**  
5 **spending caps on the EIRP?**

6 A. Spending caps would likely lead to programmatic cuts and hinder the Company's ability  
7 to manage projects effectively, including maintaining the appropriate level of resources.  
8 Creating a spending cap would result in cuts to both the program and the workforce.  
9 Spending caps fail to address the evolving needs of the program, the economy, and other  
10 circumstances that may arise, requiring the Company to respond flexibly. Additionally,  
11 spending caps can have unintended consequences, such as disincentivizing process  
12 improvements. If a cap is reached before the end of the year, it could lead to layoffs or  
13 reduced production levels as projects may allocate funds to cover the entire year rather than  
14 optimizing efficiency. This scenario shifts the focus from improving processes and  
15 productivity to merely staying within budget constraints. The Company has reduced unit  
16 costs and the additional spending being requested is due to increased miles planned because  
17 of productivity improvements, not higher unit costs. The \$215.3 million for the 12 months  
18 ending September 2025 from Case No. U-21490 was based on 113.1 miles, whereas the  
19 Company is now projecting that it will complete 138 miles in the Case No. U-21490 test  
20 year. And while Mr. Coppola notes that the projected test year spending level is 38%  
21 higher than 2023 levels, it is important to note that there is also a 37% increase in the  
22 number of projected miles from 108.9 in 2023 to 149 miles in the test year as shown in  
23 Table 7 on page 49 of my direct testimony. The Company's plan to retire 5% of vintage

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1 mains each year is essential to mitigate the risks associated with aging pipelines.  
2 Therefore, the Commission should reject Mr. Coppola's recommended disallowances for  
3 the seven 2026 EIRP projects and the EIRP spending cap of \$197 million.

4 **2. Material Condition Non-Modeled Program**

5 **Q. Please summarize Attorney General witness Coppola's recommendation regarding**  
6 **the MCNM Program.**

7 A. Beginning on page 45 of his direct testimony, Mr. Coppola summarizes the forecasted  
8 capital expenditures for the MCNM program and how this program differs from the EIRP.  
9 He also states that the Company is expanding the program to undertake four projects, the  
10 wrought iron main replacement, the high-pressure waterway crossings, leak mitigation, and  
11 replacing obsolete meters and included the projected expenditures for each program. On  
12 pages 46 through 48 of his direct testimony, Mr. Coppola provides an assessment of these  
13 four projects and the Line 1010 project. Based on his assessment of the five projects,  
14 Mr. Coppola is proposing a reduction of \$8,121,000 for 2024, \$7,108,000 for the  
15 10 months ending October 31, 2025, and \$20,525,000 in the test year for the MCNM  
16 program.

17 **Q. What is your response to Mr. Coppola's proposed reduction to remove \$1,250,000 for**  
18 **the 10 months ending October 2025 and \$4,417,000 for the projected test year for the**  
19 **Wrought Iron Mains project?**

20 A. I disagree with the proposed reduction. On page 45 of his direct testimony, Mr. Coppola  
21 states that the Company has expanded the MCNM program to supplement the EIRP and  
22 that this vintage material work should be done in the EIRP. His assertion is incorrect. The  
23 MCNM program, as described in my direct testimony on page 51, line 10, includes projects

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1 based on operational improvements that may not be represented effectively in risk model  
2 results. Additionally, as described in my direct testimony on page 52, standard pressure  
3 projects primarily made up of cast iron have been completed within the MCNM program.  
4 Cast Iron is also a vintage material type included in the EIRP. According to the Company's  
5 discovery response on page 2 of Exhibit AG-10, the remaining 12 miles of wrought iron  
6 main is planned to be split between EIRP and MCNM. On page 54 of my direct testimony,  
7 I explain that due to the lower quality materials used to manufacture wrought iron pipelines,  
8 it is not possible to choose a welding procedure that ensures the quality of the finished weld  
9 is adequate for use on the gas system. Page 5 of Exhibit AG-10 further explains that the  
10 risk model used to select EIRP projects does not account for whether the main is weldable.  
11 Audit Response U21308-SA-CE-0388, included as Exhibit A-140 (KAP-10), details that  
12 the wrought iron main replacements planned to be completed in MCNM are small segments  
13 of pipe. These smaller segments may not be prioritized in the EIRP risk modeling and  
14 could result in a leak requiring an emergent project, similar to the example provided on  
15 page 5 of Exhibit AG-10. Since the wrought iron mains are part of the Company's medium  
16 pressure system, replacing the remaining miles of wrought iron pipe is prudent for  
17 reliability and safety and the Commission should reject Mr. Coppola's recommendation.

18 **Q. What is your response to Mr. Coppola's proposed reduction to remove \$500,000 for**  
19 **the 10 months ending October 2025 and \$5,000,000 for the projected test year for the**  
20 **HP Waterway Crossings project?**

21 **A.** I disagree with the proposed reduction. On page 47 of his direct testimony, Mr. Coppola  
22 argues that the projects planned for the test year are early in development and premature to  
23 be included in rate base for this case. However, like the EIRP projects described earlier in

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1 this testimony, these projects are progressing through the design process during 2025 and  
2 have activities aligned with projects scheduled for construction in 2026, following the  
3 Company's engineering standard cadence prior to construction. The Company fully  
4 intends to complete the projects as presented in this case, and there is no reason to believe  
5 that these projects cannot be completed as planned. Therefore, Mr. Coppola's  
6 recommendation that these projects are too premature to include in rate base should be  
7 rejected by the Commission, and the Company's projection for these projects should be  
8 approved so that the Company can move forward with these important projects.

9 **Q. What is your response to Mr. Coppola's proposed reduction to remove \$2,970,000 for**  
10 **2024, \$208,000 for the 10 months ending October 2025, and \$3,375,000 for the**  
11 **projected test year for the Leak Mitigation project?**

12 A. I disagree with the proposed reduction. On page 47 of his direct testimony, Mr. Coppola  
13 states that my direct testimony is devoid of any explanation or supporting evidence to  
14 justify this spending. However, on page 51, line 23 of my direct testimony, I state that  
15 additional details on leaks and obsolete meters are included in the Material Conditions  
16 Renewals program. As noted on page 59, line 8 of my direct testimony and on page 4 in  
17 Exhibit AG-10, the Company confirmed that the key difference between the MCNM  
18 program and the Material Condition Renewals program is planned replacements are in  
19 MCNM and emergent field-initiated projects are included in the Material Condition  
20 Renewals program. The leak details included in the Material Condition Renewals program  
21 apply to this program as well. The leak mitigation included in the MCNM program is  
22 planned leak replacements, which have been completed within this program in the past.  
23 The increase in planned leaks, detailed on page 4 of Exhibit AG-10, highlights the higher

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1 volume and costs compared to previous years. Consequently, the Company identified the  
2 leak mitigation work within the MCNM program as one of the drivers for increased  
3 expenditures in the program. The Company's projection for these projects should be  
4 approved to allow the Company the funding needed to address leaks in the MCNM  
5 program.

6 **Q. What is your response to Mr. Coppola's proposed reduction to remove \$3,083,000 for**  
7 **the projected test year for the Obsolete Meters project?**

8 A. I disagree with the proposed reduction. On page 48 of his direct testimony, Mr. Coppola  
9 states there is no testimony supporting the forecasted capital spending in 2026. However,  
10 on page 51, lines 20 through 23 of my direct testimony, I state that the Company is planning  
11 to complete 5,500 obsolete meter replacements and that additional details on obsolete  
12 meters is included in the Material Conditions Renewals program. As noted on page 59,  
13 line 8 of my direct testimony and on page 4 in Exhibit AG-10, the Company confirmed  
14 that the key difference between the MCNM program and the Material Condition Renewals  
15 program is that planned replacements are in MCNM and emergent field-initiated projects  
16 are included in the Material Condition Renewals program. The obsolete meter replacement  
17 details included in my direct testimony on page 63, line 1 through page 64 line 8, which  
18 also references the Customer Metering section of the Company's NGDP, Exhibit A-42  
19 (NPD-1), apply to the MCNM program as well. The obsolete meter replacements included  
20 in the MCNM program are planned meter replacements, which are intended to meet meter  
21 exchange requirements and minimize risks of extended customer outages during emergent  
22 meter exchanges while the Company evaluates meter technologies for future use. The  
23 increase in planned meter replacements, detailed on page 4 of Exhibit AG-10, also provides

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1 details on volume and cost. Consequently, the Company identified the obsolete meter  
2 replacement work within the MCNM program as one of the drivers for increased  
3 expenditures in the program. Therefore, the Company's projection for these projects  
4 should be approved to allow the Company to meet meter exchange requirements and ensure  
5 all customers have the necessary meters.

6 **Q. What is your response to Mr. Coppola's proposed reduction for the Line 1010 project**  
7 **of \$5,150,000 for 2024, \$5,150,000 for the 10 months ending 2025, and \$4,650,000 for**  
8 **the projected test year?**

9 A. I disagree with the proposed reduction. On page 48 of his direct testimony, Mr. Coppola  
10 states that although this line was purchased from another utility, proper pressure test  
11 documentation is the Company's responsibility, and the customers should not have to pay  
12 the full cost to replace the line as a result of incomplete pressure test documentation and  
13 lack of other traceable, verifiable, and complete ("TVC") records from the original  
14 installation of the pipeline and recommends a disallowance of 50% of the cost to replace  
15 this pipeline. The Pipeline and Hazardous Materials Safety Administration ("PHMSA")  
16 TVC standard is a requirement that did not exist prior to the 2020 rule amendment. Pipeline  
17 segments installed prior to test record requirements implemented in 1970 were previously  
18 "grandfathered," or exempt, from original construction pressure test documentation  
19 requirements and allowed to operate at the highest actual operating pressure observed  
20 between 1965 and 1970. The updated 2020 rules limited this exemption to pipelines  
21 operating below 30% of the specified minimum yield strength ("SMYS"). As a result, the  
22 Company must reconfirm the maximum allowable operating pressure ("MAOP") for all  
23 pre-1970 pipelines operating above 30% SMYS. Additional details on the PHMSA TVC

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1 compliance standards are included in the MAOP projects section of Company witness  
2 Lincoln D. Warriner's rebuttal testimony. The Company evaluated multiple scenarios  
3 including repressure testing the entire Line 1010. Unlike the lines on the Company's gas  
4 transmission system, which are designed to allow for isolation, Line 1010 is part of the  
5 distribution system, directly responsible for feeding customers. This limits the Company's  
6 ability to remove that line from service for pressure testing, and therefore, the retest option  
7 was determined to not be feasible for Line 1010. Replacing Line 1010 was the best  
8 evaluated alternative and allows the Company to include improvements that serve  
9 customers such as replacing an 8" steel high pressure section with a 12" steel high pressure  
10 pipe to meet customer demand. Knowing that retesting Line 1010 is infeasible while  
11 maintaining service to customers, and with the 2020 rule changes for TVC records, and  
12 considering the additional capital improvements included in the Line 1010 replacement  
13 project, excluding 50% of the projected expenditures is not reasonable and the Commission  
14 should reject this recommendation.

15 **3. Material Condition Renewals**

16 **Q. Please summarize Attorney General witness Coppola's recommendation regarding**  
17 **the Material Condition Renewals Program.**

18 A. Beginning on page 49 of his direct testimony, Mr. Coppola stated that he found the  
19 proposed expenditures to be reasonable. However, Mr. Coppola noted that the Company  
20 anticipated a new PHMSA LDAR rule in early 2025, potentially increasing leak repairs,  
21 and forecasted an additional \$1.5 million for the test year. Since the rule is currently on  
22 hold due to a Presidential Executive Order, Mr. Coppola recommends that the Commission  
23 remove the \$1.5 million from the forecasted capital expenditures for the projected test year.

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1 **Q. What is your response to Mr. Coppola’s proposed reduction?**

2 A. I disagree with the proposed reduction. As stated on page 65, lines 16 through 21 of my  
3 direct testimony, the Company is seeking this funding to address the known leak  
4 elimination requirements of the rule and plans to eliminate the backlog of known leaks  
5 regardless of when the LDAR rule is published. The elimination of the leak backlog is  
6 prudent to significantly reduce system risks and ensure public safety. By proactively  
7 addressing these issues, the Company can prevent potential hazards, protect communities,  
8 and enhance the overall reliability and efficiency of the distribution system. Therefore,  
9 Mr. Coppola’s recommendation to reduce \$1.5 million from the forecasted capital  
10 expenditures for the projected test year should be rejected by the Commission.

11 **4. Material Condition Vintage Service Replacement**

12 **Q. Please summarize Attorney General witness Coppola’s recommendation regarding**  
13 **the Material Condition Vintage Service Replacement (“VSR”) Program.**

14 A. Beginning on page 51 of his direct testimony, Mr. Coppola argues that the Company’s  
15 forecasted increases of 64% for 2025 and 131% for 2026 compared to 2024 levels appear  
16 excessive and unsupported by recent trends. Mr. Coppola recommends a forecast of 2,564  
17 replacements, which is the actual number of replacements in 2024. Therefore, he  
18 recommends that the Commission remove capital expenditures of \$11,631,000 for the  
19 10 months ending October 2025 and \$23,875,000 for the 12 months ending October 2026.

20 **Q. What is your response to Mr. Coppola’s proposed reduction?**

21 A. I disagree with the proposed reduction. As described in my direct testimony on page 69,  
22 vintage services are identified in the three categories: In-Grid, Proactive In-Grid, and  
23 Proactive Out-of-Grid. The In-Grid vintage services are replaced as part of EIRP project

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1 work. The increase in the number of vintage services replaced in the VSR program is  
2 related to the reduction in vintage services replaced within the EIRP due to the decrease in  
3 large grid projects and the increase in smaller segment projects. The decrease in large  
4 EIRP grid projects means that more vintage services are classified as Proactive Out-of-  
5 Grid and are not designed and constructed with EIRP projects. On page 51 of his direct  
6 testimony, Mr. Coppola compares the number of VSR replacements to those completed in  
7 2022-2024. A more appropriate comparison would be to use the replacement rates in years  
8 prior to 2022, during which time the EIRP was only completing smaller segment projects.  
9 As shown on Exhibit AG-11, page 2, prior to 2022, VSR program units range from 5,056  
10 in 2021 to 9,381 in 2018. The decrease in vintage services in EIRP/Other Programs is also  
11 shown in the table included on page 2 of Exhibit AG-11. Therefore, the proposed reduction  
12 to 2,564 service replacements in the VSR program would result in an overall reduction in  
13 the number of replacements in 2025 and 2026, to 5,736 and 5,186 respectively, as the  
14 number of services completed by EIRP/Other Programs is lower in 2025 and 2026. This  
15 would reduce the total number of replacements to lower than 2024 actuals. Replacing the  
16 remaining vintage services is prudent for reliability and safety and the Commission should  
17 reject Mr. Coppola's recommendation.

18 **5. Gas Operations – Other - AMD**

19 **Q. Please describe the proposed reduction for AMD capital expenditures within the**  
20 **Compliance and Controls program recommended by Attorney General witness**  
21 **Coppola.**

22 **A.** Beginning at page 53 of his direct testimony, Mr. Coppola provides his assessment of the  
23 AMD project and argues that it produces only marginal benefits at best. He recommends

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1 that the Commission reject the Company's proposed capital expenditures for the AMD  
2 system of \$4,650,000 for 2024, \$221,000 for the 10 months ending October 2025, and  
3 \$3,181,000 for the 12 months ending October 2026. Additionally, on page 165 of his direct  
4 testimony, Mr. Coppola recommends that the Commission remove all related AMD O&M  
5 expense from 2021 through 2026 of \$1,969,000, which includes \$572,508 for the 12  
6 months ending October 2026, from this rate case as well.

7 **Q. What is your response to Mr. Coppola's proposed reductions for AMD?**

8 A. I recommend that the Commission reject both the capital and O&M adjustments proposed  
9 by Attorney General witness Coppola. As described in my direct testimony beginning on  
10 page 73, AMD technology is designed to identify methane leaks with exceptional  
11 precision, detecting methane in parts per billion ("ppb") compared to traditional equipment  
12 that measures in parts per million ("ppm"). This heightened sensitivity allows for the  
13 identification of even the smallest leaks. While Mr. Coppola only focused on leak  
14 detection in his direct testimony, other key features of AMD include measuring emission  
15 rates, tracking the path of methane emissions (breadcrumbing), providing precise  
16 geospatial data, and time-stamped datalogging. These capabilities make AMD a powerful  
17 tool for monitoring and managing methane emissions more effectively. The technology  
18 enables the Company to prioritize high-risk leaks, improving public safety through the  
19 Super Emitter Program, which identifies and escalates remediation of the largest methane-  
20 emitting leaks. AMD is more effective at locating below-ground leaks, enhancing safety.  
21 Benefits to customers include enhanced safety, risk-based prioritization, increased  
22 detection sensitivity, and support for environmental goals, aiding the Company in  
23 achieving net zero methane emissions. Overall, AMD enhances the Company's ability to

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1 manage methane emissions, contributing to improved public safety and environmental  
2 sustainability.

3 **6. Gas Operations – Other - ECAP**

4 **Q. Please describe the proposed reduction for Enterprise Corrective Action Program**  
5 **(“ECAP”) capital expenses recommended by Attorney General witness Coppola.**

6 A. Beginning on page 56 of his direct testimony, Mr. Coppola argues that the program and  
7 proposed expenditures lack clarity on the specific benefits and achievements. Mr. Coppola  
8 recommends that the Commission remove all capital expenditures for ECAP from 2023  
9 through the projected test year. He is proposing a reduction of the capital expenditures of  
10 \$49,000 for 2023, \$204,000 for 2024, \$167,000 for the 10 months ending October 2025,  
11 and \$33,000 for the projected test year based on his argument that the Company has not  
12 shown the value of the capital spending.

13 **Q. What is your response to the proposed reduction for ECAP?**

14 A. I disagree with the proposed reduction. As described in my direct testimony beginning on  
15 page 80, ECAP was initiated at Consumers Energy in 2020 to support safe and excellent  
16 operations through a structured platform for issue management and compliance. ECAP  
17 enhances transparency in reporting issues, identifying trends, and closing compliance and  
18 safety gaps with corrective actions based on risk thresholds. It aids in managing processes,  
19 analyzing data, and informing operational decisions to maintain the integrity of the energy  
20 infrastructure. Since 2022, ECAP has supported adherence to Gas Safety Management  
21 System (“GSMS”) standards in Gas Operations, Engineering, and Regulatory. Resolving  
22 non-conforming conditions, reducing customer concerns, promoting continuous  
23 improvement, and standardizing problem-solving methods are all customer benefits. In

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1 2025, Phase 4 expands the ECAP program to Corporate Safety & Health and  
2 Environmental, and improved performance here will directly contribute to cost savings for  
3 the customers through a reduction in lost time and expense. I recommend that the  
4 Commission reject the adjustment proposed by Attorney General witness Coppola.

5 **7. Geospatial Inventory and Modeling Program**

6 **Q. Please describe the proposed reduction for the Geospatial Inventory and Modeling**  
7 **Program capital and O&M expenses recommended by Attorney General witness**  
8 **Coppola.**

9 A. Beginning at page 58 of his direct testimony, Mr. Coppola argues that the Utility Network  
10 project involves only a marginal improvement in functionality and does not have a  
11 cost/benefit analysis, and recommends that the Commission remove \$2,888,000 for 2024,  
12 \$10,255,000 for the 10 months ending October 2025, and \$7,513,000 for the projected test  
13 year from the Company's forecasted capital expenditures. Additionally, on page 181 of  
14 Mr. Coppola's direct testimony, he recommends disallowance of \$517,000 in O&M  
15 expenses for the projected test year for the Utility Network project.

16 **Q. What is your response to the proposed reduction for the Geospatial Inventory and**  
17 **Modeling Program?**

18 A. I disagree with the proposed reduction. The Utility Network project is essential for  
19 transforming the Company's current GIS platform to the Esri Utility Network Model,  
20 establishing a unified data model for gas transmission, distribution, and stations. This  
21 transformation is crucial due to the growing business requirements for advanced analytics  
22 and regulatory mandates that necessitate granular geospatial insights. The current GIS  
23 platform will soon become unsupported as Esri shifts its product development focus to the

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1 ArcGIS Utility Network Management extension, ArcGIS Enterprise, and ArcGIS Pro. The  
2 existing core technology of ArcMap and the geometric network has reached its capability  
3 limits, and Esri will no longer build additional functionality for these systems.  
4 Additionally, Esri utility solution partners are moving their product lines to support only  
5 the Utility Network. The Utility Network project mitigates risks associated with the end  
6 of product support, enables detailed asset management and location-based analytics, and  
7 provides real-time GIS capabilities. It increases productivity through shortcuts, templates,  
8 and streamlined workflows, offers extensive tracing tools, 3D visualization functionality,  
9 and robust editing tools that enforce data integrity. The project also supports long  
10 transactions, allowing future network model changes, and provides up-to-date network  
11 views and historical snapshots. These capabilities will result in greater insight, efficiency,  
12 and improved safety and delivery to customers in Michigan. The current geospatial  
13 platform supports a large variety of critical processes. At present, GIS is required, and in  
14 many cases foundational to the core regulatory required process including but not limited  
15 to:

- 16 • Annual DOT & National Pipeline Mapping System Reporting
- 17 • Material Verification & MAOP Analysis
- 18 • Leak, Corrosion & Regulation Inspections
- 19 • Inline Inspection/Direct Assessment
- 20 • Transmission, Distribution and Storage Risk Modeling
- 21 • System load analysis and emergency response
- 22 • Facility locating, damage prevention risk analysis
- 23 • Construction & Emergent location and system configuration awareness

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- 1 • New customer and system improvement design
- 2 • Advanced methane detection

3 Allowing the platform to become technically obsolete and unsupported would put all these  
4 processes at significant risk of either hindering or completely halting the Company's ability  
5 to maintain safe operations. Additionally, the longer the Company goes unsupported, the  
6 more likely and impactful those issues become. The Company has already started to  
7 experience the impacts of having unsupported GIS systems with their Gas Transmission  
8 GIS and had to remediate incompatibilities with no vendor support options. Managing a  
9 major platform in this status is unsustainable. Therefore, the Utility Network project is a  
10 necessary investment to address technology obsolescence and ensure continued operational  
11 excellence. The Commission should reject the adjustment proposed by Attorney General  
12 witness Coppola.

13 **8. Gas Engineering and Supply O&M Expense**

14 **Q. Please describe the proposed reduction for Gas Engineering and Supply ("GE&S")**  
15 **O&M expenses recommended by Attorney General witness Coppola.**

16 **A.** Beginning on page 162 of his direct testimony, Mr. Coppola proposes reductions totaling  
17 \$5,258,000 in projected GE&S O&M expenses included in this rate case. His proposed  
18 reductions include \$1,513,000 in the System Integrity department, \$1,259,000 in the  
19 Quality Lean department, \$1,969,000 in the Regulatory and Compliance department for  
20 AMD O&M expenses, and \$517,000 in the Geospatial Inventory and Modeling Program  
21 for Utility Network O&M expenses. The proposed reductions for AMD and Utility

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1 Network are discussed earlier in this testimony with the proposed reductions in capital  
2 expenditures for these programs.

3 **9. System Integrity O&M Expense**

4 **Q. Please describe the proposed reduction for System Integrity O&M expenses**  
5 **recommended by Attorney General witness Coppola.**

6 A. Beginning on page 162 of his direct testimony, Mr. Coppola is proposing a reduction of  
7 \$1,513,000 of projected O&M expenses in the test year for the System Integrity department  
8 based on the argument that the Company did not provide sufficient information showing  
9 cost changes resulting from departmental reorganizations and where costs were offset in  
10 other functions or areas.

11 **Q. What is your response to the proposed reduction for System Integrity?**

12 A. I disagree with the proposed reduction. The shift in O&M expenses is unrelated to any  
13 departmental reorganization or additional job duties. As detailed in my response to  
14 discovery request U21806-AG-CE-0381, included in Exhibit AG-57, page 4, this change  
15 involves reclassifying existing salaries and expenses as O&M costs due to inspection and  
16 remediation work, which includes capital replacements or O&M repairs. This  
17 reclassification does not result in an offset or removal of O&M costs in other areas, contrary  
18 to Mr. Coppola's suggestion. Instead, it represents a shift from capital to O&M. The  
19 removal of \$1,513,000 in this salary and expense program is not prudent and would result  
20 in a reduction of necessary workforce to complete the federally and state-regulated  
21 integrity management work. I recommend that the Commission reject the adjustment  
22 proposed by Attorney General witness Coppola.

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1                   **10.    Project Management and Quality Lean O&M Expense**

2   **Q.    Please describe the proposed reduction for Project Management and Quality Lean**  
3   **O&M expenses recommended by Attorney General witness Coppola.**

4   A.    Beginning on page 164 of his direct testimony, Mr. Coppola summarizes the expenses and  
5   responsibilities provided by the Company of the Quality Lean department and is proposing  
6   a reduction of \$1,259,000 of projected O&M expenses in the test year for the Project  
7   Management and Quality Lean department based on his argument that the Company has  
8   not provided evidence showing significant benefits or cost reductions to justify the value  
9   of the department.

10 **Q.    What is your response to the proposed reduction for Project Management and**  
11 **Quality Lean?**

12 A.    I disagree with the proposed reduction. The purpose of the Lean Office is to accelerate  
13   value delivery by building lean capabilities in the organization – specifically leveraging  
14   the CE Way lean operating system to effectively manage and improve performance. The  
15   Lean Office mobilizes resources to support organizations in the application of lean tools  
16   (e.g., value stream mapping, data analysis, waste elimination, problem solving,  
17   standardized work development, etc.) to support performance improvement. Specific  
18   examples outlined in Case No. U-21806 of where the CE Way has been leveraged to  
19   achieve performance results include (1) Employee Incentive Compensation Plan  
20   operational performance measures – where \$3,600,000 in benefits have been identified by  
21   Company witness Ashley E. Meschke in her direct testimony on page 11, lines 8 through  
22   13, and (2) the EIRP plastic pipeline cost per mile reductions – where a \$216,500 reduction  
23   per mile compared to the 2023 actual cost per mile as described earlier in this testimony.

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1 The Quality Lean department supports quality implementation in planning and execution  
2 of work throughout the Company, and the Commission should approve the projected  
3 funding in order to continue to support overall business efficiency and continuous  
4 performance improvement.

5 **IV. ABATE WITNESS FITZHENRY**

6 **1. Material Condition - EIRP**

7 **Q. Please summarize ABATE witness Fitzhenry's recommendation regarding the EIRP.**

8 A. As summarized on page 10 of his direct testimony, Mr. Fitzhenry argues that there is no  
9 need to accelerate investment in EIRP and that the Company has historically completed  
10 less work than originally forecasted. He recommends reducing capital expenditures by  
11 \$79.4 million in 2025 and \$92.1 million in 2026.

12 **Q. On page 9 of his direct testimony, ABATE witness Fitzhenry states that the Company**  
13 **has not demonstrated that there are excessive safety risks with the proposed main**  
14 **replacement projects. Do you agree with this observation?**

15 A. No, I do not. On page 9 of his direct testimony, Mr. Fitzhenry states that the projects  
16 included in Table CTF-4 were risk ranked according to probabilistic risk modeling. The  
17 Company currently uses a relative risk model called the Distribution Risk Analysis Model  
18 ("DRAM") for ranking projects. Additionally, discovery request U-21806-AB-CE-0467  
19 only requested information on the top 25 highest risk distribution main segments in the risk  
20 model, included as page 5 to Exhibit AB-5. Thus, Mr. Fitzhenry's argument is based on an  
21 analysis of only 25 out of 544,000 segments. This represents a mere 0.0046% of the total  
22 segments, which is not a statistically significant sample size to draw his conclusions about  
23 the overall safety risks of the proposed main replacement projects. His direct testimony

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1 states that only 8 out of the top 25 segments have a risk score greater than the group average  
2 of 7.7. However, this fails to consider the broader context. Among the top 1,000 segments,  
3 the average risk score is 0.48, indicating that the top 25 segments are significantly higher  
4 risk compared to the majority of segments. The total risk score for all segments is 1,077,  
5 and, as shown in Exhibit AB-5, page 5, the 25 projects in question contribute a combined  
6 risk score of 192. This means these 25 segments account for roughly 18% of the total risk  
7 on the system. Addressing these high-risk segments is crucial for improving overall safety  
8 and reliability. Mr. Fitzhenry's direct testimony suggests that the Company can selectively  
9 replace only the highest risk distribution mains. However, this approach may overlook the  
10 cumulative risk posed by segments with lower individual scores but significant collective  
11 risk. A comprehensive replacement strategy is necessary to ensure long-term safety and  
12 reliability.

13 **Q. How do you respond to Mr. Fitzhenry's recommended reduction in EIRP capital**  
14 **expenditures?**

15 A. The Commission should reject the recommendation. First, the financial data used, as  
16 shown in Exhibit AB-5 on page 1, does not represent the entire annual EIRP capital  
17 expenditures. As included in the Notes section on the exhibit, the dollar amounts included  
18 only represent specific order types. A detailed summary of actual and projected capital  
19 EIRP expenses was provided in this case as Exhibit A-84 (KAP-6), and updated during  
20 discovery, included as Exhibit A-138 (KAP-8). Using the correct data, the five-year  
21 average is \$171.5 million, not the \$143 million included in Mr. Fitzhenry's direct  
22 testimony. And since 2021, the Company began completing larger projects using the grid  
23 approach, which plans for and constructs large scale EIRP projects. Using the three-year

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1 average, the average capital expenditures increase to \$220.3 million. Second,  
2 Mr. Fitzhenry uses the data provided on page 7 of Exhibit AB-5 to calculate that the  
3 Company planned 128 miles and \$250 million for 2023. This was the EIRP plan as filed  
4 in the Company's 2023 EIRP Planning Report in Case No. U-21148. This amount was  
5 also included in my direct testimony in Case No. U-21308. While the settlement agreement  
6 reached in Case No. U-21148 states that the EIRP will continue with increased spending  
7 of \$250 million for the 12 months ending September 30, 2023, it also states that Consumers  
8 Energy will review and address the length of the EIRP in the next NGDP, considering a  
9 program completion date beyond 2030. The reduction in the 2023 plan from \$250 million  
10 and 128 miles to \$182 million and 109 miles was related to the Company's decision to  
11 extend the program to 2035 after conducting the review agreed to in the U-21148  
12 settlement. The Company divided the larger projects into phases to be completed across  
13 multiple years. These changes can be seen by comparing the 2023 EIRP Planning Report,  
14 filed in December 2022, to the 2023 Performance Report, filed in April 2024.

**2023 Planning Report (U-21148)**

Project Name	Total Est Cost	Installed (Feet)
KAL1	\$13,671,221	43,787
MAC3	\$35,138,479	75,886
MAC4	\$25,342,863	80,604
FLT1	\$12,058,882	34,268
FLT3	\$24,514,185	84,646
BCY1	\$42,643,780	115,316
LAN5	\$40,550,692	133,068
ROK4	\$21,478,123	63,585
ROK5	\$3,407,328	8,976
<b>ERP Grid Projects Subtotal</b>	<b>\$218,805,554</b>	<b>640,136</b>

1070H (TOD)	\$25,931,991	35,640
<b>ERP TOD Projects Subtotal</b>	<b>\$25,931,991</b>	<b>35,640</b>

(miles)

<b>ERP Program Projects Total</b>	<b>\$244,737,544</b>	<b>675,776</b>	<b>128</b>
<b>2022 Project Carryover Cost</b>	<b>\$5,262,456</b>		
<b>Estimated ERP Distribution Total</b>	<b>\$250,000,000</b>		

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**2023 Performance Report (U-21308)**

Project Name	Total Est Cost	Installed (Feet)
KAL1 (phase 3)	\$7,199,255	21,525
MAC3 (phase 2,3)	\$13,496,841	42,700
MAC4 (phase 2,4-10)	\$20,284,581	80,378
FLT1 (phase 2-5,6)	\$14,555,890	35,459
FLT3 (phase 1-4)	\$12,309,929	77,539
BCY1 (phase 3-7,9,10)	\$35,089,086	110,711
LAN5 (phase 2-7,10)	\$32,726,206	70,076
ROK4 (phase 4,7,9,10)	\$9,897,937	38,675
ROK5 (phase 1-3)	\$7,510,376	24,192
FLT4 (phase 1)	\$880,801	11,055
MDL1 (phase 2)	\$5,670,136	18,461
SAG3 (phase 1,5)	\$1,072,240	2,836
LIV3 (phase 6)	\$63,934	6,640
<b>ERP Grid Projects Subtotal</b>	<b>\$160,757,211</b>	<b>540,247</b>

1070H (TOD)	\$10,230,205	34,948
<b>ERP TOD Projects Subtotal</b>	<b>\$10,230,205</b>	<b>34,948</b>

<b>Retirements from Prior Years Install</b>	<b>\$5,565,075</b>	<b>0</b>
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(miles)

<b>ERP Program Projects Total</b>	<b>\$176,552,491</b>	<b>575,195</b>	<b>109</b>
<b>2022 Project Carryover Cost</b>	<b>\$5,262,549</b>		
<b>Future Year Project Costs</b>	<b>\$111,592</b>		
<b>Estimated ERP Distribution Total</b>	<b>\$181,926,631</b>		

1 In addition, as shown in my direct testimony, on page 50, the Company exceeded the  
 2 installed miles requirement from the settlement agreement in Case No. U-21308,  
 3 completing 126.1 miles compared to 110.8 miles for less than \$214 million. Lastly, as  
 4 discussed in my direct testimony and earlier in this rebuttal testimony, the replacement of  
 5 vintage mains is prudent for reliability and safety and the Commission should reject  
 6 Mr. Fitzhenry's recommendation to reduce these expenditures and slow the pace of  
 7 replacements.

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1       **V.     CUB WITNESS VEERAPANENI**

2       **Q.     Please summarize the methodology used by Mr. Veerapaneni to calculate proposed**  
3       **reductions to the Company’s projected capital expenditures and O&M expenses.**

4       A.     On page 8 of CUB witness Veerapaneni’s direct testimony, he states that using 2023 and  
5       2024 historical data is appropriate to project test year expenditures and that he used the  
6       two-year historical average for calculating the capital expenditures and O&M expenses for  
7       the test year.

8       **Q.     How does the test year capital expenditure amount proposed by Mr. Veerapaneni for**  
9       **the Gas Distribution – Material Condition program compare to the test year capital**  
10       **expenditure supported by your testimony and exhibits in this proceeding?**

11      A.     As stated on pages 12 and 13 of his direct testimony and shown in Exhibit CUB-10,  
12      Mr. Veerapaneni projected \$287,898,000 compared to the Company’s projection of  
13      \$385,665,000 for the 12 months ending October 31, 2026, resulting in a \$97,767,000  
14      reduction.

15      **Q.     How does the test year capital expenditure amount proposed by Mr. Veerapaneni for**  
16      **the Gas Operations Other program compare to the test year capital expenditure**  
17      **supported by your testimony and exhibits in this proceeding?**

18      A.     As stated on page 13 of his direct testimony and shown in Exhibit CUB-10,  
19      Mr. Veerapaneni projected \$10,555,000 compared to the Company’s projection of  
20      \$17,090,000 for the 12 months ending October 31, 2026, resulting in a \$6,535,000  
21      reduction.

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1 **Q. How does the test year O&M expense amount proposed by Mr. Veerapaneni for the**  
2 **Gas Engineering and Supply O&M expenses compare to the test year O&M expenses**  
3 **supported by your testimony and exhibits in this proceeding?**

4 A. As stated on page 17 of his direct testimony and shown in Exhibit CUB-11,  
5 Mr. Veerapaneni projected \$18,200,000 compared to the Company's projection of  
6 \$22,195,000 for the 12 months ending October 31, 2026, resulting in a \$3,995,000  
7 reduction.

8 **Q. What is your response to Mr. Veerapaneni's proposed reductions?**

9 A. CUB's proposed methodology of projecting capital test year expenditures and O&M  
10 expenses using two years of historical actual data is unreasonable. For the Gas Distribution  
11 capital projects, Mr. Veerapaneni did not discuss the reasonableness of the projects  
12 proposed during the test year or the benefits the projects would provide to customers. For  
13 the Gas Engineering and Supply O&M test year expenses, Mr. Veerapaneni did not discuss  
14 the reasonableness of the department expenses and did not account for the Company  
15 changes described on page 7 of my direct testimony. The proposed reductions fail to  
16 account for the significant support I provided throughout my direct testimony for the  
17 benefits that are expected because of the planned spending and the reasonableness of the  
18 projected spending amounts. Therefore, the Commission should reject Mr. Veerapaneni's  
19 recommendations.

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1       **VI.    MEC WITNESS DELEON**

2               **1.    Material Condition EIRP**

3       **Q.    Please summarize MEC witness deLeon's EIRP recommendation.**

4       A.    On page 40 of her direct testimony, Dr. deLeon recommends that EIRP reporting include  
5           risk-ranking information and narrative descriptions regarding the use of risk-ranking  
6           driving for remediation projects. Dr. deLeon recommends using probabilistic risk models  
7           and cost-effectiveness calculations when selecting EIRP projects and proposes changes to  
8           the EIRP reports to include summarizing examined remediations, their cost-effectiveness  
9           relative to alternatives, and reasons for selecting specific remediations. For future rate  
10          cases, Dr. deLeon recommends the Company significantly increase the use of probabilistic  
11          risk modeling and cost-effectiveness calculations for all asset classes, that these models  
12          should be accessible to stakeholders and the Commission, and that the Company should  
13          develop these models for the next rate case. On page 42 of her direct testimony, Dr. deLeon  
14          recommends the Commission should require the Company to implement probabilistic risk  
15          models for EIRP before increasing EIRP spending levels above the 2024 investment level  
16          of \$195,587,000.

17       **Q.    What is your response to the proposed reduction for EIRP expenditures?**

18       A.    I disagree with the proposed reduction. First, although the Company did not include a risk  
19           rank narrative in the initial filing of this case, the risk ranking for each EIRP project was  
20           included in WP-KAP-3, and is provided as Exhibit A-142 (KAP-12). Additionally, in the  
21           Settlement Agreement of Case No. U-17643, an additional requirement to include risk  
22           rankings for all projects in a separate column was added to the Company's EIRP  
23           Performance Report, with which the Company has complied. The risk ranks for EIRP

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1 projects are included in two separate MPSC reports that the Company files annually: the  
2 EIRP Planning Report and the EIRP Performance Report. As described on page 36 of my  
3 direct testimony, EIRP projects are selected by the gas engineering teams using a risk  
4 model that assesses the risks and threats of each pipe segment, according to the Company's  
5 Distribution Integrity Management Program ("DIMP"). The Company uses this risk-based  
6 approach, combined with subject matter expert input, to select EIRP replacement projects.  
7 The Company did provide the narrative for 2025 projects in discovery response U21806-  
8 MNSC-CE-0075\_Pascarello\_Attachment\_2, included as Exhibit A-141 (KAP-11). The  
9 stated reason for selection of EIRP projects provided in Table 7, on page 36, of  
10 Dr. deLeon's testimony incorrectly identifies Transmission projects as EIRP projects.

11 **Q. Should the Commission require the Company to perform the additional EIRP**  
12 **reporting discussed on page 40 of Dr. deLeon's direct testimony?**

13 A. No. The Company already provides risk ranking information in both the EIRP Planning  
14 Report and the EIRP Performance Report by project.

15 **Q. Should the Company be required to perform the probabilistic risk modeling and cost**  
16 **effectiveness analysis for EIRP prior to expenditures increasing above 2024 levels?**

17 A. No. While probabilistic risk models offer an assessment of potential hazards, their  
18 implementation can be complex and time-consuming. The complexity of accurately  
19 modeling costs and benefits, especially in dynamic and uncertain environments, such as  
20 continued use of pipes made from vintage materials, can lead to oversimplified or flawed  
21 analyses. This is shown in Figure 5 on page 37 of Dr. deLeon's direct testimony. In this  
22 cost effectiveness example, the analysis only focused on the number of leaks remediated  
23 by the EIRP in the report year and did not address the footnote in the report stating that this

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1 count is based on scheduled leaks that were remediated with the project as opposed to  
2 making a repair and the count does not include historical, permanently repaired leaks.  
3 Reported annual leak remediations falls short as a measure of cost effectiveness for vintage  
4 material pipes due to historical repairs, safety concerns, and reliability issues. Also, the  
5 purpose of the EIRP is not leak remediation; it is vintage material replacement to enhance  
6 safety and improve reliability. Leak remediation is a benefit of replacing vintage pipe but  
7 is not a good measure of cost effectiveness of the EIRP. Additionally, Dr. deLeon states on  
8 page 22 of her direct testimony that the proposed test year expenditures show nearly a 30%  
9 increase from 2024 expenditures levels but fails to discuss that there is a 71% increase in  
10 planned steel pipe replacement using the miles shown in Table 6 on page 45 of my direct  
11 testimony. Described on page 47 of my direct testimony, the 2026 cost for steel projects  
12 is \$3.91 million per mile compared to \$1.4 million per mile for plastic pipe installation. As  
13 described on page 37 of my direct testimony, EIRP projects have a defined scope focused  
14 on replacement of vintage material pipe and elimination of the standard pressure system.  
15 The current risk assessment methods used by the Company prioritize high-risk segments  
16 based on several factors including pipe material type, age, soil conditions, and leak history.  
17 While the Company is currently planning to begin implementing probabilistic risk  
18 modeling for distribution assets in 2027 to identify projects for 2030, the Commission  
19 should not cap EIRP spending at 2024 levels prior to this implementation. The EIRP  
20 projects enhance system safety, improve reliability, and reduce emissions by replacing  
21 vintage leak prone pipe. The Company's proposed increase in spending is essential to  
22 support the annual installed mileage required for timely program completion. Reducing  
23 the budget to the 2024 investment level of \$195,587,000 could hinder progress and extend

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1 the timeline, potentially leaving outdated and leak-prone pipes in service longer than  
2 necessary. The capital expenditures I am sponsoring are important to replace aged at-risk  
3 pipe intended to improve safety and reliability. Therefore, the Commission should reject  
4 Dr. deLeon's recommendations, and the focus should remain on the Company's plan of  
5 reducing vintage main miles by approximately 5% per year to meet the 2035 completion  
6 goal.

7 **2. Material Condition VSR**

8 **Q. Please summarize MEC witness deLeon's VSR recommendations.**

9 A. Dr. deLeon recommends that the VSR program should incorporate probabilistic risk  
10 models for distribution assets and that the Commission require the Company to implement  
11 these models before increasing VSR spending levels. Additionally, Dr. deLeon  
12 recommends capping the program at the 2024 investment level of \$18,666,000.

13 **Q. What is your response to the proposed reduction for the VSR program?**

14 A. I disagree with the proposed reduction. First, as discussed above, while probabilistic risk  
15 models offer an assessment of potential hazards, their implementation can be complex and  
16 time-consuming. The VSR program began using the Company's DRAM in 2025. The  
17 current risk assessment methods have proven effective in prioritizing high-risk areas in  
18 other programs such as the EIRP. As discussed in the response to Attorney General  
19 Coppola earlier in this testimony, the proposed increase in the number of vintage services  
20 replaced in the VSR program is related to the reduction in vintage services replaced within  
21 the EIRP due to the decrease in large grid projects and the increase in smaller segment  
22 projects. The decrease in large EIRP grid projects means that more vintage services are  
23 classified as Proactive Out-of-Grid and are not designed and constructed with EIRP

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1 projects. Capping the VSR program spending at the 2024 investment level of \$18,666,000  
2 is not advisable. The proposed increase in spending is essential to support the annual  
3 number of services required for timely program completion. Reducing the budget could  
4 hinder progress and extend the timeline, potentially leaving outdated and leak-prone  
5 services in use longer than necessary. The capital expenditures I am sponsoring are  
6 important to replace aged at-risk services intended to improve safety and reliability.  
7 Therefore, the Commission should reject Dr. deLeon's recommendations.

8 **3. Material Condition Non-Modeled**

9 **Q. Please summarize MEC witness deLeon's MCNM recommendation.**

10 A. Dr. deLeon recommends that the Company incorporate probabilistic risk models for  
11 distribution assets and that the Commission require the Company to implement these  
12 models. Additionally, Dr. deLeon recommends capping the MCNM program at the 2024  
13 investment level of \$38,256,000.

14 **Q. What is your response to the proposed reduction for the MCNM program?**

15 A. I disagree with the proposed reduction. The additional \$18 million projected in the MCNM  
16 project is related to the four Company initiated projects described in my direct testimony  
17 beginning on page 54. The wrought iron main replacement at \$5 million, the high-pressure  
18 waterway crossings at \$5 million, leak mitigation at \$4 million, and replacing obsolete  
19 meters at \$3.7 million. The Commission should reject Dr. deLeon's recommendations to  
20 allow the Company to complete these important projects for the benefit of customers.

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1                   4.     Alternatives to Pipe Replacements

2     **Q.     What is your response to MEC witness deLeon’s testimony on alternatives to pipe**  
3     **replacements as they relate to the EIRP and MCNM programs?**

4     A.     Dr. deLeon’s direct testimony, page 40, recommends that when probabilistic risk models  
5     are available for distribution assets, the Company should summarize in its EIRP reports  
6     remediations examined, cost effectiveness of projects relative to alternatives, and  
7     explanations of why the Company’s remediation was selected. Additionally, Dr. deLeon’s  
8     direct testimony, page 42, states that the Company does not consider pipe repair or  
9     non-pipe alternatives (“NPA”) for the EIRP or the MCNM program, based on discovery  
10    responses indicating that repairs are not completed in either program. The EIRP and  
11    MCNM programs are focused on replacing infrastructure. Leak repairs, on the other hand,  
12    are managed through other dedicated programs. Replacing pipes made of vintage materials  
13    or due to emergent system issues is crucial due to inherent safety and reliability issues,  
14    such as corrosion, leaks, and breaks, which pose risks to public safety and service  
15    continuity. While NPAs like electrification and energy efficiency measures can reduce  
16    demand for natural gas, they would not address immediate and critical infrastructure  
17    problems. Modern pipes also reduce methane emissions, contributing to environmental  
18    sustainability, whereas NPAs might not fully mitigate emissions from existing leaks.  
19    Investing in pipe replacement ensures a reliable gas supply, and enhances public safety,  
20    making a comprehensive and effective solution.

21    **Q.     Does this complete your rebuttal testimony?**

22    A.     Yes, it does.

1 JUDGE VARCHETTI: And we will, of  
2 course, address the exhibits after cross has concluded.

3 So, Mr. Bzdok, it now appears that the  
4 witness is ready to be cross-examined, so if you would  
5 please proceed at your leisure.

6 MR. BZDOK: Thank you, Your Honor.

7 CROSS-EXAMINATION

8 BY MR. BZDOK:

9 Q. Good morning, Ms. Pascarello.

10 A. Good morning.

11 Q. Am I pronouncing your name correctly?

12 A. Yes, you are.

13 Q. And can you hear me okay?

14 A. I can.

15 Q. Okay. Thank you. I wanted to talk to you today, no  
16 surprise, about some of your rebuttal testimony to  
17 MEC/Sierra Club witness Sol deLeon. So a jumping off  
18 point for us will be your rebuttal testimony at page 32.

19 Here you are -- I'm making some notes  
20 while I'm talking to you. Here you are making -- here you  
21 are responding to witness deLeon regarding the EIRP; is  
22 that right?

23 A. Yes.

24 Q. And just for context, what does that stand for?

25 A. Enhanced Infrastructure Replacement Program.

1 Q. And just in very general terms, I know you talked about  
2 this in your written testimony, but just to sort of set  
3 the stage for today's discussion, what does that mean?

4 A. So that is a program that was started by the Company in  
5 2012 in response to a Department of Transportation and  
6 Pipeline Hazardous Material Safety Administration  
7 recommendation that operators replace aging vintage  
8 materials.

9 Q. And what do you mean by "vintage materials"?

10 A. Vintage materials are cast iron, bare steel, wrought iron,  
11 and threaded and coupled steel.

12 Q. Cast iron, wrought iron, bare steel, and the last one was  
13 --

14 A. Threaded and coupled steel.

15 Q. Thank you. The -- in the -- in the Company's exhibits and  
16 in your testimony and in some of the other witnesses'  
17 testimony, there is a spend on the EIRP in 2024 of about  
18 195.5 or 195.6 million. Does that sound right?

19 A. Yes.

20 Q. There's a projected spend for '25 of around 250.3 million  
21 on EIRP; is that right?

22 A. Yes.

23 Q. And there's a projected spend in 2026 in a test year of  
24 251.6 million on EIRP; is that right?

25 A. It -- can you ask -- repeat your question, please.

1 Q. Sure. So I think the last question was, there's a  
2 projected spend in 2026 on EIRP of 251.6 million dollars;  
3 is that right?

4 A. That's for calendar year 2026, correct.

5 Q. I -- I messed it up when I asked test year; right?

6 A. I just wanted to make sure we were clarifying that was  
7 calendar year.

8 Q. Okay. Thank you. What's the test year spend?

9 A. 250.8 million.

10 Q. Would you agree these are material increases over the  
11 actual spend in 2024 of 195.6 million?

12 A. Yes, I would agree. But as I stated in my rebuttal  
13 testimony, the driver -- primary driver for the cost  
14 increase is the miles of steel that the Company is  
15 projecting in the test year.

16 Q. Do you have access to the Sharepoint folder?

17 A. I do.

18 Q. Okay. In the Sharepoint folder, there is a folder called  
19 Michigan Environmental Council, Citizens Utility Board of  
20 Michigan, and Sierra Club, which I will hence forth refer  
21 to as MEC, CUB, and Sierra Club. There's a folder in  
22 that, and within that there is a hearings exhibit folder,  
23 and within that, there is a folder with your name on it,  
24 if you could find that.

25 A. I have it.

1 Q. Okay. Great. Now within that folder, the first document,  
2 I think it's probably the first document for you, it is  
3 for me, is titled U-21490 07-23-24. Are you able to open  
4 that in browser? You might need to refresh the Sharepoint  
5 because I actually just put it in there a minute ago.

6 A. Oh, okay.

7 Q. I work on these exams up to the minute I start talking to  
8 you.

9 A. All right. I see it now, yes.

10 Q. Okay. That is a settlement agreement of the Company's  
11 last rate case; is that right? Or it's an order approving  
12 the settlement agreement, I should say.

13 A. It appears it is, yes.

14 Q. And then if you scroll down to pdf page 6, there's an  
15 Exhibit A, which is a settlement agreement; is that right?

16 A. Page 6? Yes.

17 Q. Did you review the settlement agreement in your -- in the  
18 course of preparing your rebuttal testimony? Well, let me  
19 back up. Let me back up.

20 Page 10 of your rebuttal testimony, you  
21 are responding to a different witness, Mr. Coppola for the  
22 Attorney General?

23 A. Yes.

24 Q. In that testimony, you refer to a -- you refer to Case No.  
25 U-21490; correct?

1 A. Correct.

2 Q. In -- in -- in the course of preparing your rebuttal  
3 testimony or your direct testimony or in any other  
4 function in this case, did you happen to review the  
5 settlement agreement in 21490?

6 A. I was aware of the settlement agreement, yes.

7 Q. Okay. So were you aware of the provision in the  
8 settlement agreement in -- in paragraph 5 related to a  
9 spend amount for the EIRP in 12 months ending September  
10 30, 2025?

11 A. Yes.

12 Q. And that had a spend amount of 215.3 million; is that  
13 right?

14 A. That is correct.

15 Q. And the Company projects to exceed that amount for that  
16 timeframe; is that right?

17 A. Based on the time when these documents were -- were  
18 completed, we were projecting that, but we had not  
19 completed the test year for that term yet.

20 Q. So when you said based on when these documents were  
21 completed, what documents are you referring to?

22 A. I'm sorry. My Exhibit A-138.

23 Q. Okay. Bear with me a second.

24 Okay. So you made a reference to  
25 Exhibit A-138, which is one of your rebuttal exhibits; is

1           that right.

2       A.    Yes, that's correct.

3       Q.    Okay.  And that --

4       A.    It had updated numbers on it.

5       Q.    It has the updated numbers on it.  Okay.  Yeah, so you --

6       A.    Yes, the highlight in yellow are some corrected numbers.

7       Q.    So I'm looking -- I'm looking at the document that's A-138  
8            in the Sharepoint under the Consumers site, and I'm  
9            looking at -- within your folder of documents on the  
10           Consumers folder, and I am seeing a -- starting at line  
11           61, I am seeing a projected capital expenditures,  
12           corrected.  Is that what you were referring to?

13      A.    That's one of the corrected numbers, yes.

14      Q.    Okay.  And then there's a projected 2025 ERP -- EIRP CAP  
15            Ex in line 67 of 247 million dollars and change; is that  
16            right?

17      A.    That is correct.

18      Q.    And then there's a projected 10 months ending October 31,  
19            2025, of 204.6 million; is that right?

20      A.    That is correct.

21      Q.    And then there's a 2025 forecasted total EIRP program in  
22            facilities capital expenditures of 247 million and change  
23            on line 70?

24      A.    Correct.

25      Q.    Okay.  So is what you're saying that -- that in the

1           Company's initial filed case, there was a -- it was -- it  
2           was projected that the Company would exceed the 215.3  
3           million's number from the settlement agreement for the 12  
4           months ended September, 2025, but now based on what's  
5           going on out there in the world, the Company is projecting  
6           to be under that 215 million dollar figure for that --  
7           that reference period?

8           A.     Currently, we are projecting to be close to the 215  
9           million but with more miles completed. The 215 million  
10          has -- in my rebuttal testimony on page 10, that was a  
11          reference to 113.1 miles that was -- that was in my  
12          testimony in case U-21 -- 21490.

13                                 Currently, the Company is projecting to  
14          complete 138 miles, but we are currently projecting to be  
15          close to the 215 million dollar number.

16          Q.     Okay. Okay. Got it. Thank you. Okay.

17                                 Back to your rebuttal testimony to  
18          witness deLeon, page 32.

19          A.     Okay.

20          Q.     Line 17. So -- so the first 16 or so lines of this  
21          testimony, you're more or less recapping witness deLeon's  
22          testimony relative to the EIRP, as you understand it; is  
23          that right?

24          A.     I am recapping the recommendations of Dr. DeLeon.

25          Q.     Okay. Thank you for the clarification.



1 testimony at line -- and at question and answer that  
2 begins on line 17; is that right?

3 A. That is correct.

4 Q. The first point you make is you say, "Although the Company  
5 did not include a risk rank narrative in the initial  
6 filing of this case, the risk ranking for each EIRP  
7 project was included in WP-KAP-3, and is provided as  
8 Exhibit A-142"; correct?

9 A. Correct.

10 Q. And then you're going to go -- you go on to talk about  
11 another exhibit, but I want to stop -- I want to pause  
12 there to talk about the first exhibit that you mentioned  
13 there.

14 So do you have A-142 available?

15 A. Yes.

16 Q. Okay. Generally speaking, A-142 is referenced as an EIRP  
17 project list detail; correct?

18 A. Correct.

19 Q. And it has a -- sheet 1 is 2025 projects listed by region,  
20 and sheet 2 is 2026; right?

21 A. Correct.

22 Q. Okay. There are projects listed by zone or region in  
23 three regions, and then two projects listed -- so I'm on  
24 page 1. Sorry.

25 So on page 1, there are three project

1 regions. These are broken into three project regions, and  
2 then two projects called TOD projects; is that right?

3 A. Correct.

4 Q. Okay. And what's a TOD project?

5 A. It stands for transmission operated by distribution.

6 Q. And why are those broken out separately from the region  
7 projects?

8 A. Those projects are run through the Transmission Integrity  
9 Program Model and not through the Distribution Risk  
10 Analysis Model.

11 Q. You said those projects are run through -- those projects  
12 are run through, and you had the name of a transmission  
13 model, and you said it quickly.

14 A. I'm sorry. The Transmission Integrity Management Program,  
15 the TIMP program. They have a -- a separate model that  
16 runs transmission level assets. So these are transmission  
17 -- these are considered transmission pipelines, but they  
18 are operated by distribution.

19 Q. Okay. And that Transmission Integrity Management Program  
20 model you were referring to, that's the subject of  
21 Mr. Snyder's testimony in this case; is that fair?

22 A. That is correct.

23 Q. Okay. And then you said, "and not through the  
24 distribution risk," is that "assessment" or "analysis"  
25 model, the DRAM?

1 A. A risk analysis model. Distribution Risk Analysis Model.

2 Q. Okay. You called it the DRAM or the D-R-A-M or --

3 A. DRAM.

4 Q. Okay. Okay. So for the -- so the next column, then, has  
5 a list of notations. "S equals segment, G equals grid, HP  
6 equals high pressure (steel)"; right?

7 A. Correct.

8 Q. What's the significance of segment -- what -- let me --  
9 let me -- let me sort of jump ahead a little bit.

10 You also gave us an Exhibit A-141;  
11 right?

12 A. Yes.

13 Q. Okay. In A -- and we're going to -- we're going to toggle  
14 these two a little bit in our discussion today.

15 For the A-141, and we'll get to it more  
16 in a minute, but I just -- what I'm trying to understand  
17 is I'm trying to relate some of the information in A-142  
18 to some of the information in A-141.

19 And so I'm looking at the second column  
20 of A-142, which talks about, "S for segment, G for grid or  
21 HP for high pressure," and then I'm looking at the third  
22 column of A-141, which refers to "SP, MP, and HP" pressure  
23 designations, and I'm trying to understand if those -- if  
24 -- if -- if the notations on A-142, HP, S, and G, in some  
25 way correspond to the notations HP, MP, and SP in 141.

1 Does that make sense?

2 A. It does.

3 Q. Okay.

4 A. So --

5 Q. Can you relate those for me?

6 A. Sure. "HP" is high pressure, and that would be the same  
7 in both exhibits.

8 Q. Okay.

9 A. The "S" in Exhibit 142, the "S" designation of segment, or  
10 "G" designation as grid, is just an identifier of the size  
11 of that project. So the Company implemented a grid  
12 approach a few years ago where we started looking at  
13 implementing larger EIRP projects.

14 So the segment projects and the grid  
15 projects are related to the SP standard pressure and MP  
16 medium pressure that's on Exhibit 141.

17 Q. But there's no direct correlation between, like, S and SP,  
18 or G and MP? Some of the S projects are SP or MP; some of  
19 the G projects the same.

20 A. There's no correlation. Yeah, there's -- the -- the S and  
21 G in 142 is just really a designator of the size of the  
22 project.

23 Q. Okay. Thank you for that clarification.

24 A. It could be a standard -- I was just going to say, they  
25 could be a mix of standard pressure and medium pressure

1 segments.

2 Q. Okay. Thank you. Back to A-142. The third column -- the  
3 third column with information in it is DRAM risk rank,  
4 correct, SP, MP, HP?

5 A. Correct. I want to clarify, though, that is the project  
6 restraint.

7 Q. Okay. What's the significance of that clarification?

8 A. So in the DRAM model, there -- that model risk segments  
9 compared to segments, and then those segments are rolled  
10 into one-mile grids within the Company's GIS system, and  
11 then those one-mile grids are then built out into EIRP  
12 projects.

13 So the -- the ranking on here, outside  
14 of the high pressure rankings, are project risk rankings.  
15 The red high pressure rankings are actually segment  
16 rankings. Those are the rankings of those segments. So I  
17 just wanted to clarify that.

18 Q. The rankings outside of HP. So the rankings for -- or  
19 more directly to say that might be the rankings for SP and  
20 MP, standard and medium pressure, are project rankings?

21 A. Correct.

22 Q. Rankings for HP are segment rankings?

23 A. Correct.

24 Q. Got it. And what do the rankings mean? Do they mean this  
25 is -- this is a project -- are they -- so maybe we just

1 take a for instance.

2 Let's look at A-142, page 1. And let's  
3 look at the second project, because I want to start  
4 outside of the high pressure. OWS2 Corruna. PH, I  
5 assume, is Phase 1 and 2; is that right?

6 A. Yes.

7 Q. Okay. And that's a segment designation. And then there's  
8 a DRAM risk rank of 55 in black; right?

9 A. Correct.

10 Q. So that's a risk rank of -- that's a project risk rank of  
11 55; right?

12 A. Yes.

13 Q. And what does that mean?

14 A. So as I mentioned, the individual segments are rolled up  
15 into one-mile grids.

16 Q. Yep.

17 A. Those one-mile -- those one-mile grids are then rolled --  
18 they comprise about 7,200, 7,500 -- I have to look at my  
19 testimony for the exact number. -- grids around the  
20 state. And so within the EIRP project, there would be  
21 multiple grids. So that is a composite of all the  
22 segments and all of those grids.

23 Q. When you say, "that is a composite" -- So I appreciate  
24 that explanation. I'm trying to get now to the number.  
25 What is the number?

1 A. Yeah. So 55 would be the 55 highest ranked project out of  
2 the 7,200 grids that we have, that are rolled across --  
3 those one-mile grids that I mentioned. So it would be  
4 number 55 out of 7,200.

5 Q. Now when you say, "the 7,200 grids that we have," there  
6 are some portion of those grids where the EIRP work is  
7 complete; is that right?

8 A. Can you rephrase? I'm not sure I'm understanding what  
9 you're asking.

10 Q. It's probably my lack of knowledge of the specifics of the  
11 subject matter, honestly. Let me try it a different way.

12 Well, let me do it this way. So the --  
13 the ranking -- the ranking number 55 for that second  
14 project, OWS2, does that mean it ranks -- is that -- is  
15 that 55 -- number 55 of the EIRP projects, or number 55 of  
16 all distribution projects, or number 55 of all SPRMP  
17 projects? What's kind of the denominator there of the --  
18 the rank, if you will?

19 A. It's my understanding that that -- that is the ranking of  
20 all the grids in the state, whether there's EIRP miles in  
21 those grids or not. As I mentioned, I think it's 7,200.  
22 I'd have to go back and look at my testimony. But it's 55  
23 out of that larger number of grids.

24 Q. It's the 55th --

25 A. Highest risk segment.

1 Q. -- highest risk segment out of 7,200 in the state?

2 A. I said that wrong. Project.

3 Q. 55 highest ranked project out of the 7,200 projects in the  
4 state or grids in the state?

5 A. Grids in the state.

6 Q. And grids in the state or grids in Consumers Energy's  
7 system?

8 A. There's not a difference.

9 Q. Okay.

10 A. So -- so Consumers Energy, within our GIS system, breaks  
11 up the state into one mile squares.

12 Q. Yep.

13 A. So there's 7,200 of those one mile squares.

14 Q. Yep.

15 A. So this is 55 out of those -- all those one mile squares.

16 Q. Okay. Okay. Take a look at -- so we're back to the  
17 Sharepoint now, and we're back in the MEC, SC -- CUB and  
18 SC folder hearing exhibits, Kristine Pascarello.

19 In proposed Exhibit MEC-48, which is  
20 discovery response MEC -- MNSC-CE-915, we asked for  
21 scoring criteria used in the risk assessment  
22 prioritization, essentially, for EIRP; right? Let me  
23 rephrase the question.

24 We asked for the risk assessment method  
25 used to prioritize high-risk segments based on various

1 factors; fair?

2 A. Yes.

3 Q. And then the response directed us to a confidential  
4 attachment provided in response to MNSC-CE-09 -- 0925;  
5 correct?

6 A. Yes.

7 Q. And is that attach- -- so -- so are you in possession of  
8 that attachment or --

9 A. I have --

10 Q. -- do you have it available?

11 A. Yes.

12 Q. Okay. So if we are going to talk about any details of  
13 that attachment, it's my understanding we're going to have  
14 to do that in public session, but I don't think we're  
15 there yet. I'm going to just ask you some general  
16 questions about it first.

17 Is -- is this information -- so -- so  
18 in your response to 0915, when we asked you about how the  
19 risk ranking is done, the criteria that are used, you  
20 pointed us to this confidential attachment; correct?

21 A. Correct.

22 Q. And this confidential attachment actually came to us, to  
23 witness Snyder, in response to another question; right?

24 A. Correct.

25 Q. Okay. So what I'm trying to understand is, is this

1 attachment -- are you the witness who sort of has purview  
2 over the information in this attachment, or is witness  
3 Snyder the witness who has purview over it?

4 A. Witness Snyder.

5 Q. Okay. We will save it for him, then. Lucky you. Let me  
6 just make some notes.

7 I will ask you this, generally  
8 speaking, about the process and not about the exhibit  
9 specifically. You have provided us with -- in A-141 and  
10 A-142, with your rebuttal testimony, you provided us with  
11 risk ranking lists, essentially; right?

12 A. Yes.

13 Q. And those lists are lists of rankings for projects for  
14 which you are sponsoring the projects in the CAP Ex;  
15 right?

16 A. Yes.

17 Q. What is your relationship to or interface with the risk  
18 ranking process? In other words, is this information you  
19 receive and then -- or is this information you're involved  
20 in the compiling of, or something else?

21 A. I would say something else. So the -- the project  
22 selection and risk rank annual runs are done within the  
23 Company's engineering group.

24 Q. You said the project selection and risk rank annual runs  
25 are done within the engineering group?

1 A. Yes.

2 Q. And then what do you do with that information? Or what  
3 does your team do with that information? So what I hear  
4 you saying is we receive it?

5 A. Correct. I receive it.

6 Q. Right. And then what do you and your team do with it when  
7 you receive it? How does it go from receipt of that  
8 information to here's a set of projects for 2025, here's a  
9 set of projects for 2026?

10 A. So there's cross-functional planning that takes place that  
11 I participate in, along with other subject matter experts  
12 and the engineering group.

13 Q. Okay. And how is this information used within the  
14 cross-functional planning process, this risk rank  
15 information?

16 A. So the projects are built around the highest risk rank  
17 segments.

18 Q. Give me a second. Can we look at 142 again?

19 A. Yes.

20 Q. Okay. So I'm on 142, page 1 -- well, here's -- here's a  
21 question, first of all. So there's one page in 142 of 25  
22 projects and one page of 26 projects; right?

23 A. Correct.

24 Q. The -- and then there are risk ranks for projects on each  
25 of those sheets; correct?

1 A. Correct.

2 Q. Are the numbers for sheet 1, the 25 projects, from a  
3 different risk ranking run than the projects on the 2026  
4 list?

5 A. I believe they are, because we run the risk model  
6 annually, and we update the plans annually, but I'm not --

7 Q. So like --

8 A. -- 100 percent positive.

9 Q. Okay. So a -- just high level, right, so looking at page  
10 1 of 142, high level, I can see that -- reviewing this  
11 information, I can see that there are a number of projects  
12 here that appear to be within, shall we call it, a -- a  
13 top 10 risk rank; is that fair?

14 A. Yes.

15 Q. And then I can also see a lot of projects that have  
16 numbers that would appear to be way outside of what we  
17 might call a top 10 or a top 20 rank; is that fair?

18 A. Yes.

19 Q. So I'm trying to reconcile your statement today that the  
20 projects are built around the highest risk rank segments,  
21 which I can certainly see that in part on this  
22 information, but I also see a bunch of projects that  
23 appear not to be among the highest risk run segments, and  
24 I'm hoping you can explain that to me.

25 A. Yes. That's in my direct testimony. Let me get to that

1 page. Okay. I'm not seeing it. I may be confusing it  
2 with testimony from the last case.

3 Q. Okay.

4 A. But essentially, the -- some of the higher risk projects,  
5 for example, 972, going back to Exhibit A-40 -- A-142 --

6 Q. Yes.

7 A. -- 972 is Livonia 3, phase 5. That's a single phase of a  
8 larger project. So that phase would have rolled over into  
9 another -- into -- it's crossing years, essentially.

10 And in other cases -- well, we could be  
11 doing work because of a municipality request. For  
12 example, we're doing some work in Bay City where we  
13 switched our phases around because they are doing some  
14 bridgework, and the streets that we are currently on doing  
15 EIRP construction work the city is planning to use for  
16 their detours for bridgework. So we coordinate with the  
17 municipalities as well. So risk ranking is the primary  
18 factor, but there are other considerations.

19 Q. Okay. So Livonia Phase 3 on A-142, page 1, is in the  
20 southeast zone, it's the third row down, at LIV3 -- maybe  
21 I've got it wrong.

22 A. Yes, LIV3, phase 5; correct.

23 Q. Okay.

24 A. I pulled that out as an example because it has the highest  
25 score on that page.

1 Q. Yeah. No, examples are good. I find examples are -- are  
2 more instructive to me than talking about these things  
3 sort of as -- in generalities. So examples are great.

4 What I hear you saying is that that  
5 project is -- has a rank of 972, but you said it was a  
6 carryover project.

7 A. Correct.

8 Q. Does that mean -- go ahead.

9 A. No. Go ahead. I'm sorry. I cut you off.

10 Q. If you had something to say, I'd just as soon hear it.

11 A. Oh, I was just going to add that the 972 ranking on this  
12 sheet is specific to that phase, not the overall project.

13 Q. Okay. And then what -- what did you mean when you called  
14 it a carryover project?

15 A. So it's a project that's crossing years. So it was  
16 started in 2024 and will be finished in 2025.

17 Q. What is the significance of that fact to the fact that it  
18 has a relatively low ranking but it's on the project list?  
19 I'm trying to understand. Does that mean it was a higher  
20 risk project last year; it was ranked as a higher risk  
21 project last year, but this year it's ranked as a lower  
22 risk project, or something else?

23 A. No. It means that the LIV3 project itself was a higher  
24 risk rank project for 2024.

25 Q. Okay.

1 A. This particular phase is -- this -- this particular phase  
2 is listed as a separate project because the entire phase  
3 is going to be constructed in 2025.

4 So the previous phases were constructed  
5 in 2024. This entire phase will be constructed in 2025,  
6 so we included it in the project list. And that ranking  
7 is for that specific phase.

8 Q. Okay. I am not trying to be difficult. I'm just trying  
9 to understand.

10 Earlier today, you told me that the  
11 rankings for SP and MP are project rankings. I hear you  
12 now saying they can also be rankings for phases of a  
13 project; is that -- is that right?

14 A. Yes. But that phase -- I just want to clarify. That  
15 phase could have -- would have multiple segments within  
16 it.

17 Q. Okay. And so the rankings can be rankings for projects or  
18 rankings for phases of projects for the SP and MP?

19 A. Correct.

20 Q. Back to A-142, page 1, in the southeast zone, second row,  
21 MAC12, and then a few rows down, Royal Oak 16, are both  
22 risk ranked as number 1. Can you explain that?

23 A. No, I -- I don't know why they're both risk ranked as  
24 number 1.

25 Q. Northeast zone FLT5, which I assume is Flint 5, and

1 Saginaw 8, are both ranked as the Number 2 HP project, so  
2 I have the same question about those.

3 A. Yeah, I -- I don't know why they're ranked the same.

4 Q. Okay. Southwest zone, there are four projects where the  
5 risk rank is in bold face type. Do you see that?

6 A. Yes.

7 Q. Do you know what significance that has?

8 A. It has no significance. It's -- it's just an error.

9 Q. Okay.

10 A. There's no significance to the bold.

11 Q. Okay. In order to streamline a little bit, so if there  
12 are, on page 2, also projects with identical risk  
13 rankings, you wouldn't know why that would be the case  
14 either; fair?

15 A. That's fair, yes.

16 Q. Okay. And so what I hear you saying generally is that  
17 there's a planning process, and the risk ranking is one of  
18 the considerations that is included in the planning  
19 process, among others?

20 A. It is the --

21 Q. Various --

22 A. -- primary -- I'm sorry. I cut you off again.

23 Q. No. Go ahead. Go ahead.

24 A. No. The risk rank is the primary driver.

25 Q. Okay. These risk rankings do not include cost benefit

1 estimates; would you agree?

2 A. Yes. Our risk models do not include cost factors.

3 Q. And they do not include an assessment of the probability  
4 of failure; would you agree?

5 A. I would agree.

6 Q. And they do not include an assessment of the consequence  
7 of a failure; would you agree?

8 A. Yes, I would agree.

9 Q. Here's a general question for you about the process. How  
10 does a risk ranking determine -- so I have a set of  
11 programs, right, and I -- and I risk rank those programs.

12 Let's say I have, just for -- to keep  
13 it simple, right, I have ten programs. I risk rank them  
14 -- sorry, ten projects. And I risk rank them. I can  
15 understand that, by risk ranking them, that tells me I  
16 should do number 1 sooner than number 8.

17 How does that tell me how many I should  
18 do in a calendar year or a test year or a projected test  
19 year? How does it -- in other words, I understand it has  
20 some bearing on a sequence, but how does it bear on the  
21 amount of capital that should be spent?

22 A. So we -- we plan by region and we plan by the resources  
23 that are in those regions, and so we plan enough work to  
24 -- to -- for the crews that are work -- gas construction  
25 crews that are working in those regions.

1 Q. Okay. So is kind of the bottom-line capital determined by  
2 the capacity of the labor and contract resources available  
3 to get work done in a year?

4 A. I -- I would say yes. We -- we determine the cost after  
5 the project selection is completed.

6 Q. And the project selection -- the group of projects  
7 selected, the size of that group, is based on the capacity  
8 of the contract and labor resources available to do work  
9 in a given year?

10 A. Yes.

11 Q. So we're sort of maxing out what could be done based on  
12 resource -- contract and labor resources available to do  
13 it?

14 A. Yes.

15 Q. Okay. On Exhibit A-142, there's a note at the bottom  
16 underneath the tables. Do you see that?

17 A. Yes.

18 Q. One of the things that is stated in the note is that EIRP  
19 projects do not have completed business cases, and then  
20 there's an explanation of why. Do you see that?

21 A. Yes.

22 Q. What does it mean to have a completed business case?

23 A. Typical business cases would have a cost benefit analysis,  
24 but as I stated earlier, this program is being done to  
25 replace the aging vintage material based on the DOT and

1           PHSMA recommendation.

2                           MR. BZDOK:   Okay.   May we go off the  
3           record for a second.

4                           JUDGE VARCHETTI:   Certainly.   We're now  
5           off the record.

6                           (At 10:06 AM, recess is taken)

7                           (At 10:21 AM proceedings resume)

8                           JUDGE VARCHETTI:   We are now back on  
9           the record after our brief ten-minute break.   It appears  
10          that everyone is back.

11                          So, Mr. Bzdok, if you would like to  
12          proceed again with cross.

13                          MR. BZDOK:   Thank you.

14   BY MR. BZDOK:

15   Q.   Ms. Pascarello, we're going to talk a little bit now about  
16          Exhibit A-141.

17   A.   Okay.

18   Q.   It's my understanding from your testimony that A-141 is a  
19          list of projects and risk ranks that was presented at an  
20          EIRP technical conference on January 17 of this year; is  
21          that right?

22   A.   Yes, that's correct.

23   Q.   Were the -- you had mentioned in your testimony before the  
24          break that you believed that on A-142, the 2025 project  
25          list was generated through one risk ranking and run, and

1 the 2026 list was generated through a different risk rank  
2 run. Do you remember that?

3 A. I did not say that they were -- that they were both  
4 definitively run through different risk rankings. I said  
5 I didn't know if they were or not, but they possibly could  
6 have been.

7 Q. Okay. Okay. Give me just a second. Okay.

8 Do you know -- do you know whether the  
9 -- the list in A-141 was done through the same risk rank  
10 run as -- or runs as the ones done for A-142?

11 A. No, I don't know if they were from the same year.

12 Q. So A-142 has a 2025 projects list that you are supporting  
13 for capital expenditure approval purposes in the rate  
14 case; right?

15 A. Could you repeat that?

16 Q. A-142, page 1, has a list of 2025 projects that you were  
17 supporting for CAP Ex approval in the rate case; right?

18 A. Partially. So this is a calendar year listing.

19 Q. Right.

20 A. And so the first ten months of 2025 would be related to  
21 Case U-21490.

22 Q. Okay. And then page 2 of A-142 has a list of projects  
23 that you are supporting in the rate case; right?

24 A. For calendar year 2026, correct.

25 Q. And then A-141 is a list of projects discussed at the EIRP

1 technical conference; right?

2 A. Yes.

3 Q. And those are -- what is the timing of those projects?

4 Are they the rate case projects, or different projects, or  
5 some of each?

6 A. These would be calendar year 2025 projects based on the  
7 planning report that the Company filed in December of  
8 2024.

9 Q. Okay. So some of which you supported in the last rate  
10 case and some of which you're supporting in this rate  
11 case?

12 A. Correct.

13 Q. Okay. On A-141, page 1, second project -- project,  
14 Saginaw 9, Phase 2.

15 A. Got it.

16 Q. The risk rank -- sorry. The risk rank for this one is  
17 added to Phase 1 of SAG9. Does that mean this project was  
18 selected based on some kind of a project sequencing  
19 consideration instead of a risk rank?

20 A. Yes. It says in the selection region there's two large  
21 county drains in that area of the high pressure work, so  
22 based on the engineering design, they decided to add the  
23 SAG9 -- this phase of SAG9. They're adding it to Phase 1  
24 of SAG9 because of those high pressure drain crossings.

25 Q. Does that mean it does not have a risk rank or just the

1 risk rank is unknown or did not need to be considered?

2 A. I believe -- I believe it would have a risk rank, but it  
3 was not -- it was not selected because of the risk rank.  
4 It was selected because of the high -- of these two county  
5 drains.

6 Q. Okay. Give me just a second.

7 Take a look at A-142, page 1. I'm  
8 going to make you toggle these a little bit, but I'm not  
9 going to do a lot of these. I'll do like maybe three of  
10 these.

11 A. Okay.

12 Q. Okay. Don't hold me to that. It might be four. But it  
13 won't be like -- I'm not going to do this 20 times.

14 So page 1, northeast zone, Bay City 2,  
15 on the 2025 projects list, Bay City 2 has a risk rank of  
16 42. Do you see that?

17 A. Yes.

18 Q. And then on page 2, northeast zone, Bay City 2, which is a  
19 carryover from 2025, has a risk rank of number 1.

20 A. Yes.

21 Q. And then on A-141, page 2, fourth row from the bottom, Bay  
22 City 2 has risk ranks of 83, 119, 137, 310, and 316.

23 I'm wondering if you can shed any light  
24 on the -- the difference in the risk ranks for the Bay  
25 City 2 project from the '25 list in A-142, to the '26 list

1 in A-142, to the EIRP technical conference list in A-141.

2 It appears to me to be kind of all over the place.

3 A. So on Exhibit A-141, the different rankings that are shown  
4 there are related to those different one-mile grids that I  
5 mentioned.

6 Q. Okay.

7 A. And the 42 that would be -- on A-142 would be all of those  
8 grids -- all those one-mile grids, the risk ranking of all  
9 those combined.

10 Q. Can you shed light on how a set of grids, with what appear  
11 to be relatively low risk ranks, 83, 119, 137, 310, 316,  
12 when compiled together, could be -- could have the risk  
13 ranking of number 1?

14 A. The risk ranking is 42.

15 Q. For '26. For '25, it was risk rank number 1. Sorry. For  
16 '25, it was 42. For 256, it was number 1.

17 A. It's a -- it's a different phase.

18 Q. Okay.

19 A. The '26 is Phase 2. '25 is phases 3, 7, and 8.

20 Q. Okay. So how could grids that individually are ranked  
21 mostly in the hundreds and three hundreds sum up to become  
22 the 42nd highest ranked project?

23 A. I don't know.

24 Q. I'm going to ask you the same question about -- and like I  
25 said, I'm only going to do a couple more of these. I'm

1 going to ask you the same question about Saginaw 12, Phase  
2 1. So I find that one on A-142, northeast zone, fourth  
3 from the bottom of the northeast zone, with a risk rank of  
4 39. And then I find it on --

5 A. I'm sorry. What page are you on?

6 Q. So I'm on A-142, page 1.

7 A. Page 1.

8 Q. Northeast zone. It's fourth from the bottom of the  
9 northeast zone.

10 A. And you said Saginaw 4?

11 Q. Saginaw 12, Phase 1.

12 A. Saginaw 12, Phase 1, is fifth from the top.

13 Q. Sorry. I'm on -- yes, it is fifth from the top on A-141.

14 A. On A-142.

15 Q. Okay. Okay. I'm with you.

16 Okay. I'm going to give you three  
17 locations; okay? On page -- so on page 2, I agree. On  
18 page 2 of A-142, I agree, SAG12, Phase 1, is fifth from  
19 the top, and it has a risk rank of 17; right?

20 A. Yes.

21 Q. On page 1 of A-142, Saginaw 12, Phase 1, is fourth from  
22 the bottom of the northeast zone. Do you see it there?

23 A. Yes.

24 Q. With a risk ranking of 39; right?

25 A. Yes.

1 Q. And then on A-141, page 1, it's one -- one, two, three,  
2 four, five, six -- seven from the top.

3 A. Yes.

4 Q. With a risk rank of 220 and 326. Do you see that?

5 A. I see 220 and 326.

6 Q. Yeah. Are you able to explain those differences?

7 A. No. I don't know.

8 Q. Are there -- I'm going to try to bring this to a closure  
9 without further questions like this.

10 Are there -- are you aware from the  
11 planning process that you testified earlier that you're  
12 involved in where we take the risk rankings and the other  
13 sequencing and other considerations and come up with  
14 project risks, are you aware of any projects that are on  
15 these lists that had substantially different risk rankings  
16 in the different compilations where you -- you know why  
17 that was?

18 In other words, rather than continuing  
19 to slog through specific instances, are there -- are there  
20 ones where you know, you know, yes, there was -- there was  
21 -- there were disparities but here's the reason why?

22 A. No. Like I mentioned earlier, the -- I'm a recipient of  
23 the data.

24 Q. Okay. And that -- but that -- that sort of topic is not  
25 discussed in the planning meetings?

1 A. We do cover risk rank, but I don't -- I don't -- we don't  
2 compare -- we don't -- how do I say this? We don't  
3 discuss changes in risk ranking.

4 Q. Okay. So if I was to continue to hound you about  
5 particular instances, the answer would be the same?

6 A. Correct.

7 MR. BZDOK: I will not do that anymore.  
8 Your Honor, I am going to move to admit  
9 proposed Exhibit MEC-48, which is the public discovery  
10 response that referred to the confidential attachment in  
11 925 which we discussed a few minutes ago.

12 JUDGE VARCHETTI: All right. Is there  
13 any objection to the admission of Exhibit MEC-48?

14 I am hearing none, so Exhibit MEC-48 is  
15 admitted.

16 MR. BZDOK: Thank you.

17 Bear with me a second. May we go off  
18 the record for a moment?

19 JUDGE VARCHETTI: Certainly. We are  
20 now off the record.

21 (At 10:41 AM, recess was taken)

22 (At 10:43 AM, proceedings resume)

23 JUDGE VARCHETTI: All right. We are  
24 now back on the record.

25 And, Mr. Bzdok, you can proceed again.

1 MR. BZDOK: Thank you.

2 BY MR. BZDOK:

3 Q. We are going to -- Ms. Pascarello, we are going to turn to  
4 another topic in your rebuttal, and a page reference for  
5 you will be page 33.

6 A. Okay.

7 Q. And really, it's at the -- line 15 on page 33, you were  
8 asked a question should the Company be required to perform  
9 the probabilistic risk modeling and cost effective  
10 analysis for EIRP prior to expenditures increasing above  
11 2024 levels. Do you see that?

12 A. Yes.

13 Q. And then you provide a long answer that begins on page 33  
14 and carries over to page 35, right, with -- with a variety  
15 of different reasons?

16 A. Correct.

17 Q. Okay. You make a statement -- as part of those reasons,  
18 you make a statement on page 34, Line 4, quote, "Also, the  
19 purpose of the EIRP is not leak remediation; it is vintage  
20 material replacement to enhance safety and improve  
21 reliability." Do you see that?

22 A. Yes.

23 Q. We asked you a couple of discovery questions about this.  
24 The first one is proposed Exhibit MEC-45, which is in the  
25 Sharepoint folder for you, which is discovery request 912.

1 A. Yes.

2 Q. And this is information about how the Company measures the  
3 cost effectiveness of the ERP -- EIRP projects; correct?

4 A. That is correct.

5 MR. BZDOK: Your Honor, I am going to  
6 move to admit MEC-45 without questions.

7 JUDGE VARCHETTI: All right. Are there  
8 any objections to the admission of Exhibit MEC-45?

9 Hearing none, Exhibit MEC-45 is  
10 admitted.

11 MR. BZDOK: Thank you.

12 BY MR. BZDOK:

13 Q. And then if you would also take a look at proposed MEC-46,  
14 which is discovery response number 913.

15 A. Yes.

16 Q. Here we asked, among other things, in subpart B, we asked  
17 for information on employee or public safety incidents for  
18 these pipes; right?

19 A. Yes.

20 Q. Okay. And you provided certain information in attachment  
21 1; is that right?

22 A. Yes.

23 Q. Okay. In your folder also is the original Excel version  
24 of attachment 1. If you could open that one up as well.

25 A. Okay.

1 Q. And I'll represent to you that I have not modified this  
2 Excel in any way from the form that I received it from  
3 you, and it -- on just an eyeball check, it appears to be  
4 the same as what's attached to the exhibit; fair?

5 A. Does it have -- does it have filtering applied?

6 Q. Yes, I think I sorted it. This doesn't look right to me.  
7 I'm going to -- I'm going to take this -- I'm going to  
8 reload this; okay? This doesn't look right to me.

9 So I'm going to -- I'm going to delete  
10 this one and reload it. So if anybody's in it -- because  
11 that doesn't look right to me. If folks who are in the  
12 Excel version of 913 could close out, then I'll delete it  
13 and I'll reload it.

14 Someone's still in it. It won't let me  
15 delete it. Oh, there it goes. Okay. Great. So let me  
16 find it and reload it. Give me just a second. This is  
17 going to take me a minute because I'm going to go back to  
18 the original service of the discovery response from the  
19 Company so that I have good chain of custody here.

20 Okay. Here it is. Okay. Now I'm  
21 going to -- so you'll want to refresh your Sharepoint and  
22 then open up the new version of 913, which I'll represent  
23 that I have just now copied over from the Company's e-mail  
24 serving this discovery response on the parties.

25 Does this appear to be the Excel

1 version of the attachment to the exhibit, on an eyeball  
2 check?

3 A. Yes.

4 Q. Okay. This document presents incident years starting on  
5 line 5 and carrying down to Line 241. Do you see that?

6 A. Yes.

7 Q. Okay. So that's approximately 236 data points?

8 A. 237.

9 Q. Okay. Thanks. A DTE witness once told me Excel doesn't  
10 lie.

11 So 237 incidents are reported on this  
12 attachment; fair?

13 A. Yes.

14 Q. Okay. If I sort them -- so the second column has,  
15 "vintage materials, yes, no, or not applicable"; right?

16 A. Yes.

17 Q. And then the third column has, "non-TOD,  
18 non-transmission." What does that mean?

19 A. That means it would be on the -- on the distribution  
20 system.

21 Q. Okay. "TOD pipe only," what does that mean?

22 A. That's the transmission operated as distribution pipe that  
23 I mentioned earlier.

24 Q. Okay. Transmission pipeline, some of them are marked,  
25 "yes." What does that mean?

1 A. I believe it means that the incident occurred on -- on one  
2 of the transmission pipelines.

3 Q. Okay. And then there's a safety incident or a reporting  
4 reason; correct?

5 A. Yes.

6 Q. And then there's a cause?

7 A. Yes.

8 Q. Okay. If I sort vintage materials Z to A, that will give  
9 me the -- the yeses for vintage materials all together;  
10 right?

11 A. It appears so, yes.

12 Q. Okay. And that will -- that tells me that of the 237  
13 safety incidents that are compiled in this list, 10 of  
14 them involved vintage materials; right?

15 A. Yes.

16 Q. And of the 10 of them that involved vintage materials, one  
17 had a cause of incorrect operations, and two had causes of  
18 excavation damage; correct?

19 A. Yes.

20 Q. Leaving seven having causes of failure or leaks; correct?

21 A. Yes.

22 Q. So of the 237 safe -- incidents that are reported, 7 of  
23 them are caused by failure or leak of vintage materials;  
24 correct?

25 A. Yes.

1 Q. Okay. Okay. In response B, you make a statement that  
2 suggested to me you were kind of aware of how this shook  
3 out. You said part way down in answer B on MEC-46, you  
4 said, "Notably, the reduced number of incidents involving  
5 vintage pipes supports that efforts to replace vintage  
6 materials are mitigating risks within our system and is  
7 yielding positive results." Do you see that?

8 A. Yes.

9 Q. Okay. Hypothetically, if this incident report had a whole  
10 bunch of incidents caused by failure or leak of vintage  
11 materials, that would -- that would also be used as  
12 support for high levels of the EIRP spending; would you  
13 agree?

14 A. I don't understand your question. Can you rephrase it?

15 Q. I don't think -- I think I'm going to move on.

16 A. Okay.

17 Q. Let's move to subpart D of your response.

18 A. Okay.

19 Q. And sub -- okay. In subpart D, you discuss a variety of  
20 issues related to this topic, and then you cite some PHSMA  
21 data from 2005 to 2024 towards the bottom of that  
22 response. Do you see that?

23 A. Yes.

24 Q. You cite a statistic that according to the PHSMA data, "8  
25 percent of the incidents occurring on gas distribution

1 mains involved cast iron mains. However, only 1 percent  
2 of distribution mains are cast iron." Do you see that?

3 A. Yes.

4 Q. How does that -- so early in your testimony today, you  
5 told me that vintage materials were comprised of cast  
6 iron, wrought iron, bare steel, and threaded and coupled  
7 steel. Do you remember that?

8 A. Yes.

9 Q. In -- in the -- so am I understanding correctly that this  
10 eight percent statistic is -- relates to one of the four  
11 types of vintage materials that are on the -- the  
12 Company's system?

13 A. Yes. It specifically says, "Eight percent of incidents  
14 occurring on gas distribution mains involved cast iron  
15 mains." So this data is -- is representative of cast iron  
16 mains.

17 Q. Okay. So for Consumers' incident reporting over the time  
18 period that's available under record retention policies in  
19 the attachment to 913, would you agree that less than  
20 three percent of any of the categories of vintage material  
21 -- less than three percent of the incidents are occurring  
22 on any of the four categories of vintage materials on  
23 Consumers' system?

24 A. I would not, no.

25 Q. Okay. Why not?

1 A. Because what we provided in the attachment are the public  
2 reported incidents. There are many instances -- incidents  
3 that don't rise to the requirement of reporting that still  
4 occur within the system.

5 Q. Okay. So is what you're saying that the Company has  
6 incident data in its possession that was not provided in  
7 response to this request?

8 A. The request was for public safety incidents. We provided  
9 our defini- -- we provided what the public safety  
10 incidents reported. So what we provided were the public  
11 safety incidents.

12 Q. So what is the distinction that you're making here between  
13 public safety incidents -- what are the other incidents  
14 that were not reported?

15 A. So --

16 Q. If we asked you for -- go ahead. Go ahead.

17 A. I'm sorry. I didn't -- I didn't want to interrupt you.  
18 Go ahead.

19 Q. I asked a question, and then I started to continue  
20 talking, so that's my fault.

21 We asked for the number of employee or  
22 public safety incidents, and you indicated that these are  
23 incidents in public reporting, but there were some type of  
24 other incidents, and I'm trying to understand what  
25 distinction you were drawing there.

1 A. There -- there are -- there are requirements for public  
2 reporting, and if -- if a leak or an incident does not  
3 rise to that level -- for example, if the repair costs  
4 more than \$10,000, that -- that would be a reportable  
5 incident.

6 Q. Okay.

7 A. So we -- we do have incidents that don't meet the criteria  
8 for public reporting.

9 Q. So we didn't ask you for reported incidents; right? We  
10 asked you for employee or public safety incidents.

11 A. And we interpreted public safety incidents to mean public  
12 safety incidents that the Company was required to report.

13 Q. So what are the nature of the incidents -- I'm struggling  
14 to understand what the nature of these other incidents is.  
15 Is it like -- are you saying there's -- are they incidents  
16 without a safety incident or a reporting reason?

17 A. Correct.

18 Q. Okay. So like a leak is detected but it's not -- it's not  
19 a leak that caused property damage or a gas release or an  
20 injury or et cetera, et cetera?

21 A. Yes.

22 Q. Okay. Are the -- the PHSMA data that you're talking about  
23 on page 2 of the response, is that -- is that data  
24 covering reportable incidents, or is it covering  
25 reportable incidents and the other kinds of issues that

1           you say the Company has records of on its system?

2       A.    I don't know what's the criteria PHSMA uses for reporting  
3           that data.  That came directly from their site.

4       Q.    Okay.  Give me a second.  So you provided a link for the  
5           -- you provided a link to -- you provided two links to  
6           PHSMA in the discovery response; correct?

7       A.    Correct.

8       Q.    And the one, actually, on page 2 is a link to some PHSMA  
9           data having to do with something else in your response;  
10          right?  Not the topic we were just talking about.

11      A.    Correct.  The response in the second footnote is a link to  
12          other incidents that have happened with vintage materials  
13          in other utilities across the country.

14                                   MR. BZDOK:  Okay.  May I share screen  
15          for a moment, Your Honor?

16                                   JUDGE VARCHETTI:  Yes.  Please do.

17      BY MR. BZDOK:

18      Q.    Okay.  So if I go to your response, can you see the  
19          response?

20      A.    Yes.

21      Q.    Okay.  And then I click on your link for the PHSMA data.  
22          Can you see that?

23      A.    Yes.

24      Q.    Okay.  That takes me to the PHSMA data that you were  
25          restating here in your response; right?

1 A. This is the incidents, so this is the second footnote.

2 Q. Yes.

3 A. So you can see the date and the different incidents that  
4 have happened across the country.

5 Q. Okay. And then if I scroll part of the way down, I don't  
6 know if you can see this and I don't know if I can make it  
7 any bigger, there is this incident and consequence  
8 analysis. Do you see what I'm highlighting?

9 A. Yes.

10 Q. And this contains those 8 percent, 38 percent, and 33  
11 percent statistics that you cite in your discovery  
12 response. Do you see that?

13 A. Yes.

14 Q. And so the -- this indicates that -- that those are --  
15 those are reportable incidents statistics. Do you agree?

16 A. It says, "Submitted incident reports," so I would agree.

17 Q. Okay. So comparing, then, reportable incidents to  
18 reportable incidents, you would agree that the PHSMA data  
19 you're citing here for eight percent of incidents being --  
20 involving cast iron mains, and then I've said for all four  
21 categories of Consumers' vintage materials, less than  
22 three percent of the reportable incidents involved vintage  
23 materials, would you agree that that's -- that's the  
24 apples to apples comparison with the PHSMA data?

25 A. Yes.

1 Q. The PHSMA data that you are citing in the discovery  
2 response refers to 38 percent of the cast or wrought iron  
3 main incidents causing a fatality or injury; correct?

4 A. Correct.

5 Q. Consumers' reportable incident data would indicate that  
6 there are no -- there are no fatalities or injuries  
7 included among the reportable incidents involving vintage  
8 materials in this data set; would you agree?

9 A. Yes.

10 Q. And the PHSMA data you site in the third Romanette point  
11 on page 3 of this discovery response for 33 percent of all  
12 fatalities and 15 percent of all injuries on gas  
13 distribution mains involving cast or wrought iron  
14 pipelines, the analogue to the Consumers' data is the  
15 same, that it's zero percent; right?

16 A. Correct.

17 MR. BZDOK: Okay. Your Honor, I am  
18 going to move to admit proposed Exhibit MEC-46, discovery  
19 response 913, and the attachment.

20 JUDGE VARCHETTI: All right. Are there  
21 any objections to the admission of Exhibit MEC-46 and its  
22 attachment?

23 I am hearing none, so Exhibit MEC-46  
24 and its attachment are admitted.

25 MR. BZDOK: Thank you. Just another

1 moment to review some notes here. I think we're either  
2 done or almost done.

3 Ms. Pascarello, I appreciate your time  
4 and your answers today, and I have no further questions  
5 for you at this time.

6 JUDGE VARCHETTI: All right. Thank  
7 you, Mr. Bzdok.

8 So, Mr. Gensch, now that Mr. Bzdok has  
9 concluded his cross, do you need some time to confer with  
10 the witness to determine if you want to do redirect?

11 MR. GENSCH: I have no redirect, Your  
12 Honor.

13 JUDGE VARCHETTI: All right. No  
14 redirect.

15 In that case, we can perhaps, then,  
16 move on to the -- your request to admit the exhibits that  
17 were sponsored by Ms. Pascarello, and these exhibits were,  
18 and please jump in and correct me if I'm wrong,  
19 Mr. Gensch, Exhibits A-80, A-81, A-12 Schedule B-5.8, A-82  
20 through A-85, and A-138 through A-142. Was that correct?

21 MR. GENSCH: Yes. That's correct.

22 JUDGE VARCHETTI: Okay. Are there any  
23 objections to the admission of any of the exhibits that I  
24 just named?

25 I am hearing none, so in that case, the

1 exhibits that I just named are admitted into the record.

2 Okay. It is also my understanding that  
3 there was not going to be any additional witnesses  
4 cross-examined today; is that correct?

5 MR. GENSCH: Yes, that's correct.

6 JUDGE VARCHETTI: All right. In that  
7 case, I do believe, then -- let me ask just for the  
8 record, are there any other matters we may have to take up  
9 today?

10 All right. I am hearing none. In that  
11 case, this hearing is concluded for the day. We will  
12 reconvene again on Monday at 9:00 AM.

13 Thank you all for making this go as  
14 swiftly and as quickly as possible. It's very much  
15 appreciated. And this hearing is now adjourned, and we  
16 are off the record.

17 (At 11:16 AM, the hearing was adjourned  
18 for the day) - - -

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## C E R T I F I C A T E

I, Dawn M. Houghton, CSR-3071, do hereby certify that I reported in stenotype, via Microsoft Teams, the proceedings had in the within-entitled matter, that being Case No. U-21806, before James M. Varchetti, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Friday, May 30, 2025; and do further certify that the foregoing transcript, consisting of Volume III, Pages 335-522, is a true and correct transcript of my stenotype notes.



Dawn M. Houghton, CSR, RPR  
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My commission expires: 7-17-2029

Dated: June 3, 2025