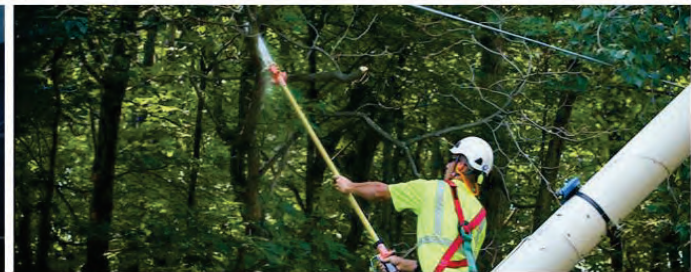
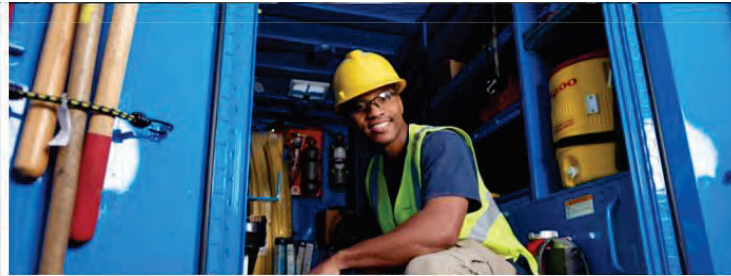


U-21806 Attorney General's Exhibits

Exhibit AG-1	CMS Energy Investor Presentations
Exhibit AG-2	New Service Connections
Exhibit AG-3	Asset Relocations-Civic
Exhibit AG-4	Asset Relocations-Reimbursable
Exhibit AG-5	Regulatory Compliance MAOP projects
Exhibit AG-6	PHMSA Rule on MAOP
Exhibit AG-7	EIRP Miles Retired, Installed and Costs
Exhibit AG-8	EIRP Large Projects Development Phase
Exhibit AG-9	EIRP Completion Extension
Exhibit AG-10	Material Condition Non-Modeled Projects
Exhibit AG-11	Vintage Services Replacement Program
Exhibit AG-12	LDAR Rule and Advanced Methane Detection
Exhibit AG-13	ECAP Cap Ex Projects
Exhibit AG-14	Utility Network IT Project
Exhibit AG-15	Transmission Pipeline Integrity Projects
Exhibit AG-16	Transmission MAOP Projects
Exhibit AG-17	Transmission Asset Relocation projects
Exhibit AG-18	Transmission Field Measurement Projects
Exhibit AG-19	Transmission Pipeline Deliverability Projects
Exhibit AG-20	Transmission Citygate Stations
Exhibit AG-21	Transmission Remote Closure Valves
Exhibit AG-22	Northville Dehydration Project
Exhibit AG-23	Storage New Well Projects
Exhibit AG-24	Storage and Compression Projects
Exhibit AG-25	Storage and Compression Large Projects
Exhibit AG-26	Storage and Compression 2024 Underspent
Exhibit AG-27	Tracking and Traceability IT Project
Exhibit AG-28	CONF ERP IT Project
Exhibit AG-29	ERP IT Project Features
Exhibit AG-30	IT Servers and Equipment Replacement
Exhibit AG-31	IT Project Forward Web Proxy Services
Exhibit AG-32	IT Projects 2024 Underspent
Exhibit AG-33	Transportation Fleet Purchases
Exhibit AG-34	CONF Revised Capital Expenditures and Rate Base Reductions
Exhibit AG-35	CONF Working Capital Adjustments Summary
Exhibit AG-36	Working Capital – Cash On Hand Balances
Exhibit AG-37	CONF W/C SAP S/4 Cloud Implementation Costs
Exhibit AG-38	W/C Cloud Computing Amortization Corrected
Exhibit AG-39	W/C Riverside Storage Field Loss Amortization
Exhibit AG-40	W/C Accrued Taxes
Exhibit AG-41	Overall Cost of Capital
Exhibit AG-42	Cost of Common Equity
Exhibit AG-43	Cost of Common Equity-DCF
Exhibit AG-44	Cost of Common Equity-CAPM
Exhibit AG-45	Cost of Common Equity-Risk Premium
Exhibit AG-46	Peer Group Utility and Non-Utility Business Mix
Exhibit AG-47	Market to Book Ratios of Peer Group
Exhibit AG-48	ROE Decisions by Regulatory Commissions
Exhibit AG-49	Cash Flow to Debt Coverage Ratio Recalculation

Exhibit AG-50	Peer Group ROEs
Exhibit AG-51	Rating Agencies Reports
Exhibit AG-52	Value Line Market Volatility Not Risk
Exhibit AG-53	Gas Sales Analysis
Exhibit AG-54	Transportation Revenue Adjustments
Exhibit AG-55	Transportation Volume Decline Not Explained
Exhibit AG-56	CONF Revised O&M Expense Reductions Summary
Exhibit AG-57	Distribution Pipeline Integrity, Lean Office, AMD
Exhibit AG-58	EIRP Training
Exhibit AG-59	Transmission Corrosion Control and MAOP Expense
Exhibit AG-60	Customer Service, Analytics and Digital
Exhibit AG-63	Voluntary Separation Program Cost Savings
Exhibit AG-65	Health Care Cost Savings
Exhibit AG-66	Incentive Compensation Operating Measures Results
Exhibit AG-67	Revised AG Revenue Deficiency Calculation
Exhibit AG-68	Baker DR AG-CE-0927 to 0929, 0931 to 0933
Exhibit AG-69	Pnacek-Pascarello DR AG-CE-0934 w-attachments, 0935 to 0942
Exhibit AG-70	Byrom DR AG-CE-0943 to 0944
Exhibit AG-71	Conrad DR AG-CE-0945 to 0947 w-attachment
Exhibit AG-72	Dreisig DR AG-CE-0948 to 0949 w-attachment
Exhibit AG-73	Grob DR AG-CE-0950 and 0951 w-attachments
Exhibit AG-74	Guinn DR AG-CE-0952
Exhibit AG-75	Griffin DR AG-CE-0957 to 0959
Exhibit AG-76	Griffin DR AG-CE-0960 to 0962, 0964, 0965, 0966 with Attachment, 0967, 0969
Exhibit AG-77	Joyce DR AG-CE-0972 to 0980, w-DR AG-CE-0507 with 0978
Exhibit AG-78	Meschke DR AG-CE-0981, 0983, 0985
Exhibit AG-79	Myers DR AG-CE-0986
Exhibit AG-80	Pascarello DR AG-CE-0987 to 0991, 0993, 0994, 0996
Exhibit AG-81	Sherwani DR AG-CE-0997, 0998, 1000, 1001 w-Attachment, 1002 w-Attachment
Exhibit AG-82	Warriner DR AG-CE-1004, 1005
Exhibit AG-83	Bulkley DR AG-CE-1012, 1013
Exhibit AG-84	Bleckman DR AG-CE-1014, 1017 to 1021
Exhibit AG-85	Bleckman DR AG-CE-1022 to 1024, 1026



Investor Meetings
March 2025





This presentation is made as of the date hereof and contains “forward-looking statements” as defined in Rule 3b-6 of the Securities Exchange Act of 1934, Rule 175 of the Securities Act of 1933, and relevant legal decisions. The forward-looking statements are subject to risks and uncertainties. All forward-looking statements should be considered in the context of the risk and other factors detailed from time to time in CMS Energy’s and Consumers Energy’s Securities and Exchange Commission filings. Forward-looking statements should be read in conjunction with “FORWARD-LOOKING STATEMENTS AND INFORMATION” and “RISK FACTORS” sections of CMS Energy’s and Consumers Energy’s most recent Form 10-K and as updated in reports CMS Energy and Consumers Energy file with the Securities and Exchange Commission. CMS Energy’s and Consumers Energy’s “FORWARD-LOOKING STATEMENTS AND INFORMATION” and “RISK FACTORS” sections are incorporated herein by reference and discuss important factors that could cause CMS Energy’s and Consumers Energy’s results to differ materially from those anticipated in such statements. CMS Energy and Consumers Energy undertake no obligation to update any of the information presented herein to reflect facts, events or circumstances after the date hereof.

The presentation also includes non-GAAP measures when describing CMS Energy’s results of operations and financial performance. A reconciliation of each of these measures to the most directly comparable GAAP measure is included in the appendix and posted on our website at www.cmsenergy.com.

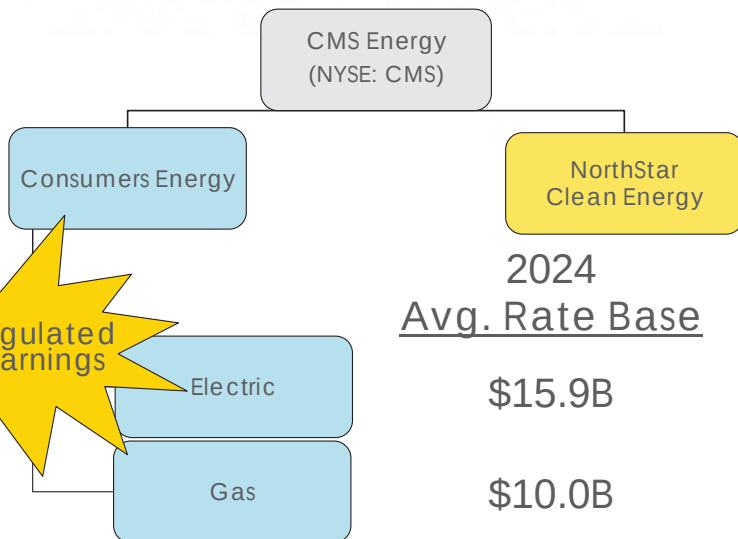
Investors and others should note that CMS Energy routinely posts important information on its website and considers the Investor Relations section, www.cmsenergy.com/investor-relations, a channel of distribution.

Presentation endnotes are included after the appendix.

CMS Energy Overview



Corporate Structure



2024
Avg. Rate Base

\$15.9B

\$10.0B

Key Information

2024 Financial Statistics

Based in Jackson, MI

>8,300	Employees (44% unionized) ^a
\$7.5B	Revenue
\$998M	Adjusted net income ^b
22 years	Industry-leading financial performance
6% to 8%	Long-term adj. EPS ^b growth
~60% ^c	Payout ratio over time

Senior Management Team

Reiji Hayes
 Executive VP & CFO

Garrick Rochow
 President & CEO

Shaun Johnson
 General Counsel & SVP Business Optimization

LeeRoy Wells
 SVP Operations

Tonya Berry
 SVP Transformation & Engineering

Brandon Hofmeister
 SVP Strategy, Sustainability & External Affairs

Consumers Energy Positioned Well . . .



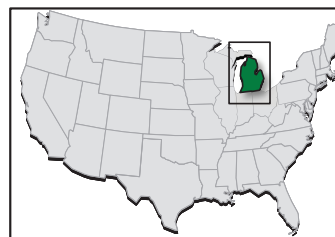
Service Territory

- **Electric Utility**
1.9M electric customers
9,853 MW of capacity
- **Gas Utility**
1.8M gas customers
309 Bcf gas storage
- **Serving 6.8M Michigan residents**

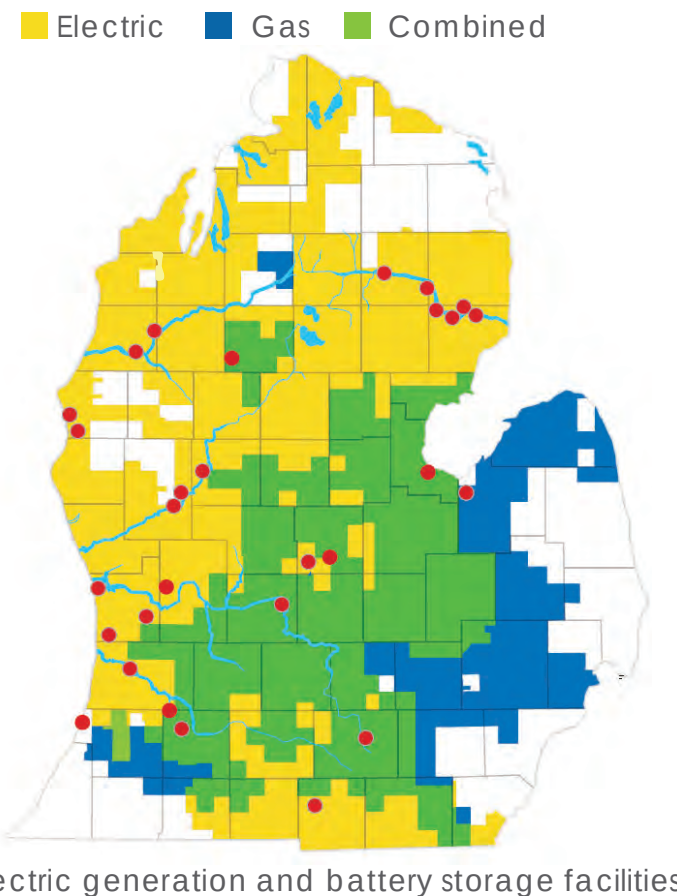
Planet Goals^a

- Exiting coal in 2025
- Net zero methane emissions by 2030
- 60% renewable energy by 2035
- 100% clean energy by 2040
- Net zero GHG emissions by 2050
 - Interim goal of 25% by 2035

Presentation endnotes are included after the appendix.



>1,300
MW
cumulative
contracted
load since
2015^b



. . . for decarbonization and to lead the Clean Energy Transformation.

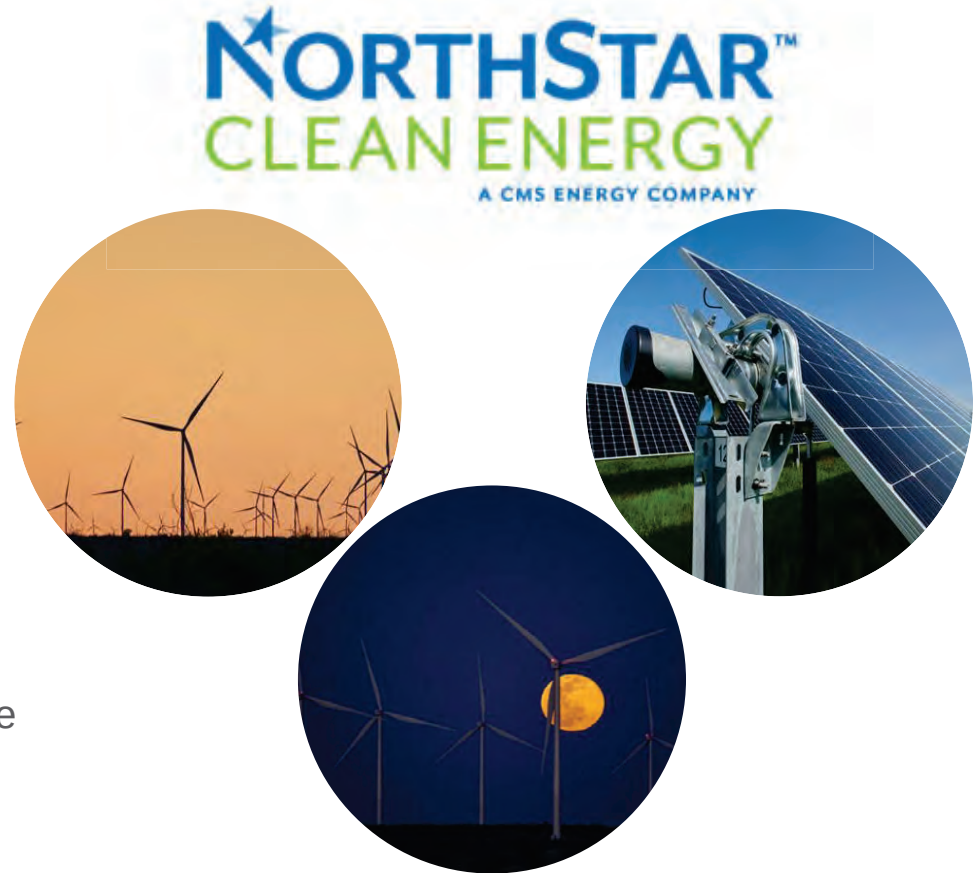
NorthStar Clean Energy^a Provides Flexible Solutions . . .

Renewable Platform

- 368 MW of wind (OH, TX)
- 64 MW of biomass (MI, NC)
- 210 MW of solar (AR, MI, WI)

Dearborn Industrial Generation (DIG) & Other

- >1,000 MW in MI (including DIG & Peakers)
- Upside: tightening capacity markets with future retirements



Presentation endnotes are included after the appendix.

. . . to help companies meet their decarbonization targets.

Near- and Long-Term Financial Objectives . . .



	<u>2025</u>	<u>Long-Term Plan</u>
Adjusted EPS guidance	\$3.54 – \$3.60 <i>Toward the high end</i>	+6% to +8% <i>Toward the high end</i>
Dividend Payout Ratio	~60%	~60% over time
Target credit ratings	Solid investment grade <i>FFO/Debt target: Mid-teens^a</i>	Solid investment grade <i>FFO/Debt target: Mid-teens^a</i>
Utility investment (\$B)	\$3.7	\$20 <i>2025 - 2029</i>
Electric sales growth <i>Incl. Energy Efficiency ~2%/yr</i>	~1%	2% - 3%
Planned equity issuance (\$M)	Up to \$500M	~\$450M/yr

Presentation endnotes are included after the appendix.

. . . provide sustainable benefits for customers AND investors.

ESG Disclosures are Transparent . . .



- [CMS Energy & Consumers Energy Websites](#)
- [SEC Filings \(10-K & Proxy\)](#)
- [CDP Corporate Questionnaire](#)
- [Biodiversity Report](#)
- [Sustainability Report](#)
- [DE&I Website](#)
- [EEO1 Report](#)
- [SASB Index \(Electric Utilities & Power Generation\)](#)
- [SASB Index \(Gas Utilities & Distributors\)](#)
- [TCFD Index](#)
- [Global Reporting Initiative \(GRI\) Index](#)
- [Global Reporting Initiative \(GRI\) Human Capital Data](#)
- [Political Engagement](#)
- [Climate Change Risk, Vulnerability and Resiliency Report](#)

. . . and align with SASB, TCFD and GRI reporting frameworks.



INVESTMENT THESIS

Investment Thesis . . .



Presentation endnotes are included after the appendix.

- Industry-leading net zero commitments
- Excellence through the **CE WAY**
- Top-tier regulatory jurisdiction^a
- Premium total shareholder return**
6% to 8% adjusted EPS growth + ~3% dividend yield

. . . is simple, clean and lean.

Infrastructure Renewal is Necessary . . .



10-yr Electric Reliability Roadmap

Includes up to 400 miles of undergrounding and 20k pole replacements per year



New Energy Legislation

Provides capital opportunity to meet 60% Renewable Portfolio Standard by 2035 and 100% Clean Energy Standard by 2040



Add 9 GW of solar and 4 GW of wind over next two decades
Add >850 MW of battery storage by 2030

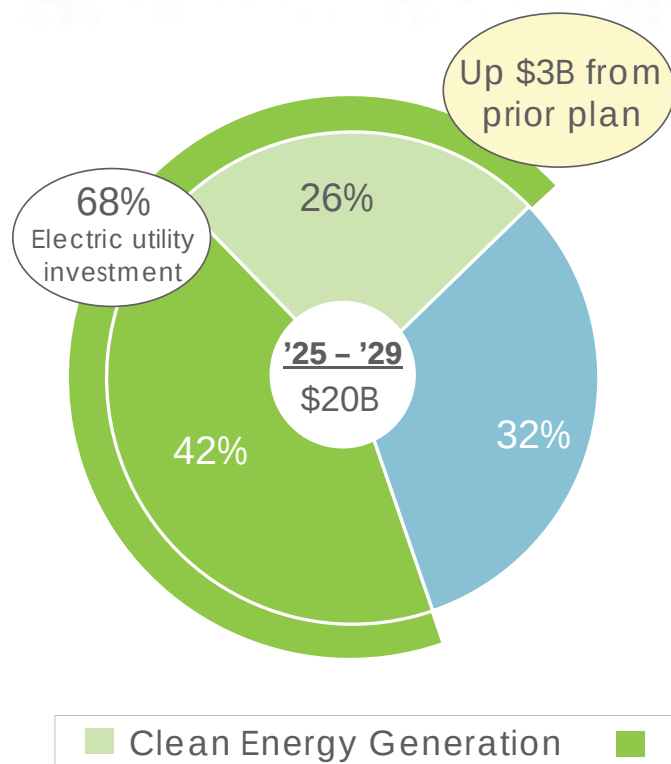
25 years of main replacement through Enhanced Infrastructure Replacement Program

. . . to modernize electric and gas systems and lead the Clean Energy Transformation.

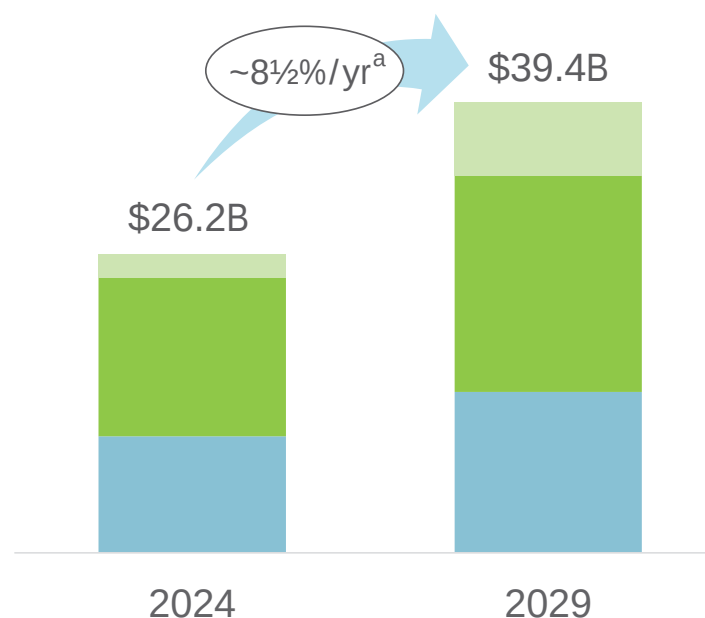
Updated Customer Investment Plan . . .



New Utility Investment Plan



Rate Base Growth



Non-Rate Base Earnings^b

- ✓ ~\$20M pre-tax for FCM by 2029
- ✓ ~\$60M/yr pre-tax for Energy Efficiency incentive
- ✓ NorthStar – DIG re-contracting opportunities

Presentation endnotes are included after the appendix.

. . . delivers benefits for customers and investors.



Long-Term Opportunities . . .

Electric Distribution

Electric Supply

Long-term Plan/ Reference Filing	Reliability Roadmap 2025 – 2035	Renewable Energy Plan (REP) 2025 – 2045	Integrated Resource Plan (IRP) 2027 – 2045+
Key Investments	• 20K poles replaced each year • Up to 400 mi/yr of undergrounding • Rebuild 20% of substations over the next 10 years	• 9,000 MW solar • 4,000 MW wind • 1,200 MW online (~70% owned) • 2,800 MW incremental (~100% owned)	• >850 MW of battery storage • Investments driving resource adequacy – addressing intermittency of renewables
Customer Value	• Drives 2nd quartile performance for SAIDI^a • Aims to restore 100% of customers within 24 hours	• Achieves Michigan’s 60% renewable energy target by 2035 in cost-effective manner • Supports demand growth	• Delivers cleaner portfolio without compromising resource adequacy • Supports demand growth
Investment	\$18B	\$14.6B	TBD
Opportunity	\$10B not in 5-yr Plan	\$10B^b not in 5-yr Plan	Additional opportunity

Presentation endnotes are included after the appendix.

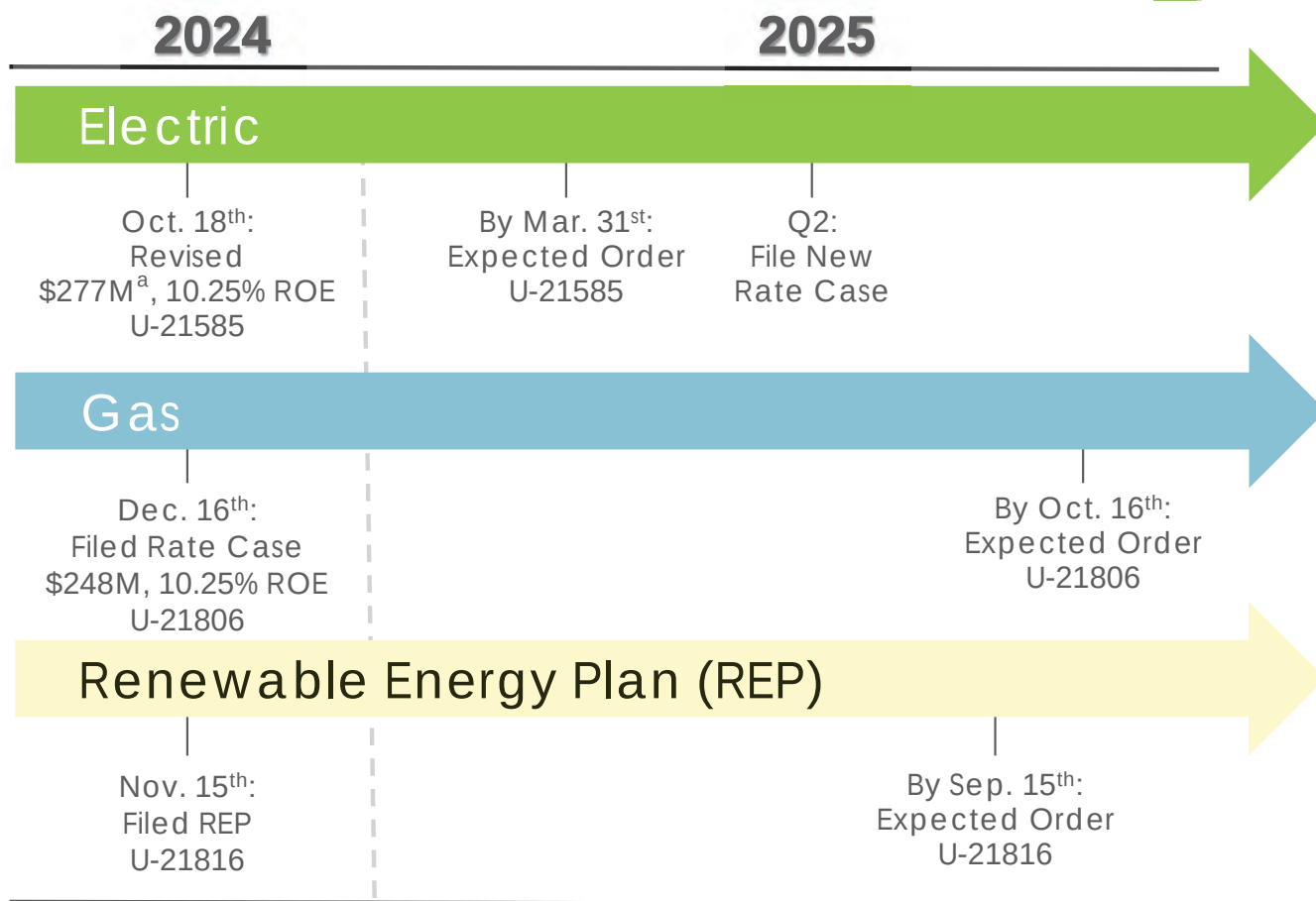
. . . are robust and largely outside of 5-year Plan.

Michigan's Strong Regulatory Environment . . .



Supportive Energy Policy

- **Timely recovery of investments**
 - ✓ Forward-looking test years/earn authorized ROEs
 - ✓ 10-month rate cases
 - ✓ Monthly fuel adjustment trackers (PSCR/GCR)
 - ✓ Constructive ROEs
- **Supportive incentives enhanced w/ 2023 Michigan Energy Law**
 - ✓ Energy efficiency incentives
 - ✓ FCM adder on PPAs
- **Appointed commissioners**



Presentation endnotes are included after the appendix.

. . . provides constructive outcomes and forward-looking visibility.

Needed Customer Investments . . .

Customer Investments

Clean Energy Transformation
(REP & IRP)^a



Electric
Reliability Roadmap



Natural Gas
Delivery Plan



Presentation endnotes are included after the appendix.

Key Affordability Drivers

- ✓ **CE Way cost savings**
 - ~\$50M/yr savings through the CE Way
 - ~\$350M since 2020
- ✓ **Large episodic savings (PPAs/coal exit)**
 - >\$200M savings through 2025
- ✓ **Energy Waste Reduction programs**
 - ~\$7.3B in customer savings since 2009,
>2% reduction in customer usage per year
- ✓ **Economic development**
 - 2% to 3% long-term annual sales growth
 - ~9 GW pipeline opportunity
 - >1,300 MW of new or expanding load since 2015^b

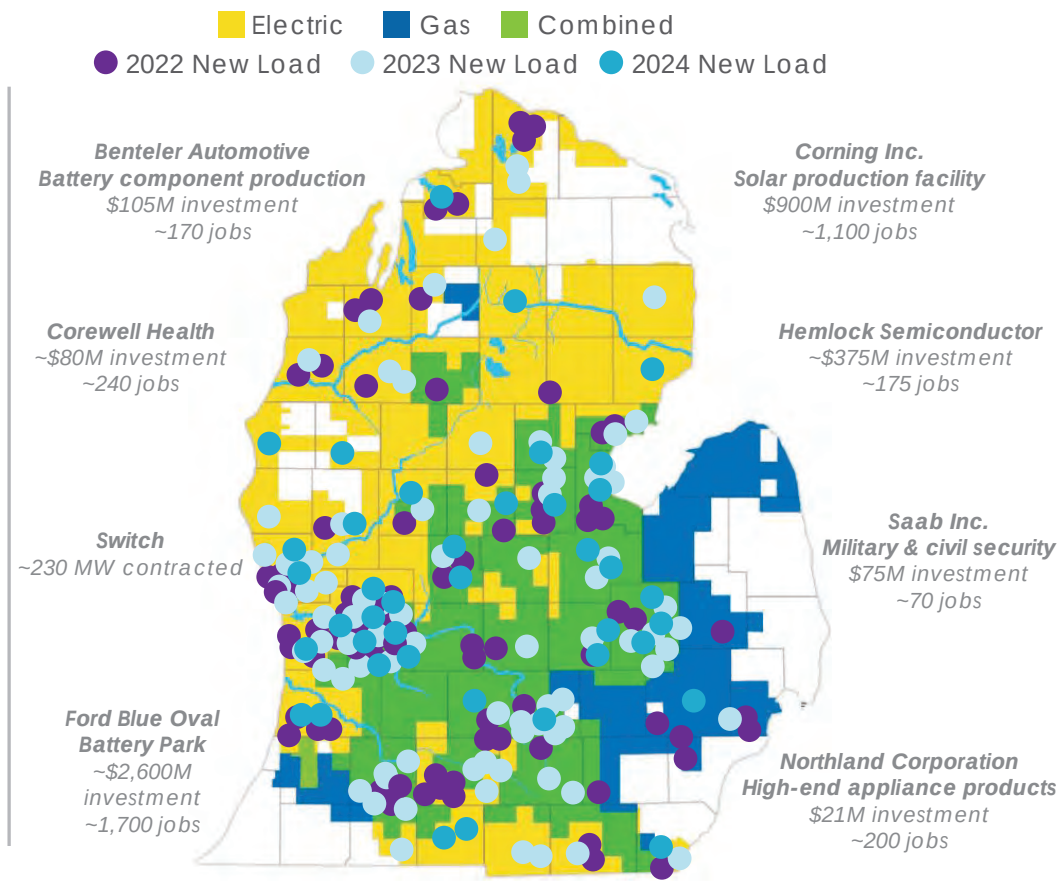
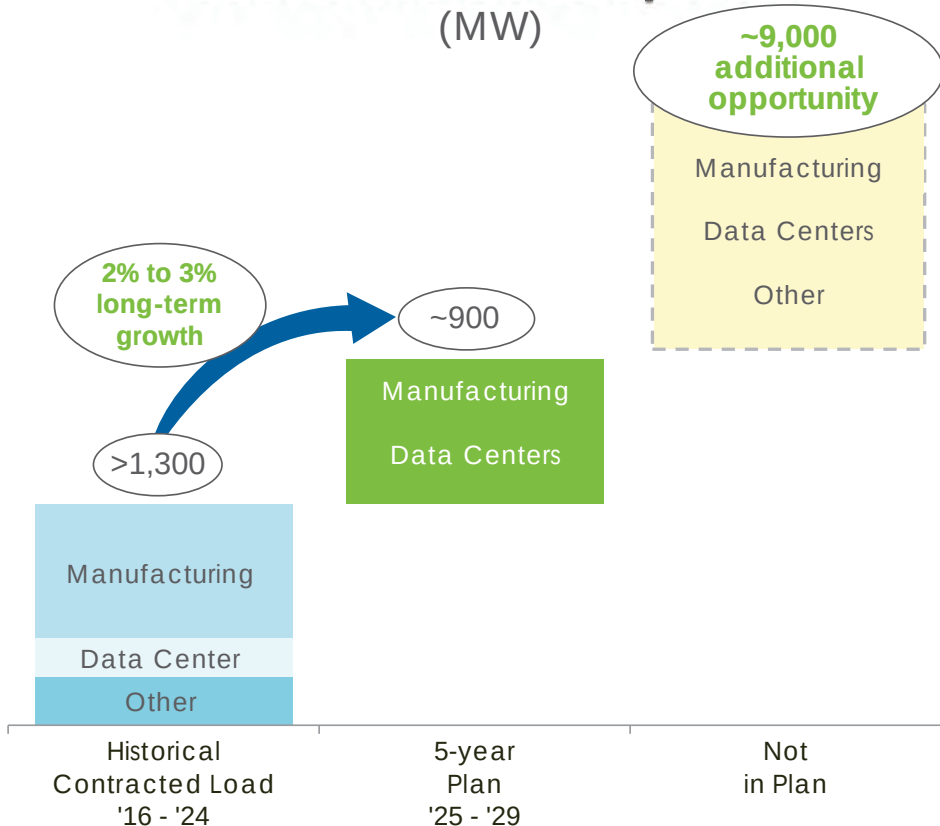
. . . enabled by key affordability drivers.

Expansive Economic Development Efforts . . .



Economic Development

(MW)



. . . drive diversified growth across Michigan and reduce customer rates.



Strong Balance Sheet . . .

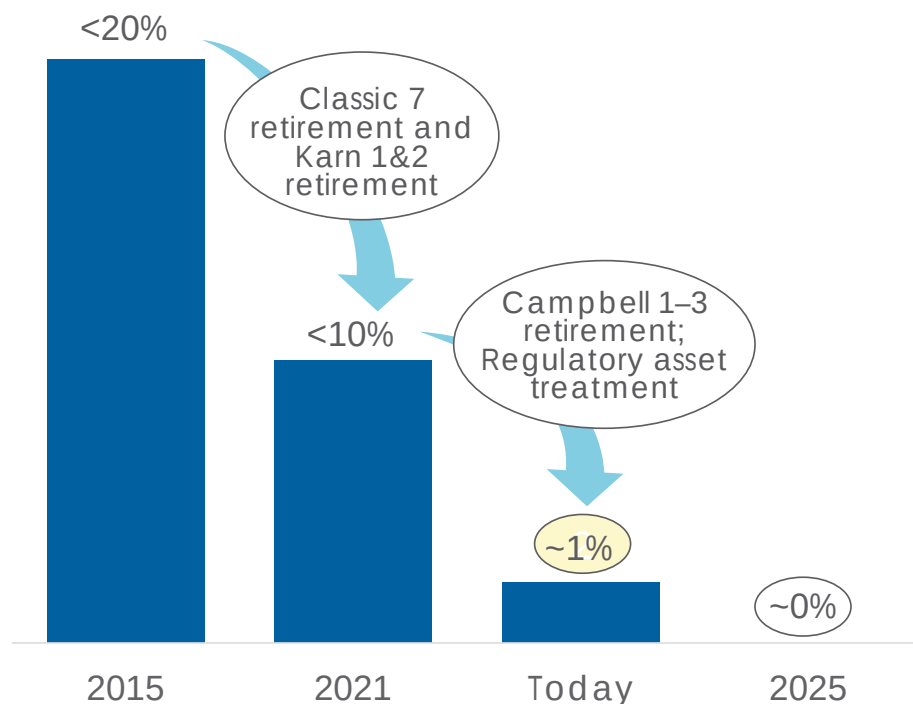
Consumers Energy	S&P	Moody's	Fitch	Key Strengths
Senior Secured	A	A1	A+	✓ Forward-looking recovery
Commercial Paper	A-2	P-2	F-2	✓ Constructive rate construct
Outlook	Stable	Stable	Stable	✓ Strong operating cash flow generation
CMS Energy				
Senior Unsecured	BBB	Baa2	BBB	✓ 100% fixed rate debt
Junior Subordinated	BBB-	Baa3	BB+	✓ Hybrid debt (w/ equity credit)
Outlook	Stable	Stable	Stable	✓ Limited near-term maturities
Last Review	Dec. 2024	Mar. 2024	Apr. 2024	

. . . maintains credit metrics and solid investment-grade ratings.

Our Clean Energy Transformation . . .



Exit Coal in 2025... (Coal % PP&E^a)



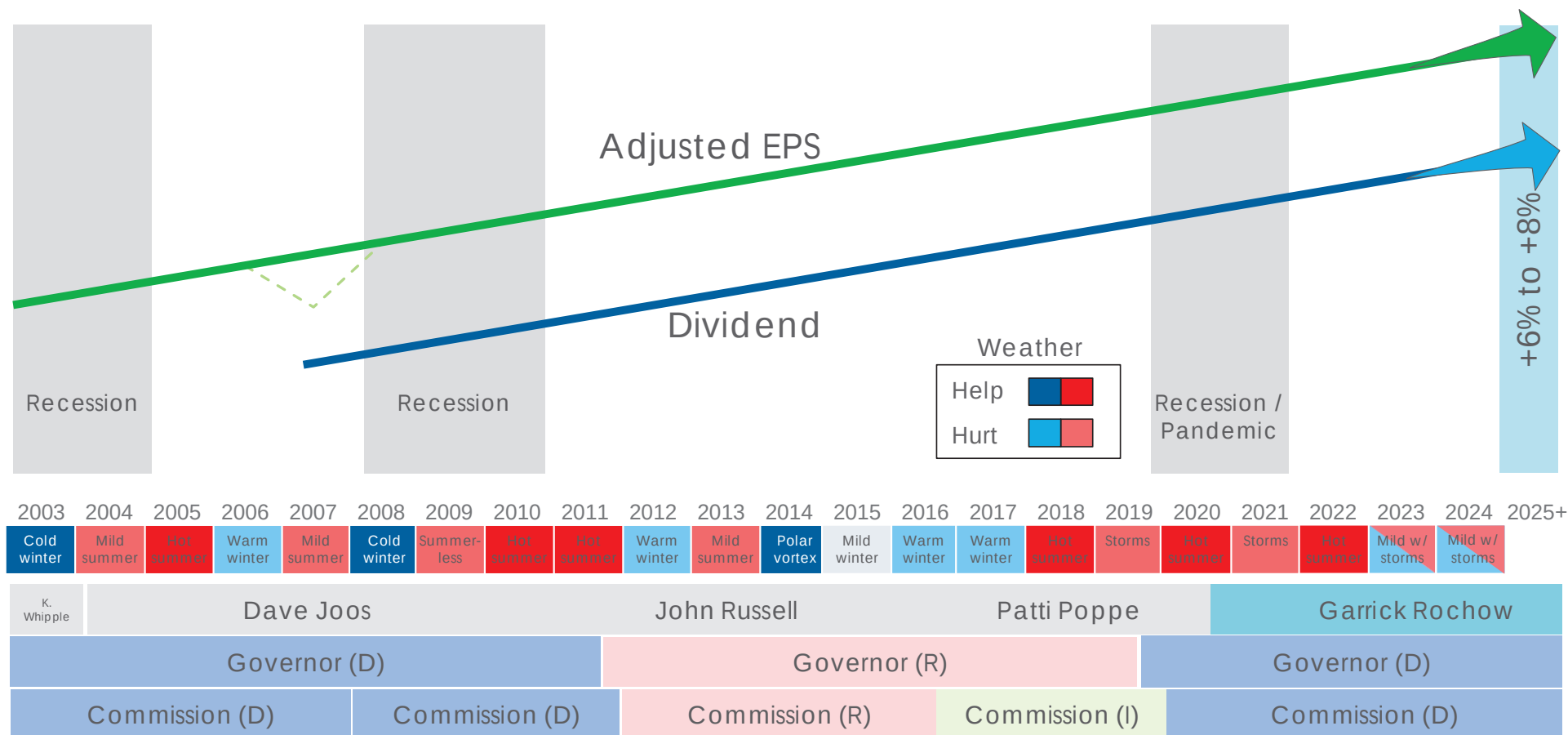
Presentation endnotes are included after the appendix.

...While Ensuring Reliability

- Purchase ~1.2 GW of existing gas capacity (Covert)
- Maintain ~1.2 GW of peaking capacity through 2031 (Karn 3&4)
- Ongoing Energy Efficiency (~2% annual savings)
- 9 GW of solar, 4 GW of wind and >850 MW of battery storage over next two decades
- 100% clean energy mandate by 2040 (includes renewables, gas w/ CCS and nuclear)

... eliminates coal in 2025 and maintains resource adequacy . 17

Industry-Leading Financial Performance . . .



. . . for over two decades, regardless of conditions.

U21806-AG-CE-0340

Page 1 of 1

Question:

54. Refer to page 14 of Mr. Warriner's direct testimony on new service connections. Please provide the actual new service installations for 2024.

Response:

Actual new business service connections installed during 2024 totaled 5,950 services.

Witness: Lincoln D. Warriner

Date: March 11, 2025

CECo Response to AG-CE-0341

U21806-AG-CE-0341 (Partial)
Page 1 of 1

Question:

55. Refer to lines 12-18 on page 15 of Mr. Warriner's direct testimony on economic projections related to new service connections.

a. As provided in prior rate cases, please provide a copy of the HIS Markit report showing the 2023 and 2024 actual housing starts in Michigan and the latest forecasted number of housing starts for 2025 and 2026 available to the Company.

b. Refer to WP-HLR-33 containing the S&P Global forecasted inflation rates. Please provide the date of this forecast and provide a copy of the latest forecast available to the Company showing the forecast date.

Response:

Partial response:

- a. Please see the attached Winter 2025 Michigan real estate and construction key indicators provided by S&P Global. IHS Markit was acquired by S&P Global in 2022.

Witness: Lincoln D. Warriner

Date: March 7, 2025

S&P Global

Winter 2025

US Markets State Economies

Michigan

CECo Response to AG-CE-0341

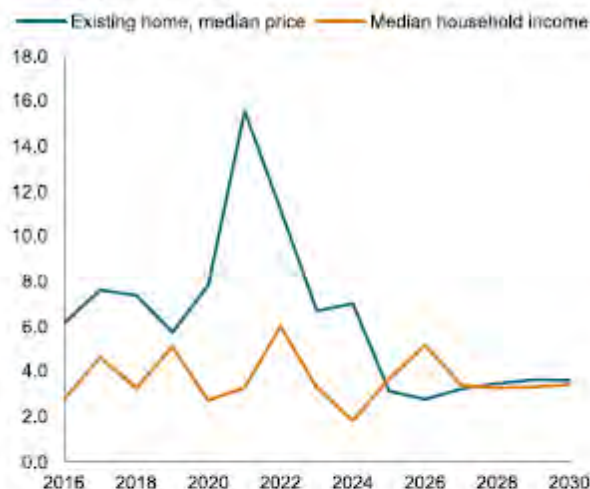
Real estate and construction

Real estate key indicators

	Historical data edge	2021	2022	2023	2024	2025	2026	2027	2028
Construction activity									
Housing starts, total private	2024	21,802	20,510	19,557	20,090	21,360	19,665	18,801	18,542
Housing starts, total private (% change)	2024	11.8	-5.9	-4.6	2.7	6.3	-7.9	-4.4	-1.4
Single-family units	2024	17,827	15,899	14,787	15,921	16,940	15,931	15,028	14,585
Multifamily units	2024	3,976	4,611	4,770	4,169	4,420	3,733	3,773	3,957
Prices and sales									
Home price, existing average (\$)	2023	229,381	245,448	259,813	278,409	287,052	294,132	302,356	311,381
Home price, existing average (% change)	2023	8.9	7.0	5.9	7.2	3.1	2.5	2.8	3.0
Home sales, existing single-family units (thous.)	2023	183.7	168.4	147.7	145.1	147.7	157.8	161.3	163.1
Home sales, existing single-family units (% change)	2023	2.2	-8.3	-12.3	-1.8	1.8	6.8	2.2	1.1

Data compiled February 2025.
Source: S&P Global Market Intelligence.
© 2025 S&P Global.

Home prices vs. median household income, percent change (annual rate)



Data compiled February 2025.
Sources: S&P Global Market Intelligence; Bureau of Economic Analysis.
© 2025 S&P Global.

Home prices vs. housing starts



Data compiled February 2025.
Sources: S&P Global Market Intelligence; Census Bureau.
© 2025 S&P Global.

Question:

60. Refer to page 22 of Mr. Warriner's direct testimony on the Large New Business main and service installations. Please provide a list of the forecasted installations for each year 2024, 2025, and 2026 with the capital expenditures amount included in the forecasted capital expenditures for the 10 months ending October 2025 and the 12 months ending October 2026. Also include the following information in Excel with your response:

- a. Project name and description
- b. Type of business
- c. Number of feet of main or service line to be installed
- d. Project cost before any CIAC, amount of CIAC, and net amount after CIAC
- e. Date contract was signed with the customer
- f. Capital expenditures forecasted for any currently unknown or unspecified projects for each forecasted period. Explain how these amounts were determined.
- g. Total capital expenditures for the year or forecasted period that matches the amount on line 2 of page 1 of Exhibit A-101.

Response:

The requested projected details are provided in the attachment to this response named U21806-AG-CE-0346_Warriner_ATT_1.

The table reflects an unspecified project amount for 2026 of \$5.07 million, \$4.78 million of that unspecified project is included in the Company's test year projection. As described on page 24 of my direct testimony, recent experience with customer requests is an indicator that the Company will receive requests for construction during 2026, and the Company is planning for those expenditures prior to the actual requests being received. The amount projected is based on recent Capital Expenditure experience by the Company.

Witness: Lincoln D. Warriner

Date: March 12, 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21806
Exhibit: AG-2
April 23, 2025
Page 6 of 6

CECo Response to AG-CE-0346

U21806-AG-CE-0346_Warriner_ATT_1															
Large New Business Project Details															
Line	Project name/Description/ Type of Business	Main Footage - Total	Main Footage - Trench	Main Footage - Bore	Project cost before CIAC	Amount of CIAC	Net Project Cost	Contract Signature Date	2023 Actual	2024 Forecast	2024 Preliminary Actual	2025 Forecast	2026 Forecast	10 Months Ending October 2025	12 Months Ending October 2026
1	RNG Facility/ Install 4" Steel High Pressure Main/ Renewable Natural Gas	21,955	11,932	3,418	5,229,274	-850,000	4,379,274	2/21/2023	4,376,653	-1,210	-1,210	0	0	0	0
2	Other Large NB/ Install 6" Steel High Pressure Main/ Solar Power Components	4,411	63	4,348	2,244,587	0	2,244,587	3/7/2024	0	3,200,000	2,666,515	0	0	0	0
3	Lansing BW&L Delta Energy Park Project/ Install 8" Steel High Pressure Main/	200		200	1,462,073	-10,000	1,452,073	In progress	-45,776	0	0	1,452,073	0	1,369,351	82,722
4	Industrial Site Redevelopment/ Install 6" Steel High Pressure Main/ Industrial Park Development	1400			726,037		726,037	No contract at this time	0	0	0	726,037	0	684,676	41,361
5	Battery Manufacturing Facilities/ Install 8" Steel High Pressure Main/ Automotive Battery Manufacturing	8,871	5,015	3,856	4,964,283	-700	4,963,583	3/31/2023	4,875,060	10,218	21,741	0	0	0	0
6	Battery Manufacturing Facilities/ Install 8" Steel High Pressure Main/ Automotive Battery Manufacturing	5,229	3,993	1,236	7,574,854	-10,000	7,564,854	4/10/2024		6,500,000	5,073,817	1,064,854	0	1,004,191	60,663
7	Install 8" Steel High Pressure Main and 2" Plastic Medium Pressure Main/ Dairy Processing	16,046	10,508	5,538	17,400,785	0	17,400,785	2/19/2019	165,356	125	125	0	0	0	0
8	Unspecified Large New Business Projects/ To be determined/ To be determined	To be determined	To be determined	To be determine d	To be determine d	To be determine d	5,067,056	To be determine d	0	0	0	0	5,067,056	0	4,778,395
9	Total						43,798,250	224,259	9,371,293	9,709,133	7,760,988	3,242,964	5,067,056	3,058,218	4,963,141

U21806-AG-CE-0349

Page 1 of 1

Question:

63. Refer to Table 10 on page 31 of Mr. Warriner's direct testimony on Asset Relocations-Civic Improvements. Please provide the list of the known specific projects forecasted for each year 2024 to 2026 with related dollar amount and show any amounts pertaining to unknown or unspecified projects for each year in Excel that total to the amount on page 1 of Exhibit A-102.

Response:

Please refer to my response to U21806-SA-CE-402, which requests similar details on the Asset Relocation-Civic Improvement projections.

Witness: Lincoln D. Warriner

Date: March 10, 2025

CECo Response to AG-CE-0350

U21806-AG-CE-0350

Page 1 of 1

Question:

64. Refer to Table 11 on page 33 of Mr. Warriner's direct testimony on Asset Relocations-Civic Improvements. Please:

- a. Expand this table to include Table 8, include also actual information for 2024, and provide it in Excel.
- b. Provide the basis for the number of forecasted projects, feet of main, and number of services for each year 2024 to 2026.

Response:

Responses are as follows:

- a. Table 8 and Table 11 are provided in Excel format in the attachment to this response named U21806-AG-CE-0350_Warriner_ATT_1. The 2024 actual values for those tables are currently unavailable as the source for that information is Attachment 9 to the Company's Gas Enhanced Infrastructure Replacement (EIRP) - Annual Report, which has not yet been completed for the 2024 calendar year.
- b. Please refer to my response to U21806-SA-CE-402 for the explanation of the values included in Table 11.

Witness: Lincoln D. Warriner

Date: March 10, 2025

U21806-AG-CE-0350_Warriner_ATT_1						
Table 8: Asset Relocation – Civic Improvement Project History						
	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>5-Year Average</u>
Projects completed	202	124	152	170	122	154
Feet of Distribution Main Installed	254,605	169,202	195,305	297,246	181,953	219,662
Services Replaced	2,924	1,729	2,377	2,494	1,228	2,494
Table 11: Asset Relocation – Civic Improvement Projection Details						
	Actual 2023	<u>2024</u> (Projected)	<u>2025</u> (Projected)	<u>2026</u> (Projected)		
Projects	122	171	176	181		
Feet of Distribution Main to be Installed	181,953	126,637	145,330	166,365		
Asset Relocation Services to be Replaced	1,228	1,640	1,689	1,740		

CECo Response to SA-CE-0402

U21806-SA-CE-402

Requested By: Cindy L. Creisher (CLC-24)

Respondent: Lincoln D. Warriner

Date of Response: 3/12/2025

Page 1 of 2

Question:

With reference to the direct testimony of Witness Lincoln Warriner, provide a further detail regarding the Asset Relocation – Civic Improvement projects that are projected for 2025, 2026 and the test year ending October 31, 2026. Include a list of known projects planned, including feet of distribution main installed, services to be replaced, capital expenditures by year, and expected completion date of each project. If the listed projects in this response do not total the projected number of projects, distribution main, services, and capital expenditures as detailed in Table 11, please further explain how the Company arrived at the total projected levels for 2025 and 2026.

Response:

The Company's projections for Asset Relocation – Civic Improvement are based on actual historical experience. The test year projection of \$82,162k is within 0.6% of the 2019-2023 five-year actual average amount of \$81,670k. The projections cannot reasonably be derived from lists of known projects as many projects are requested within the same calendar year that the relocation work needs to be completed. For example, of the 171 2024 projects identified in Table 11, 132 projects (or 77%) had lead times less than one year and 68 (or 40%) of those projects had lead times of less than six months.

The values contained in Table 11 were determined as follows:

Actual 2023: The number of projects, feet of distribution main installed, and the number of services replaced were derived from Attachment 9 to the Company's 2023 Gas Enhanced Infrastructure Replacement (EIRP) - Annual Report which was filed on April 30, 2024 in Case No. U-21308. A 2023 actual cost per foot of main installed was calculated using the following formula: $(\$83,518 \times \$1,000) / 181,953 \text{ feet of main} = \$459.01 \text{ per foot of main installed}$

2024 Projected: The number of projects, feet of distribution main to be installed, and the number of services to be replaced were derived from an extract of Civic Improvement projects from the Company's distribution project planning software on 10/31/2024.

2025 Projected: The number of projects and the number of services to be replaced were calculated by increasing the 2024 values by 3%. A 2025 estimate of cost per foot of main installed was calculated by increasing the 2023 actual cost per foot by 3% annually using the following formula: $(\$459.01 \times 1.03 \times 1.03) = \$486.96$. 2025 Feet of Distribution Main to be Installed was calculated by dividing the projected dollars for 2025 by the estimated unit cost using the following formula: $(\$70,770 \times \$1,000) / (\$486.96) = 145,330 \text{ feet}$. The current (as of 3/10/2025) list of 2025 projects provided in the attachment named U21806-SA-CE-402_Warriner_ATT_1 currently sums to a total of 145,650 feet of main.

2026 Projected: The number of projects and the number of services to be replaced were calculated by increasing the 2025 values by 3%. A 2026 estimate of cost per foot of main installed was calculated by

U21806-SA-CE-402

Requested By: Cindy L. Creisher (CLC-24)

Respondent: Lincoln D. Warriner

Date of Response: 3/12/2025

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increasing the 2023 actual cost per foot by 3% annually using the following formula: $(\$459.01 \times 1.03 \times 1.03 \times 1.03) = \$501.57$. 2026 Feet of Distribution Main to be Installed was calculated by dividing the projected dollars for 2026 by the estimated unit cost using the following formula: $(\$83,444 \times \$1,000)/(\$501.57) = 166,365$ feet.

A current list of known projects for 2025 and 2026 is provided in the attachment named U21806-SA-CE-402_Warriner_ATT_1. The known projects for 2025 and 2026 will expand as requests for relocations are received.

U21806-AG-CE-0763
Page 1 of 1

Question:

334. Refer to the attachment to discovery response AG-CE-0350 on capital expenditures for distribution asset relocation-civic. Please update the attachment with 2024 information as previously requested and provide it in Excel.

Response:

I have confirmed that the work to complete the source data for the 2024 actual information is still in progress. Therefore, I am unable to provide the requested details on the Asset Relocation – Civic Improvement work for 2024.

Witness: Lincoln D. Warriner
Date: April 1, 2025

U21806-AG-CE-0352

Page 1 of 1

Question:

66. Refer to Table 12 on page 36 of Mr. Warriner's direct testimony on Asset Relocations-Reimbursables. Please expand the table to include 2024 actual and 2024, 2025, and 2026 forecasted information and provide it in Excel.

Response:

Please see the attachment to this response named U21806-AG-CE-0352_Warriner_ATT_1.

Witness: Lincoln D. Warriner

Date: March 10, 2025

(in Thousands of Dollars)

[illegible]

U21806-AG-CE-0353

Page 1 of 1

Question:

67. Refer to lines 1-12 on page 38 of Mr. Warriner's direct testimony on Asset Relocations. Please provide the percentage escalation used for the 2024-2026 forecasts and the basis for those escalation factors.

Response:

The Asset Relocation – Reimbursable sub-program projections generally escalate at 3.5% annually. This escalation factor includes both general workload growth and cost escalation. For example, the 2025 forecast of \$15,056,779 is the result of escalating 2023 actual Customer Requested and Damage Replacement actual amount of \$14,055,664 by 3.5% for two calendar years ($\$14,055,664 \times 1.035 \times 1.035 = \$15,056,779$)

The 2026 forecast includes another calendar year of escalation at 3.5%, plus an additional \$1,431,556 in anticipation of increases related to customer requested work, similar to the increase in 2023 compared to 2022 as identified on page 37, lines 9 through 11 of my direct testimony ($\$14,055,664 \times 1.035 \times 1.035 \times 1.035 = 15,583,766 + 1,431,556 = 17,015,322$).

This expectation is based on actual historical experience for work related to customer requested relocation work and damage replacement work within the Asset Relocation – Reimbursable sub-program.

Witness: Lincoln D. Warriner

Date: March 10, 2025

U21806-AG-CE-0762

Page 1 of 1

Question:

333. Refer to the expanded Table 12 attached to discovery response AG-CE-0352 on capital expenditures for distribution asset relocation-reimbursements. Please provide a similar table that provides the number of projects, feet of main installed, and number of services for each year in Excel.

Response:

The attachment named "U21806-AG-CE-0762_Warriner_ATT_1" includes the number of work orders completed each year for 2019 through 2024. Each line item from Table 12 is further segmented into mains, services, and meter stands for the purpose of this response. The associated footage for the line items in this table are currently unavailable. No projections for 2024 through 2026 have been made by the Company for the number of work orders to be completed in each year.

Witness: Lincoln D. Warriner

Date: April 2, 2025

U21806-AG-CE-0762_Warriner_ATT_1

Table 12: Asset Relocation – Reimbursable sub-program Details
(Number of Work Orders Completed)

	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>Preliminary</u> <u>2024</u>	<u>Projected</u> <u>2024</u>	<u>Projected</u> <u>2025</u>	<u>Projected</u> <u>2026</u>
Customer Requested Relocations									
- Mains	30	17	10	24	13	11	Projections of order counts were not been developed for 2024-2026		
- Services	414	366	403	500	496	494			
- Meter Stands	2997	3565	4301	5964	5136	7433			
Damage Replacements									
- Mains	12	21	49	31	26	39	Projections of order counts were not developed for 2024-2026		
- Services	126	156	104	110	114	145			
- Meter Stands	144	98	80	93	99	119			
Large Customer Requested Relocation									
- Mains	1	1		1		1	3 orders were known for 2024; 2025 & 2026 are expected to have no activity		
- Services						1			
- Meter Stands						1			
Other									
- Mains							2024, 2025, & 2026 are expected to have no activity		
- Services									
- Meter Stands				1					
Total Asset Relocation – Reimbursable	3724	4224	4947	6724	5884	8244			

U21806-AG-CE-0357

Page 1 of 1

Question:

71. Refer to lines 11-17 on page 47 of Mr. Warriner's direct testimony on the MAOP pipeline replacement program. Please:

- a. Provide a list of MAOP projects with missing records where the Company was able to avoid replacement of the pipeline or pipeline segment and the capital expenditures avoided by undertaking the other options to replacement. Identify the alternative options undertaken.
- b. Provide a copy of the evaluation of each project with a cost of \$1 million or greater in Table 17 on page 48 that determined the pipeline segment should be replaced.

Response:

Responses are as follows:

- a. The Company has completed three MAOP – Distribution projects currently (Line 1090n, Line 1020, and Line 1009 Phase 1), and has only utilized replacement; the Company has not utilized any other method for completion of any MAOP – Distribution projects.
- b. Please refer to the attachment named U21806-AG-CE-0357_Warriner_ATT_1 for the projects with a cost of \$1 million or greater and the associated evaluation details.

Witness: Lincoln D. Warriner

Date: March 11, 2025

CECo Response to AG-CE-0357

U21806-AG-CE-0357_Warriner_ATT_x					
	C2 and C5 - Pressure Reduction	C3 - ECA	C6 - Alternative Technology	C1 - Pressure Test	C4 - Replacement
Line 1080 Dual Main	Not eligible for reconfirmation - see stagegate analysis or testimony for why new install was chosen.				
Line 1022 Lansing	Pressure reduction not feasible due to capacity restraints. System is interconnected, which would require all lines to take a reduction and have a major impact to customer deliverability.	Not enough data available to perform ECA. Distribution system is not designed to be piggable with a free-flowing smart tool, therefore method not feasible.	No alternative technology exists - method not being considered at this time.	Testing with air/nitrogen on in-service pipe not feasible due to concerns for public safety. Testing with water is not practicable due to operational risks, as segment cannot be out of service during winter operation in case of test failure. There is risk of customer impact if liquids are left in the line once testing is complete, as the distribution system is not designed to accommodate pigging tools.	Replacement has the least amount of operational and customer risk, while having the best likelihood of success to comply with timelines required per 192.624.
Line 1002f ITC Corridor	Pressure reduction not feasible due to capacity restraints. System is interconnected, which would require all lines to take a reduction and have a major impact to customer deliverability.	Not enough data available to perform ECA. Distribution system is not designed to be piggable with a free-flowing smart tool, therefore method not feasible.	No alternative technology exists - method not being considered at this time.	Testing with air/nitrogen on in-service pipe not feasible due to concerns for public safety. Testing with water is not practicable due to operational risks, as segment cannot be out of service during winter operation in case of test failure. There is risk of customer impact if liquids are left in the line once testing is complete, as the distribution system is not designed to accommodate pigging tools.	Replacement has the least amount of operational and customer risk, while having the best likelihood of success to comply with timelines required per 192.624.
Line 1041 Lapeer Rd	Pressure reduction not feasible due to capacity restraints. System is interconnected, which would require all lines to take a reduction and have a major impact to customer deliverability.	Not enough data available to perform ECA. Distribution system is not designed to be piggable with a free-flowing smart tool, therefore method not feasible.	No alternative technology exists - method not being considered at this time.	Testing with air/nitrogen on in-service pipe not feasible due to concerns for public safety. Testing with water is not practicable due to operational risks, as segment cannot be out of service during winter operation in case of test failure. There is risk of customer impact if liquids are left in the line once testing is complete, as the distribution system is not designed to accommodate pigging tools.	Replacement has the least amount of operational risk, and has the best likelihood of success for project execution for timelines required per 192.624. Replacement also allows for the segment size to be increased to 12".
Line 1002c	Pressure reduction not feasible due to capacity restraints. System is interconnected, which would require all lines to take a reduction and have a major impact to customer deliverability.	Not enough data available to perform ECA. Distribution system is not designed to be piggable with a free-flowing smart tool, therefore method not feasible.	No alternative technology exists - method not being considered at this time.	Testing with air/nitrogen on in-service pipe not feasible due to concerns for public safety. There is risk of customer impact if liquids are left in the line once testing is complete, as the distribution system is not designed to accommodate pigging tools. Segment can take an outage if city gates nearby are in-service.	Replacement allows for the company to reconfirm MAOP and allows for future risk reduction by enabling future retirement of other HP vintage lines in the area. Replacement has the least amount of operational and customer risk, while having the best likelihood of success to comply with timelines required per 192.624.
Line 1093 Shattuck	Pressure reduction not feasible due to capacity restraints. System is interconnected, which would require all lines to take a reduction and have a major impact to customer deliverability.	Not enough data available to perform ECA. Distribution system is not designed to be piggable with a free-flowing smart tool, therefore method not feasible.	No alternative technology exists - method not being considered at this time.	Testing with air/nitrogen on in-service pipe not feasible due to concerns for public safety. There is risk of customer impact if liquids are left in the line once testing is complete, as the distribution system is not designed to accommodate pigging tools. Segment can take an outage if city gates nearby are in-service.	Replacement allows for the company to reconfirm MAOP and allows for future risk reduction by enabling future retirement of other HP vintage lines in the area. Replacement has the least amount of operational and customer risk, while having the best likelihood of success to comply with timelines required per 192.624.
Line 1009/1009c (all phases)	Pressure reduction not feasible due to capacity restraints. System is interconnected, which would require all lines to take a reduction and have a major impact to customer deliverability.	Not enough data available to perform ECA. Distribution system is not designed to be piggable with a free-flowing smart tool, therefore method not feasible.	No alternative technology exists - method not being considered at this time.	Testing with air on in-service pipe not feasible due to concerns for public safety. Testing with water is not practicable due to operational risks, as segment cannot be out of service during winter operation in case of test failure. There is risk of customer impact if liquids are left in the line once testing is complete, as the distribution system is not designed to accommodate pigging tools.	Replacement has the least amount of operational and customer risk, while having the best likelihood of success to comply with timelines required per 192.624.
Line 1087b Midland	Pressure reduction not feasible due to capacity restraints. System is interconnected, which would require all lines to take a reduction and have a major impact to customer deliverability.	Not enough data available to perform ECA. Distribution system is not designed to be piggable with a free-flowing smart tool, therefore method not feasible.	No alternative technology exists - method not being considered at this time.	Testing with air/nitrogen on in-service pipe not feasible due to concerns for public safety. Testing with water is not practicable due to operational risks, as segment cannot be out of service during winter operation in case of test failure. There is risk of customer impact if liquids are left in the line once testing is complete, as the distribution system is not designed to accommodate pigging tools.	Replacement has the least amount of operational and customer risk, while having the best likelihood of success to comply with timelines required per 192.624.
Line 1006 Macomb (all phases)	Pressure reduction not feasible due to capacity restraints. System is interconnected, which would require all lines to take a reduction and have a major impact to customer deliverability.	Not enough data available to perform ECA. Distribution system is not designed to be piggable with a free-flowing smart tool, therefore method not feasible.	No alternative technology exists - method not being considered at this time.	Testing with air/nitrogen on in-service pipe not feasible due to concerns for public safety. Testing with water is not practicable due to operational risks, as segment cannot be out of service during winter operation in case of test failure. There is risk of customer impact if liquids are left in the line once testing is complete, as the distribution system is not designed to accommodate pigging tools.	Replacement has the least amount of operational and customer risk, while having the best likelihood of success to comply with timelines required per 192.624.
Line 1026f Mt Hope	Pressure reduction not feasible due to capacity restraints. System is interconnected, which would require all lines to take a reduction and have a major impact to customer deliverability.	Not enough data available to perform ECA. Distribution system is not designed to be piggable with a free-flowing smart tool, therefore method not feasible.	No alternative technology exists - method not being considered at this time.	Testing with air/nitrogen on in-service pipe not feasible due to concerns for public safety. Testing with water is not practicable due to operational risks, as segment cannot be out of service during winter operation in case of test failure. There is risk of customer impact if liquids are left in the line once testing is complete, as the distribution system is not designed to accommodate pigging tools.	Replacement has the least amount of operational and customer risk, while having the best likelihood of success to comply with timelines required per 192.624.
Line 1026i MSU PP	Pressure reduction not feasible due to capacity restraints. System is interconnected, which would require all lines to take a reduction and have a major impact to customer deliverability.	Not enough data available to perform ECA. Distribution system is not designed to be piggable with a free-flowing smart tool, therefore method not feasible.	No alternative technology exists - method not being considered at this time.	Testing with air/nitrogen on in-service pipe not feasible due to concerns for public safety. There is risk of customer impact if liquids are left in the line once testing is complete, as the distribution system is not designed to accommodate pigging tools. Segment can take an outage if city gates nearby are in-service.	Replacement has the least amount of operational and customer risk, while having the best likelihood of success to comply with timelines required per 192.624.

U21806-AG-CE-0358

Page 1 of 1

Question:

72. Refer to Table 17 on page 48 and page 49 of Mr. Warriner's direct testimony on the MAOP Distribution program. Please expand the table and provide it in Excel to include the following information:

- a. The capital expenditures for the 10 months ending October 2025 and 12 month ending October 2026.
- b. Identify the missing records for each project that require replacement of the pipeline segment.
- c. For each project in 2025 and 2026 of \$1 million or greater, provide the current phase of project development (preliminary assessment, scoping, preliminary design, engineering, construction, etc.) and the date when the project engineering will be completed and the project will be bid out or construction will start.
- d. Explain what the program adjustment costs pertain to.

Response:

Responses are as follows:

- a. Please refer to the attachment named U21806-AG-CE-0358_Warriner_ATT_1
- b. Please refer to the attachment named U21806-AG-CE-0358_Warriner_ATT_2
- c. Please refer to the attachment named U21806-AG-CE-0358_Warriner_ATT_3
- d. The Company's targeted MAOP-Distribution sub-program capital expenditures for calendar year 2025 are \$69.1 million. The sum of the individual projects planned for 2025 total \$79.0 million. The program adjustment of -9.9 million in 2025 simply reconciles the individual project estimates to the total MAOP sub-program target. The adjustment does not pertain to any specific cost item.

Witness: Lincoln D. Warriner

Date: March 12, 2025

U21806-AG-CE-0358_Warriner_ATT_2	
(a)	(b)
Line Segment	Response regarding record findings
Line 1009 Huron Park to I94	This segment was identified by the Standard Engineering Analysis to have pressure test records that are not Traceable, Verifiable, and Complete.
Line 1020 Greenfield Rd	This segment was identified by the Standard Engineering Analysis to have pressure test records that are not Traceable, Verifiable, and Complete.
Line 1002f Macomb ITC Corridor	This segment was identified by the Standard Engineering Analysis to have pressure test records that are not Traceable, Verifiable, and Complete.
Line 1009/1009c I94 to Little Mack, 10 Mile to 11 Mile	This segment was identified by the Standard Engineering Analysis to have pressure test records that are not Traceable, Verifiable, and Complete.
Line 1022f Vermontville	This segment was identified by the Standard Engineering Analysis to have pressure test records that are not Traceable, Verifiable, and Complete.
Line 1087b East & West Segments	This segment was identified by the Standard Engineering Analysis to have pressure test records that are not Traceable, Verifiable, and Complete.
Line 1090n	This segment was identified by the Standard Engineering Analysis to have pressure test records that are not Traceable, Verifiable, and Complete.
Line 1006 Ph 1 Groebel Dr to Mound Rd	This segment's MAOP is grandfathered under 192.619(c) in lieu of a pressure test record, and operates above 30% SMYS.
Line 1009c Ph 3 Little Mack - 10 mile to 9 mile, Macomb	This segment was identified by the Standard Engineering Analysis to have pressure test records that are not Traceable, Verifiable, and Complete.
Line 1026f Mt Hope	This segment was identified by the Standard Engineering Analysis to have pressure test records that are not Traceable, Verifiable, and Complete.
Line 1093 Shattuck Rd	This segment's MAOP is grandfathered under 192.619(c) in lieu of a pressure test record, and operates above 30% SMYS.
Line 1080 Dual Main	N/A
Line 1026i MSU PP	This segment was identified by the Standard Engineering Analysis to have pressure test records that are not Traceable, Verifiable, and Complete.
Line 1022	This segment's MAOP is grandfathered under 192.619(c) in lieu of a pressure test record, and operates above 30% SMYS.
Line 1041 Lapeer Rd	This segment was identified by the Standard Engineering Analysis to have pressure test records that are not Traceable, Verifiable, and Complete.
Line 1002c	This segment's MAOP is grandfathered under 192.619(c) in lieu of a pressure test record, and operates above 30% SMYS.

CECo Response to AG-CE-0358

U21806-AG-CE-0358_Warriner_ATT_3						
Consumers Energy Company						
Regulatory Compliance Program -						
MAOP Compliance Projects						
2025 - 2034						
Line No.	(a)	(b)	(c)	(d)		
	Project	TOD Line	Project Name	Current Phase of Development	Design Complete	Bid-out (B)/ Construction Start (CS)
1	Number					
2						
3	TBD	1002	(*TBD*) Line 1002 Type IIb			
4	Multiple	1002c	(multiple DAPPs) Line 1002c, covering four years	Planning		
4.1	30380	1002c	1002C_YR0_MAIN ST_TYPE III	Design	3/4/2025	May 2025 (B)
4.2	30381	1002c	1002C_YR1_NAKOTA_TYPE III	Design	11/1/2025	Nov 2025 (B)
4.3	30382	1002c	1002C_YR1_11 MILE RD_TYPE III	Design	11/1/2025	Nov 2025 (B)
4.4	30383	1002c	1002C_YR1_WASHINGTON_TYPE III	Design	11/1/2025	Nov 2025 (B)
4.5	30483	1002c	NAKOTA_VTG_MAIN_REPLACE_FOR_1002C	Design	6/1/2025	7/1/25 (CS)
4.6	30491	1002c	1002C_YR0_ROCHESTER RD_TYPE III	Design	3/5/2025	May 2025 (B)
4.7	30492	1002c	1002C_YR0_JOHN R_TYPE III	Design	2/10/2025	2/14/25 (B)
4.8	30493	1002c	NAKOTA_2_VTG_MAIN_REPLACE_FOR_1002C	Design	7/1/2025	8/1/25 (CS)
4.9	30494	1002c	WOODLAWN_VTG_MAIN_REPLACE_FOR_1002C	Design	8/1/2025	9/1/25 (CS)
5	22150	1002f	(22150) Line 1002f Line Macomb ITC Corridor MAOP	Design Construction	1/22/2025	4/1/2025 (CS)
6	22702	1006	(22702) Line 1006, Groebel Dr to Mound Rd, MAOP	Planning Design	12/1/2025	3/2/2026 (CS)
7	TBD	1006	(*TBD*) Line 1006 Ph 3 MAOP			
8	22738	1006	(22738) Line 1006, 11 Mile Mound to RR St., MAOP			
9	TBD	1008	(*TBD*) Line 1008 Type II MAOP			
10	22157	1009/1009c	(22157) Line 1009/1009c I94 to Little Mack, 10 Mile to 11 Mile MAOP Ph2	Design Construction	2/16/2025	5/4/2025 (CS)
11	22494	1009/1009c	(22494) Line 1009/1009c Little Mack, 10 Mile to 9 Mile MAOP Ph3	Planning Design	12/1/2025	3/2/2026 (CS)
12	22496	1009/1009c	(22496) Line 1009/1009c 11 Mile to RS22 MAOP Ph4			
13	TBD	1019k	(*TBD*) Line 1019k Type IIb MAOP			
14	TBD	1019w	(*TBD*) Line 1019w Type I MAOP			
15	TBD	1019z	(*TBD*) Line 1019z Type IIb MAOP			
16	22409	1020	(22409) Line 1020 MAOP Greenfield Rd	Construction		
17	22861	1022	(22861) Line 1022 MAOP Phase 1 Airport CG to State Rd & State Rd to W Grand River	Planning Design	10/6/2025	Q4 2025 (B)
18	22511	1022f	(22511) Line 1022f Vermontville MAOP (less than \$1M)	Planning/Design Construction	11/7/2024	4/7/2025
19	22996	1026f	(22996) Line 1026f Mt Hope MAOP	Planning Design	10/6/2025	1/5/2026 (CS)
20	22998	1026i	(22998) Line 1026i MAOP MSU PP			
21	22781	1041	(22781) Line 1041 MAOP Lapeer Rd			
22	TBD	1049d	(*TBD*) Line 1049d Type I MAOP			
23	21948 & 21250	1080	Line 1080 Dual Main West of M Avenue City Gate	Design Construction	12/20/2024	3/17/2025 (CS)
24	TBD	1082	(*TBD*) Line 1082 Type IIa MAOP Kilgore and Portage			
25	TBD	1082	(*TBD*) Line 1082 Type IIa MAOP Lovers Lane			
26	TBD	1082f	(*TBD*) Line 1082f Type IIa MAOP			
27	21674 & 23139	1087b	(21674/23129) Line 1087b MAOP Ph 1 West Segment (Elisabetta Rd?)	Design Construction	2/11/2025	10/1/2025 (CS)
28	21675	1087b	(21675) Line 1087b MAOP Ph 2 East Segment	Design Construction	2/11/2025	10/1/2025 (CS)
29	TBD	1087f	(*TBD*) Line 1087f MAOP			
30	TBD	1090l	(*TBD*) Line 1090l Type I MAOP			
31	22532	1090n	(22532) Line 1090n Davis St MAOP (less than \$1M)	Design Close-out	9/17/2024	10/24/2024
32	TBD	1091	(*TBD*) Line 1091 Type I MAOP			
33	21676	1093	(21676) Line 1093 MAOP Shattuck Rd	Planning Design	10/3/2025	Q4 2025 (B)

CECo Response to AG-CE-0357

U21806-AG-CE-0358_Warriner_ATT_1									
Table 17: MAOP Distribution sub-program									
Compliance Project List									
Project Number	Project Name	2023 Actual (\$000)	Preliminary 2024 Actual (\$000)	2024 Projected (\$000)	2025 Projected (\$000)	2026 Projected (\$000)	10 Months Ended 10/31/2025 (\$000)	12 Months Ended 10/31/2026 (\$000)	Construction Completion Year
21948 & 21250	Line 1080, West from Kalamazoo	363	2,779	3,829	30,041	465	29,945	561	2025
22861 & 22862	Line 1022, Airport CG to State Rd & State Rd to W Gr River	41	63	87		39,781		33,151	2026
22781	Line 1041, Lapeer Rd	244	70	306					2028
22393	Line 1002c	934	3,091	688	15,428	40,063	9,452	39,362	2029
21676	Line 1093, Shattuck Rd					20,901		17,417	2026
21788	Line 1009, Huron Park to I-94	24	3,159	3,183					2024
22511	Line 1022f, Vermontville		300		373		228	144	2025
2157 & 224	Line 1009/1009c I-94 to Little Mack, 10 Mile to 11 Mile; 9 Mile to 10 Mile				19,935	9,643	12,213	15,759	2025 2026
22702	Line 1006, Groebel Dr to Mound Rd		98	161		6,215		5,179	2026
22150	Line 1002f, Macomb ITC Corridor			16	2,980		1,826	1,154	2025
22409	Line 1020, Greenfield Rd		427	258					2024
21674 & 216	Line 1087b, East and West Segments		179	505	10,173		6,233	3,940	2025
TBD	Line 1026f, Mt Hope					10,829		9,024	2026
TBD	Line 1026i, MSU PP								2027
22532	Line 1090n, Davis St		253	218	109		67	42	2025
	Program Adjustment			44	-9,923			-9,923	
Total 2023-2026 Projection		\$1,607	\$10,418	\$9,295	\$69,117	\$127,897	\$59,964	\$115,811	

U21806-AG-CE-0360

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Question:

74. Refer to pages 52-59 of Mr. Warriner's direct testimony on the planned MAOP Distribution projects. For each of the projects where the Company determine that pipeline cutouts would be necessary to re-establish the pipe properties, please provide the number of cutouts that would be necessary.

Response:

The estimated number of samples are provided in the table below. These estimates are based on the minimum number required per CFR 192.607(e)(2), which states one dig per mile rounded up to the nearest whole number. The actual number of samples that will be required is unknown until final field tie-in details are determined as other pipe segments may be exposed during construction.

Line No.	(a)	(b)	(c)	(d)	(e)	(f)
	Line Segment	Estimated Capital Cost	Length (miles)	Expected Pipe Size	Construction Complete Year	# of samples
1						
2	Line 1009 Huron Park to I94	3,183,351	0.5	12"	2024	1
3	Line 1020 Greenfield Rd	258,395	0.038	12"	2024	1
4	Line 1002f Macomb ITC Corridor	2,991,188	0.07	26"	2025	1
5	Line 1009/1009c I94 to Little Mack, 10 Mile to 11 Mile	19,935,392	1.53	12"	2025	2
6	Line 1022f Vermontville	378,402	0.038	8"	2025	1
7	Line 1087b East & West Segments	10,677,954	0.81	12"	2025	1
8	Line 1090n	326,919	0.012	8"	2025	1
9	Line 1006 Ph 1 Groebel Dr to Mound Rd	6,295,452	0.31	24"	2026	1
10	Line 1009c Ph 3 Little Mack - 10 mile to 9 mile, Macomb	9,643,900	1.3	12"	2026	2
11	Line 1026f Mt Hope	10,828,963	0.758	8"	2026	1
12	Line 1093 Shattuck Rd	20,900,643	1.76	12"	2026	2
13	Line 1026i MSU PP	3,420,311	0.133	8"	2027	1
14	Line 1022	39,867,880	3.5	16"	2026	4
15	Line 1041 Lapeer Rd	30,543,990	3.4	12"	2027	4
16	Line 1002c	177,542,697	8.15	24"	2029	9

Witness: Lincoln D. Warriner

Date: March 12, 2025

PHMSA Rules & Regulations

The remainder of this exhibit consists of 78 pages PHMSA
Rules and Regulations

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191 and 192

[Docket No. PHMSA–2011–0023; Amdt. Nos. 191–26; 192–125]

RIN 2137–AE72

Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments

AGENCY: Pipeline and Hazardous
Materials Safety Administration
(PHMSA), DOT.

ACTION: Final rule.

SUMMARY: PHMSA is revising the Federal Pipeline Safety Regulations to improve the safety of onshore gas transmission pipelines. This final rule addresses congressional mandates, National Transportation Safety Board recommendations, and responds to public input. The amendments in this final rule address integrity management requirements and other requirements, and they focus on the actions an operator must take to reconfirm the maximum allowable operating pressure of previously untested natural gas transmission pipelines and pipelines lacking certain material or operational records, the periodic assessment of pipelines in populated areas not designated as “high consequence areas,” the reporting of exceedances of maximum allowable operating pressure, the consideration of seismicity as a risk factor in integrity management, safety features on in-line inspection launchers and receivers, a 6-month grace period for 7-calendar-year integrity management reassessment intervals, and related recordkeeping provisions.

DATES: The effective date of this final rule is July 1, 2020. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of July 1, 2020. The incorporation by reference of ASME/ANSI B31.8S was approved by the Director of the Federal Register as of January 14, 2004.

FOR FURTHER INFORMATION CONTACT: Technical questions: Steve Nanney, Project Manager, by telephone at 713–272–2855. General information: Robert Jagger, Senior Transportation Specialist, by telephone at 202–366–4361.

SUPPLEMENTARY INFORMATION:

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 - A. Purpose of the Regulatory Action

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I. Executive Summary

A. Purpose of the Regulatory Action

PHMSA believes that the current regulatory requirements applicable to gas pipeline systems have increased the level of safety associated with the transportation of gas. Still, incidents continue to occur on gas pipeline systems resulting in serious risks to life and property. One such incident occurred in San Bruno, CA, on

September 9, 2010, killing 8 people, injuring 51, destroying 38 homes, and damaging another 70 homes (PG&E incident). In its investigation of the incident, the National Transportation Safety Board (NTSB) found among several causal factors that the operator, Pacific Gas and Electric (PG&E), had an inadequate integrity management (IM) program that failed to detect and repair or remove the defective pipe section. PG&E was basing its IM program on incomplete and inaccurate pipeline information, which led to, among other things, faulty risk assessments, improper assessment method selection, and internal assessments of the program that were superficial and resulted in no meaningful improvement in the integrity of the pipeline system nor the IM program itself.

The PG&E incident underscored the need for PHMSA to extend IM requirements and address other issues related to pipeline system integrity. In response, PHMSA published an ANPRM seeking comment on whether IM and other requirements should be strengthened or expanded, and other related issues, on August 25, 2011 (76 FR 53086).

The NTSB adopted its report on the PG&E incident on August 30, 2011, and issued several safety recommendations to PHMSA and other entities. Several of these NTSB recommendations related directly to the topics addressed in the 2011 ANPRM and are addressed in this final rule. Also, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act) was enacted on January 3, 2012. Several of the 2011 Pipeline Safety Act's statutory requirements related directly to the topics addressed in the 2011 ANPRM and are a focus of this rulemaking.

Another incident that influenced this rulemaking was the rupture of a gas transmission pipe operated by Columbia Gas near Sissonville, WV, on December 11, 2012. The escaping gas ignited, and fire damage extended nearly 1,100 feet along the pipeline right-of-way and covered an area roughly 820 feet wide. While there were no fatalities or serious injuries, three houses were destroyed by the fire, and several other houses were damaged. The ruptured pipe was one of three in the area that cross Interstate 77, and the incident closed the highway in both directions for 19 hours until a section of thermally damaged road surface approximately 800 feet long could be replaced. Following this incident, the NTSB finalized an accident report on February 19, 2014, issuing recommendations to PHMSA to include principal arterial roadways,

including interstates, other freeways and expressways, and other principal arterial roadways as defined by the Federal Highway Administration, to the list of “identified sites” that establish a high consequence area (HCA) for the purposes of an operator’s IM program.

On April 8, 2016, PHMSA published an NPRM to seek public comments on proposed changes to the gas transmission pipeline safety regulations (81 FR 20722). A summary of those proposed changes, and PHMSA’s response to stakeholder feedback on the individual provisions, is provided below in section IV of this document (Analysis of Comments and PHMSA Response).

The purpose of this final rule is to increase the level of safety associated with the transportation of gas. PHMSA is finalizing requirements that address the causes of several recent incidents, including the PG&E incident, by clarifying and enhancing existing requirements. PHMSA is also addressing certain statutory mandates of the 2011 Pipeline Safety Act and NTSB recommendations. While the NPRM addressed 16 major topic areas, PHMSA believes the most efficient way to manage the proposals in the NPRM is to divide them into three rulemaking actions. PHMSA is finalizing the provisions in this final rule as a first step. PHMSA anticipates completing a second rulemaking to address the topics in the NPRM regarding repair criteria in HCAs and the creation of new repair criteria for non-HCAs, requirements for inspecting pipelines following extreme events, updates to pipeline corrosion control requirements, codification of a management of change process, clarification of certain other IM requirements, and strengthening IM assessment requirements.¹ A third rulemaking is expected to address requirements related to gas gathering lines that were proposed in the NPRM.²

B. Summary of the Major Provisions of the Regulatory Action in Question

Several of the amendments made in this rule are related to congressional legislation from the 2011 Pipeline Safety Act. The Act provides a 6-month grace period, with written notice, for the completion of periodic integrity management reassessments that otherwise would be completed no later than every 7 calendar years.³ Another requirement is that operators explicitly consider and account for seismicity in identifying and evaluating potential

threats.⁴ The Act also requires operators to report exceedances of the maximum allowable operating pressure (MAOP) of gas transmission pipelines.⁵ PHMSA is incorporating these changes into the PSR at 49 CFR parts 190–199 in this final rule.

This rule also requires operators of certain onshore steel gas transmission pipeline segments to reconfirm the MAOP of those segments and gather any necessary material property records they might need to do so, where the records needed to substantiate the MAOP are not traceable, verifiable, and complete. This includes previously untested pipelines, which are commonly referred to as “grandfathered” pipelines, operating at or above 30 percent of specified minimum yield strength (SMYS). Records to confirm MAOP include pressure test records or material property records (mechanical properties) that verify the MAOP is appropriate for the class location.⁷ Operators with missing records can choose one of six methods to reconfirm their MAOP and must keep the record that is generated by this exercise for the life of the pipeline. PHMSA has also created an opportunistic method by which operators with insufficient material property records can obtain such records. These physical material property and attribute records include the pipeline segment’s diameter, wall thickness, seam type, grade (the minimum yield strength and ultimate tensile strength of the pipe), and Charpy V-notch toughness values (full-size specimen and based on the lowest operational temperatures),⁸ if applicable or required. PHMSA considers “insufficient” material property records to be those records where the pipeline’s physical material properties and attributes are not documented in

traceable, verifiable, and complete records.

PHMSA is requiring operators to perform integrity assessments on certain pipelines outside of HCAs, whereas prior to this rule’s publication, integrity assessments were only required for pipelines in HCAs. Pipelines in Class 3 locations, Class 4 locations, and in the newly defined “moderate consequence areas” (MCA)⁹ must be assessed initially within 14 years of this rule’s publication date and then must be reassessed at least once every 10 years thereafter. These assessments will provide important information to operators about the conditions of their pipelines, including the existence of internal and external corrosion and other anomalies, and will provide an elevated level of safety for the populations in MCAs while continuing to allow operators to prioritize the safety of HCAs. This action fulfills the section 5 mandate from the 2011 Pipeline Safety Act to expand elements of the IM requirements beyond HCAs where appropriate.

This rule also explicitly requires devices on in-line inspection (ILI), launcher or receiver facilities that can safely relieve pressure in the barrel before inserting or removing ILI tools, and requires the use of a device that can indicate whether the pressure has been relieved in the barrel or can otherwise prevent the barrel from being opened if the pressure is not relieved. PHMSA is finalizing this requirement in this final rule because it is aware of incidents where operator personnel have been killed or seriously injured due to pressure build-up at these stations.

C. Costs and Benefits

Consistent with Executive Order 12866, PHMSA has prepared an assessment of the benefits and costs of the final rule as well as reasonable alternatives. PHMSA estimates the annual costs of the rule to be approximately \$32.7 million, calculated using a 7 percent discount rate. The costs reflect additional integrity assessments, MAOP reconfirmation, and ILI launcher and receiver upgrades.

PHMSA is publishing the Regulatory Impact Analysis (RIA) for this rule in the public docket. The table below

⁹ A MCA is defined in § 191.3 as an onshore area within a potential impact circle, as that term is defined in § 192.903, containing either (1) 5 or more buildings intended for human occupancy or (2) any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, as defined in the Federal Highway Administration’s *Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1*.

¹ RIN 2137–AF39.

² RIN 2137–AF38.

³ 2011 Pipeline Safety Act § 5(e).

⁴ 2011 Pipeline Safety Act § 29.

⁵ 2011 Pipeline Safety Act § 23.

⁶ MAOP means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

⁷ PHMSA uses class locations throughout part 192 to provide safety margins and standards commensurate with the potential consequence of a pipeline failure based on the surrounding population. Class locations are defined at § 192.5. A Class 1 location is an offshore area or a class location unit with 10 or fewer buildings intended for human occupancy. A Class 2 location is a class location unit with more than 10 but fewer than 46 buildings intended for human occupancy. A Class 3 location is a class location unit with 46 or more buildings intended for human occupancy, and a Class 4 location is where buildings with 4-or-more stories above ground are prevalent.

⁸ A Charpy V-notch impact test and its values indicate the toughness of a given material at a specified temperature and is used in fracture mechanics analysis.

provides a summary of the estimated costs for the major provisions in this rulemaking (see the RIA for further detail on these estimates). PHMSA finds that the other final rule requirements will not result in incremental costs.

PHMSA did not quantify the cost savings from material properties verification under the final rule compared to existing regulations. PHMSA also elected to not quantify the benefits of this rulemaking and instead

discusses them qualitatively. PHMSA estimated total annual costs of the rule of \$31.4 million using a 3 percent discount rate, and \$32.7 million using a 7 percent discount rate.

SUMMARY OF ANNUALIZED COSTS, 2019–2039
[\$2017 thousands]

Provision	Annualized cost	
	3% Discount rate	7% Discount rate
1. MAOP Reconfirmation & Material Properties Verification	\$25,848	\$27,899
2. Seismicity	0.00	0.00
3. Six-Month Grace Period for Seven Calendar-Year Reassessment Intervals	0.00	0.00
4. In-Line Inspection Launcher/Receiver Safety	27.4	37.5
5. MAOP Exceedance Reports	0.00	0.00
6. Strengthening requirements for assessment methods	0.00	0.00
7. Assessments outside HCAs	5,482	4,713
8. Related Records Provisions	0.00	0.00
Total	31,357	32,650

II. Background

A. Detailed Overview

Introduction

Recent significant growth in the nation's production and use of natural gas is placing unprecedented demands on the Nation's pipeline system, underscoring the importance of moving this energy product safely and efficiently. Changing spatial patterns of natural gas production and use and an aging pipeline network has made improved documentation and data collection increasingly necessary for the industry to make reasoned safety choices and for preserving public confidence in its ability to do so. Congress recognized these needs when passing the 2011 Pipeline Safety Act, calling for an examination of issues pertaining to the safety of the Nation's pipeline network, including a thorough application of the risk-based integrity assessment, repair, and validation system known as IM.¹⁰

This final rule advances the goals established by Congress in the 2011 Pipeline Safety Act and is consistent with the emerging needs of the natural gas pipeline system. This final rule also advances the important discussion about the need to adapt and expand risk-based safety practices. As some severe pipeline incidents have occurred

in areas outside HCAs¹¹ where the application of IM principles are not required, and as gas pipelines continue to experience failures from causes that IM was intended to address, this conversation is increasingly important.

This final rule strengthens IM requirements, including to ensure operators select the appropriate inspection tool or tools to address the pertinent identified threats to their pipeline segments, and clarifies and expands recordkeeping requirements to ensure operators have and retain the basic physical and operational attributes and characteristics of their pipelines. Further, this final rule establishes requirements to periodically assess pipeline segments in locations outside of HCAs where the surrounding population is expected to potentially be at risk from an incident, which are defined in the rule as MCAs. Even though these pipeline segments are not within currently defined HCAs, they could be located in areas with significant populations. This change facilitates prompt identification and remediation of potentially hazardous defects while still allowing operators to make risk-based decisions on where to

allocate their maintenance and repair resources.

Natural Gas Infrastructure Overview

The U.S. natural gas pipeline network is designed to transport natural gas to and from most locations in the lower 48 States. Approximately two-thirds of the lower 48 States depend almost entirely on the interstate transmission pipeline system for their supply of natural gas.¹² One can consider the Nation's natural gas pipeline infrastructure as three interconnected parts—gathering, transmission, and distribution—that together transport natural gas from the production field, where gas is extracted from underground, to its end users, where the gas is used as an energy fuel or chemical feedstock. This final rule applies only to gas transmission lines and does not address gas gathering or natural gas distribution infrastructure and its associated issues. Currently, there are over 300,000 miles of onshore gas transmission pipelines throughout the U.S.¹³

Transmission pipelines primarily transport natural gas from gas treatment plants and gathering systems to bulk customers, local distribution networks, and storage facilities. Transmission pipelines can range in size from several inches to several feet in diameter. They can operate over a wide range of pressures, from a relatively low 200 pounds per square inch gage (psig) to

¹¹ HCAs are defined at § 192.903. There are two methods that can be used to determine and HCA, the specific differences of which we do not address here. Very broadly and regardless of which method used, operators must calculate the potential impact radius for all points along their pipelines and evaluate corresponding impact circles to identify what populations are contained within each circle. Potential impact circles with 20 or more structures intended for human occupancy, or those circles with "identified sites" such as stadiums, playgrounds, office buildings, and religious centers, are defined as HCAs.

¹² U.S. Department of Energy, "Appendix B: Natural Gas," *Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure*, p. NG–28, April 2015.

¹³ U.S. DOT Pipeline and Hazardous Materials Safety Administration Data as of 4/26/2018.

¹⁰ The IM regulations specify how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate the integrity of gas transmission pipelines in HCAs that could, in the event of a leak or failure, affect high consequence areas in the United States. These areas include certain populated and occupied areas. See § 192.903.

over 1,500 psig. They can be hundreds of miles long, and can operate within the geographic boundaries of a single State, or cross one or more State lines.

Regulatory History

PHMSA and its State partners regulate and enforce the minimum Federal safety standards authorized by statute¹⁴ and codified in the PSR for jurisdictional¹⁵ gas gathering, transmission, and distribution systems.

Federal regulation of gas pipeline safety began in 1968 with the creation of the Office of Pipeline Safety and the passage of the Natural Gas Pipeline Safety Act of 1968 (Pub. L. 90-481). The Office of Pipeline Safety issued interim minimum Federal safety standards for gas pipeline facilities and the transportation of natural and other gas by pipeline on November 13, 1968, and subsequently codified broad-based gas pipeline regulations on August 19, 1970 (35 FR 13248). The PSR were revised several times over the following decades to address different aspects of natural gas transportation by pipeline, including construction standards, pipeline materials, design standards, class locations, corrosion control, and MAOP.

In the mid-1990s, following models from other industries such as nuclear power, PHMSA started to explore whether a risk-based approach to regulation could improve safety of the public and reduce damage to the environment. During this time, PHMSA found that many operators were performing forms of IM that varied in scope and sophistication but that there were no uniform standards or requirements.

PHMSA began developing minimum IM regulations for both hazardous liquid and gas transmission pipelines in response to a hazardous liquid accident in Bellingham, WA, in 1999 that killed 3 people and a gas transmission incident in Carlsbad, NM, in 2000 that killed 12. PHMSA finalized IM regulations for gas transmission pipelines in a 2003 final rule.¹⁶ The IM regulations are intended to provide a structure to operators to focus resources on improving pipeline integrity in the areas where a failure would have the greatest impact on public safety. The IM

final rule accelerated the integrity assessment of pipelines in HCAs, improved IM systems, and improved the government's ability to review the adequacy of IM plans.

The IM regulations require that operators conduct comprehensive analyses to identify, prioritize, assess, evaluate, repair, and validate the integrity of gas transmission pipelines in HCAs. Approximately 7 percent of onshore gas transmission pipeline mileage is located in HCAs.¹⁷ PHMSA and State inspectors review operators' IM programs and associated records to verify that the operators have used all available information about their pipelines to assess risks and take appropriate actions to mitigate those risks.

Since the implementation of the IM regulations, sweeping changes in the natural gas industry have caused significant shifts in supply and demand, and the Nation's pipeline network faces increased pressures from these changes as well as from the increased exposure caused by a growing and geographically dispersing population. Also, long-identified pipeline safety issues, some of which IM set out to address, remain problems. A records search following the PG&E incident required by Congress in the 2011 Pipeline Safety Act, showed that some pipeline operators do not have the records they need to substantiate the current MAOP of their pipelines, as required under existing regulations, and lacked other critical information needed to properly assess risks and threats and perform effective IM.¹⁸ PHMSA's inspection experience indicates pipelines continue to be vulnerable to failures stemming from outdated construction methods or materials. Finally, some severe pipeline incidents have occurred in areas outside HCAs where the application of IM principles is not required.

Following the significant pipeline incident in 2010 at San Bruno, CA, in which 8 people died and more than 50 people were injured, Congress charged PHMSA with improving the IM regulations. Additionally, the NTSB and Government Accountability Office

(GAO) issued recommendations regarding IM.¹⁹ Comments in response to a 2011 ANPRM on these and related topics suggested there were many common-sense improvements that could be made to IM, as well as a clear need to extend certain IM provisions to pipelines outside of HCAs that were not covered by the IM regulations. A large portion of the transmission pipeline industry has voluntarily committed to extending certain IM provisions to non-HCA pipe, which demonstrates a common understanding of the need for this strategy.

Through this final rule, PHMSA is making improvements to IM and is improving the ability of operators to engage in a long-range review of risk management and information needs, while also accounting for a changing landscape and a changing population.

Supply Changes

The U.S. natural gas industry increased production dramatically between 2005 and 2017, from 19.5 trillion cubic feet per year to 28.8 trillion cubic feet per year.²⁰ This growth was enabled by the production of "unconventional" natural gas supplies using improved technology to extract gas from low permeability shales. The increased use of directional drilling²¹ and improvements to a long-existing industrial technique—hydraulic fracturing,²² which began as an experiment in 1947—made the recovery of unconventional natural gas easier and economically viable. This has led to decreased prices and increased use of natural gas, despite a reduction in the production of conventional natural gas of about 14 billion cubic feet per day. Unconventional shale gas production now accounts for nearly 70 percent of overall gas production in the U.S.

Growth in unconventional natural gas production has shifted production away from traditionally gas-rich regions towards inland shale gas regions. To illustrate, in 2004, wells in the Gulf of Mexico's produced 5,066,000 million

¹⁴ Title 49, United States Code, Subtitle VIII, Pipelines, Sections 60101, *et. seq.*

¹⁵ Typically, onshore pipelines involved in the "transportation of gas"—see 49 CFR 192.1 and 192.3 for detailed applicability.

¹⁶ "Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)." 68 FR 69778; December 15, 2003. Corrected April 6, 2004 (69 FR 18227) and May 26, 2004 (69 FR 29903).

¹⁷ Per PHMSA's 2018 Annual Report, accessed April 9, 2019, 20,435 of the 301,227 miles of gas transmission pipelines are classified as being in HCAs.

¹⁸ An effective IM program requires operators to analyze many data points regarding threats to their systems in addition to pipe attributes, including, but not limited to, construction data (year of installation, pipe bending method, joining method, depth of cover, coating type, pressure test records, etc.), operational data (maximum and minimum operating pressures, leak and failure history, corrosion monitoring, excavation data, corrosion surveys, ILI data, etc.).

¹⁹ More information on the NTSB recommendations being addressed in this rule are discussed in further detail in Section II. D. of this document "National Transportation Safety Board Recommendations." See also, GAO-06-946, Natural Gas Pipeline Safety: Integrity Management Benefits Public Safety, but Consistency of Performance Measures Should be Improved," September 8, 2006.

²⁰ U.S. Department of Energy, Energy Information Administration, "U.S. Natural Gas marketed Production" <https://www.eia.gov/dnav/ng/hist/n9050us2a.htm>, accessed 6/28/18.

²¹ Directional drilling is the practice of drilling non-vertical wells.

²² The extraction of oil or gas deposits performed by forcing open fissures in subterranean rocks by introducing liquid at high pressures.

cubic feet of natural gas per year (Mcf/year), approximately 20 percent of the Nation's natural gas production at the time. By 2016, that number had fallen to 1,220,000 Mcf/year, and approximately 4 percent of natural gas production in the U.S. During that same period, Pennsylvania's share of production grew from 197,217 Mcf/year to 5,463,783 Mcf/year, or approximately 17 percent of total natural gas production in the U.S.^{23 24} An analysis conducted by the Department of Energy's Office of Energy Policy and Systems Analysis projects that the most significant increases in production through 2030 will occur in the Marcellus and Utica Basins in the Appalachian Basin,²⁵ and natural gas production is projected to grow from the 2015 levels of 66.5 Bcf/d to more than 93.5 Bcf/d.²⁶

Demand Changes

The increase in domestic natural gas production has led to lower average natural gas prices.²⁷ In 2004, the outlook for natural gas production and demand growth was weak. Monthly average spot prices at Henry Hub²⁸ were high based on historic comparison of prices, fluctuating between \$4 per million British thermal units (Btu) and \$7 per million Btu. Prices rose above \$11 per million Btu for several months in both 2005 and 2008.²⁹ Since 2008, after production shifted to onshore unconventional shale resources, and price volatility fell away following the Great Recession, natural gas has traded between about \$2 per million Btu and \$5 per million Btu.³⁰

These low prices have fueled consumption growth and changes in

markets and spatial patterns of consumption. A shift towards natural gas-fueled electric power generation, cleaner than other types of fossil fuels, is helping to serve the needs of the Nation's growing population, and increased gas production and lower domestic prices have created opportunities for international export.

Plentiful domestic natural gas supply and comparatively low natural gas prices have changed the economics of electric power markets.³¹ To accommodate recent growth and expected future growth in natural gas-fueled power, changes in pipeline infrastructure will be needed, including flow reversals of existing pipelines; additional lines to gas-fired generators; looping of existing networks, where multiple pipelines are laid parallel to one another along a single right-of-way to increase the capacity of a single system; and, potentially, new pipelines as well.

Increasing Pressures on the Existing Pipeline System Due to Supply and Demand Changes

Despite the significant increase in domestic gas production and the widespread distribution of domestic gas demand, significant flexibility and capacity in the existing transmission system mitigates the level of pipeline expansion and investment required. Some of the new gas production is located near existing or emerging sources of demand, which reduces the need for additional natural gas pipeline infrastructure. In many instances where new natural gas transmission capacity is needed, the network is being expanded by pipeline investments to enhance network capacity on existing lines rather than increasing coverage through new infrastructure. Additionally, operators have avoided building new pipelines by increasing pipeline diameters or operating pressures. In short, the nation's existing pipeline system is facing the brunt of this dramatic increase in natural gas supply and the shifting energy needs of the country.

In cases where use of the existing pipeline network is high, the next most cost-effective solution is to add capacity to existing lines via compression.³² Compression requires infrastructure investment in the form of more compressor stations along the pipeline route, but it can be less costly, faster, and simpler for market participants in

comparison to building a new pipeline. Adding compression, however, raises pipeline operating pressures and can expose previously hidden defects.

New pipeline projects have been proposed to address pending supply constraints and higher prices. However, gaining public acceptance for natural gas pipeline construction has proved to be a substantial challenge. Pipeline expansion and construction projects often face significant challenges in determining feasible right-of-ways and developing community support for the projects.

Data Challenges

Operators and regulators must have an intimate understanding of the threats to, and operations of, their entire pipeline system. Data gathering and integration are important elements of good IM practices, and while operators have made many strides over the years to collect more and better data, several data gaps still exist. Ironically, the comparatively positive safety record of the Nation's gas transmission pipelines to date makes it harder to quantify some of these gaps. Over the 20-year period of 1998–2017, transmission facilities accounted for 50 fatalities and 179 injuries, or about one-sixth to one-seventh of the total fatalities and injuries caused by natural gas pipeline incidents in the U.S.³³ Given the relatively limited number of significant incidents that occur, it can be challenging to project the possible impact of low-probability but high-consequence events. See the RIA included in the public docket for a more detailed analysis of key types of incidents that may be mitigated by this final rule.

On September 9, 2010, a 30-inch-diameter segment of an intrastate natural gas transmission pipeline owned and operated by PG&E ruptured in a residential area of San Bruno, CA. The natural gas that was released subsequently ignited, resulting in a fire that destroyed 38 homes and damaged 70. Eight people were killed, many were injured, and many more were evacuated from the area.

The PG&E incident exposed several problems in the way data on pipeline conditions is collected and managed, showing that the operator had inadequate records regarding the physical and operational characteristics of their pipelines. These records are necessary for the correct setting and validation of MAOP, which is critically

²³ U.S. Department of Energy, Energy Information Administration, "Gulf of Mexico—Offshore Natural Gas Withdrawals," https://www.eia.gov/dnav/ng/hist/na1060_r3fntf_2a.htm, accessed 6/28/18.

²⁴ U.S. Department of Energy, Energy Information Administration, "Pennsylvania Natural Gas Gross Withdrawals," <https://www.eia.gov/dnav/ng/hist/n9010pa2a.htm>, accessed 6/28/18.

²⁵ U.S. Department of Energy, "Appendix B: Natural Gas," *Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure*, p. NG–28, April 2015.

²⁶ *Id.*, at NG–6.

²⁷ *Id.*, at NG–11.

²⁸ Henry Hub is a Louisiana natural gas distribution hub where conventional Gulf of Mexico natural gas can be directed to gas transmission lines running to different parts of the country. Gas bought and sold at the Henry hub serves as the national benchmark for U.S. natural gas prices. (*Id.*, at NG–29, NG–30).

²⁹ Energy Information Administration, Natural Gas Spot and Futures Prices, http://www.eia.gov/dnav/ng/ng_pri_fut_s1_m.htm, retrieved August 2018.

³⁰ U.S. Department of Energy, "Appendix B: Natural Gas," *Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure*, p. NG–11, April 2015.

³¹ *Id.*, at NG–9.

³² Gas can be reduced in volume by increasing its pressure. Therefore, operators can pack more gas into their lines if they can increase the pressure of the gas being transported.

³³ PHMSA, Pipeline Incident 20-Year Trends, <http://www.phmsa.dot.gov/pipeline/library/data-stats/pipelineincidenttrends>.

important for providing an appropriate margin of safety to the public.

Much of operator data is obtained through the assessments and other safety inspections required by IM regulations. However, this testing can be expensive, and the approaches to obtaining data that are most efficient over the long term may require significant upfront costs to modernize pipes and make them suitable for automated inspection. As a result, there continue to be data gaps that make it hard to fully understand the risks to and the integrity of the Nation's pipeline system.

To evaluate a pipeline's integrity, operators generally choose between three methods of testing a pipeline: Inline inspection (ILI), pressure testing, and direct assessment (DA). In 2017, PHMSA estimates that about two-thirds of gas transmission interstate pipeline mileage was suitable for ILI, compared to only about half of intrastate pipeline mileage, and therefore, intrastate operators use more pressure testing and DA than interstate operators.

ILIs are performed using tools, referred to as "smart pigs," which are usually pushed through a pipeline by the pressure of the product being transported. As the tool travels through the pipeline, it identifies and records potential pipe defects or anomalies. Because these tests can be performed with product in the pipeline, the pipeline does not have to be taken out of service for testing to occur, which can prevent excessive cost to the operator and possible service disruptions to consumers. Further, unlike pressure testing, ILI does not risk destroying the pipe, and it is typically less costly to perform on a per-unit basis than other assessment methods.

Pressure tests, also known as hydrostatic tests, are used by pipeline operators as a means to determine the integrity (or strength) of the pipeline immediately after construction and before placing the pipeline in service, as well as periodically during a pipeline's operating life. In a pressure test, water or an alternative test medium inside the pipeline is pressurized to a level greater than the normal operating pressure of the pipeline. This test pressure is held for a number of hours to ensure there are no leaks in the pipeline.

Direct assessment is the visual evaluation of a pipeline at a sample of locations along the line to detect corrosion threats, dents, and stress corrosion cracking of the pipe body and seams. In general, corrosion direct assessments are carried out by performing four steps. Operators will review records and other data, then

inspect the pipeline through assessments that do not require excavation or use mathematical models and environmental surveys to find likely locations on a pipeline where corrosion is most likely to occur. For external corrosion, operators must use two or more complementary indirect assessment tools, including, for example, close interval surveys, direct current voltage gradient surveys, and alternating current voltage gradient surveys, to determine potential areas of corrosion to examine. For internal corrosion, operators must analyze data to establish whether water was present in the pipe, determine the locations where water would likely accumulate, and provide for a detailed examination and evaluation of those locations. Areas identified where corrosion may be occurring are then excavated, examined visually, and remediated as necessary. Operators also perform a post-assessment on segments where corrosion direct assessments are used to evaluate the effectiveness of the technique and determine re-assessment intervals as needed.³⁴

For cracking, operators collect and analyze data to determine whether the conditions for stress corrosion cracking are present, prioritize potentially susceptible segments of pipelines, and select specific sites for examination and evaluation. A DA would then evaluate the presence of stress corrosion cracking and determine its severity and prevalence. Operators are required to repair anomalies, if found, and determine further mitigation requirements as necessary.

Direct assessment can be prohibitively expensive to use on a wide scale and may not give an accurate representation of the condition of lengths of entire pipeline segments when the high expense leads the operator to select an insufficient number of observations. Further, as DA can only be used to validate specific threats, an operator that relies solely on a DA without performing a thorough risk analysis or running multiple tools specific to multiple threats might be leaving other threats unremediated in their pipelines.

Ongoing research and industry response to the ANPRM³⁵ and NPRM³⁶ indicate that ILI and spike hydrostatic

pressure testing³⁷ is more effective than DA for identifying pipe conditions that are related to stress corrosion cracking defects. Regulators and operators agree that improving ILI methods as an alternative to hydrostatic testing is better for risk evaluation and management of pipeline safety. Hydrostatic pressure testing can result in substantial costs, occasional disruptions in service, and substantial methane emissions due to the routine evacuation of natural gas from pipelines prior to tests. Further, many operators prefer not to use hydrostatic pressure tests because it can be destructive.³⁸ ILI testing can obtain data along a pipeline not otherwise obtainable via other assessment methods, although this method also has certain limitations.³⁹

This final rule expands the range of permissible assessment methods and incorporates new guidelines to help operators in the selection of appropriate assessment methods. Promoting the use of ILI technologies, combined with further research and development by PHMSA as well as stakeholders to make ILI testing more accurate, is expected to drive innovation in pipeline integrity testing technologies that leads to improved safety and system reliability through better data collection and assessment.

Flow Reversals, Product Changes, and Manufacturing Defects

Significant growth of production outside the Gulf Coast region—especially in Pennsylvania and Ohio⁴⁰—is causing a reorientation of the Nation's transmission pipeline network. The most significant of these changes will require reversing flows on pipelines to move gas from the Marcellus and Utica shale formations to the southeastern Atlantic region and the Midwest.

Reversing a pipeline's flow can cause added stress on the system due to changes in gas pipeline pressure and temperature, which can increase the risk

³⁷ A "spike" hydrostatic pressure test is typically used to resolve cracks that might otherwise grow during pressure reductions after hydrostatic tests or as the result of operational pressure cycles.

³⁸ National Transportation Safety Board, "Pacific Gas and Electric Company; Natural Gas Transmission Pipeline Rupture and Fire; San Bruno, California; September 9, 2010," *Pipeline Accident Report NTSB/PAR-11-01*, Page 96, 2011.

³⁹ For example, ILI tools are ideal for gathering certain information about the physical condition of the pipe, including corrosion, deformations, or cracking. However, ILI technology cannot reliably detect other conditions, such as coating damage or environmental issues.

⁴⁰ U.S. Energy Information Administration, "Annual Energy Outlook 2019," p. 78—Dry shale gas production by region. <https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf>

³⁴ See PHMSA's fact sheet on DA at <https://primis.phmsa.dot.gov/Comm/FactSheets/FSdirectAssessmentGas.htm>.

³⁵ "Pipeline Safety: Safety of Gas Transmission Pipelines—Advanced Notice of Proposed Rulemaking," 76 FR 5308; August 25, 2011.

³⁶ "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines," 81 FR 20722; April 8, 2016.

of internal corrosion. Occasional failures on natural gas transmission pipelines have followed operational changes that include flow reversals and product changes.⁴¹ Operators have recently submitted proposed flow reversals and product changes on gas transmission lines. In response to this phenomenon, PHMSA issued an Advisory Bulletin in 2014 notifying operators of the potentially significant impacts such changes may have on the integrity of a pipeline and recommended additional actions operators should consider performing before, during, and after flow reversals, product changes, and conversions to service, including notifications, operations and maintenance requirements, and IM requirements.⁴²

Data indicates that some pipelines are vulnerable to issues stemming from outdated construction methods or materials. Some gas transmission infrastructure was made before the 1970s using techniques that have proven to contain latent defects due to the manufacturing process. For example, pipe manufactured using low frequency electric resistance welding is susceptible to seam failure. Because these pipelines were installed before the Federal gas regulations were issued, many of those pipes were exempted from certain regulations, most notably the requirement to pressure test the pipeline segment immediately after construction and before placing the pipeline into service. A substantial amount of this type of pipe is still in service.⁴³ The IM regulations include specific requirements for evaluating such pipe if located in HCAs, but infrequent-yet-severe failures that are attributed to longitudinal seam defects continue to occur. The NTSB's investigation of the PG&E incident in San Bruno determined that the pipe failed due to a similar defect, a fracture originating in the partially welded longitudinal seam of the pipe. According to PHMSA's accident and incident database, between 2010 and 2017, 30 other reportable incidents were

attributed to seam failures, resulting in over \$18 million of reported property damage.

Protecting the Safety and Integrity of the Nation's Pipeline System Beyond HCAs

The current IM program improves pipeline operators' ability to identify and mitigate the risks to their pipeline systems. IM regulations require that operators adopt procedures and processes to identify HCAs; determine likely threats to the pipeline within the HCA; evaluate the physical integrity of the pipe within the HCA; and repair, remediate, or monitor any pipeline defects found based on severity. Because these procedures and processes are complex and interconnected, effective implementation of an IM program relies on continual evaluation and data integration.

HCAs were first defined on August 6, 2002,⁴⁴ providing concentrations of populations with corridors of protection spanning 300, 660, or 1,000 feet, depending on the diameter and MAOP of the particular pipeline.⁴⁵ In a later NPRM,⁴⁶ PHMSA proposed changes to the definition of a HCA by introducing the concept of a covered segment, which PHMSA defined as the length of gas transmission pipeline that could potentially impact an HCA.⁴⁷ Previously, only distances from the pipeline centerline related to HCA definitions. PHMSA also proposed using Potential Impact Circles (PIC), Potential Impact Zones, and Potential Impact Radii (PIR) to identify covered segments instead of a fixed corridor width. The final Gas Transmission Pipeline Integrity Management Rule, incorporating the new HCA definition using the PIR and PIC concepts, was issued on December 15, 2003.⁴⁸

The PG&E incident in 2010 motivated a comprehensive reexamination of gas transmission pipeline safety. In response to the PG&E incident, Congress

passed the 2011 Pipeline Safety Act, which directed PHMSA to reexamine many of its safety requirements, including the expansion of IM regulations for transmission pipelines.

Further, both the NTSB and the GAO issued several recommendations to PHMSA to improve its IM program and pipeline safety. The NTSB noted in a 2015 study⁴⁹ that IM requirements have reduced the rate of failures due to deterioration of pipe welds, corrosion, and material failures. However, the NTSB noted that pipeline incidents in HCAs due to other factors increased between 2010 and 2013, and the overall occurrence of gas transmission pipeline incidents in HCAs has remained stable. Since 2013 there have been an average of 9 incidents within HCAs, which is below a peak of 12 incidents per year in 2012 and 2013, but still higher than the number of incidents in 2010 and 2011. The NTSB also found many types of basic data necessary to support comprehensive probabilistic modeling of pipeline risks are not currently available.

Looking at Risk Beyond HCAs

PHMSA posed a series of questions to the public in the context of an August 25, 2011, ANPRM titled "Safety of Gas Transmission Pipelines" (76 FR 53086), including whether the regulations governing the safety of gas transmission pipelines needed changing. In particular, PHMSA asked whether to add prescriptive language to IM requirements, and whether other issues related to system integrity should be addressed by strengthening or expanding non-IM requirements. PHMSA sought comment on the definition of an HCA and whether additional restrictions should be placed on the use of DA as an IM assessment method. PHMSA also requested comment on non-IM requirements, including valve spacing and installation, corrosion control, and whether regulations for gathering lines needed to be modified.

PHMSA received 103 submissions containing thousands of comments in response to the ANPRM, which are summarized in more detail below. This feedback helped identify a series of proposed improvements to IM, including improvements to assessment goals such as integrity verification, MAOP verification, and material documentation; adjusted repair criteria; clarified protocol for identifying threats,

⁴¹ On September 29, 2013, the Tesoro High Plains pipeline leaked 20,000 barrels of crude oil in a North Dakota field. The location of pressure and flow monitoring equipment had not been changed to account for the reversed flow. On March 19, 2013, Exxon's Pegasus pipeline failed; the flow on that pipeline was reversed in 2006.

⁴² "Pipeline Safety: Guidance for Pipeline Flow Reversals, Product Changes, and Conversion to Service," ADB PHMSA-2014-0040, 79 FR 56121; September 18, 2014.

⁴³ Currently, PHMSA's data shows that roughly 168,000 of the Nation's 301,000 miles of onshore gas transmission pipelines were installed prior to the 1970 requirement for hydrostatic pressure testing. See <https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?PortalPages>.

⁴⁴ "Pipeline Safety: High Consequence Areas for Gas Transmission Pipelines," *Final rule*, 67 FR 50824; August 6, 2002.

⁴⁵ The influence of the existing class location concept on the early definition of HCAs is evident from the use of class locations themselves in the definition, and the use of fixed 660 ft. distances, which corresponds to the corridor width used in the class location definition. This concept was later significantly revised, as discussed later, in favor of a variable corridor width based on case-specific pipe size and operating pressure.

⁴⁶ "Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)," *Notice of Proposed Rulemaking*, 68 FR 4278; January 28, 2003.

⁴⁷ HCA and PIR definitions are in 49 CFR 192.903.

⁴⁸ "Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)," *Final rule*, 68 FR 69778; December 15, 2003.

⁴⁹ National Transportation Safety Board, "Safety Study: Integrity Management of Gas Transmission Pipelines in High Consequence Areas," NTSB SS-15/01, January 27, 2015.

risk assessments and management, and prevention and mitigation measures; expanded and enhanced corrosion control; requirements for inspecting pipelines after incidents of extreme weather; and new guidance on how to calculate MAOP in order to set operating parameters more accurately and predict the risks of an incident. PHMSA published an NPRM on April 8, 2016 (81 FR 20722), which is discussed in more detail below.

Many of these aspects of IM have been an integral part of PHMSA's expectations since the inception of the IM program. As specified in the first IM rule, PHMSA expects operators to start with an IM framework, evolve a more detailed and comprehensive IM program, and continually improve their IM programs as they learn more about the IM process and the material condition of their pipelines through integrity assessments.

Section 23 of the 2011 Pipeline Safety Act required PHMSA to have pipeline operators conduct a records verification to ensure that their records accurately reflect the physical and operational characteristics of their pipelines in certain HCAs and class locations, and to confirm the established MAOP of those pipelines. Based on the data received from operators following the records verification, incidents that have occurred in non-HCA areas, and other knowledge gained since the 2011 Pipeline Safety Act was passed, PHMSA has become increasingly concerned that a rupture on the scale of San Bruno, with the potential to cause death and serious injury, as well as damage to the environment or the disruption of commerce, could occur elsewhere on the Nation's pipeline system in both HCA and non-HCA pipeline segments. There have been several recent incidents in non-HCAs that show significant incidents can occur in non-HCAs. For example, on December 14, 2007, two men were driving in a pickup truck on Interstate 20 near Delhi, LA, when a 30-inch gas transmission pipeline owned by Columbia Gulf Transmission Company ruptured. One of the men was killed, and the other was injured.

Further, on December 11, 2012, a 20-inch-diameter gas transmission line operated by Columbia Gas Transmission Company ruptured about 106 feet west of Interstate 77 (I-77) in Sissonville, WV. An area of fire damage about 820 feet wide extended nearly 1,100 feet along the pipeline right-of-way. Three houses were destroyed by the fire, and several other houses were damaged. Reported losses, repairs, and upgrades from this incident totaled over \$8.5

million, and major transportation delays occurred. I-77 was closed in both directions because of the fire and resulting damage to the road surface. The northbound lanes were closed for approximately 14 hours, and the southbound lanes were closed for approximately 19 hours while the road was resurfaced, causing delays to both travelers and commercial shipping.

Finally, on April 29, 2016, an incident occurred on a Texas Eastern Transmission Corporation gas transmission line operated by Spectra Energy near Delmont, PA, which is approximately 25 miles away from Pittsburgh, PA. The explosion seriously injured one person, destroyed a house, damaged three other homes and vehicles outside, and caused the evacuation of nine other homes in the area. Even though the pipeline was in a Class 1 rural area, it still had a significant impact on the local population.

The Nation's population is growing, moving, and dispersing, leading to changes in population density that can affect the class location of a pipeline segment, as well as whether it is in an HCA. The definition of HCA is not necessarily an accurate reflection of whether an incident will have an impact on people. Requiring assessment and repair criteria for pipelines that, if ruptured, could pose a threat to areas where any people live, work, or congregate would improve public safety and would improve public confidence in the Nation's natural gas pipeline system.

Some pipeline operators have said they are already moving towards expanding the protections of IM beyond HCAs. In 2012, the Interstate Natural Gas Association of America (INGAA) issued a "Commitment to Pipeline Safety,"⁵⁰ underscoring its efforts towards a goal of zero incidents, a committed safety culture, a pursuit of constant improvement, and applying IM principles on a system-wide basis. To accomplish this goal, INGAA's members committed to performing actions that include applying risk management beyond HCAs; raising the standards for corrosion management; demonstrating "fitness for service" on pre-regulation pipelines; and evaluating, refining, and

improving operators' ability to assess and mitigate safety threats. These actions aim to extend protection to people who live near pipelines but not within defined HCAs. Further, this final rule takes important steps toward developing a comprehensive approach for the entire industry by finalizing requirements for assessments outside of HCAs.

This final rule implements risk management standards that most accurately target the safety of communities while also providing sufficient ability to prioritize areas of greatest possible risk and impact.

Given the results of incident investigations, IM considerations, and the feedback from the ANPRM and the NPRM, PHMSA has determined it is appropriate to improve aspects of the current IM program and codify requirements for additional gas transmission pipelines to receive integrity assessments on a periodic basis to monitor for, detect, and remediate pipeline defects and anomalies. In addition, to achieve the desired outcome of performing assessments in areas where people live, work, or congregate, while balancing the cost of identifying such locations, PHMSA based the requirements for identifying those locations on effective processes already being implemented by pipeline operators and that protect people on a risk-prioritized basis.

Establishing integrity assessment requirements for non-HCA pipeline segments is important for providing safety to the public. Although those pipeline segments are not within defined HCAs, they will usually be in populated areas, and pipeline accidents in these areas may cause fatalities, significant property damage, or disrupt livelihoods. This final rule adopts a newly defined definition for MCAs to identify additional non-HCA pipeline segments that would require integrity assessments, thus assuring the timely discovery and repair of pipeline defects in MCA segments that could potentially impact people, property, or the environment. At the same time, operators can allocate their resources to HCAs on a higher-priority basis.

B. Pacific Gas and Electric Incident of 2010

On September 9, 2010, a 30-inch-diameter segment of a gas transmission pipeline owned and operated by PG&E ruptured in a residential neighborhood in San Bruno, CA, producing a crater approximately 72 feet long by 26 feet wide. The segment of pipe that ruptured weighed approximately 3,000 pounds, was 28 feet long, and was found 100 feet

⁵⁰ Letter from Terry D. Boss, Senior Vice President of Environment, Safety and Operations to Mike Israni, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, dated January 20, 2012, "*Safety of Gas Transmission Pipelines*, Docket No. PHMSA-2011-0023." INGAA represents companies that operate approximately 65 percent of the gas transmission pipelines, but INGAA does not represent all pipeline operators subject to 49 CFR part 192.

south of the crater. Over the course of the incident, 47.6 million standard cubic feet of natural gas was released. The escaping gas ignited, and the resultant fire destroyed 38 homes, damaged another 70, killed 8 people, injured approximately 60 people (10 seriously), destroyed or damaged 74 vehicles, and caused the evacuation of over 300 more people. The initial 911 calls described the fire as a “gas station explosion” and a “possible airplane crash.” After 91 minutes, PG&E was able to shut off the flow of gas to the rupture site, which allowed firefighters to approach the rupture site and begin containment efforts. Firefighting operations continued for 2 days; more than 900 emergency responders from San Bruno and surrounding areas were part of the emergency response, 600 of which were firefighters and emergency medical services personnel.⁵¹

The NTSB, in its pipeline accident report for the incident, determined that the probable cause of the accident was PG&E’s inadequate quality assurance and control when it relocated the line in 1956 and an inadequate IM program. The NTSB determined that PG&E’s IM program was deficient and ineffective because it was based on incomplete and inaccurate pipeline information, did not consider the pipeline’s design and materials contribution to the risk of a pipeline failure, and failed to consider the presence of previously identified welded seam cracks as part of its risk assessment. These deficiencies resulted in the selection of an examination method that could not detect welded seam defects and led to internal assessments of PG&E’s IM program that were superficial and resulted in no improvements. Ultimately, this inadequate IM program failed to detect and repair or remove the defective pipe section.

The NTSB found that PG&E’s inaccurate geographic information system records at the time of the incident indicated that the ruptured segment was constructed from 30-inch-diameter seamless API 5L X42 steel pipe. However, seamless pipe has never been available in 30-inch diameter. According to PG&E employees who testified during the investigation, all 30-inch pipe purchased by PG&E at that time would have been double submerged arc welded, which has been found in cases to be susceptible to weld failure. This inaccuracy was

compounded with the discovery that the material code from the journal voucher that PG&E’s records were originally composed from erroneously indicated the ruptured segment was X52 grade pipe (52,000 pounds per square inch (psi)), not X42 grade pipe (42,000 psi). X52 pipe has a higher minimum yield strength than X42 pipe,⁵² and incorporating such values into MAOP calculations would produce values that would be inconsistent with the pipeline’s actual MAOP. PG&E also could not produce any design, material, or construction specifications from the 1956 construction project. In short, no one from PG&E could reliably determine what type of pipe was in the ground that ruptured.

The NTSB also noted that PHMSA’s exemption of pipelines installed before 1970 from the regulatory requirement for pressure testing, which likely would have detected the installation defects, was a contributing factor to the accident. When the initial Federal minimum safety standards for natural gas transmission pipelines were finalized in 1970, an exemption was carved out for pre-1970s pipelines from the requirement for a post-construction hydrostatic pressure test. This exemption was not proposed in any of the NPRMs that preceded the initial regulations and was based on an assertion from the Federal Power Commission⁵³ that “there are thousands of miles of jurisdictional interstate pipelines installed prior to 1952,⁵⁴ in compliance with the then-existing codes, that could not continue to operate at their present pressure levels and be in compliance with [the proposed MAOP determination requirements].”⁵⁵ Upon reviewing the operating record of interstate pipeline companies, the Commission found “no evidence that would indicate a material increase in safety would result from requiring wholesale reductions in the pressure of existing pipelines which have been proven capable of withstanding present operating pressures through actual operation.” The Office of Pipeline Safety, at the time, determined it “[did] not now have enough information to determine that existing operating pressures are unsafe,”

and taking into account the statements from the Federal Power Commission, included the “grandfather” clause in the final rule to permit the continued operation of pipelines at the highest pressure to which the pipeline had been subjected during the 5 years preceding July 1, 1970.^{56 57} The 5-year limit was prescribed so that operators would be prevented from “using a theoretical MAOP which may have been determined under some formula used 20, 30, or 40 years ago.”⁵⁸

The NTSB noted in its investigation that the “grandfathering” of the ruptured line resulted in missed opportunities to detect the defective pipe, as a hydrostatic pressure test to the prescribed levels for a Class 3 location would likely have exposed the defective pipe that led to the accident. Following the PG&E incident, the California Public Utilities Commission (CPUC) required PG&E and other gas transmission pipeline operators regulated by CPUC to either hydrostatically pressure test or replace certain transmission pipelines with grandfathered MAOPs, stating that gas transmission pipelines “must be brought into compliance with modern standards for safety” and that “historic exemptions must come to an end.”⁵⁹ Currently, PHMSA’s data shows that roughly 168,000 of the Nation’s 301,000 miles of onshore gas transmission pipelines were installed prior to the 1970 requirement for hydrostatic pressure testing.⁶⁰

On April 1, 2014, the Department of Justice indicted PG&E for multiple criminal violations of part 192 for the 2010 incident in San Bruno, CA. The trial began on June 14, 2016, and after a 5 ½ week trial, a Federal jury found PG&E guilty of knowingly and willingly violating 5 sections of PHMSA’s IM regulations and obstructing the NTSB investigation.

Specifically, with respect to the Federal Pipeline Safety Regulations, the jury found that between 2007 and 2010, PG&E knowingly and willfully failed to: (1) Gather and integrate existing data and information that could be relevant to identifying and evaluating potential threats on covered pipeline segments; (2) identify and evaluate all potential

⁵⁶ 35 FR 13248.

⁵⁷ This requirement is currently under § 192.619(c).

⁵⁸ 35 FR 13248.

⁵⁹ “Decision Determining Maximum Allowable Operating Pressure Methodology and Requiring Filing of Natural Gas Transmission Pipeline Replacement or Testing Implementation Plans;” California Public Utilities Commission Order; June 9, 2011.

⁶⁰ <https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?PortalPages>.

⁵¹ National Transportation Safety Board. 2011. *Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010*. Pipeline Accident Report NTSB/PAR-11/01. Washington, DC.

⁵² 52,000 psi vs. 42,000 psi.

⁵³ The predecessor of the Federal Energy Regulatory Commission.

⁵⁴ Between 1935 and 1951, the B31 Code only required a pipeline be tested to a pressure of 50 psig in excess of the pipeline’s proposed MAOP. The 1970 regulations required pressure testing to 125 percent in excess of the proposed MAOP.

⁵⁵ “Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards,” 35 FR 13248; August 19, 1970.

threats to each covered pipeline segment; (3) include in its baseline assessment plan all potential threats on a covered segment and to select the most suitable assessment method; (4) prioritize high-risk pipeline segments for assessment where certain changed circumstances rendered the manufacturing threats on those segments unstable; and (5) prioritize pipeline segments containing low-frequency ERW pipe or other similar pipe as a high-risk segment for assessment if certain changed circumstances rendered a manufacturing seam threat on that segment unstable.

Congress required PHMSA, per the 2011 Pipeline Safety Act, to issue regulations to confirm the material strength of previously untested natural gas transmission pipelines located in HCAs and operating at a pressure greater than 30 percent of SMYS. Through this final rule, PHMSA is implementing that congressional directive and other safety measures. This final rule will improve the safety and public confidence of the Nation's onshore natural gas transmission pipeline system.

C. Advance Notice of Proposed Rulemaking

On August 25, 2011, PHMSA published an ANPRM to seek public comments regarding the revision of the Federal Pipeline Safety Regulations applicable to the safety of gas transmission pipelines. In the 2011 ANPRM, PHMSA requested comments on 122 questions spread through 15 broad topic areas covering both IM and non-IM requirements. Among the issues related to IM that PHMSA considered included whether the definition of an HCA should be revised and whether additional restrictions should be placed on the use of certain pipeline assessment methods. PHMSA also requested comment on non-IM regulations, including whether revised requirements are needed for mainline valve spacing and actuation, whether requirements for corrosion control should be strengthened, and whether new regulations are needed to govern the safety of gas gathering lines and underground natural gas storage facilities. Based on the comments received on several of the ANPRM topics, PHMSA developed proposals for some of those topics in a NPRM that is the basis for this final rule. That NPRM and the comments received, are discussed below. PHMSA did not find it appropriate to address all the topics in a single rulemaking. Those topics that were not discussed further in the NPRM

for this final rule have been discussed or will be discussed in other rulemakings.

D. National Transportation Safety Board Recommendations

On August 30, 2011, following the issuance of the ANPRM, the NTSB adopted its report on the gas pipeline incident that occurred on September 9, 2010, in San Bruno, CA. On September 26, 2011, the NTSB issued safety recommendations P-11-8 through -20 to PHMSA. Several of the NTSB's recommendations related directly to the topics discussed in the 2011 ANPRM and 2016 NPRM, and they shaped the direction of this final rule. The NTSB recommendations addressed in this final rule include:

- Exemption of Facilities Installed Prior to the Regulations. NTSB Recommendation P-11-14: *Amend Title 49 Code of Federal Regulations 192.619 to repeal exemptions from pressure test requirements and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test.*

- Pipe Manufactured Using Longitudinal Weld Seams. NTSB Recommendation P-11-15: *“Amend Title 49 Code of Federal Regulations Part 192 of the Federal pipeline safety regulations so that manufacturing- and construction-related defects can only be considered stable if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the maximum allowable operating pressure.”*

- Incorporating interstates, highways, etc., into the list of “identified sites” that establish a HCA. NTSB Recommendation P-14-1: *“Revise Title 49 CFR Section 903, Subpart O, Gas Transmission Pipeline Integrity Management, to add principal arterial roadways including interstates, other freeways and expressways, and other principal arterial roadways as defined in the Federal Highway Administration’s ‘Highway Functional Classification Concepts, Criteria and Procedures’ to the list of ‘identified sites’ that establish an HCA.*

- Increase the use of ILI tools. NTSB Recommendation P-15-20: *“Identify all operational complications that limit the use of in-line inspection tools in piggable pipelines, develop methods to eliminate the operational complications, and require operators to use these methods to increase the use of in-line inspection tools.”*

E. Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011

The 2011 Pipeline Safety Act relates directly to the topics addressed in PHMSA's ANPRM of August 25, 2011, and the NPRM issued on April 8, 2016. The related topics and statutory citations include, but are not limited to:

- Section 5(e)—Allow periodic reassessments to be extended for an additional 6 months if the operator submits sufficient justification.
- Section 5(f)—Requires the expansion of IM system requirements, or elements thereof, beyond HCAs, if appropriate.
- Section 23—Requires the reporting of each exceedance of the MAOP that exceeds the build-up allowed for the operation of pressure-limiting or -control devices.
- Section 23—Requires testing to confirm the material strength of previously untested natural gas transmission pipelines and pipelines lacking records that accurately reflect the pipeline's physical and operational characteristics.
- Section 29—Requires consideration of seismicity when evaluating pipeline threats.

F. Notice of Proposed Rulemaking

On April 8, 2016, PHMSA published an NPRM seeking public comments on the revision of the Federal Pipeline Safety Regulations applicable to the safety of gas transmission pipelines and gas gathering pipelines (81 FR 20721).⁶¹ When developing the NPRM, PHMSA considered the comments it received from the ANPRM and proposed new pipeline safety requirements and revisions of existing requirements in several major topic areas, including those topics addressing congressional mandates and related NTSB recommendations. A summary of the NPRM proposals and topics pertinent to this rulemaking, the comments received on those specific proposals, and PHMSA's response to the comments received is below under the “Analysis of Comments and PHMSA Response” section.

PHMSA determined it could more quickly move a rulemaking that focuses on the mandates from the 2011 Pipeline Safety Act by splitting out the other provisions contained in the NPRM into two other, separate rules. Promptly issuing a final rule focused on mandates will improve safety and respond to Congress, industry, and public safety groups.

⁶¹ <https://www.regulations.gov/document?D=PHMSA-2011-0023-0118>.

As such, not all the topics from the NPRM nor the comments received on those topics are discussed as a part of this rulemaking. PHMSA intends to issue two additional final rules to address the remaining topics from the NPRM.

III. Analysis of NPRM Comments, GPAC Recommendations, and PHMSA Response

On April 8, 2016, PHMSA published an NPRM (81 FR 20722) proposing several amendments to 49 CFR part 192. The NPRM proposed amendments addressing topic areas including verification of pipeline material properties, MAOP reconfirmation, IM clarifications, MAOP exceedance reports, ILI launcher and receiver safety, assessing areas outside of HCAs, and recordkeeping. The comment period for the NPRM ended on July 7, 2016. PHMSA received approximately 300 submissions containing thousands of comments on the NPRM. Submissions were received from groups representing the regulated pipeline industry; groups representing public interests, including environmental groups; State utility commissions and regulators; members of Congress; specific pipeline operators; and private citizens.

Some of the comments PHMSA received in response to the NPRM were comments beyond the scope or authority of the proposed regulations. The absence of amendments in this proceeding involving other pipeline safety issues (including several topics listed in the ANPRM) does not mean that PHMSA determined additional rules or amendments on those other issues are not needed. Such issues may be the subject of other existing rulemaking proceedings or future rulemaking proceedings.

The remaining comments reflect a wide variety of views on the merits of particular sections of the proposed regulations. PHMSA read and considered all the comments posted to the docket for this rulemaking.

The Technical Pipeline Safety Standards Committee, commonly known as the Gas Pipeline Advisory Committee (GPAC; the committee), is a statutorily mandated advisory committee that advises PHMSA on proposed safety standards, risk assessments, and safety policies for natural gas pipelines.⁶² The GPAC is one of two pipeline advisory committees that focus on technical safety standards that were established under the Federal Advisory Committee Act (Pub. L. 92–463, 5 U.S.C. App. 1–

16) and section 60115 of the Federal Pipeline Safety Statutes (49 U.S.C. Chap. 601). Each committee consists of 15 members, with membership divided among Federal and State agencies, regulated industry, and the public. The committees consider the “technical feasibility, reasonableness, cost-effectiveness, and practicability” of each proposed pipeline safety standard and provide PHMSA with recommended actions pertaining to those proposals.

Due to the size and technical detail of this rulemaking, the GPAC met five times to discuss this rulemaking throughout 2017 and 2018.⁶³ During those meetings, the GPAC considered the specific regulatory proposals of the NPRM and discussed various comments made on the NPRM’s proposal by stakeholders, including the pipeline industry at large, public interest groups, and government entities. To assist the GPAC in its deliberations, PHMSA presented a description and summary of the major proposals in the NPRM and the comments received on those issues. PHMSA also assisted the committee by fostering discussion and developing recommendations by providing direction on which issues were most pressing.

For the proposals finalized in this rulemaking, the committee came to consensus when voting on the technical feasibility, reasonableness, cost-effectiveness, and practicability of the NPRM’s provisions. In many instances, the committee recommended changes to certain proposals that the committee found would make certain proposals more feasible, reasonable, cost-effective, or practicable.

The substantive comments received on the NPRM as well as the GPAC’s recommendations are organized by topic below and are discussed in the appropriate section with PHMSA’s response and resolution to those comments.

A. Verification of Pipeline Material Properties and Attributes—§ 192.607

i.—Applicability

1. Summary of PHMSA’s Proposal

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records used to establish MAOP to ensure they accurately reflect the physical and operational

characteristics of the pipelines and to confirm the established MAOP of gas transmission pipelines. Since 2012, operators have submitted information indicating that a portion of transmission pipeline segments do not have adequate records to establish MAOP or that accurately reflect the physical and operational characteristics of the pipeline. Therefore, PHMSA determined that additional regulations are needed to implement this requirement of the 2011 Pipeline Safety Act. Specifically, PHMSA proposed that operators conduct tests and other actions needed to confirm and document the physical and operational characteristics for those pipeline segments where adequate records are not available, and PHMSA proposed standards for performing these actions. PHMSA sought to appropriately address pipeline risk without extending the requirement to all pipelines where risk and potential consequences are not as significant, such as pipelines in remote, sparsely-populated areas. As a result, PHMSA proposed criteria that would require material properties verification for higher-risk locations through a new § 192.607; specifically, by adding requirements for the verification of pipeline material properties for existing onshore, steel, gas transmission pipelines that are located in HCAs or Class 3 or Class 4 locations.

2. Summary of Public Comment

Several citizen and public safety groups, including Pipeline Safety Trust (PST), Pipeline Safety Coalition, National Association of Pipeline Safety Representatives (NAPSR), Coalition to Reroute Nexus, Earthworks, and The Michigan Coalition to Protect Public Rights-of-Way, supported the proposed provisions for establishing adequate material properties documentation and records. Some of these groups noted that the need for this section in the regulations would suggest poor operator implementation of the IM requirements since the inception of subpart O back in 2003.

Trade associations and pipeline industry entities were largely opposed to the material properties verification requirements for several reasons outlined below.

Many trade association and pipeline industry commenters expressed concern that the material properties verification requirements were potentially retroactive. American Petroleum Institute (API) and American Gas Association (AGA) asserted that this proposal would require operators to document and verify the material properties of existing pipelines beyond

⁶³ Specifically, the GPAC met on January 11–12, 2017; June 6–7, 2017; December 14–15, 2017; March 2, 2018; and March 26–28, 2018. Information on these meetings can be found at [regulations.gov](https://www.regulations.gov) under docket PHMSA–2011–0023 and at PHMSA’s public meeting page: <https://primis.phmsa.dot.gov/meetings/>.

⁶² 49 U.S.C. 60115.

what was required by the regulations that were in place at the time those pipelines were put into service. These commenters stated that this retroactive requirement extends beyond the congressional authority provided to PHMSA. Several commenters, including AGL Resources, Dominion East Ohio, and New Jersey Natural Gas, expressed concern with the proposed provisions for verifying specific physical characteristics of pipelines, fittings, valves, flanges, and components for existing transmission pipelines. These stakeholders stated that it might be impossible to achieve "reliable, traceable, verifiable, and complete" records on a retroactive basis for existing pipelines. Some commenters, including AGA, stated that a pipeline's MAOP should be considered confirmed and there should be no need to further document material properties to verify the MAOP if operators had a pressure test record of a test conducted at 1.25 times MAOP for the pipeline segment.

Commenters also expressed concern about PHMSA's proposed new references to the material properties verification requirements under § 192.607 throughout part 192, which could be interpreted as being applicable not only to a subset of transmission pipelines but also to distribution pipelines. Commenters stated that PHMSA did not provide justification within the NPRM for applying material properties verification requirements to distribution systems, and such requirements would significantly impact distribution systems. These commenters requested that PHMSA explicitly exclude distribution pipelines from the proposed material properties verification requirements. Similarly, some commenters urged PHMSA to restrict these requirements only to gas transmission lines operating at greater than 30 percent SMYS based on the premise that lines operating below 30 percent SMYS, in most cases, tend to leak before rupture and are therefore less risky to the public. Additionally, commenters suggested that PHMSA review the various cross-references in the NPRM and eliminate those that would expand the applicability of the material properties verification requirements beyond onshore steel gas transmission pipelines in HCAs and Class 3 and Class 4 locations.

Some commenters recommended changing the size limit for small components that might trigger the material properties verification requirements from greater-than-or-equal-to 2 inches to greater-than 2 inches. A further comment on components discussed how the material

properties verification provisions, as proposed, require the operator to know the weld-end bevel conditions for in-service valves and flanges. Operators noted, however, that once a weld-end is welded to a piece of pipe or other component, there is no method that can be employed to determine the condition of that bevel. Accordingly, the commenters requested this requirement be deleted or clarified. There was also a comment to delete the sampling requirement and not perform material properties verification if, when the applicable pipeline is excavated for repairs, a repair sleeve is installed. Other commenters felt that the proposed material properties verification requirements would not deliver clear, identifiable safety benefits and would lead to several unintended consequences that would decrease the integrity of pipeline systems and cause energy supply disruption. Accordingly, these commenters suggested PHMSA withdraw the proposed requirements for material properties verification.

Multiple commenters also expressed concerns that the revised provisions for establishing MAOP under § 192.619, specifically the requirement for operators to maintain all records necessary to establish and document a pipeline's MAOP as long as the pipeline remains in service, would impose extensive new recordkeeping requirements applicable to operators of distribution pipelines, including retroactive recordkeeping requirements. Commenters requested that PHMSA clarify that the new recordkeeping requirements in § 192.619(f) are applicable only to gas transmission pipelines.

Pipeline industry entities also provided comments on the relationship of the material properties verification requirements in § 192.607 and the MAOP reconfirmation requirements in § 192.624. The Gas Piping Technology Committee (GPTC) suggested that the proposed material properties verification requirements be revised to include an option of using the provisions of § 192.619(a)(1) for establishing MAOP when traceable, verifiable, and complete material property records are not available for calculating design pressure. Similarly, commenters suggested operators should be allowed to establish design yield strengths for unknown pipe grade as described at § 192.107(b)(1). Xcel Energy also stated that if an operator has previously established MAOP as per the § 192.619(a)(2) strength test requirements or will do so per the proposed § 192.624 methodology for pressure test or pressure reduction, the

verification of pipeline material proposed in § 192.607 is not necessary for the purpose of ensuring safe operation.

Over the course of the meetings on June 7, 2017, and December 14, 2017, the GPAC had a robust discussion regarding the applicability of the material properties verification requirements. More specifically, the GPAC discussed the fact that two separate activities drive the need for material properties verification: (1) MAOP reconfirmation for pipelines lacking traceable, verifiable, and complete records to support the pipeline's current MAOP; and (2) the application of IM principles, especially where anomaly response and remediation calculations are concerned. The GPAC believed these aspects needed to be addressed separately in the final rule.

Subsequently, on December 14, 2017, the GPAC recommended that PHMSA modify the proposed rule by removing the applicability criteria of the material properties verification requirements and make material properties verification a procedure for obtaining missing or inadequate records or otherwise verifying pipeline attributes if and when required by MAOP reconfirmation requirements or by other code sections. In discussing the issue, the GPAC recognized that the broad applicability of the material properties verification requirements in the proposed rule was PHMSA's attempt to address the issue of inadequate records for MAOP verification, IM requirements and standard pipeline operations. The GPAC believed amending the proposed rule to remove the proposed applicability and instead explicitly refer back to the material properties verification requirements, when needed, in various regulatory sections, would more closely follow Congress' direction in the 2011 Pipeline Safety Act.

This change would also obviate the need for operators to create a material properties verification program plan per the originally proposed requirements, so the GPAC recommended PHMSA remove that requirement from the rule. Further, the committee recommended during a later meeting that PHMSA consider modifying the rule in both §§ 192.607 and 192.619 to clarify that the material properties verification requirements apply to onshore steel gas transmission lines and not to distribution or gathering pipelines.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the scope and requirements for

reconfirming the material properties of pipelines with unknown or undocumented properties. PHMSA agrees that the need for this rule is caused, in part, by poor implementation of existing IM requirements. However, PHMSA disagrees that the requirements would not deliver safety benefits or would lead to decreased integrity of pipeline systems and cause energy supply disruption. The basic knowledge of pipeline material properties is essential to pipeline safety.

PHMSA disagrees that material properties verification is not needed if the pipeline segment has been pressure tested to 1.25 times MAOP. Other reasons for needing documented, confirmed material properties (*e.g.*, wall thickness, yield strength, and seam type) include IM program requirements, implementation of pipe repair criteria and determination of the design pressure of the pipeline segment. This rule supplements existing IM requirements by providing operators a method to reconfirm material properties without necessarily performing destructive testing of the pipe material. Operators can use this method in their IM programs, to reconfirm MAOP where needed, to implement repair requirements, and to otherwise comply with part 192 where necessary. Indeed, PHMSA hopes that operators will use this method for material properties verification even when not specifically required by part 192 because it provides a common-sense, opportunistic, and practical approach for gathering the records necessary to substantiate safe MAOPs, properly implement IM, and otherwise ensure the safe operation of the nation's pipeline network.

PHMSA also disagrees that material properties verification is only needed for pipeline segments operating at pressure greater than 30 percent of SMYS. IM requirements apply to all gas transmission pipeline segments in HCAs, including those that operate at less than 30 percent of SMYS. Moreover, the gas transmission subpart O integrity management regulations at § 192.917(b), *Data gathering and integration*, require operators to gather pipe attributes including pipe wall thickness, diameter, seam type and joint factor, manufacturer, manufacturing date, and material properties. These physical properties and attributes are explicitly outlined in ASME/ANSI B31.8S—2004 Edition, section 4, table 1—Data Elements for Prescriptive Pipeline Integrity Program, which is incorporated by reference in § 192.7.

PHMSA did not intend that the requirements proposed in § 192.607 would be retroactive or would apply to

distribution or gathering lines. Therefore, PHMSA is clarifying the final rule to assure that the provisions finalized in § 192.607 are not retroactive⁶⁴ and apply only to transmission lines. However, PHMSA believes that operators with IM programs that are properly following subpart O, specifically § 192.917(b), should already have this pipe information.

Regarding material properties verification for non-line pipe components, PHMSA is revising this final rule to apply the requirements to components greater than 2 inches and is removing the requirement to know the weld-end bevel conditions. PHMSA agrees with the GPAC members who commented that 2-inch pipe is not used in mainline applications and need not be subject to additional regulatory requirements to maintain safety. Also, fittings and flanges will have an ANSI class rating that will confirm whether the components meet or exceed the MAOP of the pipeline, so further regulatory requirements for components under 2 inches are not necessary to maintain safety.

To further address comments and the GPAC recommendations related to the scope and applicability of the material properties verification requirements, PHMSA is modifying this final rule to address MAOP reconfirmation and material properties verification separately from the application of IM principles. PHMSA believes this change will improve the organization of the rule. PHMSA is accomplishing this by removing the applicability criteria of the material properties verification requirements and making material properties verification a procedure for obtaining records for physical pipeline properties and attributes that are not documented in traceable, verifiable, and complete records or otherwise verifying physical pipeline properties and attributes when required by MAOP reconfirmation requirements, IM requirements, repair requirements, or other code sections. This obviates the need for all operators to create a material properties verification program plan per the originally proposed requirements, so PHMSA is removing that requirement from the rule as well.

⁶⁴ The material properties verification requirements are not retroactive as they mandate the creation and retention of records as operators execute the methodology in § 192.607 on a prospective basis. Operators who have not verified their records in accordance with this methodology before the effective date of this rule will not be subject to enforcement action based on § 192.607. After the effective date of the rule, operators with missing or inadequate records must follow the verification methodology in § 192.607.

Instead, only operators who do not have traceable, verifiable, and complete records will be required to create such a plan.

A. Verification of Pipeline Material Properties and Attributes—§ 192.607

ii.—Method

1. Summary of PHMSA's Proposal

The conventional method for determining the properties of unknown steel pipe material is to cut test specimens known as "coupons" out of the pipe and perform destructive testing. Because of the large amount of pipe operators reported in Annual Report submissions for which there are unknown or inadequately documented properties, the cost of such a conventional approach would likely be onerous. Therefore, PHMSA proposed standards in § 192.607 by which operators could develop a material properties verification plan and use an opportunistic sampling technique to reconstitute and document material properties in a more cost-effective manner. More specifically, PHMSA proposed to allow operators to use recently developed technology to perform *in situ*, non-destructive examinations for determining the properties of unknown steel pipe material.

While PHMSA acknowledged in the preamble of the NPRM that such techniques may not be possible in every situation, PHMSA stated that it was aware that this option is already being widely deployed in the pipeline industry. Secondly, PHMSA proposed to allow operators to determine pipe properties at a sampling of similar locations and apply those results to the entire population of pipeline segments. PHMSA proposed to allow operators to take advantage of opportunities when the pipeline is exposed for other reasons, such as during maintenance and repair excavations, by requiring that material properties be verified whenever the pipe is exposed. This would reduce the number of excavations that might otherwise be required. Excavations are a large portion of the cost of reconstituting material properties for unknown pipe.

2. Summary of Public Comment

Several commenters suggested that the data required by the material properties verification process proposed by PHMSA can be obtained only through destructive pipe testing. These commenters asserted that the proposed requirements would lead to unnecessary service outages, increased methane emissions, and increased personnel

safety risks due to unnecessary excavation activities. Black Hills Energy stated that their pipeline system consists of mainly smaller-diameter transmission pipelines and that the proposed provisions would force them to take lines out of service to perform costly cutouts. API asserted that the expense and risk required for the excavations necessary to comply with the proposed provisions outweigh the value of obtaining and documenting material pipe properties. Some commenters suggested that it would be less costly for operators to simply replace pipe rather than obtain the material properties for pipe already in the ground. A commenter asserted that the proposed requirements would require unnecessary breaching of the pipeline coating, which is important for effective cathodic protection. API suggested that rather than requiring operators to gather documentation on material properties that may only be of marginal value for assessing pipeline safety, PHMSA should require a combination of hydrostatic pressure testing and ILI. API stated that, as opposed to the proposed rule's focus on the precise documentation of materials, this would appropriately shift the emphasis of the proposed regulations to confirming MAOP and away from material properties verification.

Several commenters stated that some of the data that PHMSA proposed operators verify is unnecessary for MAOP reconfirmation or other operational reasons. For example, the Interstate Natural Gas Association of America (INGAA) stated that several of the data elements that would need to be verified pursuant to the proposed material properties verification requirements are unnecessary for integrity management-related activities. Commenters suggested that PHMSA limit the required records to what is needed to calculate design pressure in order to determine MAOP. Commenters noted that the proposed requirements would require testing for stress corrosion cracking (SCC) in all cases, and that the requirement should be limited to only pipelines that are susceptible to SCC. Some commenters disagreed with the requirement to determine and keep a record for the chemical composition of steel transmission pipeline segments installed prior to the effective date of the final rule, suggesting that this information has not been previously required. Another commenter stated that the basis for having accurate chemical composition records is unclear. PG&E recommended that

PHMSA recognize that chemical composition and manufacturing specifications provide limited information that can be used to evaluate the safety of an existing pipeline system. Piedmont Natural Gas stated that any requirement to retroactively obtain ultimate tensile strength and chemical composition is unnecessarily burdensome and detracts from the ultimate goal of pipeline safety by diverting valuable resources away from other risk-reduction efforts. A similar comment asserted there was no benefit in determining pipeline chemical compositions, as there is a high probability that many pipelines that might otherwise have adequate material documentation would fail the recordkeeping requirements because of a lack of existing chemical composition records and would subsequently be subject to the entire material properties verification process.

Pipeline industry entities also commented on the proposed sampling and testing requirements that would occur during excavations. Commenters asserted that the sampling requirements should be removed, and the number of excavations should not be specified. One commenter stated that the minimum number of excavations should be determined by the operator in their material properties verification plan and through statistical analysis aimed at achieving targeted confidence levels. Texas Pipeline Association (TPA) stated that there is no technical justification for the number of material properties tests being required at each test location by the proposed rule, and that the requirement of five tests in each circumferential quadrant for non-destructive tests and one test in each circumferential quadrant for destructive tests is unsupported in the proposal. TPA further stated that they are unaware of any indication that there is great variability in material properties within the body of a pipe, and that presently, material properties verification involves a single test per cylinder. Additionally, commenters stated this requirement could be unnecessarily costly and have a negative impact on pipeline safety, as the integrity of the pipeline would need to be compromised to perform these evaluations and a new joint of pipe would need to be welded onto the existing pipeline. Lastly, Spectra Energy Partners objected to the requirement that non-destructive testing be validated with unity plots comparing the results from non-destructive and destructive testing. They stated that this severely limits the value of non-destructive

testing since the operator will have to remove samples for destructive testing to create the unity plots.

CenterPoint Energy stated that the definition of excavation is unclear, and that pipe may be excavated to a point for many operational activities, including spotting for construction safety and installing cathodic protection tests or current source wires. CenterPoint Energy stated that they do not view these types of excavations as opportunities for material properties verification data gathering because that would require the full exposure of a pipeline segment and the removal of good coating from the pipe. Another commenter suggested that confidence specifications for non-destructive testing would add significant cost due to inherently inaccurate test results.

Similarly, there were comments that encouraged consistency between the material properties verification requirements and the requirements for recordkeeping for materials, pipe design, and pipeline components. These comments suggested that inconsistencies between the documentation and the recordkeeping requirements could create scenarios where operators meet the recordkeeping requirements but do not have adequate documentation to prevent the material properties verification requirements from triggering.

Some commenters opposed the proposed requirement to obtain a "no objection" letter from PHMSA in order to use a new or other technology. PG&E recommended that PHMSA provide additional regulatory language to allow an operator to proceed with the new technology if a "no objection letter" to PHMSA is not received within 45 days prior to the planned use of technology. They stated that operators put in considerable time to set up contracts, schedule work, acquire permits, and that waiting on an approval or disapproval from PHMSA can dramatically impact schedule and costs. Further, commenters suggested that PHMSA's enforcement and regulatory procedures do not provide for "no objection" letters, and adding a new process that is not well-defined could cause additional confusion.

AGA proposed an alternative approach to material properties verification, MAOP reconfirmation, and integrity assessments outside of HCAs, which other pipeline industry entities supported. The approach included requiring operators to either pressure test or utilize an alternative technology that is determined to be of equal effectiveness on high-risk gas transmission pipelines that do not have

a record of a subpart J pressure test or are currently utilizing the grandfather clause for MAOP determination (§ 192.619(c)). AGA suggested a three-tiered approach that prioritized pipelines located in HCAs and operating at pressures greater than 30 percent SMYS. The approach also included the use of ILI tools on all gas transmission pipelines that are able to accommodate inspection by means of an instrumented ILI tool. The ILI tool used would be qualified to find defects that would fail a subpart J pressure test. Commenters stated that this alternative approach is simpler and would allow operators to focus resources on the areas of highest risk within pipeline systems. In conjunction with AGA's approach, commenters recommended including language that would allow the use of advanced ILI and non-destructive evaluations to comply with the proposed material properties verification requirements.

Certain commenters also suggested PHMSA provide a deadline by which operators must implement their material properties verification plan, as it was unclear in the proposal. Following committee discussion and PHMSA feedback, industry groups also recommended to allow operators to use their own statistical sampling plans when undertaking material properties verification rather than have PHMSA specify the number of samples that must be obtained.

At the GPAC meeting on December 14, 2017, the committee recommended that PHMSA modify the method for material properties verification by clarifying that operators are only required to confirm attributes pertinent to the goal of MAOP reconfirmation, integrity management, or other reasons when the material properties verification is being performed. The GPAC also recommended that PHMSA require operators keep records developed using the material properties verification method. The GPAC recommended that PHMSA retain the opportunistic approach of obtaining unknown or undocumented material properties when excavations are performed for repairs or other reasons, using a one-per-mile standard proposed by PHMSA, but allow operators to propose an alternative statistical approach and submit a notification to PHMSA with justification for their method. The GPAC also recommended that if operators notify PHMSA of an alternative sampling approach, and the operator does not receive an objection letter from PHMSA within 90 days of such a notification, the operator can proceed with their chosen method

unless PHMSA notifies the operator that additional review time or additional information from the operator is needed for PHMSA to complete its review.

Similarly, the committee recommended PHMSA delete specified program requirements for how to address sampling failures and replace that with a requirement for operators to determine how to deal with sample failures through an expanded sample program that is specific to their system and circumstances. They further recommended that PHMSA require operators to notify PHMSA of the expanded sample program and establish a minimum standard that sampling programs must be based on a minimum 95 percent confidence level.

Further, the committee recommended that PHMSA retain the flexibility for operators to conduct either destructive or non-destructive tests when material properties verification is needed and requested PHMSA drop accuracy specifications but retain the requirement that any test methods used be validated and be performed with calibrated equipment. The GPAC also recommended PHMSA reduce the number of quadrants at which non-destructive evaluation tests be made from four to two.

Regarding the number of test locations and the number of excavations that must be performed, the GPAC recommended PHMSA accommodate situations where a single material properties verification test is needed (e.g., additional information is needed for an anomaly evaluation/repair) and drop the mandatory requirements for testing multiple joints for large excavations. The GPAC also recommended PHMSA clarify the applicability of the requirements for developing and implementing procedures for conducting material properties verification tests on populations of undocumented or inadequately documented pipeline segments and the minimum number of excavations and tests that must be performed for those pipeline segments.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the method for material properties verification. PHMSA disagrees with implementing the alternative approach proposed by AGA, but the underlying comments of AGA and others related to having an alternative approach are discussed in this rulemaking and are addressed below. PHMSA strongly believes that knowledge of pipeline physical properties and attributes are essential for a modern IM program (see

§ 192.917(b)—*Data gathering and integration*) as well as effective pipeline and public safety. The PG&E incident at San Bruno, CA, was caused, in part, by PG&E mistakenly classifying the pipe that failed as seamless pipe. That pipe was welded seam pipe, and the failure occurred at a partially welded seam.

The NPRM included a list of material properties that could be confirmed using the material properties verification process. One of them in particular, steel toughness, is conventionally obtained only through destructive testing. It was not PHMSA's intent that toughness would need to be confirmed every time an operator was performing material properties verification, thus in effect requiring destructive testing for every location. Therefore, PHMSA is modifying this final rule to address toughness properties in a separate paragraph and is allowing the use of techniques that are reliable without specifying destructive testing. This is intended to accommodate new, non-destructive techniques currently under development. The new paragraph with these requirements also makes it clear that toughness is required only where needed and not necessarily in every case. PHMSA is also modifying other sections of this final rule to provide reasonably conservative default toughness values so that operators may achieve the goals of IM and MAOP reconfirmation using assumed values without the need for destructive testing. These changes will be discussed further in subsequent sections of this document.

Similarly, PHMSA is modifying the verbiage related to the listing of material properties to which the material properties verification process would apply. The clarification will make it clear that the material properties verification process only applies to the pertinent properties needed to achieve the goals of the activity for which material properties verification is needed, such as MAOP reconfirmation or IM. This avoids the potential for requiring that all properties be documented each time an operator goes out to perform material properties verification when only a subset of properties is needed.

PHMSA is also replacing the prescriptive accuracy specifications and unity plot validation for non-destructive testing with more general verbiage that requires that methods are validated and that operators account for the accuracy of the method used. This change will help accommodate new technology and techniques currently under development and avoid situations that

might require destructive testing to validate the non-destructive methods.

In response to the comments, PHMSA is relaxing the number of test points for non-destructive tests from four quadrants to two quadrants. This allows the operator to perform material properties verification on the top half of the pipe and would avoid the need to access the bottom half of the pipe when the repair or maintenance activity would not otherwise require it. PHMSA is also removing the proposed requirement to conduct material verification at multiple locations within a single large excavation based on the number of joints of line pipe exposed. PHMSA believes the methods described in this final rule will provide operators accurate material properties information without requiring more excavation activities than necessary.

In this final rule, PHMSA is modifying § 192.607 to specifically list the types of excavations where operators that need to verify material properties should seek to conduct material properties verification. This revision intends to avoid requiring operators perform the material properties verification process at partial excavations that do not expose the pipeline segment. For example, PHMSA considers excavations associated with direct examinations of anomalies to be an opportunity to perform material properties verification. Similarly, PHMSA is modifying the language to acknowledge the need to perform one-time material properties verification activities at specific locations, such as when performing repairs. An operator who has complete material documentation for a particular pipeline segment would not need to undertake the sampling program at excavations on that particular segment. The sampling program is specifically required when the operator needs to document material properties for entire segments of pipelines.

PHMSA disagrees with the removal of the number of samples needed and is maintaining the minimum standard to define the number of excavations in the sampling program as 1 per mile or 150 if the population of pipeline segments is more than 150 miles, whichever is less. However, PHMSA is modifying the rule to provide operators the option of proposing an alternative sampling program if they send a notification and justification of the alternative program to PHMSA in accordance with the new notification procedures at § 192.18. Operators may use an alternative sampling program 91 days after submitting a notification per § 192.18 to PHMSA if the operator has not received

a letter of objection or a request from PHMSA for more time to review.

PHMSA is also withdrawing the expanded sampling requirements to address cases where operators identify problems in the initial sampling program. Instead, operators may use an alternative sampling approach that addresses how the operator's sampling plan will address findings that reveal physical pipeline properties and attributes that are not consistent with all available information or existing expectations or assumed physical pipeline properties and attributes used for pipeline operations and maintenance in the past. Operators taking such an approach must notify PHMSA of the adverse findings and provide PHMSA with specific details of the alternative sampling plan with a justification for such a plan in a notification to PHMSA. The alternative sampling program must be designed to achieve a 95 percent confidence level. In accordance with the new notification procedures at § 192.18, operators may use an alternative sampling plan 91 days after submitting a notification to PHMSA if the operator has not received a letter of objection or a request from PHMSA for more time to review.

In response to committee discussion, PHMSA is modifying its notification process broadly throughout part 192 to allow operators to propose using methods and technologies by notifying PHMSA in accordance with the new procedures in § 192.18. If an operator does not receive a letter of objection or a request from PHMSA for more time to review within 90 days of the notification, then the operator may use the proposed method or technology. Some committee members were concerned that some provisions throughout the NPRM would require action from PHMSA in the form of a "no objection" letter. Members noted that such a process can leave companies unable to proceed until PHMSA provided affirmative approval of the request. Committee members suggested that it may be more efficient and less burdensome for PHMSA to issue letters to operators only when they specifically object to proposed plans or solutions, and otherwise allow the operator to proceed as planned in the absence of such a letter. Other members were concerned that PHMSA might authorize sub-optimal plans or technologies by missing a deadline. To this end, members recommended an approach where PHMSA could request additional time for review beyond the 90-day period. PHMSA noted at the meeting that this is a similar process that is used by PHMSA for state waivers and the

change should improve regulatory efficiency.

PHMSA's letter or email of objection will specify the reasons PHMSA does not approve of the proposed method or technology, while a request from PHMSA for more time to review the notification will extend the review period beyond 90 days. Further, to establish a verifiable record, it will be PHMSA's policy to send a "no objection" letter or email, either before or after the 90-day review period, when PHMSA does not object to an operator's proposed method or technology. PHMSA is applying this approach to other places in this rulemaking that require notifications and has created a general notification provision in subpart A of part 192.

PHMSA is modifying the recordkeeping requirement for the material properties verification provisions to avoid potential conflicts with other provisions in this rulemaking, such as MAOP reconfirmation, to clarify that operators are required to keep any records created, for the life of the pipeline, when verifying specific properties using the methods in § 192.607. These records must also be traceable, verifiable, and complete. These recordkeeping requirements are not retroactive, as they mandate the creation and retention of records as operators execute the methodology in § 192.607 on a prospective basis.

PHMSA disagrees with commenters that asked for PHMSA to establish a deadline for operators to complete the sampling programs. The opportunistic approach PHMSA proposed and retained for this final rule requires material properties verification activities to occur at excavation sites where operators are directly examining anomalies; performing *in-situ* evaluations; or are performing repairs, remediation, or maintenance. PHMSA does not expect operators to perform material properties verification for unknown pipe properties on pipeline segments exposed during one-call excavations. PHMSA has determined this approach is reasonable and will minimize the cost impacts of this final rule. A deadline for the material properties verification requirements of this rulemaking is not practical because it is impossible to forecast the rate or timing at which opportunities would arise to perform material properties verification for a given population of pipe.

Lastly, operators should have most of the required pipe information from following § 192.917(b) since subpart O of part 192 was codified over 15 years

ago in 2003. Section 192.917(b) requires operators to identify and evaluate the potential threats to pipeline segments by gathering and integrating existing data and information on the entire pipeline that could be relevant to the pipeline segment. In performing this identification and evaluation, operators must follow the requirements in ASME/ANSI B31.8S, section 4, and at a minimum gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S. The material properties needed to establish and substantiate MAOP are included in these lists.

B. MAOP Reconfirmation—§§ 192.624 & 192.632

i.—Applicability

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to require operators reconfirm MAOP for the following three categories of pipeline:

(1) Grandfathered pipe, in direct response to section 23(d) of the 2011 Pipeline Safety Act and NTSB recommendation P-11-14;

(2) Pipe for which documentation is inadequate to support the MAOP, in direct response to section 23(c) of the 2011 Pipeline Safety Act; and

(3) Pipe that has experienced a reportable in-service incident since its most recent successful subpart J pressure test due to an original manufacturing-related defect; a construction-, installation-, or fabrication-related defect; or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spots, or stress corrosion cracking.

It is important to note that a given pipeline segment for which the MAOP reconfirmation process would apply might fit into one, two, or all three of these proposed categories. For pipeline segments where records of the pipeline physical properties and attributes to substantiate the current MAOP are not documented in traceable, verifiable, and complete records, only those segments located within an HCA or a Class 3 or Class 4 location would be subject to the MAOP reconfirmation process under the NPRM.

This proposal directly correlates to section 23 of the 2011 Pipeline Safety Act and NTSB recommendation P-11-14 regarding the need for spike hydrostatic testing where in-service incidents have occurred. The NTSB recommended such testing for all pipe manufactured before 1970.

For pipeline segments where operators established the MAOP in accordance with the grandfather clause

at § 192.619(c) (*i.e.*, pipeline segments where the MAOP is based upon the highest actual operating pressure records from a 5-year interval between July 1, 1965, to July 1, 1970, and where operators therefore do not have pressure test or material property records) or for segments with a history of in-service incidents caused by cracks or crack-like defects, PHMSA proposed to restrict the applicability of MAOP reconfirmation to HCAs, Class 3 or Class 4 locations, or MCAs, if the MCA segment can accommodate an ILI tool. The proposed inclusion of pipeline segments in these locations and with these traits slightly expand on the mandate contained in section 23 of the 2011 Pipeline Safety Act, which applied only to previously untested pipeline segments operating at a pressure greater than 30 percent SMYS located in an HCA.

In recommendation P-11-14, the NTSB recommended that all pipe manufactured before 1970 be subjected to a hydrostatic pressure test that would include a spike hydrostatic test, which PHMSA considered in its process for reconfirming MAOP. PHMSA's preliminary evaluation concluded that doing so may not be cost-effective, since a large amount of such pipe could be in remote locations where the likelihood of personal injury or property damage as a result of an incident would be low.

PHMSA's proposal expanded the applicability of MAOP reconfirmation beyond the minimum required by the congressional mandate to include pipe operating at less than 30 percent SMYS. In addition, the NPRM expanded the location criteria to include some non-HCA locations in the form of MCAs and Class 3 and Class 4 locations. As PHMSA proposed in the definitions section of the NPRM, MCAs are areas that, while not meeting the HCA criteria, include 5 or more persons or dwellings intended for human occupation or are otherwise locations where people congregate, including the right-of-ways of major roadways. See section H of this final rule for additional background on the MCA definition. The NPRM also specified that the MAOP reconfirmation process would apply only to MCA pipeline segments able to accommodate an ILI tool. This provision would not preclude an operator from choosing to conduct a pressure test, but it would avoid forcing operators to conduct a pressure test because the pipeline segment was not "piggable."

2. Summary of Public Comment

Many stakeholders provided input on the proposed provisions in § 192.624 that require MAOP reconfirmation for pipeline segments previously excluded

from testing by the grandfather clause, pipeline segments without adequate documentation to substantiate the current MAOP, and pipeline segments that have experienced a reportable in-service incident.

Regarding the first criterion above, several commenters, including INGAA, AGA, and NAPS, generally supported the provision requiring operators of pipeline segments where the MAOP was established via the grandfather clause to reconfirm the MAOP of those segments. Several of the pipeline industry trade associations and industry entities, however, did not support the proposed application of these criteria to all grandfathered pipeline segments within HCAs, Class 3 and Class 4 locations, and Class 1 and Class 2 piggable segments within MCAs. Gas Processors Association's Midstream Association (GPA) and AGA stated that while they support the congressional mandate to conduct testing to confirm the material strength of previously untested gas transmission pipelines in HCAs that operate at a pressure above 30 percent SMYS, they oppose the proposed provisions which extend to additional pipeline segments. INGAA and Washington Gas supported the applicability of MAOP reconfirmation in MCAs for pipelines operating at greater than or equal to 30 percent SMYS but disagreed with the proposed provisions that included MCA pipelines operating at less than 30 percent SMYS.

Some citizen groups, including PST, expressed concern that the proposed changes regarding the grandfather clause did not go far enough and suggested that PHMSA should fully implement the recommendations set forth by the NTSB. They stated that PHMSA should eliminate the grandfather clause given that the proposed provisions would not include the following groups of pipelines: (1) Pipelines in non-HCA areas within Class 1 and Class 2 locations; and (2) pipeline segments for which there is an inadequate record of a hydrostatic pressure test in areas newly designated as an MCA that are not capable of being assessed by an in-line tool. Conversely, Northeast Gas Association (NGA) stated that PHMSA should retain the grandfather clause as it prevents existing, historically safe, and maintained pipelines from being subjected to unwarranted requirements.

For pipeline segments where operators do not have adequate documentation to support the current MAOP and that PHMSA proposed would be subject to the new MAOP reconfirmation requirements, some commenters stated that they support the

requirement to the extent that it is consistent with the congressional mandate to reconfirm MAOP for pipeline segments with insufficient records within Class 3 and Class 4 locations and Class 1 and Class 2 HCAs. These commenters further stated that § 192.624(a)(2) within the proposed MAOP reconfirmation requirements should be revised to clarify that it applies only to those gas transmission pipeline segments in HCAs and Class 3 and Class 4 locations that were constructed and put into operation since the adoption of the Federal Pipeline Safety Regulations in 1970, stating that otherwise § 192.624(a)(2) would apply to those pipelines put into service prior to the implementation of Federal regulations where the requirement to maintain a pressure test record does not apply. Some commenters also stated that PHMSA should revise § 192.624(a) within the proposed MAOP reconfirmation requirements to make clear that operators that have used one of the proposed allowable methods for establishing MAOP in § 192.624(b) other than the pressure test method are not required to have a pressure test record to comply with the record requirements of the section. Washington Gas asserted that the MAOP reconfirmation requirements should apply to only pipeline segments in HCAs that operate at a pressure of greater than or equal to 30 percent SMYS. Other commenters, including Xcel Energy, stated that the proposed provisions should allow operator discretion regarding what constitutes a reliable, traceable, verifiable, and complete record to determine the necessary documentation to support a pressure test record and the necessary material properties for MAOP verification. Additionally, AGA recommended the deletion of the phrase “reliable, traceable, verifiable, and complete” from the proposed MAOP reconfirmation provisions in § 192.624(a)(2). Similarly, other commenters, including INGAA, recommended omitting “reliable” from the phrase and provided a suggested definition for “traceable, verifiable, and complete.”

Lastly, with regard to the third category of applicable pipeline segments to the proposed MAOP reconfirmation requirements, many commenters either disagreed or requested clarification for the requirement that MAOP must be reconfirmed in cases where an in-service incident occurred due to a manufacturing defect listed under § 192.624(a)(1). For example, INGAA stated that an operator can evaluate such manufacturing defects more

effectively through ongoing operations and maintenance activities rather than through MAOP reconfirmation, and that the defects PHMSA is concerned with are already addressed through integrity management. Similarly, Boardwalk Pipeline stated that pipelines that have experienced an in-service incident because of the listed defects in § 192.624(a)(1) should be subject to integrity management measures rather than MAOP reconfirmation. TransCanada and TPA recommended adding text to the applicability section of the MAOP reconfirmation requirements that would exclude a pipeline segment from such requirements if the operator has already acted to address the cause of the reported incident. Additionally, one commenter suggested that this requirement should apply only to pipelines in HCAs. Some commenters, including AGA and Consolidated Edison of New York (Con Ed), also requested additional time to comply with the proposed MAOP reconfirmation provisions, asserting that operators would be required to replace many of their transmission mains to comply with the new requirements because their current records would not be satisfactory. Due to the urban density and scale of the service areas of certain operators, AGA and Con Ed stated that this replacement process would take longer than the 15-year schedule provided in the rule. One commenter suggested that if the applicability criteria for pipeline segments with in-service incidents and manufacturing defects remains in the rule, it should be limited to a more contemporary time frame, such as a rolling 15-year window or those in-service incidents that have occurred since 2003. Pipeline Safety Trust, on the other hand, stated that the proposed timeframe of 15 years is too long for operators to reconfirm MAOP in HCAs and complete critical safety work, and they urged PHMSA to adopt significantly shorter timelines in the final rule.

Additionally, AGA asserted that the proposed MAOP provisions do not address how the completion plan and completion dates of the section would apply to pipelines that might experience a failure in the future and would then be subject to the proposed MAOP reconfirmation requirements, or for pipelines that are not currently located in a MCA but may be in the future. Lastly, INGAA stated that section 23 of the 2011 Pipeline Safety Act requires that PHMSA consult with the Chairman of the Federal Energy Regulatory Commission (FERC) and State regulators

before establishing timeframes for the testing of previously untested pipes, and it is not evident that PHMSA has complied with this requirement.

As a general comment, several stakeholders, including AGA, Louisville Gas & Electric, New Mexico Gas Company, National Grid, NW Natural, PECO Energy, TECO Pipeline Gas, and New York State Electric and Gas (NYSEG), proposed an alternative method for MAOP reconfirmation where operators would execute two separate sets of actions that they stated could be performed simultaneously or separately. First, operators would either assess high-risk gas transmission pipelines using a pressure test or an alternative technology that is determined to be of equal effectiveness. Operators would categorize these pipelines in three tiers and schedule them for testing depending on the pipeline's SMYS and class location. Second, operators would use an ILI tool on all gas transmission pipelines, regardless of class location, that are capable of accommodating ILI tools. The ILI tool used would be qualified to find defects that would fail a subpart J pressure test. These commenters stated that this alternative methodology was necessary because the proposed provisions would create operational inefficiencies that would likely result in excessive cost and limited public benefit. In addition to providing this alternative proposal, many of these commenters provided other assorted comments on the proposed provisions.

At the GPAC meeting on March 26, 2018, the GPAC recommended that PHMSA revise the scope of the proposed MAOP reconfirmation provisions by excluding lines with previously reported incidents due to crack defects. To go along with this, the GPAC also recommended PHMSA create a new section in subpart O of part 192, the natural gas IM regulations, to address pipeline segments with crack-related incident histories. Doing these actions would eliminate the need for the proposed definitions of “modern pipe,” “legacy pipe,” and “legacy construction techniques,” and the impact of this is discussed later in this document.

The GPAC also recommended that the MAOP reconfirmation provisions be revised to apply to pipeline segments in HCAs or Class 3 or Class 4 locations that do not have traceable, verifiable, and complete records necessary to establish MAOP under § 192.619. Previously, the provisions were applicable to those pipeline segments without traceable, verifiable, and complete subpart J pressure test records. Similarly, the GPAC recommended that the MAOP

reconfirmation provisions only apply to grandfathered pipelines in HCAs, Class 3 or Class 4 locations, or MCAs able to accommodate inspection with ILI tools, and that have MAOPs producing a hoop stress greater than or equal to 30 percent SMYS. In the NPRM, the provisions applied to all grandfathered pipelines in those locations regardless of SMYS. In making this recommendation, the GPAC also suggested PHMSA review the costs and benefits of applying the MAOP reconfirmation provisions to non-HCA Class 3 and Class 4 grandfathered pipe with MAOPs less than 30 percent SMYS.

During the meeting on March 27, 2018, the GPAC also recommended revisions to other sections related to the applicability of MAOP reconfirmation provisions, including withdrawing the proposed revisions to § 192.503, which tied general requirements of the subpart J pressure test to alternative MAOP and MAOP reconfirmation provisions, and withdrawing the proposed revisions to § 192.605(b)(5), which cross-referenced several sections related to the MAOP reconfirmation requirements to the requirements regarding an operator's procedural manuals.

The GPAC also examined the provisions related to the completion date of these actions and recommended that PHMSA revise the appropriate paragraph to account for pipelines that may be subject to these requirements in the future, such as for pipelines that are not in an HCA or Class 3 or Class 4 location now, but due to population growth or development may be in such a location in the future. More specifically, the GPAC recommended that an operator would have to complete all actions required by the MAOP reconfirmation provisions on 100 percent of their pipelines that meet the applicability requirements by 15 years after the effective date of the rule or as soon as practicable but no later than 4 years after the pipeline segment first meets the applicability conditions, whichever is later. The GPAC also recommended PHMSA consider a waiver or no-objection procedure if operators cannot meet the requirements within 4 years under this scenario.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the applicability of MAOP reconfirmation. After considering these comments and as recommended by the GPAC input, PHMSA is modifying the rule to address many of these comments.

Regarding the applicability of the new MAOP reconfirmation requirements at

§ 192.624, PHMSA notes that a simplistic repeal of the “grandfather clause” at § 192.619(c) is not practical because it applies to gathering and distribution lines. As the proposed rule was primarily focused on the safety of gas transmission pipelines, a broad repeal of the grandfather clause was not contemplated in the proposed rule. Further, a major expansion of the MAOP reconfirmation requirements beyond the scope of the congressional mandate in the 2011 Pipeline Safety Act would be costly, and the GPAC noted at the meeting on March 26, 2018, that there may be cost-benefit concerns to test all grandfathered pipelines. The GPAC recommended PHMSA analyze requiring operators to reconfirm the MAOP of all grandfathered lines, and PHMSA considered this as an alternative in the RIA.⁶⁵

In response to the comments received and the recommendations of the GPAC, PHMSA is modifying the applicability of the MAOP reconfirmation requirements as follows: (1) The applicability related to pipeline segments with past in-service incidents is being eliminated. As commenters mentioned, operational failures are already addressed within integrity management and other subparts of part 192. Section 192.617, for example, would require an operator of a gas transmission line that had an in-service incident caused by an incorrect MAOP to determine the proper MAOP of the segment before placing it back into service. Causes of in-service failures are also already incorporated into the risk analyses required by the current IM regulations. If the cause of an incident is an incorrect MAOP, for example, then operators would be required to reconfirm it following the incident within their IM program. However, PHMSA is adding a new paragraph to strengthen the IM requirements at § 192.917(e)(6) to specifically include actions operators must take to address pipeline segments susceptible to cracks and crack-like defects. (2) PHMSA is also modifying the applicability of these requirements by specifying the MAOP reconfirmation requirements are applicable to pipeline segments that do not have the pipeline physical properties and attributes needed to establish MAOP documented in traceable, verifiable, and complete records, specifically those records required to establish and substantiate the MAOP in accordance with § 192.619(a), including those records required under § 192.517(a). More specifically, these requirements to verify

MAOP would apply to such pipelines without traceable, verifiable, and complete records in HCAs and Class 3 and Class 4 locations as specified in the congressional mandate. Further, PHMSA is dropping the word “reliable” from the applicability section of the regulatory text to be consistent with previous PHMSA advisory bulletins on this topic.⁶⁶ (3) PHMSA is modifying the applicability of the MAOP reconfirmation provisions for “grandfathered” pipeline segments to pipelines with an MAOP greater than or equal to 30 percent of SMYS, as specified in the congressional mandate. In addition to these requirements applying to grandfathered pipelines in HCAs, PHMSA is retaining the MAOP reconfirmation applicability requirement for grandfathered pipeline segments in Class 3 and Class 4 locations and in piggable MCAs to address the NTSB recommendation on this topic. As per the committee's suggestion, PHMSA analyzed whether it would be feasible to make the MAOP reconfirmation requirements applicable to non-HCA Class 3 and Class 4 pipe operating below 30 percent SMYS. This analysis is presented as an alternative in the RIA for this rulemaking. Ultimately, PHMSA did not choose to include these categories of pipelines in the scope for the applicability of the MAOP reconfirmation requirements because the GPAC recommended it was cost-effective for the provision to only apply to pipe operating above 30 percent SMYS in Class 3 and 4 locations and because those pipelines present the greatest risk to safety.

With respect to the completion date, PHMSA acknowledges the comments received stating that pipeline segments could meet applicability criteria at some point in the future such that it would be difficult or impossible to meet the 15-year deadline for completion. Therefore, PHMSA agrees with the GPAC recommendation discussed above and is modifying the requirements in this final rule to include an alternative completion deadline of 4 years for pipeline segments that meet the applicability standards at some point in the future, for example for those pipeline segments that were in non-HCA locations that later become HCA locations. However, PHMSA emphasizes that this 4-year timeframe does not supersede, invalidate, or otherwise modify the existing requirements in § 192.611 for operators to confirm or revise the MAOP of

⁶⁶ Pipeline Safety: Verification of Records; 77 FR 26822; May 7, 2012; <https://www.govinfo.gov/content/FR-2012-05-07/pdf/2012-10866.pdf>.

⁶⁵ See section 5.9.1 of the RIA for further details.

segments within 24 months of a change in class location.

PHMSA also acknowledges that some commenters thought the 15-year compliance timeframe for MAOP reconfirmation was too long. PHMSA believes a 15-year timeframe is necessary to be consistent with § 192.939, which allows operators to use a confirmatory direct assessment to confirm their MAOP in two, 7-year inspection cycles. This timeframe was discussed by the GPAC and was approved by unanimous vote. PHMSA will note that operators are required to have 50 percent of the applicable mileage completed within 8 years of the effective date of the rule. PHMSA would expect operators to prioritize and reconfirm the MAOP of the highest-risk segments first.

PHMSA is also withdrawing miscellaneous revisions to § 192.503, which tied general requirements of the subpart J pressure test to alternative MAOP and MAOP reconfirmation provisions, and miscellaneous revisions from § 192.605(b)(5), which cross-referenced several sections related to MAOP requirements to the requirements regarding an operator's procedural manuals. These changes were made to simplify the regulations.

Additionally, because PHMSA has eliminated pipeline segments with past in-service incident history from the scope of the MAOP reconfirmation requirements, PHMSA is striking the proposed references within the MAOP reconfirmation requirements to the alternative MAOP requirements at § 192.620(a)(ii). Operators who used the alternative requirements to establish the MAOP of their pipelines were required to have complete documentation⁶⁷ and therefore would not be subject to the MAOP reconfirmation requirements. If an operator had previously established the MAOP of a pipeline segment under the alternative MAOP requirements, but has since lost the records necessary to validate the alternative, they would have to reconfirm MAOP using the alternative MAOP requirements, or apply for a special permit to continue operation.

Per the requirement in section 23 of the 2011 Pipeline Safety Act, PHMSA consulted with members of FERC and State regulators, including representatives from NAPS and the National Association of Regulatory Utility Commissioners, as appropriate, to establish the timeframes for

completing MAOP reconfirmation. As a part of this consultation, which occurred as a function of the GPAC meetings from 2017 through 2018, PHMSA accounted for potential consequences to public safety and the environment while also accounting for minimal costs and service disruptions. These representatives provided both input and positive votes that the provisions surrounding MAOP reconfirmation were technically feasible, reasonable, cost-effective, and practicable if certain changes were made. As previously discussed, PHMSA has taken the GPAC's input into consideration when drafting this final rule and made the according changes to the provisions.

B. MAOP Reconfirmation—§§ 192.624 & 192.632

ii.—Methods

In developing regulations to reconfirm MAOP where necessary, Congress mandated that PHMSA consider safety testing methodologies that include pressure testing and other alternative methods, including in-line inspections, determined to be of equal or greater effectiveness. The NTSB recommended an expansive pressure test approach to address the safety issues identified in their investigation of the PG&E incident through recommendations P-11-14 and P-11-15. In response to the congressional mandate, PHMSA evaluated other methodologies and identified five additional methods that could provide an equivalent or greater level of safety. Therefore, PHMSA proposed to allow the following six methods for MAOP reconfirmation, including the conventional pressure test method.

Summary of PHMSA's Proposal: Method 1—Pressure Test

A pressure test is the most conventional assessment method by which an operator may reconfirm a pipeline segment's MAOP. PHMSA proposed standards for conducting pressure tests for MAOP reconfirmation in part to meet the intent of NTSB recommendations P-11-14 and P-11-15. First, PHMSA proposed minimum test pressure standards where a pipeline segment's MAOP would be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor. Second, if the pipeline segment might be susceptible to cracks or crack-like defects,⁶⁸ then the operator

must incorporate a spike pressure feature into the pressure test procedure. PHMSA proposed standards for the spike hydrostatic test in § 192.506. If the operator has reason to believe any pipeline segment may be susceptible to cracks or crack-like defects, the operator would be required to also estimate the remaining life of the pipeline in accordance with the same standards specified in Method 3, the engineering critical assessment method.

Summary of Public Comment: Method 1—Pressure Test

Several commenters opposed the proposed provisions requiring a spike test to be conducted as part of the pressure test for the purposes of MAOP reconfirmation, and these comments are discussed further under the "spike test" portion of the proposal and comment summary of this rulemaking.

API suggested that a pipeline segment's MAOP can be best established through performing a combination of pressure tests and ILI examinations, and they discussed how operators could conduct hydrostatic pressure testing to determine the in-place yield strength of a segment of pipeline by conducting a "spike" test pressure held for a few minutes followed by a subpart J pressure test approximately 10 percent below the spike level. API further stated that using ILI tools in conjunction with this method would further substantiate the results, as geometry ILI tools capable of measuring inside diameter to detect yielding could further substantiate and quantify the results of the pressure test.

AGA stated that while they believe that pressure testing is a straightforward and well-established method, the proposed Method 1 MAOP reconfirmation requirements are unnecessarily complex. AGA further stated that subpart J provides different requirements and specifications for pressure tests based on the type of pipe being tested, and that Method 1 should refer to subpart J rather than to § 192.505(c) specifically, which requires unnecessarily stringent requirements. PG&E supported the proposed provisions and committed to pressure testing all pipes.

INGAA stated that since the basic strength properties of steel pipe do not change over time, PHMSA should not limit allowable tests to only those conducted after July 1, 1965, as was proposed in § 192.619(a)(2)(ii). They emphasized that the test parameters, not

⁶⁷ "Pipeline Safety: Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines; Final Rule," October 17, 2008; 73 FR 62148. The effective date of the rule was November 17, 2008.

⁶⁸ These pipelines can include pipelines constructed with "legacy pipe" or using "legacy construction techniques;" pipelines with evidence or risk of stress corrosion cracking or girth weld

cracks; or pipelines that have experienced an incident due to an original manufacturing-related defects, construction-related defects, installation-related defects, or fabrication-related defects.

the test date, should be considered for MAOP reconfirmation. Further, INGAA stated that recognizing the validity of earlier tests would not necessarily mean that no further pressure tests would be conducted, as periodic testing may be required to ensure the continued integrity of the pipeline segment under the operator's integrity management program. However, such additional tests are managed under IM, which is separate from MAOP reconfirmation.

Certain commenters stated that a spike test is not required to establish an adequate margin of safety for MAOP reconfirmation and suggested PHMSA eliminate spike testing from the pressure test method of MAOP reconfirmation.

Regarding the proposed definitions of "legacy pipe" and "legacy construction," AGA and Xcel Energy commented that as proposed, the definitions could be interpreted to apply to distribution pipelines as well as gas transmission pipelines. Commenters requested that PHMSA explicitly exclude distribution pipelines from these definitions, which would be applicable to all part 192.

On March 26, 2018, the GPAC recommended that PHMSA delete the spike test requirements from the pressure test method of MAOP reconfirmation. The GPAC also recommended that PHMSA require operators to perform a pressure test in accordance with subpart J of part 192 rather than refer to specific requirements in § 192.505. Further, and as discussed during the meetings of December 2017 and March 26, 2018, if the applicable pressure test segment does not have traceable, verifiable, and complete MAOP records, the operator must use the best available information upon which the MAOP is currently based to conduct the pressure test. The GPAC recommended PHMSA create a requirement for the operator of such a pipeline segment to add the test segment to its plan for opportunistically verifying material properties in accordance with the material properties verification provisions. During the meeting, PHMSA noted that most pressure tests would present at least two opportunities for material properties verification at the test manifolds.

PHMSA Response: Method 1—Pressure Test

PHMSA appreciates the information provided by the commenters regarding the pressure test method of MAOP reconfirmation (Method 1). After considering these comments and as recommended by the GPAC, PHMSA is eliminating the spike testing

requirement as part of the pressure test method of MAOP reconfirmation. As commenters stated, spike testing is primarily used for the mitigation of cracks and crack-like defects, and PHMSA has determined it would therefore be more appropriate to be placed within the context of threat management under IM. Additionally, PHMSA is removing the definitions for and related references to "legacy pipe" and "legacy construction" in this final rule because the applicability to pipe with "legacy pipe or construction" leaks or failures was dropped from the applicability criteria for MAOP reconfirmation. PHMSA also modified the rule to refer to subpart J pressure tests rather than paragraph § 192.505(c), specifically, and to recognize the validity of earlier pressure tests. Lastly, if an operator does not have traceable, verifiable, and complete records for the material properties needed to establish MAOP by pressure testing, PHMSA is requiring that operators test, in accordance with the material verification requirements, the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. Further, if there is a failure during the pressure test, the operator must test any removed pipe from the pressure test failure in accordance with the material properties verification requirements to ensure that the segment of pipe is consistent with operator's sampling program established under § 192.607. This will avoid issues where operators may not have the documented and verified physical pipeline material properties and attributes that would otherwise be necessary to perform a hydrostatic pressure test to reconfirm MAOP.

Summary of Proposal: Method 2—Pressure Reduction

In the NPRM, PHMSA proposed that pipeline operators could choose to reduce the MAOP of the applicable pipeline segment to reconfirm the segment's MAOP. This approach would use the recent operating pressure as a *de facto* pressure test, and then an operator would set the pipeline segment's MAOP at a slightly lower pressure. PHMSA proposed that operators using this method set the pipeline's MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 18 months preceding the effective date of the final rule divided by the greater of either 1.25 or the applicable class location, which are the same safety factors as used for the pressure testing in Method 1. PHMSA included standards for establishing the highest actual sustained pressure for the

purposes of reconfirming MAOP under this method and included standards for addressing class location changes. Additionally, PHMSA proposed that, if the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects, the operator would be required to estimate the remaining life of the pipeline.

Summary of Public Comment: Method 2—Pressure Reduction

AGA commented that the 18-month look-back time frame listed in the pressure reduction MAOP reconfirmation method is a much too narrow time frame for consideration and that the section should be rewritten to clarify that the pressure reduction should be taken from either (1) the immediate past 18 months, or (2) 5 years from the time the last pressure reduction was taken, stating that tying the baseline pressure to the effective date of the rule is arbitrary. Enterprise Products recommended that PHMSA clarify the derating criteria used for pipes that use this method of reconfirming MAOP. Further, Piedmont expressed concern that this method does not account for the actual gap that can occur between MAOP and operating pressure. Some commenters questioned whether the MAOP from which to take a pressure reduction was based on the most recent pressure test or the historical highest-pressure test, and some commenters suggested PHMSA revise this provision to allow operators to reconfirm the MAOP based on the existing MAOP and not using an 18-month look-back period unless an incident caused by a material-related or construction-related defect has occurred on the pipeline since its last subpart J pressure test.

TPA stated that using this method unfairly penalizes operators in situations where the operator has prepared for future needs and has not operated at MAOP for a period greater than 18 months. Similarly, another commenter suggested that operators who have already reduced MAOP on pipeline segments to be proactive should not be penalized by having to take an additional reduction in MAOP.

Some commenters recommended limiting the applicability of this method to those pipelines operating at 30 percent SMYS or greater.

Regarding the pressure reduction method for MAOP reconfirmation, the GPAC recommended PHMSA increase the look-back period from 18 months to 5 years and remove the requirements for operators selecting to take the pressure reduction to reconfirm MAOP to

perform fracture mechanics analysis on those pipeline segments.

PHMSA Response: Method 2—Pressure Reduction

PHMSA appreciates the information provided by the commenters regarding the pressure reduction method of MAOP reconfirmation (Method 2). After considering these comments and as recommended by the GPAC, PHMSA is increasing the look-back period to 5 years from the publication date of the rule and is removing the requirements for operators to perform fracture mechanics analysis on those pipeline segments where the operator has selected Method 2. PHMSA made this change because the 5-year look-back period is consistent with IM requirements regarding MAOP confirmation.

Summary of PHMSA's Proposal: Method 3—Engineering Critical Assessment

Method 3 directly addresses the congressional mandate for PHMSA to consider safety testing methodologies that include other alternative methods, including ILI, determined to be of equal or greater effectiveness. Demonstrating that knowledge gained from an ILI assessment provides an equivalent level of safety as a pressure test is technically challenging. PHMSA used best safety practices gained from implementation of integrity management since 2003; development of class location special permits; and technical research on related topics, such as analysis of crack defects and seam defects. PHMSA applied these principles and analytical methods to develop an engineering critical assessment (ECA) methodology, which applies state-of-the-art fracture mechanics analysis to analyze defects in the pipe and determine if those defects would or would not survive a hydrostatic pressure test at the test pressure needed to establish MAOP. In addition, PHMSA proposed that if the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects, the operator would be required to estimate the remaining life of the pipeline using the fracture mechanics standards PHMSA specified.

Summary of Public Comment: Method 3—Engineering Critical Assessment

Several trade associations and pipeline industry entities stated that ILI is the best and most practical method for MAOP reconfirmation due to its cost-effectiveness and environmentally friendly nature, and that PHMSA should allow operators to use ILI as a

reconfirmation method. These commenters, however, also stated that the requirements proposed for the usage of ILI with an ECA are overly complicated and burdensome, and they specifically recommended that the final rule should be simplified so that this method will play a greater role in MAOP reconfirmation in lieu of a pressure test. For example, INGAA asserted that PHMSA should remove the requirements in the ECA related to operations, maintenance, and integrity management, arguing that these requirements do not factor into MAOP reconfirmation and would be covered elsewhere in part 192. Further, INGAA proposed additional alternatives for using the ECA method to obtain necessary data for MAOP reconfirmation, asserting that these alternatives would be less burdensome and equally effective. More specifically, INGAA suggested removing duplicate regulatory language, removing the pre-approval process for ILI, and adding unity plots as a method for operators to demonstrate that ILI is reliable for identifying and sizing actionable anomalies. TransCanada and PECO Energy Co. stated that for the ECA method to be used by industry, the detailed requirements listed under this method in the proposed rule should be replaced with the use of standard ECA best practices.

Some commenters suggested that operators have long relied on sound engineering judgments and conservative assumptions to account for record gaps. Commenters stated that, if stripped of the ability to use sound engineering judgment and conservative assumptions, operators would need to substantially invest in processes, procedures, tests, and project engineering and support to develop and implement a comprehensive material properties verification plan as outlined in the proposed regulations. Another commenter asked for clarification on using assumptions of Grade A pipe (30,000 psi) versus the use of 24,000 psi as noted in § 192.107(b)(2) if the SMYS or actual material yield strength and ultimate tensile strength is unknown or is not documented in traceable, verifiable, and complete records.

Another commenter suggested that in cases where a pipeline has been pressure tested, but not to the level of 1.25 times MAOP, PHMSA should allow operators to augment the original test with an ECA and other analysis to reconfirm the pipeline segment's MAOP under method 3.

The PST stated that there are certain cases in which the ECA method should not be allowed as an alternative to

pressure testing. Citing a white paper prepared by Accufacts, Inc. on ECA methodology, the PST recommended that PHMSA prohibit the use of the ECA method for determining the strength of a pipeline segment in cases where there are girth weld crack threats, significant stress corrosion cracking threats, or dents with stress concentrator threats.

During the GPAC meeting on March 27, 2018, the GPAC recommended that PHMSA remove the fracture mechanics analysis for failure stress and crack growth analysis requirements from the ECA method of MAOP reconfirmation and move them to a stand-alone section in the regulations. Further, the GPAC recommended that such a section should not specify when, or for which pipeline segments, fracture mechanics analysis would be required. The GPAC suggested that this new fracture mechanics section outline a procedure by which operators perform fracture mechanics analysis when required or allowed by other sections of part 192, which was similar to its treatment of the proposed material properties verification procedures at § 192.607. Under the GPAC's proposal, the ECA method for MAOP reconfirmation would not contain any specific technical fracture mechanics requirements or Charpy V-notch toughness values but would instead refer to the new fracture mechanics section. Other recommendations related specifically to the new fracture mechanics section are discussed in that area of the proposal and comment summary section of this document.

The GPAC also recommended PHMSA add a requirement to verify material properties in accordance with the rule's material properties verification provisions if the information needed to conduct a successful ECA is not documented in traceable, verifiable, and complete records.

PHMSA Response: Method 3—Engineering Critical Assessment

PHMSA appreciates the information provided by the commenters regarding the ECA method of MAOP reconfirmation (Method 3). As recommended by the GPAC, PHMSA is removing the fracture mechanics analysis requirements from the ECA method of MAOP reconfirmation and moving them to a new stand-alone § 192.712. PHMSA agrees this change will improve comprehension of the regulations. This new section does not specify when, or for which pipeline segments, fracture mechanics analysis would be required but instead outlines a procedure by which operators perform

fracture mechanics analysis when required by other sections of part 192. Section 192.712 is referenced in the pressure reduction, ECA, and “other technology” methods of MAOP reconfirmation under § 192.624, as well as in § 192.917 for cyclic fatigue loading. Therefore, the ECA method for MAOP reconfirmation does not contain any specific technical fracture mechanics requirements or Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperature) but instead refers to the new § 192.712. Comments related to the assumptions an operator can use when material properties are unknown are addressed in the discussion on § 192.712 below. PHMSA also added a requirement to verify material properties in accordance with the rule’s material properties verification provisions at § 192.607 if the information needed to conduct a successful ECA is not documented in traceable, verifiable, and complete records.

PHMSA disagrees that the additional analytical requirements, beyond ILI, are overly complicated or burdensome. To conclude that an ECA is of equal or greater effectiveness as a pressure test for the purposes of MAOP reconfirmation, as mandated by Congress, more than an ILI and repair program is required. A pressure test proves that any flaws in the pipe are small enough to hold the test pressure without leaking. Such subcritical flaws must be analyzed to prove that they would pass a pressure test, even if the pressure test is not conducted. A fracture mechanics analysis is capable of reliably drawing such conclusions but must be carefully and capably performed. Such an analysis also requires accurate data. In the absence of reliable data for key parameters, such as fracture toughness, PHMSA allows the use of appropriately conservative assumptions. This is discussed in more detail in the sections below.

Based on an ASME report and research sponsored by PHMSA,⁶⁹ the ECA analysis can be reliably used to ascertain if a pipeline segment would pass a pressure test, even if it has seam weld cracking, and the final rule includes requirements for conducting ILI using tools capable of detecting girth

weld cracks. The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure (PFP) of each defect.

PHMSA also notes that the final rule addresses cases where a pipeline has been pressure tested, but not to the level of 1.25 times MAOP, by allowing operators to account for those test results and augment the original test with an ECA, or conduct an ILI tool assessment program to characterize defects remaining in the pipe along with using an ECA to establish MAOP, to reconfirm the pipeline segment’s MAOP using Method 3. Detailed ILI requirements are addressed in new § 192.493, which is discussed in more detail below.

PHMSA is moving the ECA process requirements in this final rule to a new stand-alone § 192.632. Section 192.624(c)(3) (ECA method of MAOP reconfirmation) and the new § 192.632 will cross-reference each other. PHMSA decided to make this change when finalizing this rulemaking only to improve the readability of the regulations. No substantive changes were made to the requirements in connection with this organizational change.

Summary of PHMSA’s Proposal: Method 4—Pipe Replacement

When reconfirming MAOP on certain pipeline segments, some operators may face significant technical challenges or costs when performing either a pressure test or an ILI examination, and it may be more economically viable to replace the pipeline. Therefore, PHMSA proposed to allow pipe replacement for operators to reconfirm their MAOP. In such cases, the replacement pipeline would be designed, constructed, and pressure tested according to current standards to establish MAOP.

Summary of Public Comment: Method 4—Pipe Replacement

Commenters, including Mid-American Energy Company and Paiute Pipeline, stated their support for this method. The GPAC similarly supported this method and did not recommend any changes for this aspect of MAOP reconfirmation.

PHMSA Response: Method 4—Pipe Replacement

PHMSA appreciates the information provided by the commenters regarding the pipe replacement method of MAOP reconfirmation (Method 4). After considering these comments and as recommended by the GPAC, PHMSA is

retaining the proposed rule text for Method 4 in the final rule.

Summary of PHMSA’s Proposal: Method 5—Pressure Reduction for Small, Low-Pressure Pipelines

For low-pressure, smaller-diameter pipeline segments with small potential impact radii (PIR), PHMSA proposed an MAOP reconfirmation method similar to the pressure reduction under Method 2. Operators of pipeline segments for which (1) the MAOP is less than 30 percent SMYS, (2) the PIR is less than or equal to 150 feet, (3) the nominal diameter is equal to or less than 8 inches,⁷⁰ and (4) which cannot be assessed using ILI or a pressure test, may reconfirm the MAOP as the highest actual operating pressure sustained by the pipeline segment 18 months preceding the effective date of the final rule, divided by 1.1. In addition to this pressure reduction, operators of these lines would be required to perform external corrosion direct assessments in accordance with the IM provisions, develop and implement procedures to evaluate and mitigate any cracking defects, conduct a specified number of line patrols at certain intervals, conduct periodic leak surveys, and odorize the gas transported in the pipeline segment.

Summary of Public Comment: Method 5—Pressure Reduction for Small, Low- Pressure Pipelines

AGA stated that PHMSA did not provide enough justification for imposing the additional pressure reduction requirements listed under this method, asserting that this method should require either a 10 percent pressure reduction or the implementation of additional preventative actions that are feasible and practical, but not both. TPA stated that the 18-month criterion penalizes operators who may have operated pipelines at lower capacities to anticipate future needs. Furthermore, TPA urged PHMSA to limit the requirements for MAOP reconfirmation under Method 5 to the reduction in MAOP and not impose additional safety requirements, stating that these pipelines are generally considered low-stress pipelines and that their risk of rupture is very low. Similarly, API stated that the proposed requirements for odorization and frequent instrumented leak surveys are impractical. Some commenters felt that the terms for small potential impact radius and the applicable diameters should be defined.

⁷⁰ 8.625 inches actual diameter.

⁶⁹ See: American Society of Mechanical Engineers (ASME) Standards Technology Report “Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas” (STP-PT-011), and “Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1” (Task 4.5); <https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390>.

On March 27, 2018, the GPAC recommended PHMSA delete the size and pressure criteria of this method and base the applicability solely on a potential impact radius of less than or equal to 150 feet. The GPAC also recommended increasing the look-back period to 5 years from 18 months. Further, the GPAC recommended PHMSA strike the additional requirements in this method related to external corrosion direct assessment, crack analysis, gas odorization, and fracture mechanics analysis. They also recommended PHMSA change the frequency of patrols and surveys to 4 times a year for Class 1 and Class 2 locations, and 6 times per year for Class 3 and Class 4 locations.

PHMSA Response: Method 5—Pressure Reduction for Small, Low-Pressure Pipelines

PHMSA appreciates the information provided by the commenters regarding the pressure reduction method of MAOP reconfirmation for small, low-pressure pipelines (Method 5). After considering these comments and as recommended by the GPAC, PHMSA is deleting the pipeline segment size and pressure criteria of this method and basing the applicability solely on a potential impact radius of less than or equal to 150 feet. PHMSA believes this change streamlines the regulations while maintaining pipeline safety. PHMSA is increasing the look-back period to 5 years, which is consistent with other sections of part 192, including integrity management. Additionally, PHMSA is deleting the requirements in this method related to external corrosion direct assessment, crack analysis, gas odorization, and fracture mechanics analysis. PHMSA is also changing the frequency of patrols and surveys to 4 times a year for Class 1 and Class 2 locations, and 6 times per year for Class 3 and Class 4 locations. PHMSA believes these changes increase regulatory flexibility while maintaining pipeline safety.

Summary of Proposal: Method 6—Alternative Technology

PHMSA proposed that operators may use an alternative technical evaluation process that provides a documented engineering analysis for the purposes of MAOP reconfirmation. If an operator elects to use an alternative method for MAOP reconfirmation, it would have to notify PHMSA and provide a detailed fracture mechanics analysis—including the safety factors—to justify the establishment of the MAOP using the proposed alternative method. The notification would have to demonstrate

that the proposed alternative method would provide an equivalent or greater level of safety than a pressure test. PHMSA included this option to allow and encourage the continual research and development needed to improve state-of-the-art fracture mechanics analysis, integrity assessment methods, advances in metallurgical engineering, and new techniques.

Summary of Public Comment: Method 6—Alternative Technology

For the alternative technologies method of MAOP reconfirmation, several stakeholders opposed the timeframes, case-by-case approval process, and procedural barriers PHMSA proposed for using this method. Several commenters, including Cheniere Energy, Delmarva Power & Light, and INGAA, suggested that the procedural hurdles required by the proposed provisions would make this option difficult for operators to use for MAOP reconfirmation as well as for any other provisions PHMSA allows alternative technology use with notification. More specifically, these commenters suggested that a process whereby PHMSA could object to the use of an alternative technology at any time during a project's lifecycle does not provide the level of certainty necessary for operators to move forward with using alternative technologies. That uncertainty would deter the development of what could be better or safer alternatives.

Piedmont stated that it does not believe that the role of PHMSA includes determining the appropriate technologies to be used to reconfirm MAOP. Piedmont further stated that currently under subpart O, operators are required to obtain approval from PHMSA to use alternative technologies for integrity assessment, and that operators have waited more than 180 days for PHMSA to respond to these requests. Piedmont stated that this uncertainty cannot be reconciled with the planning and business considerations that an operator must consider when evaluating how to invest in technology and which methods to use for establishing MAOP. The PST stated that the approval process should be similar to the process used for special permits and that before these methods are approved by PHMSA, they should be subject to public review and comment under the National Environmental Policy Act of 1969 (NEPA).

At the meeting on March 27, 2018, the GPAC recommended PHMSA incorporate the 90-day notification and objection procedure for the use of

alternative technology. To summarize, operators would have to notify PHMSA of its intent to use other technology, and PHMSA would have 90 days to respond with an objection if PHMSA had one, or a need for more review time. Otherwise, the operator would be free to use the proposed method or technology.

PHMSA Response: Method 6—Alternative Technology

PHMSA appreciates the information provided by the commenters regarding the other technology method of MAOP reconfirmation (Method 6). After considering these comments and as recommended by the GPAC, PHMSA is modifying the rule to incorporate the 90-day notification and objection procedure the committee recommended. Operators would have to notify PHMSA of its intent to use other technology to reconfirm MAOP in accordance with § 192.18, and PHMSA would have 90 days to respond with an objection if PHMSA had one or a notice that PHMSA required more time for its review, which would extend the timeframe. Without a notice of objection or additional review by PHMSA, the operator would be allowed to use the alternative technology. PHMSA has successfully applied the notification process to other technology assessments under subpart O since its inception and does not believe a special permit process is warranted for every notification for alternative technology. PHMSA believes the changes made in the final rule will address the concerns about timeliness of notification reviews by PHMSA.

B. MAOP Reconfirmation—§ 192.624

iii.—Spike Test

1. Summary of PHMSA's Proposal

The “spike” hydrostatic pressure test is a special feature of the pressure testing method of MAOP reconfirmation. PHMSA intends this aspect of the MAOP reconfirmation process to address the intent of NTSB recommendations P-11-14 (related to spike testing for grandfathered pipe) and P-11-15 (related to pressure testing to show that manufacturing and construction-related defects are stable).

PHMSA proposed that a spike test would be required for cases where a pipeline segment might be susceptible to cracks or crack-like defects. Such pipe may include “legacy pipe;” pipe constructed using “legacy” construction techniques; pipelines that have experienced an incident due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect; or pipe with

stress corrosion cracking or girth weld cracks. Cracks and crack-like defects in some cases may be susceptible to a phenomenon called “pressure reversal,” which is the failure of a defect at a pressure less than a pressure level that the flaw has previously experienced and survived. The increased stress from the test pressure may cause latent cracks that are almost, but not quite, large enough to fail to grow during the test. If the crack does not fail before the test is completed, the resultant crack that remains in the pipe may be large enough to no longer be able to pass another pressure test. The spike portion of the pressure test is designed to cause such marginal crack defects to fail during the early, spike phase of the pressure test. The post-spike, long-duration test pressure validates the operational strength of the pipe. Using a short-duration, very high spike pressure followed by a long-duration integrity verification pressure provides greater assurance that the test is not “growing cracks” that could fail in-service after the test is completed. PHMSA proposed standards for the spike hydrostatic test in § 192.506. PHMSA used several technical reports and studies, including PHMSA-sponsored research, to inform the standards proposed for the spike test. Those materials include, American Society of Mechanical Engineers Standards Technology Report “Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas” (STP-PT-011), and “Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1” (Task 4.5).⁷¹

2. Summary of Public Comment

Some commenters supported the concept of requiring the use of a spike hydrostatic pressure test as part of the MAOP reconfirmation process for establishing MAOP but expressed concern over specific aspects of the provision. For example, AGA urged PHMSA to allow pneumatic pressure tests as well as hydrostatic pressure tests. In addition, AGA disagreed with the allotted test duration provided in the proposal. Similarly, other operators who commented, such as CenterPoint Energy and Dominion East Ohio, stated that the proposed spike test target hold pressure of 30 minutes exceeds the time needed to determine the mechanical integrity of the pipeline test segment and will cause pre-existing crack-like defects to grow. Alternatively,

Dominion Transmission, Tallgrass Energy Partners, SoCalGas, and Paiute Pipelines stated that a test level of 100 percent SMYS, not 105 percent SMYS, would be sufficient to remediate cracking threats. Enterprise Products stated that the requirements for the design of a spike test should be based on integrity science, such as fatigue life and reassessment intervals, and suggested PHMSA’s proposed spike test pressure limits were set at an arbitrary level. Enterprise further stated that the utility of stressing a pipe beyond 100 percent of its yield strength is questionable and potentially damages the pipe. Other commenters, including MidAmerican Energy Co., requested that pneumatic spike tests to 1.5 times MAOP be allowed when the resultant pressure complies with the limitations stated in the table in § 192.503(c).

Trade associations and pipeline industry entities, including INGAA, GPA, and TPA, asserted that PHMSA should eliminate the spike test requirement for establishing MAOP entirely. These commenters stated that the proposed provisions went beyond what was required to reconfirm MAOP for an accepted margin of safety. These commenters further asserted that spike testing is not an appropriate technique for MAOP reconfirmation, and it could result in unintended negative consequences without improving pipeline safety. They stated that spike testing is an aggressive and destructive technique that should be used only in cases in which time-dependent threats, such as a significant risk of stress corrosion cracking, exist.

INGAA and other commenters agreed with PHMSA that the use of spike hydrostatic testing is appropriate for time-dependent threats, such as stress corrosion cracking. INGAA, however, suggested changes to the proposed spike hydrostatic pressure test provisions and the cross-reference to those provisions in the proposed IM assessment method revisions to limit the spike testing requirement to time-dependent threats, to test to a minimum of 100 percent SMYS instead of 105 percent, and to provide an alternative for use of an instrumented leak survey. INGAA agreed that spike testing is the best means of testing a pipeline with a history of environmental cracking, such as stress corrosion cracking that has developed while a pipeline is in service, and noted that a spike test may be of value for in-service pipelines where metallurgical fatigue is of concern. INGAA further stated that pressure cycling should not need to be included in the proposed spike test provisions and that PHMSA should amend the

proposed rule to limit spike testing only to those pipeline segments with stress corrosion cracking.

An additional commenter suggested PHMSA should allow operators to use the short-duration spike portion of a spike pressure test to determine the lower bound of the yield strength of the test section, including all pipe and components that are subjected to the test pressure. Such a test, if used for this purpose, must also confirm that yielding beyond that experienced in a standard tensile test to determine yield strength, typically on the order of 0.5 percent, has not occurred. This confirmation may be demonstrated by data from a pressure-volume plot of the test or a post-test geometry tool in-line inspection.

Public interest and other groups, including Pipeline Safety Coalition, Environmental Defense Fund (EDF), and NAPSRS, expressed support for spike testing, stating that it would provide for increased pipeline safety. NAPSRS further stated that the option of applying to use alternative technology or an alternative technological evaluation process would allow for some flexibility in cases in which a hydrostatic test is impractical. EDF also suggested additional measures to mitigate emissions from methane gas lost during testing.

At the GPAC meeting on March 2, 2018, the GPAC recommended that PHMSA revise the spike test requirements to change the minimum spike pressure to the lesser of 100 percent SMYS or 1.5 times MAOP, reduce the spike hold time to a minimum of 15 minutes after the spike pressure stabilizes, revise the applicable language to refer specifically to “time-dependent” cracking, incorporate the 90-day notification and objection procedure discussed for other sections, and adjust the SME requirements by adding language describing a “qualified technical subject matter expert” where applicable.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the requirements for spike pressure testing. After considering these comments and as recommended by the GPAC, PHMSA is modifying the rule to change the minimum spike pressure to the lesser of 100 percent SMYS or 1.5 times MAOP, as PHMSA believes these pressures are sufficient to maintain pipeline safety. PHMSA is specifying a spike hold time of a minimum of 15 minutes after the spike pressure stabilizes, rather than a 30-minute overall hold time, to be consistent with pipeline safety. Additionally, PHMSA is

⁷¹ <https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390>.

modifying the rule to revise the applicable language to refer specifically to “time-dependent” cracking, incorporate the same notification procedure under § 192.18 with the 90-day timeframe for objections or requests for more review time, and adjust the SME requirements by using broader language describing a “qualified technical subject matter expert” where applicable instead of specifying technical fields of expertise such as metallurgy or fracture mechanics. PHMSA believes these changes increase regulatory flexibility while maintaining pipeline safety.

In addition, as stated above, the spike test is being removed from the MAOP reconfirmation requirements. The spike test procedure in the new § 192.506 would be used whenever required by other requirements in part 192 to address crack remediation and the integrity threat of cracks and crack-like defects.

PHMSA disagrees with allowing pneumatic spike tests to 1.5 times MAOP based on safety concerns. Pneumatic pressure tests are allowed in § 192.503(c), with certain limitations, for new, relocated, or replaced pipe. For new, relocated, or replaced pipe, there is knowledge that the pipe is likely sound and is usually manufactured with recent mill pressure tests to confirm the pipe meets applicable standards. A spike test to perform an integrity assessment on *in-situ* pipe with known or suspected cracks or crack-like defects presents a much higher likelihood of the pipeline segment experiencing a leak or rupture during the test with resultant consequences, including the possibility of fire or explosion. PHMSA notes that conducting a pneumatic test using a compressible gas, such as air, nitrogen, or methane, would be a safety concern for the public and operating personnel. Gas that is highly compressed has stored energy that would be suddenly released should there be a flaw in the pipe. Liquids, such as water, do not have the stored energy release that a compressible gas has should the pipe have a flaw that either leaks or ruptures. Therefore, the safety risk of performing a hydrostatic pressure test (with water) is much lower due to the less-compressible nature of liquids. Compressed gas would be a fire or explosion hazard to the public. However, as specified in the proposed and final rules, operators that desire to use a pneumatic spike test may propose using such a test, with justification, by submitting a notification to PHMSA.

B. MAOP Reconfirmation—§ 192.624 iv.—Fracture Mechanics

1. Summary of PHMSA’s Proposal

In the proposal, PHMSA determined that fracture mechanics analysis is a key aspect of meeting the congressional mandate to consider safety testing methodologies for MAOP reconfirmation of equal or greater effectiveness as a pressure test, including other alternative methods such as ILI. Demonstrating that knowledge gained from an ILI assessment provides an equivalent level of safety as a pressure test is technically challenging. An ILI assessment might reveal the presence of crack flaws and crack-like defects and characterize them within the accuracy of tool performance capabilities, but determining whether those cracks would survive a pressure test to reconfirm MAOP requires very in-depth and highly technical analysis. Such an analysis not only requires an accurate characterization of cracks, it also requires accurate and known metallurgical properties of the pipe. To address these aspects, PHMSA proposed more detailed requirements in § 192.921 for evaluating defects discovered during ILI to account for tool accuracy and other factors to accurately characterize flaw dimensions and support accurate fracture mechanics analysis. In addition, the material properties verification and documentation requirements PHMSA proposed are critical to performing fracture mechanics analysis of ILI-discovered defects that would be accurate enough to establish MAOP in a way that is demonstrably equivalent in safety to a pressure test. In the MAOP reconfirmation provisions, PHMSA proposed new requirements for fracture mechanics analysis for failure stress and cracks, listing specific requirements, standards, and data operators must use when performing a fracture mechanics analysis.

2. Summary of Public Comment

Most industry stakeholders were opposed to the proposed fracture mechanics requirements. AGA, New Mexico Gas Co., and TPA suggested that fracture mechanics have a limited place in preventing pipeline failures or predicting them accurately and should not be a component of MAOP reconfirmation. AGA stated that the rule should not prescriptively require fracture mechanics calculations to be performed for a broad range of applications but should be narrowed to include only transmission pipelines operating at a hoop stress greater than 30 percent SMYS, given that pipelines

that operate below 30 percent SMYS have a strong tendency to leak rather than rupture.

Commenters also stated that requiring fracture mechanics as any part of the MAOP reconfirmation process was overly burdensome and unclear. Specifically, API stated that some of the requirements listed under the MAOP reconfirmation requirements were overly conservative and burdensome for most situations where this technique would be used. For instance, a commenter noted that there is no non-destructive evaluation (NDE) methodology for obtaining Charpy V-notch toughness values. Therefore, PHMSA’s requirement to obtain Charpy V-notch toughness values eliminates the availability of non-destructive testing. Further, a commenter noted that the proposed ECA analysis prescribed a body toughness of 5-ft.-lbs. and a seam toughness of 1-ft.-lbs., which are arbitrary and very conservative. Vintage pipelines will not have Charpy V-notch toughness data, and requiring an overly conservative assumption of toughness is not reasonable. Toughness can vary depending on the manufacturer, the manufacturing method, and the pipe vintage, and it should not be prescribed in the regulations. The commenter further noted that using the conservative defaults, especially the overly conservative defaults PHMSA proposed, may result in an unacceptably short remaining life of the pipeline.

Similarly, commenters recommended PHMSA allow alternative methods of assessing strength properties that provide a suitable lower bound to the actual strengths. Allowing alternative methods will provide flexibility to consider conservative, but realistic, estimates of material properties. Commenters also stated that SMEs in both metallurgy and fracture mechanics are not needed to validate non-destructive test (NDT) methods. Engineers with knowledge in test validation methods but not necessarily metallurgy and fracture mechanics are capable of validating NDT methods.

More broadly, Energy Transfer Partners suggested that the proposed language for fracture mechanics is misplaced in MAOP reconfirmation and should be moved to the proposed requirements for non-HCA assessments, or elsewhere, since this text more closely resembles an “assessment.” Other commenters agreed with that concept, suggesting fracture mechanics is more appropriate under the IM measures for threat mitigation rather than for MAOP reconfirmation.

As previously discussed in this document, the GPAC recommended

PHMSA move the fracture mechanics analysis requirements out of the ECA method of MAOP reconfirmation and into a new stand-alone section in the regulations, making it a process for performing fracture mechanics analysis whenever required or allowed by part 192. The committee therefore recommended that PHMSA delete any cross-references to the MAOP reconfirmation and the spike pressure test provisions. The GPAC also recommended that operators make and retain specific records to document fracture mechanics analyses performed.

Along with moving the fracture mechanics analysis requirements to a stand-alone section, the GPAC had several specific recommendations related to how the requirements would function. The GPAC recommended PHMSA remove ILI tool performance specifications and replace them with a requirement for operators to verify tool performance using unity plots or equivalent technologies, and also recommended revisions to the fracture mechanics requirements by striking the sensitivity analysis requirements and replacing them with a requirement for operators to account for model inaccuracies and tolerances.

As it pertains to the Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperatures) used in fracture mechanics analysis, the GPAC recommended that operators could use a conservative Charpy V-notch toughness value based on the sampling requirements of the material properties verification provisions or use Charpy V-notch toughness values from similar-vintage pipe until the actual properties are obtained through the operator's opportunistic testing program. The GPAC recommended that PHMSA clarify that default Charpy V-notch toughness values of 13-ft.-lbs. for pipe body and 4-ft.-lbs. for pipe seam only apply to pipe with suspected low-toughness properties or unknown toughness properties. Further, if a pipeline segment has a history of leaks or failures due to cracks, the GPAC recommended PHMSA require the operator to work diligently to obtain any unknown toughness data. In the interim, operators of such pipeline segments must use Charpy V-notch toughness values of 5-ft.-lbs. for pipe body and 1-ft.-lbs. for pipe seam. The GPAC also recommended PHMSA include a 90-day notification procedure similar to the previously agreed-upon procedure if operators wanted to request the use of differing Charpy V-notch toughness values.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the proposed fracture mechanics requirements. After considering these comments and as recommended by the GPAC, PHMSA is moving the fracture mechanics analysis requirements out of the ECA method of MAOP reconfirmation and into a new stand-alone § 192.712 in the regulations, making it a process by which operators must perform fracture mechanics analysis whenever required by part 192. This change was made to increase the readability of the regulations. As a part of making these provisions into a stand-alone section in the regulations, PHMSA is also deleting the references within § 192.712 to the MAOP reconfirmation and the spike pressure test provisions. PHMSA is adding a requirement for operators to make and retain specific records documenting any fracture mechanics analyses performed. PHMSA is also removing ILI tool performance specifications and sensitivity analysis requirements and replacing them with a requirement for operators to verify tool performance using unity plots or equivalent technologies and to account for model inaccuracies and tolerances. This change will increase regulatory flexibility while maintaining pipeline safety.

Regarding the default Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperatures) used in fracture mechanics analysis when actual values are not known, industry and the GPAC had significant comments. PHMSA is aware of pipe manufactured per API Specification 5L in this decade (2010–2019) with Charpy V-notch toughness values for the weld seam as low as 1-ft. lbs. that has been used in gas transmission pipelines. Furthermore, API 5L does not contain required minimum Charpy V-notch toughness values for the weld seam.

A single default assumed toughness value might be inappropriate or overly conservative under some circumstances, or it might be a proper choice under other circumstances. To address this issue in this final rule, PHMSA is allowing the use of: (1) Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperatures) from the same vintage and the same steel pipe manufacturers with known properties; (2) a conservative Charpy V-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in § 192.607; (3) maximum Charpy V-notch

toughness values of 13.0 ft.-lbs. for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects if the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects; (4) maximum Charpy V-notch toughness values of 5.0 ft.-lbs. for body cracks and 1.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion if the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects; or (5) other appropriate Charpy V-notch toughness values that an operator demonstrates can provide conservative Charpy V-notch toughness values for the analysis of the crack-related conditions of the line pipe upon submittal of a notification to PHMSA. These modifications will provide flexibility to operators for considering conservative but realistic estimates of material properties.

PHMSA is also clarifying that operators do not need to use distinct metallurgy and fracture mechanics subject matter experts to review fracture mechanics analyses. In this final rule, PHMSA is replacing that requirement with a general requirement stating that fracture mechanics analyses must be reviewed and confirmed by a qualified subject matter expert. PHMSA expects a qualified subject matter expert to be an individual with formal or on-the-job technical training in the technical or operational area being analyzed, evaluated, or assessed. The operator must be able to document that the individual is appropriately knowledgeable and experienced in the subject being assessed.

B. MAOP Reconfirmation—§ 192.624 v.—Legacy Construction Techniques/ Legacy Pipe

1. Summary of PHMSA's Proposal

PHMSA proposed to add a definition to part 192 for “legacy construction techniques,” which defined historical practices used to construct or repair transmission pipeline segments that are no longer recognized as acceptable. In addition, PHMSA proposed a definition for “legacy pipe” that is defined by the presence of specific legacy manufacturing, welding, and joining techniques.

2. Summary of Public Comment

AGA expressed significant concerns with the proposed definitions of legacy pipe and legacy construction techniques for the purposes of part 192, commenting that PHMSA should eliminate the use of the terms entirely or otherwise revise these definitions to

exclude currently acceptable manufacturing and construction techniques. AGA stated if PHMSA were to codify the definitions of legacy pipe and legacy construction techniques, then PHMSA should limit its catch-all provisions within the language of the definitions to pipes with a longitudinal joint factor of less than 1.0. Doing so would ultimately include pipes with unknown joint factors, as § 192.113 requires a default longitudinal joint factor of 0.80 for any pipe with an unknown longitudinal joint factor. Similarly, AGL Resources, Alliant Energy, Atmos Energy, and TECO Peoples Gas supported AGA's suggested revisions to the definitions of legacy construction techniques and legacy pipe. API commented that PHMSA's proposed definition of legacy construction technique inappropriately includes the repair technique of puddle welds and recommended PHMSA clarify the definitions of wrought iron and pipe made from Bessemer steel. Dominion Transmission commented there may be instances where the longitudinal seam for modern day pipe is unknown, yet the pipe is not a high-risk seam type. They stated that such pipe does not present an integrity threat and should be excluded from the "legacy pipe" definition.

Gas Piping Technology Committee commented that the proposed definition of legacy construction techniques seems to contain some erroneous information. They asserted that the proposed definition went too far by implying that all the listed methods are no longer used to construct or repair pipelines, stating that while wrinkle bends may no longer be a common construction technique, they are still allowed under § 192.315 for steel pipe operating at a pressure producing a hoop stress of less than 30 percent of SMYS. Similarly, Oleksa and Associates commented that some operators are still installing Dresser couplings.

The Michigan Public Service Commission staff suggested that PHMSA add to the definition of "legacy construction techniques" a subsection that addresses other legacy construction techniques that are not in the current list and include within this subsection language referencing "all other" techniques. Northern Natural Gas proposed PHMSA eliminate the phrase "including any of the following techniques" from the definition of legacy construction techniques as it implies the list is not complete. They suggested that the definition of legacy pipe should differentiate between ductile and brittle pipe by toughness values in both the seam and the pipe

body. Lastly, SoCalGas thought it would be more appropriate to reference these definitions under the IM regulations in subpart O instead of defining the terms in the context of the entire part.

These definitions were taken up by the GPAC in the context of the scope of MAOP reconfirmation, and they recommended in the meeting on March 26, 2018, that the definitions be withdrawn. Because the GPAC recommended to revise the scope of MAOP confirmation to not include pipelines with previous reportable incidents due to crack defects, these definitions would no longer be needed in the rule.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the proposed definitions for "legacy pipe" and "legacy construction techniques." After considering these comments and as recommended by the GPAC, PHMSA is withdrawing these definitions from the final rule. Because the revised scope of MAOP confirmation requirements, discussed in the previous sections, no longer includes pipelines with previous reportable incidents due to crack defects, these definitions are no longer necessary.

C. Seismicity and Other Integrity Management Clarifications—§ 192.917

1. Summary of PHMSA's Proposal

Subpart O of 49 CFR part 192 prescribes requirements for managing pipeline integrity in HCAs. It requires operators of covered segments to identify potential threats to pipeline integrity and use that threat identification in their integrity programs. Included within this process are requirements to identify threats to which the pipeline is susceptible, collect data for analysis, and perform a risk assessment. Special requirements are included to address particular threats such as third-party damage and manufacturing and construction defects.

Following the PG&E incident, the NTSB recommended that PG&E evaluate every aspect of its IM program, paying particular attention to the areas identified in the incident investigation, and implement a revised IM program. PHMSA held a workshop on July 21, 2011, to address perceived shortcomings in the implementation of IM risk assessment processes and the information and data analysis (including records) upon which such risk assessments are based. PHMSA also sought input from stakeholders on these issues in the ANPRM.

Section 29 of the 2011 Pipeline Safety Act requires that operators consider the seismicity of the geographic area in identifying and evaluating all potential threats to each pipeline segment, pursuant to 49 CFR part 192. Pipeline threat analysis is addressed as one program element in the IM regulations in subpart O. Addressing seismicity is already implicitly required by § 192.917 as part of addressing outside force threat through the incorporation by reference of ASME B31.8S. Based on the direction of the mandate, PHMSA proposed to explicitly require that operators analyze seismicity and related geotechnical hazards, such as geology and soil stability, as part of the threat identification IM program element and mitigate those threats of outside force damage. PHMSA determined this would clarify expectations for this requirement and explicitly implement section 29 of the 2011 Pipeline Safety Act.

PHMSA also proposed revisions to § 192.917(e) to clarify that certain pipe designs must be pressure tested to assume that seam flaws are stable and that failures or changes to operating pressures that could affect seam stability are evaluated using fracture mechanics analysis.

2. Summary of Public Comment

There was broad support for explicitly requiring the consideration of the seismicity of a geographic area when identifying and evaluating all potential threats to a pipeline segment, and several stakeholders suggested minor revisions to the proposal. California Public Utilities Commission (CPUC) supported the proposed provisions and recommended adding text that would require consideration of any significant localized threat that could affect the integrity of the pipeline. CPUC further commented that operating conditions on the pipeline must also be a factor when operators identify local threats.

Some commenters, including PG&E and NGA, requested further clarification regarding what would constitute a seismic event for the purposes of identifying threats under the IM program for compliance purposes. AGA requested clarification on the requirements regarding whether operators are expected to conduct a one-time investigation on the risk of seismicity and geology, or if there is an expectation of a periodic requirement for re-investigation.

Multiple commenters disagreed with the proposed requirement in § 192.917(e) for operators to perform annual cyclic fatigue analyses if an operator identifies cyclic fatigue as a threat. INGAA and National Fuel

suggested that cyclic fatigue is an uncommon risk for natural gas pipelines and asserted that PHMSA did not provide significant technical justification for this analysis requirement. Some commenters suggested that the proposal to address cyclic fatigue and require pressure tests on seam threats is an overcompensation for the level of risk the threats present. Trade associations and pipeline industries proposed several alternative requirements for the conditions under which cyclic fatigue analyses should be required. API stated that they did not object to the measures listed, but the proposed provisions in § 192.935(b)(2) imply that an operator must take all the actions listed. API asserted that PHMSA should modify this proposed provision to state that operators must consider taking the actions listed but would not be specifically required to take all of them. Other commenters expressed concern that these proposed requirements conflict with the proposed requirements for pipeline segments needing to undertake MAOP reconfirmation because they experienced an incident due to manufacturing and construction (M&C) defects. Specifically, the requirements under § 192.917(e)(3) only allow operators to consider M&C defects stable if they have been subjected to a hydrostatic pressure test of 1.25 times MAOP, which would seemingly disallow or otherwise make fruitless the other methods of MAOP reconfirmation for these types of pipeline segments.

At the GPAC meeting on January 12, 2017, the GPAC recommended that no changes should be made to the proposed provisions on seismicity.

Regarding § 192.917(e)(2), which was discussed during the meeting on June 6–7, 2017, the GPAC noted that, under this provision, operators should be monitoring for condition changes that would cause the threat to potentially activate, and those condition changes should be what triggers a reassessment. The GPAC also noted problems with a suggested revision of performing a cyclic fatigue analysis within a 7-calendar-year period to match certain IM requirements because it would then impose a hard deadline on the continuous monitoring process and would prompt operators to act and again study cyclic fatigue even if the monitoring showed no evidence of cyclic fatigue being a threat. At the meeting, PHMSA suggested that operators could ensure the data involved in a cyclic fatigue analysis is periodically verified within a period not exceeding 7 years to align with IM requirements, but operators would only

be required to perform a full evaluation if the data has changed. Following that discussion, the GPAC recommended revising the proposed requirements for cyclic fatigue at § 192.917 based on the discussion of GPAC members and considering PHMSA's proposed language that was presented at the meeting.

At the GPAC meeting on March 26–28, 2018, a public commenter suggested PHMSA remove the word “hydrostatic” from the requirements for considering M&C-related defects stable because any strength test that is approved in subpart J should qualify. Further, that public commenter suggested adding language where a pressure reduction or an ILI assessment with an ECA could be allowed for M&C defects as well. Another public commenter suggested removing references to cracks in these sections if PHMSA was intending to create a new section dedicated to addressing crack defects.

Ultimately, the GPAC recommended PHMSA revise the proposed requirements for M&C defects by deleting a cross-reference with the MAOP reconfirmation requirements, updating an applicability reference, and considering removing the term “hydrostatic” while allowing other authorized testing procedures. For the requirements related to electric resistance welded (ERW) pipe, the GPAC recommended PHMSA delete the phrase related to pipe body cracking and have those requirements be addressed in a new section within the IM regulations related to crack defects.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the consideration of seismicity and manufacturing- and construction-related defects under the IM regulations. After considering these comments as well as recommendations by the GPAC, PHMSA is revising § 192.917(e)(2) to require operators monitor operating pressure cycles and periodically determine if the cyclic fatigue analysis is valid at least once every 7 calendar years, not to exceed 90 months, as necessary. PHMSA is also deleting a reference to the MAOP reconfirmation requirements in § 192.624 and is referencing the new § 192.712 for fracture mechanics analysis. PHMSA believes these changes are consistent with current IM requirements and will increase regulatory flexibility while maintaining pipeline safety.

In § 192.917(e)(3), PHMSA deleted a cross-reference to the MAOP reconfirmation requirements in § 192.624 and replaced it with a

requirement to prioritize the pipeline segment if it has experienced an in-service reportable incident since its most recent successful subpart J pressure test due to an original manufacturing-related defect; or a construction-, installation-, or fabrication-related defect. This clarifies that the IM requirement in § 192.917(e)(3) is not part of the MAOP reconfirmation standards. Although the GPAC asked PHMSA to consider removing the term “hydrostatic” and allow other testing procedures, PHMSA is retaining the term “hydrostatic” in § 192.917(e)(3), as the proposed revision, as written, addresses NTSB recommendation P–11–15. The NTSB specifically recommended that PHMSA amend part 192 so that manufacturing- and construction-related defects can only be considered stable following a postconstruction hydrostatic pressure test of at least 1.25 times the MAOP. Therefore, deleting the word “hydrostatic” would be contrary to the letter and intent of this NTSB recommendation.

For the requirements related to ERW pipe in § 192.917(e)(4), PHMSA has deleted the phrase related to pipe body cracking and deleted a cross-reference to the MAOP reconfirmation requirements in § 192.624, referencing the new § 192.712 for fracture mechanics analysis instead for cracking and crack-related issues. PHMSA made these changes to streamline the regulations and increase readability.

D. 6-Month Grace Period for 7-Calendar-Year Reassessment Intervals—§ 192.939

1. Summary of PHMSA's Proposal

Section 5 of the 2011 Pipeline Safety Act identifies a technical correction amending 49 U.S.C. 60109(c)(3)(B) to allow the Secretary of Transportation to extend the 7-calendar-year IM reassessment interval for an additional 6 months if the operator submits written notice to the Secretary with sufficient justification of the need for the extension. The NPRM proposed to codify this technical correction as required by the statute.

2. Summary of Public Comment

PHMSA received a comment regarding the 6-month grace period for the 7-calendar-year reassessment interval from a trade organization expressing general support of the proposed provisions and requesting that PHMSA clarify that the 6-month extension begins after the close of the 7-calendar-year reassessment interval period, which would be consistent with

the 2011 Pipeline Safety Act revision to the Federal Pipeline Safety Statutes.

At the GPAC meeting on January 12, 2017, the GPAC voted that the proposed changes on the 6-month grace period for the reassessment intervals are technically feasible, reasonable, cost-effective, and practicable, and did not recommend that PHMSA modify these proposed provisions.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the grace period for IM reassessment intervals. After considering the comment and as recommended by the GPAC, PHMSA is retaining the proposed revisions to § 192.939 in this final rule. The proposed rule clearly stated that the 6-month extension begins after the close of the 7-calendar-year reassessment interval period. This is mirrored in PHMSA's frequently asked questions (FAQ) for the IM program,⁷² which clarifies that the maximum interval for reassessment may be set using the specified number of calendar years in accordance with the 2011 Pipeline Safety Act. The use of calendar years is specific to gas pipeline reassessment interval years under IM and does not alter the interval requirements that appear elsewhere in the code for various inspection and maintenance requirements.

E. ILI Launcher and Receiver Safety—§ 192.750

1. Summary of PHMSA's Proposal

PHMSA determined that more explicit safety requirements are needed when performing maintenance activities that use launchers and receivers for inserting and removing ILI maintenance tools and devices. The current regulations for hazardous liquid pipelines under part 195 have, since 1981, contained safety requirements for scraper and sphere facilities. However, the current regulations for natural gas transmission pipelines do not similarly require controls or instrumentation to protect against an inadvertent breach of system integrity due to the incorrect operation of launchers and receivers for ILI tools, or scraper and sphere facilities. As a result, PHMSA proposed to add a new section to the Federal Pipeline Safety Regulations to require ILI launchers and receivers include a suitable means to relieve pressure in the barrel and either a means to indicate the pressure in the barrel or a means to prevent opening if pressure has not been relieved. While most launchers and

receivers are already equipped with such devices, some older facilities may not be so equipped. Under the proposed provisions, operators would be required to have this safety equipment installed consistent with current industry practice.

2. Summary of Public Comment

Stakeholders, including TPA, provided input on PHMSA's changes to the requirements for safety when performing maintenance activities that utilize launchers and receivers for inserting and removing inspection and maintenance tools and devices. TPA supported the proposed safety additions to the regulations but stated that § 192.750 should be included within the regulations for pipeline components rather than the subpart for pipeline maintenance. In addition, TPA suggested PHMSA revise the language to allow 18 months after the effective date of the rule to comply with the provisions. This change would allow for more time to plan, budget, and complete the work safely. Another commenter recommended these provisions be effective prior to the next time an operator would use an applicable launcher or receiver. Public interest groups and others, such as PST and NAPSRS, had broad support for the proposed provisions regarding ILI launcher and receiver safety.

At the GPAC meeting on January 12, 2017, a public commenter suggested clarification on PHMSA's use of the term "relief device" or "relief valve" within the proposed provisions. During discussion, the committee noted that there are requirements for "relief valves" elsewhere in the code, and calling a needed safety device for ILI launchers and receivers a "relief valve" would then make it subject to those additional requirements. Based on that discussion, the committee recommended that PHMSA modify the proposed rule to clarify that the rule does not require "relief valves" or use "relief valve" as an officially defined term within the provision, as those terms have distinct meanings within the broader context of the Federal Pipeline Safety Regulations.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding launcher and receiver safety. After considering these comments and the GPAC input, PHMSA is finalizing the provisions as they were proposed in the NPRM, with the exception of a compliance date 1 year after the effective date of the rule. This approach avoids disruption of work planned

within a year of the effective date of the rule, and it allows operators that are not planning work until beyond the 1-year grace period to implement the upgrade before the next planned use. Therefore, special modification work would not be required before the launcher or receiver is needed. Operators would not be required to perform the upgrades until the launcher or receiver is to be used.

Consistent with the originally proposed language, this final rule does not use the term "relief valve" and instead uses the generic phrase "device capable of safely relieving pressure." The proposed rule effectively avoided any potential for confusion with respect to the defined term "relief valve" and the requirements associated with those components, therefore no change to this wording was necessary for this final rule.

PHMSA believes that this requirement is appropriately located in subpart M, "Maintenance," of part 192, and notes that the comparable requirement in part 195 for hazardous liquid pipelines is located in subpart F, "Operations and Maintenance."

F. MAOP Exceedance Reporting—§§ 191.23, 191.25

1. Summary of PHMSA's Proposal

Section 23 of the 2011 Pipeline Safety Act requires that operators report each exceedance of a pipeline's MAOP beyond the build-up allowed for the operation of pressure-limiting or control devices. On December 21, 2012 (77 FR 75699), PHMSA published Advisory Bulletin ADB-2012-11 to advise operators of their responsibility under section 23 of the 2011 Pipeline Safety Act to report such exceedances. The advisory bulletin further stated that the reporting requirement is applicable to all gas transmission pipeline facility owners and operators. PHMSA advised pipeline owners and operators to submit this information in the same manner as safety-related condition reports. The information pipeline owners and operators submit should comport with the information listed at § 191.25(b), and pipeline owners and operators submitting such information should use the reporting methods listed at § 191.25(a).

Although this provision of the 2011 Pipeline Safety Act is self-executing, PHMSA proposed to revise the safety-related condition reporting requirements under part 191 to codify this requirement and harmonize part 191 with the statutory requirement by eliminating the reporting exemption and to provide a consistent procedure,

⁷² FAQ-41 at <https://primis.phmsa.dot.gov/gasimp/faqs.htm>.

format, and structure for operators to submit such reports.

2. Summary of Public Comment

Trade associations, citizen groups, and pipeline industries generally supported PHMSA's codification of the statutory reporting requirements for MAOP exceedances for transmission lines.

API and GPA objected to MAOP exceedance reporting requirements for unregulated gathering pipelines. GPA stated that PHMSA did not sufficiently weigh the benefits of reporting MAOP exceedance against the hurdles to compliance for unregulated gathering pipelines. GPA also questioned whether PHMSA has the authority to require unregulated gathering pipelines report MAOP exceedance, since complying with this reporting requirement would necessitate that unregulated gathering pipelines establish MAOP, which they are currently not required to do. Citizen and other safety groups, including Earthworks, NAPS, the Pipeline Safety Coalition, and PST, supported the inclusion of unregulated gathering pipelines in this section, stating that it would improve pipeline safety.

Several commenters suggested editorial revisions to streamline and improve these provisions. NGA expressed concern that the proposed provisions could apply to distribution systems and suggested that PHMSA clarify that reporting requirements for MAOP exceedance only apply to transmission pipelines. Additionally, Spectra Energy Partners requested that PHMSA require reporting of MAOP exceedances only when the operator is unable to respond to MAOP exceedances within the timeframe required elsewhere in part 192.

One operator expressed concern that the proposed change would require operators to submit additional safety-related condition reports anytime the operator had to implement a pressure reduction upon discovering an immediate condition.

At the GPAC meeting on June 7, 2017, there was brief discussion on whether the 5-day reporting requirement was too prescriptive, but the committee agreed that PHMSA was properly implementing the statutory requirement as written and intended by Congress. Following that discussion, the committee recommended that PHMSA modify the proposed rule to clarify that the MAOP exceedance reporting provisions do not apply to gathering lines.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding MAOP exceedance reporting. The 2011 Pipeline Safety Act mandates that an operator report MAOP exceedances on gas transmission lines, regardless of whether the operator corrects the safety-related condition through repair or replacement. After considering the comments PHMSA received on the NPRM and as recommended by the GPAC, PHMSA is inserting the word "only" in the additional MAOP exceedance reporting provision in § 191.23(a)(10) to make it clearer that the amended requirement applies only to gas transmission lines and not to gathering or distribution lines. Conforming changes were made to § 191.23(a)(6). PHMSA notes that the prior safety-related condition reporting requirements and exceptions related to pressure exceedances for gathering and distribution lines have not been altered.

G. Strengthening Assessment Requirements—§§ 192.150, 192.493, 192.921, 192.937, Appendix F

i. Industry Standards for ILI—§§ 192.150, 192.493

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to revise § 192.150 to incorporate by reference a NACE Standard Practice, NACE SP0102–2010, "In-line Inspection of Pipelines," to promote a higher level of safety by establishing consistent standards for the design and construction of pipelines to accommodate ILI devices.

In § 192.493, PHMSA proposed requirements for operators to comply with the requirements and recommendations of API STD 1163, In-line Inspection Systems Qualification Standard; ANSI/ASNT ILI-PQ–2005, In-line Inspection Personnel Qualification and Certification; and NACE SP0102–2010, In-line Inspection of Pipelines. PHMSA also proposed to allow operators to conduct assessments using tethered or remotely controlled tools.

2. Summary of Public Comment

NAPS supported the proposed provisions in § 192.493, commenting that the incorporation by reference of the three consensus standards provides enhanced guidance for the determination of adequate procedures and qualifications related to in-line inspections of transmission pipelines.

Some industry representatives commented that it is unnecessary to incorporate American Society for Nondestructive Testing (ASNT) ILI-PQ by reference since API 1163 requires

that providers of ILI services ensure that their employees are qualified. Others commented that PHMSA should exclude requirements contained in section 11 of API 1163, which pertains to quality management systems. Lastly, industry representatives asserted that ILI vendors may not be able to meet the 90 percent tool tolerance specified in the referenced standards, and PHMSA should relocate these proposed requirements to a different subpart.

Several commenters noted that if PHMSA required compliance with "the requirements and recommendations of" the recommended practices and standards, it would create enforceable requirements out of actions that the standards themselves did not necessarily mandate.

During the GPAC meeting of March 2, 2018, the committee recommended PHMSA revise this provision by striking the phrase "the requirements and the recommendations of," so that recommendations within the incorporated standard would not be made mandatory requirements.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the incorporation by reference of industry standards for ILI. After considering these comments and as recommended by the GPAC, PHMSA is deleting the phrase "the requirements and the recommendations of" from §§ 192.150 and 192.493 so that the recommendations within the incorporated standard would not be made mandatory requirements.

PHMSA believes that the inclusion of the NACE standard at § 192.150 will help to address the NTSB recommendation P–15–20, which asked PHMSA to identify all operational complications that limit the use of ILI tools in piggable pipelines, develop methods to eliminate those complications, and require operators use such methods to increase the use of ILI tools. PHMSA also believes that more pipelines will become piggable in the future as the nation's pipeline infrastructure ages and is eventually replaced. A current provision in the regulations requires that all new and replaced pipeline be piggable, and as operators address higher-risk infrastructure through this rulemaking, there is a likelihood that some previously unpiggable pipe will be replaced.

PHMSA disagrees that ASNT ILI-PQ is unnecessary. The foreword of API 1163 states "This standard serves as an umbrella document to be used with and complement companion standards."

NACE SP0102, In-line Inspection of Pipelines and ASNT ILI-PQ, In-line Inspection Personnel Qualification and Certification.” These three standards are complimentary and are intended to be used together. PHMSA also disagrees that quality requirements should be excluded from the rule. One of the fundamental objectives of this rule is to establish a minimum standard for quality in conducting ILI. Also, the consensus industry standard API 1163 only uses 90 percent tool tolerance as an example to illustrate key points but does not specify or establish a minimum standard tool tolerance of 90 percent.

G. Strengthening Assessment Requirements—§§ 192.150, 192.493, 192.921, 192.937, Appendix F

ii. Expand Assessment Methods Allowed for IM—§§ 192.921(a) and 192.937(c)

1. Summary of PHMSA’s Proposal

In the current Federal Pipeline Safety Regulations, § 192.921 requires that operators with pipelines subject to the IM rules must perform integrity assessments. Currently, operators can assess their pipelines using ILI, pressure test, direct assessment, and other technology that the operator demonstrates provides an equivalent level of understanding of the condition of the pipeline.

In the NPRM, PHMSA proposed to require that direct assessment only be allowed when the pipeline cannot be assessed using ILI. As a practical matter, direct assessment is typically not chosen as the assessment method if the pipeline can be assessed using ILI. Further, PHMSA proposed to add three additional assessment methods to the regulations:

1. A spike hydrostatic pressure test, which is particularly well-suited to address stress corrosion cracking and other cracking or crack-like defects;
2. Guided Wave Ultrasonic Testing (GWUT), which is particularly appropriate in cases where short segments such as road or railroad crossings are difficult to assess; and
3. Excavation with direct *in situ* examination.

2. Summary of Public Comment

NAPSR expressed its support for the proposed provisions. Many comments expressed concerns with the proposed provisions for the assessment methods regarding uncertainties in reported results. Multiple commenters stated that operators should be able to run the appropriate assessment or ILI tools for the threats that are known or likely to exist on the pipeline based on its

condition. Atmos Energy commented that ASME/ANSI B318.S requirements should be the standard to which operators are required to follow. Enable Midstream Partners proposed that PHMSA add “significant” to make a distinction between significant and insignificant threats and offered specific language to address its concerns. PG&E commented on the proposed provisions for ILI assessments, requesting that PHMSA provide guidance as to how to explicitly consider the numerous uncertainties associated with ILI regarding anomaly location accuracy, detection thresholds, and sizing accuracy, and suggested that PHMSA allow industry guidance and best practices to be used where practical. Some commenters expressed concern that PHMSA proposed to add requirements surrounding the detection of anomalies that many ILI tools could not meet. These commenters stated that there are no tools designed to find girth weld cracks and that most incidents caused by girth weld cracks have third-party excavation damage as a contributing factor. Commenters further stated that this is a threat that is best handled by procedures that require caution around girth welds during excavation and backfilling procedures.

Several entities commented on the proposed qualification requirements under the ILI assessment method provisions, expressing concern that they are redundant with existing operator qualification regulations under the IM regulations at § 192.915 and the proposed revisions to § 192.493 incorporating the industry ANSI standard on ILI personnel qualification. Multiple entities proposed changes to remove such redundancies and improve clarity.

Commenters requested clarification that the proposed text in the IM assessment provisions “apply one or more of the following methods for each threat to which the covered segment is susceptible” does not mean that at least one assessment is required for each threat. Additionally, commenters disagreed with adding an explicit requirement for a “no objection” letter as notification of using “other technology” and suggested that if this notification is required, operators should be allowed to proceed with the technology if they do not receive a “no objection” letter from PHMSA within a certain period.

The NTSB commented that PHMSA’s proposal to revise the pipeline inspection requirements to allow the direct assessment method to be used only if a line is not capable of inspection by internal inspection tools

directly conflicts with the recommendations of their pipeline safety study, *Integrity Management of Gas Transmission Lines in High Consequence Areas*, which recommended that PHMSA develop and implement a plan for eliminating the use of direct assessment as the sole integrity assessment method for gas transmission pipelines. The CPUC asserted that direct assessment must always be supplemented with other methods, such as ILI or a pressure test.

Many industry entities argued that PHMSA’s proposed changes to the IM assessment provisions limiting direct assessment to unpiggable lines are not technically justified. Several entities, including AGA and API, believed it was unreasonable to limit operators’ ability to use direct assessment for pipeline assessments unless all other assessment methods have been determined unfeasible or impractical. PG&E requested that PHMSA recognize that although a pipeline may be considered piggable, it does not mean that ILI technology is available, and they provided specific suggestions for revision. Similarly, AGA stated that free-swimming flow-driven ILI tools are often not compatible with intrastate transmission lines for several reasons, stating that certain conditions must exist to assess a pipeline by ILI and obtain valid data, including adequate flow rate, lack of bends or valves that would impede diameter, and ability to insert and remove the tool from the system. Therefore, AGA provided a suggested definition for “able to accommodate inspection by means of an instrumented in-line inspection tool.”

Trade associations asserted that direct assessment is a proven assessment technique that works in addressing the threat of corrosion. INGAA stated that the criteria for when direct assessment can be used should depend on whether direct assessment can provide the necessary information about the pipe condition rather than whether other assessment methods can be used. AGA commented that it is not aware of any industry study that would suggest that direct assessment does not work effectively to identify corrosion defects in certain circumstances, which it describes in its comments. In addition, AGA stated that direct assessment is a predictive tool that identifies areas where corrosion could occur, including time-dependent threats, while other methods can only detect where corrosion has resulted in a measurable metal loss. Atmos Energy commented that limiting the use of direct assessment only to those pipeline segments that are not capable of

inspection by internal inspection tools is not consistent with other requirements of subpart O.

At the GPAC meeting on December 15, 2017, the committee voted to revise the “no objection” process to incorporate language stating that, if an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA of an alternative sampling approach, the operator can proceed with their method. Additionally, the GPAC, during the meeting on March 2, 2018, recommended that PHMSA change these provisions to clarify that operators should select the appropriate assessment based on the threats to which the pipeline is susceptible and remove certain language that is duplicative to another existing section of the regulations. The GPAC also recommended that PHMSA clarify that direct assessment is allowed where appropriate but may not be used to assess threats for which the method is not suitable. Further, the GPAC wanted PHMSA to incorporate the notification and objection procedure and 90-day timeframe that the GPAC approved under the material properties verification requirements.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the inclusion of additional assessment methods for integrity assessments. After considering these comments and as recommended by the GPAC, PHMSA is clarifying in this final rule that operators should select the appropriate assessment method based on the threats to which the pipeline is susceptible and is removing language regarding the qualification of persons reviewing ILI results that is duplicative with existing § 192.915. PHMSA is also clarifying in § 192.921 that direct assessment is allowed where appropriate but may not be used to assess threats for which the method is not suitable, such as assessing pipe seam threats. In addition, PHMSA incorporated the notification procedure under § 192.18 with the 90-day timeframe and objection process.

PHMSA notes that other comments regarding the determination of suitable assessment methods for applicable threats and ILI tool capabilities relate to long-standing IM regulations that were not proposed for revision. PHMSA did provide substantial additional guidance and standards for implementing the integrity assessment requirements for ILI by incorporating the industry standards in § 192.493, as discussed in the previous sections.

G. Strengthening Assessment Requirements—§§ 192.150, 192.493, 192.921, 192.937, Appendix F

iii. Guided Wave Ultrasonic Testing—Appendix F

1. Summary of PHMSA’s Proposal

When expanding assessment methods for both HCA and non-HCA areas, PHMSA proposed to add three additional assessment methods, one being GWUT. Under the existing regulations, GWUT is considered “other technology,” and operators must notify PHMSA prior to its use. PHMSA developed guidelines for the use of GWUT, which have proven successful, and proposed to add them under a new Appendix F to part 192—Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing. As such, future notifications to PHMSA would not be required, representing a cost savings for operators.

2. Summary of Public Comment

Multiple entities commented in support of using GWUT and the inclusion of proposed Appendix F. NAPS expressed its agreement with and support for the proposed Appendix. American Public Gas Association (APGA) applauded PHMSA for including guidelines for GWUT; however, it cautioned that the guidance only specifies Guided Ultrasonics LTD (GUL) Wavemaker G3 and G4, which use piezoelectric transducer technology, as acceptable technology. APGA recommended that Magnetostrictive Sensor technology also be included as an acceptable guided wave technology, stating that at least one of its members reported good results using this technology for guided wave assessment of an unpiggable segment of a transmission pipeline.

A commenter noted that the requirement of both torsional and longitudinal wave modes in all situations introduces unnecessary complexity into the GWUT data interpretation process. The commenter further noted that PHMSA should specify that torsional wave mode is the primary wave mode when utilizing GWUT, and that longitudinal wave mode may be used as an optional, secondary mode. Other commenters recommended additional changes to Appendix F, such as stating that qualified GWUT equipment operators are trained to understand the strengths, weaknesses, and proper applications of each wave mode and should have the freedom to select the appropriate and most effective wave mode(s) for the given situation. PG&E requested that

PHMSA recognize that this technology is used at locations other than casings as implied in the introductory paragraph and commented that double-ended inspections are not always required to meet the specification.

During the GPAC meeting on December 15, 2017, the GPAC agreed with the provisions related to Appendix F and GWUT but recommended PHMSA revise the “no objection” letter process.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding GWUT. After considering these comments and as recommended by the GPAC, PHMSA is removing the reference to GUL equipment for clarity. PHMSA is modifying the notification process to allow operators to proceed with an alternative process for using GWUT if the operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA in accordance with § 192.18. PHMSA believes this change increases regulatory flexibility while maintaining pipeline safety.

In this final rule, PHMSA is retaining the requirement to use both torsional and longitudinal wave modes since that is a long-standing requirement in PHMSA’s guidance for accepting GWUT as an allowed technology under an “other technology” notification. Also, PHMSA recognizes that GWUT is used at locations other than casings, although it is most often deployed for the integrity assessment of cased crossings. However, double-ended inspections would not always be required to meet Appendix F, and Appendix F does not require double-ended inspections. Double-ended inspections are not necessary as long as the guided wave ultrasonic test covers the entire length of the assessment as well as the “dead zone” where the equipment is set up.

The proposed rule already addresses validation of operator training, but in this final rule, PHMSA is deleting the sentence “[t]here is no industry standard for qualifying GWUT service providers” to provide clarity.

H. Assessing Areas Outside of HCAs—§§ 192.3, 192.710

i. MCA Definition—§ 192.3

1. Summary of PHMSA’s Proposal

In the NPRM, PHMSA introduced a new definition for a Moderate Consequence Area (MCA). The proposed rule defined an MCA as an onshore area, not meeting the definition of an HCA, that is within a potential impact circle, as defined in § 192.903, containing 5 or more buildings intended

for human occupancy; an occupied site; or a right-of-way for a designated interstate, freeway, expressway, or other principal four-lane arterial roadway as defined in the Federal Highway Administration's "Highway Functional Classification Concepts, Criteria and Procedures." PHMSA proposed that requirements for data analysis, assessment methods, and immediate repair conditions within these MCAs would be similar to requirements for HCA pipeline segments but with longer timeframes so that operators could properly allocate resources to higher-consequence areas. PHMSA proposed that the 1-year repair conditions that currently exist for HCA pipeline segments would be 2-year repair conditions when found on MCA pipeline segments. These changes would ensure the prompt remediation of anomalous conditions that could potentially affect people, property, or the environment, commensurate with the severity of the defects, while still allowing operators to allocate their resources to HCAs on a higher-priority basis.

2. Summary of Public Comment

The NTSB stated that the proposed provisions to create an MCA category and include a highway size threshold in the definition of an MCA accomplishes part of what the NTSB intended in Safety Recommendation P-14-1. However, the NTSB objected to the proposed highway coverage as being limited to four lanes and stated its support of expanding the highway size threshold as they had specifically recommended in P-14-1. The NTSB asserted that the proposed language would exclude the category of other principal arterial roadways wider than four lanes when, in fact, the wider roadways should be included.

INGAA supported the addition of an MCA category to the Federal Pipeline Safety Regulations but recommended several modifications to the proposed definition. INGAA suggested PHMSA should limit the definition of an MCA to only those pipeline segments that could be assessed through an ILI inspection, amend the MCA definition to avoid ambiguity regarding residential structures, remove "outside areas and open structures" from the portion of the definition of MCA related to "identified sites," include timeframes for incorporating changes to existing MCAs, and permit operators to use the edge of the pavement rather than the highway right-of-way to determine if a roadway intersects with a Potential Impact Circle.

AGA, API, APGA, and several pipeline entities agreed with INGAA's

comments on the modification to PHMSA's proposed MCA definition. Additionally, AGA, API, and APGA emphasized PHMSA should remove the reference to "a right-of-way" for the designated roadways, commenting that the MCA definition could be interpreted so that if a Potential Impact Circle touches any portion of the roadway right-of-way, the pipeline segment is an MCA. That interpretation would put undue burden on operators in areas where its pipelines lay at or near the edge of the public right-of-way that would not normally contain "persons or property" that would sustain damage or loss in the event of a pipeline failure. Further, API added that the reference to "a right-of-way" is problematic because roadway right-of-ways are variable, cannot be seen with the naked eye, and are often not included in publicly available data sources.

Commenters also disagreed with the definition of "occupied site" within the MCA definition. GPA asserted that the criterion used in the MCA definition should be limited to interstate highways, and the definition of "occupied site" should be eliminated to more clearly distinguish between MCAs and HCAs and to provide greater clarity in identifying and managing MCAs. Similarly, Enlink Midstream commented that PHMSA should eliminate the definition of occupied site and remove this criterion from the proposed definition of MCA. Doing so would permit the continued focus on HCAs that the IM process was intended to accomplish. AGL Resources also expressed concern with the proposed definition of occupied site, commenting that this definition could require operators to effectively perform a census-like identification of structures to verify the count of persons within that structure.

There were conflicting viewpoints on where the definition of MCA should be placed in the regulations. API and other commenters stated that they preferred a new category and a distinct definition for MCA as opposed to expanding the definition of HCA or making a subcategory in the HCA definition for MCAs, whereas SoCalGas encouraged expanding the scope of HCAs rather than creating a new category.

Enterprise Products commented PHMSA should move the MCA definition to subpart O and remove the "occupied site" criteria from the proposed definition of MCA, which would provide more distinction between MCAs and HCAs in the regulations and would also more appropriately place them under the IM regulations.

AGA and several other organizations expressed concern over the resource-intensive administrative task of identifying MCAs, especially pertaining to recordkeeping requirements. API asserted that the proposed provisions would limit operators' ability to prioritize resources for pipelines that pose the highest risk. They further stated that while they agree with the inclusion of all Class 3 and Class 4 locations, occupied sites, and major roadways in the definition of MCA, they disagree with the proposed threshold of five buildings intended for human occupancy within the potential impact radius. They suggested that a more appropriate threshold would be more than 10 buildings intended for human occupancy, as that number is consistent with longstanding part 192 class location designations.

Multiple groups, such as AGI, INGAA, and Cheniere Energy, also stated objections over various aspects of defining and identifying MCAs and provided suggestions for revised language, including several broad clarifications or deletions to the definition. In addition to requesting modifications to the definition of MCA, INGAA objected to the provided geographic information system (GIS) layer for right-of-way determination, and suggested that PHMSA provide one database for roadway classification. Numerous trade associations and pipeline companies asked PHMSA to consider a qualifier that the definition of MCA only applies to pipelines operating at greater than 30 percent SMYS. EnLink Midstream suggested using a threshold level of 16-inch pipe diameter to identify pipelines that pose a greater risk.

The GPAC had a comprehensive discussion on the MCA definition during the meeting on March 2, 2018, and approved of the definition with some changes. First, the GPAC recommended changing the highway description within the definition to remove reference to the roadway "rights-of-way" and to add language so that the highway consists of "any portion of the paved surface, including shoulders." Secondly, the GPAC recommended clarifying that highways with 4 or more lanes are included, and they also wanted PHMSA to work together with the Federal Highway Administration to provide operators with clear information relative to this aspect of the rulemaking and discuss it in the preamble. The GPAC also recommended that PHMSA discuss in the preamble what they expect the definition of "piggable" to be, as it is critical for aspects of the MCA

definition as it relates to MAOP confirmation. Finally, the GPAC recommended PHMSA modify the term “occupied sites” in the MCA definition and in the definitions section of part 192 by removing the language referring to “5 or more persons” and the timeframe of 50 days and tying the requirement into the HCA survey for “identified sites” as discussed by GPAC members and PHMSA at the meeting. The committee noted that such site identification could be made through publicly available databases and class location surveys. The committee suggested PHMSA consider the necessary sites and enforceability of the definition per direction by the committee members.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the definition of moderate consequence area. After considering these comments and the GPAC input, PHMSA is modifying the highway description within the definition to remove reference to the roadway “rights-of-way” and to add language so that the highway consists of “any portion of the paved surface, including shoulders.” Also, PHMSA is specifying that highways with 4 or more lanes are included. PHMSA believes these changes provide additional clarity.

Per the GPAC’s request that PHMSA provide additional guidance on what roadways are included in the MCA definition as it pertains to “other principal roadways with 4 or more lanes,” PHMSA notes that the Federal Highway Administration defines *Other Principal Arterial* roadways⁷³ as those roadways that serve major centers of metropolitan areas, provide a high degree of mobility, and can also provide mobility through rural areas. Unlike their access-controlled counterparts (interstates, freeways, and expressways), abutting land uses can be served directly. Forms of access for *Other Principal Arterial* roadways include driveways to specific parcels and at-grade intersections with other roadways. For the most part, roadways that fall into the top three functional classification categories (Interstate, Other Freeways & Expressways, and Other Principal Arterials) provide similar service in both urban and rural areas. The primary difference is that

there are usually multiple arterial routes serving a particular urban area, radiating out from the urban center to serve the surrounding region. In contrast, an expanse of a rural area of equal size would be served by a single arterial. The MCA definition does not include all roadways that meet this definition but instead is limited to those roadways meeting this definition that have four or more lanes.

With respect to “occupied sites,” PHMSA evaluated the comments and the GPAC discussion and concluded that including occupied sites within the MCA definition was not necessary. Industry representatives on the GPAC asserted that most locations meeting the definition of occupied site are, as a practical matter, already included as an identified site and designated as an HCA. Commenters suggested most operators find it expedient to declare sites similar to occupied areas as HCAs instead of counting the specific occupancy of such locations to see if they meet the occupancy standard over the course of a year. Operators then monitor occupancy in subsequent years for changes that might change the site’s status as an occupied site. Such an approach would require fewer resources and be more conservative from a public safety standpoint. Based on these comments, PHMSA is persuaded that including another category of locations, similar to identified sites in HCAs but with a lower occupancy standard of 5 persons, is unnecessarily burdensome without a comparable decrease in risk.

PHMSA disagrees that the MCA definition should be moved to subpart O. The term is used in sections outside of subpart O. Including the MCA definition in § 192.3 is necessary for it to apply to the sections in which it is used throughout part 192.

H. Assessing Areas Outside of HCAs—§§ 192.3, 192.710

ii. Non-HCA Assessments—§ 192.710

1. Summary of PHMSA’s Proposal

PHMSA proposed to add a new § 192.710 to require that pipeline segments in Class 3 or Class 4 locations, and piggable segments in MCAs, be initially assessed within 15 years and no later than every 20 years thereafter on a recurring basis. PHMSA also proposed to require assessments in these areas be conducted using the same methods that are currently allowed for HCAs. PHMSA has found that operators have assessed significant non-HCA pipeline mileage in conjunction with performing HCA integrity assessments in the same pipeline. Therefore, PHMSA proposed to allow the use of those prior

assessments of non-HCA pipeline segments to comply with the new § 192.710.

In effect, to this limited population of pipeline segments outside of HCAs, PHMSA proposed to expand the applicability of IM program elements related to baseline integrity assessments, remediating conditions found during integrity assessments, and periodic reassessments. In addition, under the proposed provisions, MCAs would be subject to other requirements related to the congressional mandates, including material properties verification and MAOP reconfirmation. Any assessments an operator would conduct to reconfirm MAOP under proposed § 192.624 would count as an initial assessment or reassessment, as applicable, under the proposed requirements for non-HCA assessments.

2. Summary of Public Comment

The NTSB and multiple citizen groups supported the expansion of IM elements to gas transmission pipelines in areas outside those currently defined as HCAs. However, several entities, including PST, stated that applying a limited suite of IM tools to these areas was insufficient and requested that the full suite of IM elements be applied to the additional pipeline segments. Some citizen groups expressed concern that the 15-year implementation period and 20-year re-inspection period was too long.

While pipeline companies and trade associations generally supported PHMSA’s efforts to expand IM elements beyond HCAs, many of them stated concerns over the time and cost required to identify MCAs, the efficacy of the changes, and the language and requirements regarding both the limitation of assessments to pipeline segments accommodating inline inspection tools and (re)assessment periods. Many groups requested a clear, concise set of codified requirements for IM outside of HCAs to simplify identification, recordkeeping, and repairs.

Several commenters provided input on the allowable assessment methods for non-HCAs. AGA suggested that PHMSA create a new subpart consisting of a clear and concise set of codified requirements for the non-HCA assessments, including new definitions regarding the limitation of assessments to pipeline segments accommodating instrumented inline inspection tools. Many trade associations and pipeline companies stated that they thought the direct assessment method could achieve a satisfactory level of inspection in place of costlier in-line inspection,

⁷³ Federal Highway Administration, Office of Planning, Environment, & Realty (HEP), *Highway Functional Classification Concepts, Criteria and Procedures (2013)* https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classifications/section03.cfm#Toc336872980.

especially given the additional detail added to the in-line inspection assessment method in the proposal. API requested that PHMSA allow operators to rely on any prior assessments performed under subpart O requirements of part 192 in effect at the time of the assessment rather than limit the allowance to ILI. Furthermore, other organizations supported AGA's proposal that mirrors and extends to MCAs the two-methodology approach used to determine HCAs in the existing § 192.903, which allows for identification based on class location or by the pipeline's potential impact radius.

Entities, including API and Atmos Energy, requested clarification regarding assessment periods and reassessment intervals due to the language regarding shorter reassessment intervals "based on the type [of] anomaly, operational, material and environmental conditions [. . .], or as otherwise necessary." Those commenters said that language was vague and subject to varying interpretations, so they suggested revisions to the language for the reassessment intervals. Lastly, AGA suggested that PHMSA define the term "pipelines that can accommodate inspection by means of an instrumented in-line inspection tool" used in proposed §§ 192.710 and 192.624, stating that providing the criteria that a pipeline must meet to be able to accommodate an in-line inspection tool would remove uncertainty and inconsistency in determining which pipelines meet PHMSA's proposed qualifier.

The GPAC discussed the provisions related to assessments outside of HCAs during the meeting on March 2, 2018. The GPAC found the provisions to be technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified that direct assessment could be used only if appropriate for the threat being assessed and could not be used to assess threats for which direct assessment is not suitable, and removed the provisions related to low-stress assessments. The GPAC also recommended revising the initial assessment and reassessment intervals for applicable pipeline segments from an initial assessment within 15 years of the effective date of the rule and periodic assessments every 20 years thereafter to an initial assessment within 14 years of the effective date of the rule and periodic assessments every 10 years thereafter. The GPAC stated that the prioritization of initial assessments and reassessments should be based on the risk profiles of the pipelines. The GPAC also wanted

PHMSA to apply the assessment and reassessment requirements only to pipelines with MAOPs greater than or equal to 30 percent SMYS.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding integrity assessments outside HCAs. After considering these comments and as recommended by the GPAC, PHMSA is modifying the rule to specify that direct assessment may be used only if appropriate for the threat being assessed and cannot be used to assess threats for which direct assessment is not suitable, such as assessing pipe seam threats. PHMSA made these changes to provide clarity regarding the proper use of direct assessments.

In addition, PHMSA is revising the applicability of § 192.710 to apply only to pipelines with an MAOP of greater than or equal to 30 percent of SMYS. PHMSA made this change because the GPAC recommended it was cost-effective for the provision to only apply to pipe operating above 30% SMYS in Class 3 and 4 locations and because those pipelines present the greatest risk to safety. Because of this modification, PHMSA is withdrawing provisions related to low-stress assessments since they will no longer be applicable.

Based on the comments and recommendations from the GPAC, PHMSA is also modifying the initial assessment deadline and reassessment intervals for applicable pipeline segments to 14 years after the publication date of the rule and every 10 years thereafter, which was reduced from 15 years and 20 years, respectively. PHMSA believes this change increases regulatory flexibility while maintaining pipeline safety. PHMSA is also adding a requirement that the initial assessments must be scheduled using a risk-based prioritization.

PHMSA disagrees with the need to implement a dual approach to MCA identification that would be similar to the ways that HCAs are identified. Subpart O and the IM regulations were first promulgated before pipeline operators had experience with potential impact radius (PIR) techniques, and incorporating an alternative HCA identification method into the original IM regulations using conventional class locations was convenient and appropriate. Pipeline operators now have over 15 years of experience working with the PIR concept; therefore, PHMSA determined using the PIR method for determining MCAs in the definition of MCAs is appropriate. PHMSA also disagrees that a separate subpart would be preferable and is

retaining the requirements for MCA assessments in a new § 192.710.

PHMSA believes the requirement to have a shorter reassessment interval is clear and is not modifying that aspect of the rule. PHMSA included a requirement for operators to not automatically default to the maximum reassessment interval but to establish shorter reassessment intervals "based upon the type anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety" when appropriate. Operators have been required to perform similar analyses and adjustment of reassessment intervals for HCAs since the inception of the IM regulations in 2003 and should be familiar with this process over 15 years later. PHMSA believes that stating the overarching goal of assuring public safety by evaluating each pipeline and its circumstances and establishing appropriate assessment intervals based on those circumstances provides clear intent and is an appropriate approach.

PHMSA believes that the term "piggable segment" is very widely understood in the industry and is not including additional definitions or regulatory language to expand upon this term. PHMSA understands that a pipeline segment might be incapable of accommodating an in-line inspection tool for a number of reasons, including but not limited to short radius pipe bends or fittings, valves (reduced port) that would not allow a tool to pass, telescoping line diameters, and a lack of isolation valves for launchers and receivers. Some unpiggable pipelines can be made piggable with modest modifications, but others cannot be made piggable short of pipe replacement.

PHMSA understands that a pipeline segment is piggable if it can accommodate an instrumented ILI tool without the need for major physical or operational modification, other than the normal operational work required by the process of performing the inline inspection. This normal operational work includes segment pigging for internal cleaning, operational pressure and flow adjustments to achieve proper tool velocity, system setup such as valve positioning, installation of temporary launchers and receivers, and usage of proper launcher and receiver length and setup for ILI tools. In addition, a pipeline segment that is not piggable for a particular threat because of limitations in technology such that an ILI tool is not commercially available, might be piggable for other threats. For example, a pipeline that is unable to accommodate a crack tool might be able

to accommodate a conventional MFL or deformation tool, and thus be piggable for those threats. Launcher and receiver lengths are not a reason for a pipeline to be considered unpiggable, since through a minor modification they can be modified to be piggable, and the removal of launchers or receivers from the pipeline segment does not make a pipeline unpiggable either.

I. Miscellaneous Issues

i. Legal Comments

The following section discusses industry comments related to legal and administrative procedure issues with the proposed rule.

Summary of Public Comment

Several commenters asserted that the proposed provisions go beyond PHMSA's statutory authority provided by the 2011 Pipeline Safety Act. Many trade associations and pipeline industry entities stated that PHMSA exceeded the congressional mandates in the proposed provisions by imposing retroactive recordkeeping requirements and retroactive material properties verification requirements. These comments are discussed in more detail in their respective sections above.

Commenters asserted that, in the 2011 Pipeline Safety Act, Congress identified specific factors that PHMSA is required to consider when proposing regulations per the statutory mandates, including whether certain proposed provisions would be economically, technically, and operationally feasible, and that the proposed rule did not adequately address these factors. For example, AGA expressed concerns that PHMSA proposed to adopt NTSB recommendations without independently justifying those provisions based on the specific factors required by Congress or providing the reasoning behind adopting said recommendations.

AGA and INGAA also stated that PHMSA did not adequately consider the impact that the Natural Gas Act of 1968 would have on implementation of the proposed rule. Noting that operators are required to obtain permission from FERC before removing pipelines from service or replacing pipelines, these commenters stated that obtaining permissions could hinder operators from quickly performing required tests and repairs. INGAA and AGA also stated that PHMSA did not consult with FERC and State regulators about implementation timelines for certain provisions, which PHMSA is required to do in accordance with 49 U.S.C.

60139(d)(3) because gas service would be affected by the proposed rule.

PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the statutory authority for the proposed rule. With regard to the comments about imposing retroactive recordkeeping requirements and retroactive material properties verification requirements, PHMSA explained in this document that the final provisions of this rule are prospective and do not create retroactive requirements. This topic is discussed in more detail in the respective sections about recordkeeping and material properties verification.

Pertaining to PHMSA's broader authority, Congress has authorized the Federal regulation of the transportation of gas by pipeline in the Pipeline Safety Laws (49 U.S.C. 60101 *et seq.*) and established the current framework for regulating pipelines transporting gas in the Natural Gas Pipeline Safety Act of 1968, Public Law 90-481. Through these laws, Congress has delegated the DOT the authority to develop, prescribe, and enforce minimum Federal safety standards for the transportation of gas, including natural gas, flammable gas, or toxic or corrosive gas, by pipeline. As required by law, PHMSA has considered whether the provisions of this rule are economically, technically, and operationally feasible and has provided relevant analysis in the Regulatory Impact Analysis and preamble of this rule.

In accordance with section 23 of the 2011 Pipeline Safety Act, PHMSA consulted with the Federal Energy Regulatory Commission and State regulators as appropriate to establish the timeframes for completing MAOP reconfirmation. As a part of this consultation, PHMSA accounted for potential consequences to public safety and the environment while also accounting for minimal costs and service disruptions. Furthermore, PHMSA will note that both a FERC member and a NPSR member are on the GPAC, providing both input and positive votes that the provisions were technically feasible, reasonable, cost-effective, and practicable if certain changes were made. As previously discussed, PHMSA has taken the GPAC's input into consideration when drafting this final rule and made the according changes to the provisions.

I. Miscellaneous Issues

ii.—Records

1. Summary of PHMSA's Proposal

Many pipeline records are necessary for the correct setting and validation of MAOP, which is critically important for providing an appropriate margin of safety to the public. Much of operator and PHMSA data is obtained through testing and inspection under the existing IM requirements. Section 192.917(b) requires operators to gather pipeline attribute data as listed in ASME/ANSI B31.8S—2004 Edition, section 4, table 1. ASME/ANSI B31.8S—2004 Edition, section 4.1 states:

"Pipeline operator procedures, operation and maintenance plans, incident information, and other pipeline operator documents specify and require collection of data that are suitable for integrity/risk assessment. Integration of the data elements is essential in order to obtain complete and accurate information needed for an integrity management program. Implementation of the integrity management program will drive the collection and prioritization of additional data elements required to more fully understand and prevent/mitigate pipeline threats."

However, despite this requirement, there continue to be data gaps that make it hard to fully understand the risks to and the integrity of the nation's pipeline system. Therefore, PHMSA proposed amendments to the records requirements for part 192, specifically under the general recordkeeping requirements, class location determination records, material mechanical property records, pipe design records, pipeline component records, welder qualification records, and the MAOP reconfirmation provisions.

2. Summary of Public Comment

Several commenters provided input on the proposed amendments to the records requirements for part 192. Several public interest groups, including Pipeline Safety Coalition and PST, supported the increased emphasis on recordkeeping requirements, stating that the requirements are a proactive response to NTSB recommendations and are common-sense business best practices.

Several commenters opposed the proposed provisions providing general recordkeeping requirements for part 192. Commenters asserted that these proposed provisions apply significant new recordkeeping requirements on operators by requiring that operators

document every aspect of part 192 to a higher and impractical standard than before. Commenters also stated that the proposed recordkeeping requirements appear to be retroactive and stated that it would be inappropriate to require operators to document compliance in cases where there have not been requirements to document or retain records in the past. Commenters also asserted that the Pipeline Safety Laws at 49 U.S.C. 60104(b) prohibits PHMSA from applying new safety standards pertaining to design, installation, construction, initial inspection, and initial testing to pipeline facilities already existing when the standard is adopted, and that PHMSA does not have the authority to apply these requirements retroactively. These commenters suggested that even the recordkeeping requirements in these non-retroactive subparts could not be changed under PHMSA's current authority. Subsequently, commenters requested that PHMSA confirm that the proposed general, material, pipe design, and pipeline component recordkeeping requirements would not apply to existing pipelines and that recordkeeping requirements for the qualification of welders and qualifying plastic pipe joint-makers would not apply to completed pipeline projects.

Additionally, several commenters also requested that PHMSA clarify that many of the proposed recordkeeping requirements apply only to gas transmission lines. AGA also expressed concern regarding the proposed reference to material properties verification requirements in the proposed general recordkeeping requirements, which, as written, would also require distribution pipelines without documentation to comply with the proposed material properties verification requirements.

Many commenters opposed the proposed application of the term "reliable, traceable, verifiable, and complete" in part 192 beyond the requirements for MAOP records, and AGA recommended the deletion of "reliable, traceable, verifiable, and complete" from proposed provisions under MAOP reconfirmation. Similarly, other commenters, including INGAA, recommended omitting "reliable" from the phrase and provided a suggested definition for "traceable, verifiable, and complete" records. Additionally, commenters opposed the use of this term in the general recordkeeping requirements at § 192.13, stating that it would apply a new standard of documentation to part 192. Citing a 2012 PHMSA Advisory Bulletin in which PHMSA stated that verifiable

records are those "in which information is confirmed by other complementary, but separate, documentation," INGAA requested that PHMSA acknowledge that a stand-alone record will suffice and a complementary record is only necessary for cases in which the operator is missing an element of a traceable or complete record.⁷⁴ INGAA also provided examples of records that they believed to be acceptable, and requested that PHMSA include these examples in the final preamble.

Several commenters also opposed the proposed Appendix A to part 192 that summarizes the records requirements within part 192 and requested that it be eliminated, stating that Appendix A goes beyond summarizing the existing records requirements and introduces several new recordkeeping requirements and retention times. Commenters also asserted that Appendix A should not be retroactive. Some commenters supported the inclusion of Appendix A, saying that it is a much-needed clarification of record requirements and retention. Noting that the title of Appendix A suggests that it is specific to gas transmission lines but that it does include some record retention intervals for distribution lines, NAPSRS recommended that Appendix A be expanded to include records and retention intervals for all types of pipelines. Many commenters requested that PHMSA clarify that the proposed changes to Appendix A apply only to gas transmission lines.

Some commenters also opposed the newly proposed recordkeeping requirements for pipeline components at § 192.205. Commenters, including Dominion East Ohio, stated that PHMSA should exclude pipeline components less than 2 inches in diameter, as these small components are often purchased in bulk with pressure ratings and manufacturing specifications only printed on the component or box. They further stated that in doing this, PHMSA would be consistent with its proposed material properties verification requirements. Another commenter stated that these requirements should be eliminated because they are duplicative of the current requirements for establishing and documenting MAOP at § 192.619(a)(1).

Some commenters also opposed the proposed recordkeeping requirements regarding qualifications of welders and welding operators and qualifying persons to make joints in §§ 192.227 and 192.285, stating that keeping these

records for the life of the pipeline is not needed, nor are they necessary for the establishment of MAOP.

Issues related to records were discussed during all of the GPAC meetings in various capacities. At the meeting in January 2017, several issues were discussed, including: broad records guidance in a general duties clause might be a good idea in theory but might cause unintended consequences, and they discussed the advisability of addressing necessary record components individually in the context of specific code sections.

The GPAC discussed the proposed addition of "reliable" to the phrase "traceable, verifiable, and complete" (TVC) record in the proposed rule. The "TVC" standard was recommended by the NTSB following the PG&E incident. Changing that standard could potentially derail work being done by operators to meet that traceable, verifiable, and complete record standard.

The GPAC also discussed PHMSA's statutory authority to impose the proposed recordkeeping requirements, even in subparts that are retroactive, because PHMSA is not requiring particular types of design, installation, construction, etc., but is requiring that operators keep records relevant to current operation.

At the GPAC meeting on June 6, 2017, the GPAC discussed the proposed recordkeeping requirements for the qualification of welders and welding operators as well as the qualification of persons making joints on plastic pipe systems. Specifically, the discussion revolved around whether the recordkeeping requirements should be for the life of the pipeline, as proposed in the NPRM, or whether it should be for 5 years. Certain members believed it should be a 5-year requirement to be consistent with other operator qualification requirements, and other members believed that a 5-year requirement would be adequate due to the "bathtub curve" phenomenon where pipelines are more likely to fail early or late in their service history. Therefore, having the records for welding qualification within that early period would be sufficient.

Following that discussion, the committee recommended that PHMSA modify the proposed rule to delete the word "reliable" from the records standard to now read "traceable, verifiable, and complete" wherever that standard is used; clarify that documentation be required to substantiate the current class location under § 192.5(d); and modify the recordkeeping provisions related to the

⁷⁴ <https://www.phmsa.dot.gov/regulations-fr/notice/2012-10866>; 77 FR 26822; May 7, 2012, "Pipeline Safety: Verification of Records."

qualification of welders and the qualification of persons joining plastic pipe to include an effective date and change the retention period of the necessary records to 5 years.

At the March 2, 2018, meeting, the GPAC recommended that PHMSA withdraw the general duty recordkeeping requirement at § 192.13(e) and Appendix A; modify the recordkeeping requirements for pipeline components to clarify they apply to components greater than 2 inches in nominal diameter; and revise the requirements related to material, pipe design, and pipeline component records to clarify the effective date of the requirements.

At the meeting on March 27, 2018, the GPAC recommended that PHMSA provide guidance in the preamble regarding what constitutes a traceable, verifiable, and complete record. Further, the GPAC recommended PHMSA clarify that the MAOP recordkeeping requirements in the MAOP establishment section at § 192.619(f) apply only to onshore, steel, gas transmission pipelines, and that they only apply to the records needed to demonstrate compliance with paragraphs (a) through (d) of the section. The GPAC suggested PHMSA could remove examples of acceptable MAOP documents from the rule and include that listing in the preamble of the final rule and through guidance materials.

The GPAC also recommended that PHMSA clarify that the MAOP recordkeeping requirements are not retroactive, that existing records on pipelines installed prior to the rule must be retained for the life of the pipeline, that pipelines constructed after the effective date of the rule must make and retain the appropriate records for the life of the pipeline, and that MAOP records would be required for any pipeline placed into service after the effective date of the rule. Further, the GPAC recommended PHMSA revise the rule by changing other sections, including §§ 192.624 and 192.917, to require when and for which pipeline segments missing MAOP records would need to be verified in accordance with the MAOP reconfirmation and material properties verification requirements of the rulemaking.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the proposed records requirements. After considering these comments and as recommended by the GPAC, PHMSA is modifying the rule to withdraw the proposed § 192.13(e) and Appendix A to avoid possible confusion regarding

recordkeeping requirements. Also, whenever new recordkeeping requirements are included, PHMSA modified the rule to clarify that the new requirements are not retroactive. To the degree that operators already have such records, they must retain them. Operators must retain records created while performing future activities required by the code.

In addition to these general modifications, with regard to specific records requirements, PHMSA is modifying the rule as follows: (1) In § 192.5(d), operators must retain records documenting the current class location (but not historical class locations that no longer apply because PHMSA agrees they are not necessary). (2) In § 192.67, the rule is being modified to delete reference to “original steel pipe manufacturing records” to avoid retroactivity concerns, add wall thickness and seam type to clarify that this manufacturing information must be recorded, and include an effective date to eliminate retroactivity concerns. (3) In § 192.205, records for components are only required for components greater than 2 inches (instead of greater than or equal to 2 inches) (see Section III(A)(i)(3)). (4) In § 192.227, records demonstrating each individual welder qualification must be retained for a minimum of 5 years because PHMSA believes 5 years of welder qualification records are sufficient to evaluate whether systemic issues are present upon inspection and at the start-up of the pipeline. (5) In § 192.285, records demonstrating plastic pipe joining qualifications at the time of pipeline installation in accordance must be retained for a minimum of 5 years because PHMSA believes 5 years of records are sufficient to evaluate whether systemic issues are present upon inspection and at the start-up of the pipeline. (6) In § 192.619, PHMSA clarified that new recordkeeping for MAOP only apply to onshore, steel, gas transmission pipelines. In addition, PHMSA deleted the sentence with examples of records that establish the pipeline MAOP, which include, but are not limited to, design, construction, operation, maintenance, inspection, testing, material strength, pipe wall thickness, seam type, and other related data to prevent redundancies in the regulations as this list is maintained in § 192.607.

PHMSA notes that the recordkeeping requirements in this final rule under §§ 192.67, 192.127, 192.205, and 192.227(c) applicable to gas transmission pipelines will apply to offshore gathering pipelines and Type A gathering pipelines as well. In

accordance with this final rule’s requirements, operators of such pipelines must keep any of the pertinent records they have upon this rule’s issuance, and they must retain any records made when complying with these requirements following the publication of this rule. PHMSA notes that the requirements for creating records in §§ 192.67, 192.127, 192.205, and 192.227(c) are forward-looking requirements. However, and in accordance with this final rule, operators must retain any records they currently have for their pipelines. Any records generated through the course of operation, including, most notably, records generated by the material properties verification process at § 192.607, must also be retained by operators for the life of the pipeline.

As requested by the GPAC, PHMSA considered moving § 192.619(e) to be a subsection of § 192.619(a) and considered referencing § 192.624 in § 192.619(a). However, PHMSA is retaining the proposed paragraph (e) in the final rule and the reference to § 192.624 within § 192.619(e) because it more clearly requires pipeline segments that meet any of the applicability criteria in § 192.624(a) must reconfirm MAOP in accordance with § 192.624, even if they comply with § 192.619(a) through (d). This also avoids the potential for conflict if this requirement were to be placed in a paragraph that applies to gathering lines and distribution lines. It also makes it clear that pipeline segments with MAOP reconfirmed under § 192.624 are not required to comply with § 192.619(a) through (d).

Lastly, throughout this final rule, PHMSA is deleting the word “reliable” from the records standard to now read “traceable, verifiable, and complete” wherever that description is used. PHMSA issued advisory bulletins ADB 12–06 on May 7, 2012 (77 FR 26822) and ADB 11–01 on January 10, 2011 (76 FR 1504). In these advisory bulletins, PHMSA provided clarification and guidance that all documents are not records and provided additional information on the definition and standard for records. For a document to be a record, it must be traceable, verifiable, and complete. PHMSA provides further explanation of these concepts below.

Traceable records are those which can be clearly linked to original information about a pipeline segment or facility. Traceable records might include pipe mill records, which include mechanical and chemical properties; purchase requisition; or as-built documentation indicating minimum pipe yield

strength, seam type, wall thickness and diameter. Careful attention should be given to records transcribed from original documents as they may contain errors. Information from a transcribed document, in many cases, should be verified with complementary or supporting documents.

Verifiable records are those in which information is confirmed by other complementary, but separate, documentation. Verifiable records might include contract specifications for a pressure test of a pipeline segment complemented by pressure charts or field logs. Another example might include a purchase order to a pipe mill with pipe specifications verified by a metallurgical test of a coupon pulled from the same pipeline segment. In general, the only acceptable use of an affidavit would be as a complementary document, prepared and signed at the time of the test or inspection by a qualified individual who observed the test or inspection being performed.

Complete records are those in which the record is finalized as evidenced by a signature, date or other appropriate marking such as a corporate stamp or seal. For example, a complete pressure testing record should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, and elevation information as applicable. An incomplete record might reflect that the pressure test was initiated, failed and restarted without conclusive indication of a successful test. A record that cannot be specifically linked to an individual pipeline segment is not a complete record for that segment. Incomplete or partial records are not an adequate basis for establishing MAOP or MOP. If records are unknown or unknowable, a more conservative approach is indicated.

For example, a mill test report must be traceable, verifiable, and complete, which is a typical record for pipelines. For the mill test report to be traceable it would need to be dated in the same time frame as construction or have some other link relating the mill record to the material installed in the pipeline, such as a work order or project identification. For the mill test report to be verified, it would need to be confirmed by the purchase or project specification for the pipeline or the alignment sheet with consistent information. Such an example would be verified by independent records. For the mill test report to be complete, it must be signed, stamped, or otherwise authenticated as a genuine and true record of the material by the source of the record or

information, in this example it could be the pipe mill, supplier, or testing lab.

Another common record is a pressure test record, which must be traceable, verifiable, and complete. For the pressure test record to be traceable, it would need to identify a specific and unique segment of pipe that was tested (such as mileposts, survey stations, etc.) or have some other link relating the pressure test to the physical location of the test segment, such as a work order, project identification, or alignment sheet. For the pressure test record to be verified, it would need to be confirmed by the purchase or project specification for the pipeline or the alignment sheet with consistent information. Such an example would be verified by independent records. For the pressure test record to be complete, it should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, elevation information, and any other information required by § 192.517, as applicable. An incomplete record might reflect that the pressure test was initiated, failed and restarted without conclusive indication of a successful test.

I. Miscellaneous Issues

iii.—Cost/Benefit Analysis, Information Collection, and Environmental Impact Issues

NPRM Assumptions/Proposals

U.S. Code, title 49, chapter 601, section 60102 specifies that the U.S. Department of Transportation (U.S. DOT), when prescribing any pipeline safety standard, shall consider relevant available gas and hazardous liquid pipeline safety information, environmental information, the appropriateness of the standard, and the reasonableness of the standard. In addition, the U.S. DOT must, based on a risk assessment, evaluate the reasonably identifiable or estimated benefits and costs expected to result from implementation or compliance with the standard. PHMSA prepared a preliminary regulatory impact analysis (RIA) to fulfill this statutory requirement for the proposed rule and a new regulatory impact analysis (RIA) for this final rule. In addition, PHMSA's Environmental Assessment (EA) is prepared in accordance with NEPA, as amended, and the Council on Environmental Quality (CEQ) regulations for implementing NEPA (40 CFR parts 1500–1508). When an agency anticipates that a proposed action will not have significant environmental effects, the CEQ regulations provide for the preparation of an EA to determine

whether to prepare an environmental impact statement or finding of no significant impact.

Summary of Public Comment

Cost Impacts

Several commenters provided input on the cost analysis conducted in the PRIA, providing comments on the structure, assumptions, and unit costs in the PRIA as well as on the lack of accounting for impacts such as the abandonment of pipelines and the cost increase to electricity ratepayers.

Some public interest groups provided input on the cost analysis in the PRIA. EDF stated that the PRIA reasonably addressed uncertainty and lack of information surrounding certain key data assumptions. EDF further stated that the PRIA aligned with Office of Management and Budget guidance on the development of regulatory analysis for rulemakings. They stated that PHMSA used conservative values when making best professional judgments. PST asserted that the costs included in the PRIA for reconfirmation of MAOP, data gathering, record maintenance, and data integration for lines subject to the IM provisions result from the current IM regulations and practices and should not be attributed to this rulemaking. They further stated that the PRIA should be amended to remove these costs related to lines within HCAs.

Several trade associations and industry pipeline entities provided input on the assumptions, methodology, and unit costs used in the PRIA, stating that PHMSA underestimated the cost of complying with the proposed regulations. AGA stated that the organization of the PRIA by “topic areas” made it difficult to evaluate the cost estimates of the various provisions of the rule and requested that PHMSA provide a RIA with the final rule that addresses each regulatory section as organized in the preamble. Many commenters, including INGAA, AGA, AGL Resources, and Piedmont, stated that the PRIA underestimated the cost impacts of increased material properties verification, recordkeeping, and MAOP reconfirmation requirements. AGL Resources asserted that complying with the proposed record requirements would involve increased labor and investment costs that should be quantified in the final RIA. AGA stated that it was unclear whether or how the PRIA incorporated material properties verification costs related to material documentation, plan creation, revisions, and testing. NYSEG asserted that the PRIA underestimated the cost impact of the proposed rule on smaller local

distribution companies with combined transmission and distribution systems and estimated that they would have to perform IM elements on 8 times the mileage currently in their IM program. Lastly, INGAA provided a higher cost for MAOP confirmation than was estimated in the PRIA due in large part to their assumption that industry would continue to rely on pressure testing, as they asserted that the proposed methods for ILI and ECA are not feasible.

INGAA, AGA, and API submitted detailed cost analyses to the rulemaking docket, while many other commenters (approximately 40) provided estimated unit costs for various provisions of the proposed rule that were generally higher than the unit costs used in the PRIA. For example, Southwest Gas stated that the costs included in the PRIA for options such as ILI and pressure testing were not representative of the costs to their system. With regard to the cost of integrity assessments, BG&E stated that it would cost them over \$1 million per year to perform integrity assessments on the additional 100 miles of MCA transmission pipelines, a total which equates to a higher cost per mile estimate than was used in the PRIA. Additionally, New Mexico Gas Co. stated that the proposed rule would cost their company \$5.6 million per year to perform integrity assessments on 528 miles of MCA transmission pipe. Vectren estimated the impact to its transmission system would cost \$22 million annually. Lastly, PG&E stated that their forecasted costs to implement the proposed rule are significantly higher than the estimates in the PRIA. PG&E provided a comparison of the PRIA costs with their expected expenditures to comply with many provisions in the proposed rule. They projected the cost of compliance would require an upfront investment of \$578 million in addition to \$222 million per year (as well as a reoccuring cost of \$30 million every 7 years) and stated that, comparatively, the PRIA estimates a present value annualized cost of \$47 million per year.

Some stakeholders provided input on the estimated number of miles that PHMSA used to determine the regulatory impact of the provisions in the proposed rule. For example, INGAA stated that it assumed the mileage estimated by PHMSA for estimation of MAOP confirmation, material properties verification, and integrity assessments outside HCAs to be accurate with the addition of reportable in-service incidents since last pressure test data. INGAA also asserted that the mileage estimated for MCA transmission pipes should be done on the per-foot basis

instead of on the per-mile basis because these pipes are likely to be an aggregation of short pipeline segments that are 1 mile or shorter in length. The North Dakota Petroleum Council asserted that proposed changes in the definition of onshore gathering lines would dramatically increase the number of miles of regulated gathering wells beyond the mileage estimates in the PRIA.

Some commenters asserted that the financial impact of the proposed rule would be immense and that, because operators would not be able to bear these costs alone, they would likely pass the costs on to the ratepayers. For example, APGA stated that all of their member utilities purchase gas and pay transportation charges to transmission pipelines to deliver gas from the producer to the utility. They asserted that ratepayers would pay for the costs that would be incurred by their transmission suppliers to comply with this rule. Similarly, Indiana Utility Regulatory Commission requested that PHMSA consider the costs to ratepayers in its cost analysis. Other commenters stated that this rule could force operators to take significant portions of their pipelines out of service while they are brought into compliance and that the PRIA failed to recognize that FERC requires interstate natural gas pipelines operators to provide demand charge credits to customers when service is disrupted.

Some commenters stated that the proposed rule may cause pipeline abandonment and that these impacts should be considered in the final RIA. Boardwalk Pipeline stated that if a pipe is no longer economic to operate, but FERC does not grant abandonment authority, a pipeline company would be forced to either operate a pipeline that may not meet PHMSA standards or undertake expensive replacement projects. Boardwalk Pipeline further stated that while operators may seek to recover the costs of replacement projects through rate increases, in a competitive pipeline market where operators are forced to discount their pipeline rates in order to retain customers, these costs might be too great to recover. Similarly, the Independent Petroleum Association of America stated that the PRIA failed to account for the costs that could be incurred by operators if pipeline infrastructure is abandoned because the cost that would be required to comply with the rule would necessitate this abandonment. The Public Service Commission of West Virginia suggested that, should operators abandon wells and pipelines due to the requirements of this proposed rule, it could cause an

environmental and economic liability for State regulators if operators abandon wells and pipelines without proper clean up.

Several commenters expressed concern that PHMSA's cost-benefit analysis does not meet the requirements established by the 2011 Pipeline Safety Act and the Administrative Procedures Act (APA). Trade associations stated that the PRIA does not fulfill PHMSA's statutory obligations because it omits relevant costs, relies on incorrect assumptions, and contains multiple inconsistencies. INGAA asserted that the PRIA does not comply with the APA because the finding in the PRIA that the proposed benefits outweigh the costs is contingent on an underestimation of the costs of the proposed rule. INGAA also noted that flawed cost-benefit analysis can be grounds for courts to reject agency rulemakings. INGAA asserted that the proposed rulemaking does not comply with the Paperwork Reduction Act (PRA), because PHMSA's estimate of the information collection burden did not include the costs of these additional recordkeeping requirements for transmission pipeline operators.

Benefit Estimates

PHMSA also received comments on the benefits associated with the proposed rule. Physicians for Social Responsibility expressed their support of the proposed rule and the analysis of reduced accidents and increased worker safety in the PRIA. Additionally, Physicians for Social Responsibility stated that many harmful air pollutants, such as nitrous oxide, sulfur dioxide, particulate matter, formaldehyde, and lead, are all associated with gas pipelines and compressor stations. They further stated that this rule would help reduce or mitigate this pollution and that these public health benefits should be accounted for in the benefits calculations.

Other commenters, including AGA and INGAA, stated that PHMSA overestimated the damage caused by incidents in the quantification of benefits in the PRIA. AGA stated that PHMSA allowed one major incident to skew the data in their benefits analysis and proposed that PHMSA adopt a new approach to quantify the benefits of reduced accidents. INGAA stated that using data from the past 13 years skewed the results and that the most recent 5 years of incident history would more reasonably reflect positive developments in pipeline safety, given that significant developments in pipeline safety have occurred within this time period.

Several commenters provided input on the proposed use of the social cost of carbon and the social cost of methane in the PRIA. EDF and National Resource Defense Council supported the use of the social costs of carbon and methane methodology in the PRIA. However, these commenters stated that the estimates for social costs of carbon and methane were likely too conservative and that the values should be higher than those used in the PRIA. These commenters stated that PHMSA should encourage the Interagency Working Group on Social Cost of Carbon to update regularly the social cost of carbon and social cost of methane as new economic and scientific information emerges. API stated that the proposed use of the social cost of methane to calculate the benefits of emissions reductions was flawed due to the discount rates used by PHMSA. They asserted that PHMSA used low discount rates that led to a liberal damage estimate. In addition, API and Industrial Energy Consumers of America asserted that the social cost of carbon values used by PHMSA inappropriately impose global carbon costs on domestic manufacturers, which damages the industry's ability to compete internationally. AGA stated that the process used to develop the social cost of methane values in the PRIA did not undergo sufficient expert and peer review. INGAA stated that PHMSA overestimated the amount of greenhouse gas emissions that the rule would reduce.

Environmental Impacts

Several commenters noted that the 2011 Pipeline Safety Act mandates that PHMSA consider the environmental impacts of proposed safety standards. Citizen groups stated that the proposed regulation fulfills this statutory obligation and is a step forward in reducing methane emissions from natural gas pipelines. Multiple citizen groups emphasized the consequences of climate change, the high global warming potential of methane, and the responsibility of natural gas systems for a significant portion of U.S. methane emissions. Citizen groups underlined the importance of regulating methane leaks and considering methane's climate implications in natural gas regulations. The Lebanon Pipeline Awareness Group addressed local environmental impacts, requesting that pipelines not be permitted to contaminate agricultural soils.

Trade associations asserted that PHMSA did not fulfill its statutory obligation to consider the full environmental impacts of the proposed

safety standards, suggesting that PHMSA failed to consider several topics in the NPRM that would have direct environmental impacts. These commenters claimed that certain topics and their impacts, including IM clarifications, MAOP reconfirmation, and hydrostatic pressure testing, were mischaracterized in the EA, and that PHMSA further underestimated the number of excavations that would need to be made per the proposal as well as the impacts of procuring and disposing of water for hydrostatic tests.

Trade associations further expressed concerns that, while PHMSA had addressed the emissions avoided under the proposed rule, PHMSA had not addressed the extent to which the proposed rule would increase emissions. AGA and INGAA noted that operators need to purge lines of natural gas before conducting hydrostatic tests or removing pipelines from service for replacement or repair. These commenters stated that the proposed regulation would increase methane emissions by increasing the number of hydrostatic tests, pipeline replacements, and pipeline repairs required and asserted that the EA did not take the increased emissions from these blowdowns into account. INGAA asserted that not considering these methane emissions constituted a violation of the 2011 Pipeline Safety Act and failure to "engage in reasoned decision making." INGAA also suggested that the methane emissions resulting from this rulemaking would run counter to President Obama's goals of reducing methane emissions.

EDF and PST commissioned a study from M.J. Bradley & Associates (MJB&A) that calculated the extent to which the proposed rule would result in blowdown emissions. MJB&A found that potential methane emissions resultant from the proposed rule would increase annual methane emissions from natural gas transmission systems by less than 0.1 percent and increase annual methane emissions from transmission system routine maintenance by less than one percent. MJB&A also noted five mitigation methods that if implemented, could decrease blowdown emissions by 50 to 90 percent.⁷⁵ MJB&A calculated that the societal benefits of methane reduction outweighed the mitigation costs for all mitigation options considered. Based on

⁷⁵ The methods are (1) gas flaring; (2) pressure reduction prior to blowdown with inline compressors; (3) pressure reduction prior to blowdown with mobile compressors; (4) transfer of gas to a low-pressure system; and (5) reducing the length of pipe requiring blowdown by using stopples.

this study, EDF asserted that while the marginal increase in emissions from the proposed rule would be small, the total emissions from blowdowns would nonetheless be significant. They stated that PHMSA should require operators to select and implement one of the mitigation options and report to PHMSA information about their blowdown events, such as the mitigation option selected and the amount of product lost due to blowdowns required by the proposed rule. EDF also stated that if operators do not mitigate blowdown emissions, they should be required to provide an engineering or economic analysis demonstrating why mitigation is deemed infeasible or unsafe.

AGA stated that the EA did not address other environmental impacts resultant from hydrostatic pressure testing. AGA noted two anticipated water-related impacts: (1) Hydrostatic pressure testing's water demand could aggravate water scarcity in already water-scarce environments, and (2), the water used in hydrostatic tests could introduce contaminants if disposed on-site (or be very expensive to transport to off-site disposal). AGA explained that wastewater from hydrostatic tests could include hydrocarbon liquids and solids, chlorine, and metals.

AGA also asserted that the EA did not adequately consider the land disturbances that could result from the proposed hydrostatic testing requirements, nor did it consider that performing inline inspections and modifying pipelines to accommodate inline inspection tools would generate waste and disturb natural lands. AGA explained that operators must clean pipelines prior to conducting inline inspections or modifying pipelines for inline inspection tools and that this cleaning could produce large volumes of pipeline liquids, mill scale, oil, and other debris. AGA expressed concerns that the proposed EA did not discuss these environmental impacts associated with requiring MAOP confirmation, given that PHMSA anticipates that most affected pipelines would verify MAOP using ILI and pressure testing.

AGA also provided input on the local environmental impacts of the proposed increased testing and inspection. AGA expressed concerns that the EA had (1), underestimated the quantity of excavations that would be required under the proposed rule, and (2), inadequately assessed the environmental impacts of those excavations. AGA asserted that the EA had insufficiently considered the extent to which more excavations would generate water and soil waste. AGA also suggested that the proposed rule may

induce operators to modify or replace pipelines and that these modifications and replacements may affect land beyond existing rights of way. AGA asserted that this additional land area should be considered in the EA.

Trade associations raised other technical issues regarding the EA. AGA expressed concerns that PHMSA provided insufficient information about methods used to calculate values in the EA and that this insufficient documentation interfered with stakeholders' ability to provide comments on the values that PHMSA chose. INGAA asserted that the proposed rule fell short of several legal obligations under NEPA, stating that the EA does not provide the required "hard look" at environmental impacts, that the EA does not adequately discuss the indirect and cumulative effects of the proposed rule, and that the purpose and need statement in the EA do not fulfill NEPA instructions. INGAA also expressed concern that PHMSA did not consider sufficient regulatory alternatives, stating that the EA considered solely the proposed rule, one regulatory alternative, and the no action alternative. INGAA stated that given the many provisions of the proposed rule, this approach was too limited.

Other Impacts

Some trade associations and pipeline industry entities provided input that the PRIA failed to account for the indirect effects of operators shifting resources to comply with the proposed rule. For example, AGA stated that the PRIA did not consider the potential indirect impacts the rule might impose on distribution lines. They asserted that the magnitude and prescriptiveness of the proposed rule would require distribution companies with intrastate transmission and distribution assets to reassign their limited resources to transmission lines.

Some commenters stated that PHMSA did not consider that the proposed rule would divert resources away from voluntary safety programs their companies are initiating, stating that these voluntary safety measures would be scaled back because of the proposed rule. For example, AGA stated that accelerated pipe replacement programs that replace aging cast iron, unprotected steel pipe, and vintage plastic pipe, would lose resources as operators shift staff and capital to comply with the proposed rule. They further asserted that failing to replace these pipes would delay reductions in methane emissions from old, leaky pipes.

PHMSA Response

Cost Impacts

PHMSA has reviewed the comments related to the RIA for the proposed rule and has revised the final analysis consistent with the final rule and in consideration of the comments. PHMSA addressed the comments received on the RIA in two key ways. First, PHMSA revised many of the requirements in the final rule, including (a) revising or clarifying that the final provisions do not apply to gas distribution or gas gathering pipelines; (b) revising MAOP reconfirmation requirements for grandfathered pipelines to include only those lines with MAOP greater than or equal to 30 percent SMYS; (c) streamlining the process for operators to use an alternative technology for MAOP reconfirmation; (d) removing the term "occupied sites" in the MCA definition; and (e) revising the records provisions to remove certain proposed provisions and clarifying that the new requirements are not retroactive. These changes, as well as others made in the final rule, result in less costly and more cost-effective requirements. Second, in response to comments received, PHMSA made several revisions to the analysis conducted in the RIA for the proposed rule, discussed below. Also, in response to comments, PHMSA revised the final RIA to align more closely to the preamble organization.

PHMSA acknowledges the baseline issues associated with establishing MAOP, data collection, and other provisions noted in the comments. In the final RIA, PHMSA is including estimated incremental costs to reconfirm MAOP for lines within HCAs based on a current compliance baseline. Attributing compliance to existing pipeline safety regulations would reduce both the costs and benefits of the final rule. Regarding the comments that the RIA for the proposed rule underestimated the cost impacts of material properties verification, recordkeeping, and MAOP confirmation, as discussed above, the changes to the scope and applicability of the MAOP reconfirmation, data, and recordkeeping provisions result in common-sense, cost-effective requirements. For example, PHMSA designed the final requirements for material properties verification to allow operators the option of a sampling program that opportunistically takes advantage of repairs and replacement projects to verify material properties simultaneously. The final provisions allow, over time, operators to collect enough information to gain significant

confidence in the material properties of pipe subject to this requirement.

Further, as discussed under the section regarding the material properties verification process, the final rule removes the applicability criteria of the material properties verification requirements and makes a procedure for obtaining pipeline physical properties and attributes that are not documented in traceable, verifiable, and complete records or for otherwise verifying pipeline attributes when required by MAOP reconfirmation requirements, IM requirements, repair requirements, or other code sections. Therefore, due to the changes made from the proposed rule, the material properties verification requirements mandated by section 23 of the 2011 Pipeline Safety Act represent a cost savings in comparison to existing regulations, although PHMSA has not quantified those savings.

With regard to the operator-provided cost information or estimates of the proposed rule, the commenters' estimates were not transparent enough for PHMSA to discern the assumptions and inputs underlying the estimates. As a result, PHMSA could not reliably confirm whether the cost information accurately reflected the quantity and character of the actions required by the proposed rule. To improve the transparency of the analysis and address commenters' concerns about PHMSA's reliance on best professional judgment in the RIA for the proposed rule, PHMSA contacted five vendors of pipeline inspection and testing services to obtain updated cost estimates for several unit costs that were based on best professional judgement in the RIA for the proposed rule. These vendors provided representative incremental costs associated with the final rule requirements. In the final RIA, PHMSA used prices provided by vendors to estimate unit costs for all MAOP reconfirmation and integrity assessment methods, as well as for upgrades to launchers and receivers.

Regarding MAOP reconfirmation specifically, in the RIA for the proposed rule PHMSA assumed operators would conduct MAOP reconfirmation using either pressure testing or ILL. In the final RIA, based on feedback received during a GPAC meeting,⁷⁶ PHMSA assumed that operators would reconfirm MAOP using a mix of all six available compliance methods.

Additionally, in the final RIA, PHMSA analyzed the requirements for MAOP reconfirmation and integrity

⁷⁶GPAC Meeting, March 26–28, 2018. For a transcript of the meeting, see <https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=970>.

assessments outside HCAs for each operator individually based on the information they submitted in their Annual Reports. Based on the information in operator Annual Reports and the final rule requirements for MAOP reconfirmation, some operators will incur less of an impact than indicated by their public comments.

Regarding the comment that the proposed changes to the definition of onshore gathering lines would dramatically increase the number of miles of regulated gathering wells beyond the mileage estimates in the RIA for the proposed rule, this final rule does not change the definition of gathering pipelines.

With respect to pipelines located within MCAs, PHMSA confirmed the analysis of the length of gas transmission pipelines located within MCAs in the RIA for the proposed rule by integrating additional spatial data from the U.S. Census Bureau, U.S. Geological Survey, Environmental Systems Research Institute, and Tele-Atlas North America, Inc. For additional details on the MCA GIS analysis, see section 5.7 of the RIA for the final rule. This allowed PHMSA to confirm the number of impacted miles.

Additionally, due to existing state MAOP reconfirmation requirements, PHMSA updated the RIA to reflect that impacts in California are not attributable to the rule. Lastly, PHMSA presented all impacted mileage on a dollar-per-foot basis instead of dollars per mile, based on comments received that these pipeline segments are likely to be an aggregation of short pipeline segments that are a mile or shorter in length.

Regarding the comment that PHMSA underestimated the cost impact of the proposed rule on smaller local distribution companies with combined gas transmission and gas distribution systems, PHMSA conducted an analysis of the rule's impact on small entities by comparing entity-level cost estimates to annual entity revenues and identifying entities for which annualized costs may exceed 1 percent and 3 percent of revenue. As documented in the final Regulatory Flexibility Act (FRFA) analysis, PHMSA relied on conservative assumptions in performing this sales test, which may overstate, rather than understate, compliance costs for small entities. PHMSA found that the final rule will not have a significant economic impact on small entities.

PHMSA does not agree that the final rule requirements constitute a significant energy action. PHMSA agrees with the comment that the costs would be passed on to ratepayers; however, PHMSA disagrees that these costs

would be immense. E.O. 13211 requires agencies to prepare a Statement of Energy Effects when undertaking certain agency actions if, among other criteria, the regulation is expected to see an increase in the cost of energy production or distribution in excess of one percent. The annualized cost of these requirements represents less than 0.1 percent of pipeline transportation of natural gas (North American Industry Classification System code 486210) industry revenues (\$25 billion), adjusting the 2012 Economic Census value into 2017 dollars using the Gross Domestic Product Implicit Price Deflator Index. Therefore, in the aggregate it is extremely unlikely that these requirements would cause a significant increase in costs that utilities would pass on to the ratepayer.

Available information supports that, in the baseline, operators are replacing or abandoning certain pipelines regardless of the implementation of this rule as well as taking other actions such as making lines piggyback.⁷⁷ As discussed above, in the final RIA, PHMSA assumed some use of pipe replacement and abandonment as a means of operators reconfirming MAOP. However, the costs of replacing infrastructure operating beyond the design useful life are not attributable to safety regulations and investment in plant, including a return on investment, are already recovered through rates.

The RIA for the final rule meets all PHMSA's requirements under applicable acts and executive orders. The analysis involves estimating a baseline scenario and changes under the regulation. PHMSA has used its judgement, available data, information, and analytical methods to develop an analysis of the baseline and incremental costs and benefits under the rule. As discussed above, some costs and benefits may be attributable to existing requirements and some may occur in the absence of the rule.

Benefits Estimates

PHMSA agrees that recent data is more reflective of recent improvements in pipeline safety and performance relative to current standards. For the final RIA, PHMSA used more recent data on pipeline incidents from 2010 to

2017 versus the 2003 to 2015 data used in the RIA for the proposed rule. PHMSA used the data from 2010 on because PHMSA updated its incident reporting methodology in 2010, and this period therefore provides the largest available sample of consistently reported incident data. Regarding the benefits analysis for the preliminary RIA developed for the NPRM potentially being skewed by one major incident (the PG&E incident at San Bruno), there is no evidence that more serious incidents are not possible in the future in the absence of the regulation, and therefore, PHMSA does not exclude this incident when qualitatively assessing benefits. At the same time, and although PHMSA developed this rule to prevent future, similar incidents, PHMSA cannot know with certainty whether a similar incident would occur again absent this rulemaking. According to the historical record, serious incidents, like the one occurring at San Bruno, occur approximately once per decade. For example, on August 19, 2000, a 30-inch-diameter natural gas transmission pipeline operated by the El Paso Natural Gas Company ruptured adjacent to the Pecos River near Carlsbad, NM. The released gas ignited and burned for 55 minutes. Twelve persons camping near the incident location were killed, and their three vehicles were destroyed.⁷⁸ Similarly, on March 23, 1994, a 36-inch-diameter natural gas transmission pipeline owned and operated by Texas Eastern Transmission Corporation ruptured in Ellison Township, NJ. The incident caused at least \$25 million in damages, dozens of injuries, and the evacuation of hundreds.⁷⁹ More detailed data on current pipeline integrity in relation to populations and the environment would enable more detailed predictions of the benefits of regulations.

Due to the speculative nature of predicting the occurrence, avoidance, and character of specific future pipeline incidents, in the final RIA, PHMSA elected not to quantify the rule's benefits. PHMSA uses this approach rather than make highly uncertain predictions about both a specific number of future incidents avoided due to the final rule, and the character of avoided incidents with respect to effects on benefit-analysis endpoints (e.g., fatalities, injuries, evacuation). The

⁷⁷ PG&E. 2011. "Pacific Gas And Electric Company's Natural Gas Transmission Pipeline Replacement Or Testing Implementation Plan." California Public Utilities Commission; Consolidated Edison Company Of New York. 2016. "Consolidated Edison Company Of New York, Inc. 2017–2019 Gas Operations Capital Programs/Projects." New York State Department of Public Service. <http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-G-0061&submit=Search>.

⁷⁸ Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico, August 19, 2000, Pipeline Accident Report, NTSB/PAR–03/01, Washington, DC.

⁷⁹ Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Pipeline Accident Report, NTSB/PAR–95–01, Washington, DC.

quantified benefits for each provision therefore represent the quantity of a given benefit category required to achieve a dollar value equal to the provision's compliance cost.

PHMSA does not have data on harmful air pollutants such as nitrous oxide, sulfur dioxide, particulate matter, formaldehyde, and lead associated with gas pipelines and compressor stations, or the reductions in these pollutants under the rule. Therefore, the analysis did not address the environmental costs associated with these pollutants. PHMSA did not include estimates of benefits based on the social cost of methane for the final rule.

Environmental Impacts

Regarding the comments stating that the preliminary EA did not adequately consider the air emissions that would result from hydrostatic pressure testing, inline inspections, excavations, and MAOP reconfirmation, PHMSA revised the EA to address this issue. Commenters asserted that by increasing the number of hydrostatic tests, pipeline replacements, and pipeline repairs required, the proposed provisions would increase methane "blowdown" emissions that result from the required purging of natural gas pipelines before conducting these actions. PHMSA revised the EA to include a discussion of the study conducted by M.J. Bradley & Associates (MJB&A)⁸⁰ that calculated the extent to which the proposed rule would result in blowdown emissions.

MJB&A found that unmitigated blowdown from the miles of transmission pipeline that would be required to conduct a MAOP determination would release an average of 1,353 metric tons per year of methane to the atmosphere for the 15-year compliance period⁸¹ proposed by PHMSA. By comparison, historical unintentional releases from natural gas transmission pipelines outside of HCAs with piggyback lines greater than 30 percent SMYS (a universe of facilities that could be subject to MAOP reconfirmation in MCAs) averaged 13,500 metric tons per year from 2010 to 2017. These releases were caused by 163 incidents that released an average of 663.4 metric tons per incident.⁸²

⁸⁰ The study was commissioned by EDF and PST and is available at <http://blogs.edf.org/energyexchange/files/2016/07/PHMSA-Blowdown-Analysis-FINAL.pdf>.

⁸¹ See § 192.624(b).

⁸² "Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data." Phmsa.Dot.Gov. 2017. <https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data>.

Therefore, if the final rule requirements avoided two average incidents per year, the rule would not result in any net methane releases. MJB&A further stated that the potential methane emissions resultant from the NPRM would increase annual methane emissions from natural gas transmission systems by less than 0.1 percent and increase annual methane emissions from transmission system routine maintenance/upsets by less than one percent. Given these factors, PHMSA does not believe that the final rule will result in a significant, if any, increase in methane releases.

In response to comments, PHMSA revised the EA to also include a discussion of water-related impacts resulting from hydrostatic pressure testing as well as waste generation and disturbances from hydrostatic pressure testing and inline inspections. Operators must conduct all waste and wastewater disposal activities in accordance with federal, state, and local regulations and permit requirements, and the final rule requires processes and procedures in which pipeline operators are already familiar with respect to pipeline IM. Regarding the comments on the environmental impacts of pipe replacement, as discussed above, the impacts of replacing infrastructure that is operating beyond the design useful life are not attributable to the final rule requirements. While the final RIA assumes that operators will comply with MAOP reconfirmation using pipe replacement for approximately 300 miles of pipe, PHMSA did not consider these replacements to be incremental costs. Similarly, the environmental impacts are not attributable to the final rule requirements.

Other Impacts

PHMSA disagrees with the analysis of operators shifting resources away from safety programs to comply with the proposed rule. PHMSA has revised and clarified the pipeline safety and integrity applicability of the final rule such that many operators will incur lower costs than previously anticipated. The final rule also provides long compliance schedules to enable planning for efficient compliance actions.

IV. GPAC Recommendations

This section briefly summarizes the NPRM proposals, the GPAC's major comments on the proposals discussed, and the recommendations of the committee regarding how those provisions should be finalized. More detail, the presentations, and the transcripts from all of the meetings are

available in the docket for this rulemaking.⁸³ The provisions, which are presented in the order they were discussed at the GPAC meetings, the changes the committee agreed upon, and the corresponding vote counts are as follows:

6-Month Grace Period for 7-Calendar-Year Reassessment Intervals (§ 192.939(b))

In the NPRM, PHMSA proposed to allow operators to request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to the Secretary with sufficient justification of the need for the extension in accordance with the technical correction at section 5 of the 2011 Pipeline Safety Act. The committee had no objections or substantial comments on this provision and voted 12–0 that it was, as published, technically feasible, reasonable, cost-effective, and practicable.

Safety Features on ILI Launchers and Receivers (§ 192.750)

In the NPRM, PHMSA proposed to require operators equip ILI tool launchers and receivers with a device capable of safely relieving pressure in the barrel before the insertion or removal of ILI tools, scrapers, or spheres. Further, PHMSA proposed requiring operators to use a suitable device to indicate that pressure has been relieved in the barrel or otherwise provide a means to prevent the opening of the barrel if pressure has not been relieved. The committee voted 12–0 that this provision was, as published, technically feasible, reasonable, cost-effective, and practicable, as long as PHMSA clarified that the rule language does not require "relief valves" or use "relief valve" as a term. Some committee members were concerned that using language related to "relief valves" would bring in other code requirements, which was not PHMSA's intent.

Seismicity (§§ 192.917, 192.935(b)(2))

In the NPRM, PHMSA proposed to include seismicity in the list of factors operators must evaluate for the threat of outside force damage when considering preventative and mitigative measures, as well as include the seismicity of an area as a pipeline attribute in an operator's data gathering and integration when performing risk analyses. The committee had no substantial comments or recommendations on this topic, and

⁸³ <https://www.regulations.gov/docket?D=PHMSA-2011-0023>.

they voted 12–0 that this provision was, as published, technically feasible, reasonable, cost-effective, and practicable.

Records (§§ 192.5(d), 192.13(e), 192.67, 192.127, 192.205, 192.227(c), 192.285(e), 192.619(f), 192.624(f), Appendix A)

In the NPRM, PHMSA proposed to clarify that the records required by part 192 must be documented in a reliable, traceable, verifiable, and complete manner. PHMSA summarized the recordkeeping requirements of part 192 in a new Appendix A, and required that operators must re-establish pipeline documentation whenever records were not available and make and retain records demonstrating compliance with part 192. Issues related to records were discussed through the final 4 GPAC meetings over the course of 2017 and 2018. The committee found the assorted provisions related to records as being technically feasible, reasonable, cost-effective, and practicable, if certain changes were made. Specifically, the committee recommended the word “reliable” be deleted from the records standard so that it reads “traceable, verifiable, and complete” records wherever the standard is used. Members noted that the NTSB never used the term “reliable,” and a PHMSA advisory bulletin reflects the language without referring to “reliable” records. In the class location requirements at § 192.5, the committee recommended PHMSA clarify that documentation be required to substantiate the current class location and not previous historical ones. The committee also recommended that PHMSA modify the requirements for the qualification of welders and persons joining plastic pipe to include an effective date and change the records retention provision to a period of 5 years.

During the June 2017 GPAC meeting, the committee recommended PHMSA amend provisions related to the general duty clause for records and edit the corresponding reference to retention periods in Appendix A. After further discussion, during the meeting on March 2, 2018, the committee recommended PHMSA withdraw the proposed addition of § 192.13. Similarly, in the June 2017 meeting, the committee recommended PHMSA modify the proposed Appendix A to clarify that it does not apply to distribution or gathering pipelines. After considering the issue at the meeting on March 2, 2018, the committee recommended PHMSA withdraw proposed Appendix A from the rulemaking.

Other changes the committee suggested regarding the proposed recordkeeping requirements included revising the record provisions for materials, pipe design, and components to clarify the effective date of those provisions and recommended PHMSA clarify that the recordkeeping provisions for components only applies to components greater than 2 inches in nominal diameter. The recordkeeping provisions proposed under the MAOP determination and MAOP reconfirmation sections were discussed by the GPAC separately and are expanded upon under the discussions for those specific topics below.

Following those discussions over the course of multiple meetings, the committee voted unanimously that the provisions related to recordkeeping requirements in part 192 were technically feasible, reasonable, cost-effective, and practicable, if PHMSA made the changes outlined above.

IM Clarifications (§§ 192.917(e)(2), (e)(3) & (e)(4))

In the NPRM, PHMSA proposed several changes to provisions related to how operators use data in their IM programs and manage certain types of defects. PHMSA proposed changes regarding an operator’s analysis of cyclic fatigue and clarifying that certain pipe, such as low-frequency electric resistance welded pipe, must have been pressure tested for an operator to assume that any seam flaws are stable. PHMSA also proposed that any failures or changes to operation that could affect seam stability must be evaluated using a fracture mechanics analysis.

Regarding cyclic fatigue, some GPAC members expressed concern that PHMSA proposed to require an annual analysis of cyclic fatigue even if the underpinning conditions affecting cyclic fatigue had not changed. Certain GPAC members wanted to ensure that it would be a change in conditions that would trigger an evaluation and that operators would not necessarily need to do an evaluation within a certain period otherwise. During the meeting, PHMSA suggested it would consider changing cyclic fatigue analysis from annually to periodically based on any changes to cyclic fatigue data and other changes to loading conditions since the previous analysis was completed, not to exceed 7 calendar years. Further, PHMSA would consider whether there was conflict with this section and the MAOP reconfirmation requirements, which was a concern brought up during the public comment period of the meeting. Following the discussion, the committee voted 11–0, that the provisions related

to cyclic fatigue were technically feasible, reasonable, cost-effective, and practicable if PHMSA revised the paragraph based on the GPAC member discussion and PHMSA’s proposed language at the meeting.

For the provisions related to the stability of manufacturing- and construction-related defects, PHMSA proposed during the GPAC meeting to provide that an operator could consider manufacturing- and construction-related defects as stable only if the covered segment has been subjected to a subpart J pressure test of at least 1.25 times MAOP and the covered segment has not experienced a reportable incident attributed to a manufacturing or construction defect since the date of the most recent subpart J pressure test. Pipeline segments that have experienced a reportable incident since its most recent subpart J pressure test due to an original manufacturing-related defect, a construction-related defect, an installation-related defect, or a fabrication-related defect would be required to be prioritized as a high-risk segment for the purposes of a baseline assessment or a reassessment. PHMSA proposed to explicitly lay out these requirements in the regulations rather than cross-reference these requirements to the MAOP reconfirmation provisions. Additionally, PHMSA indicated it would create a stand-alone section to deal with pipeline cracking issues within the IM regulations and would delete a specific reference to “pipe body cracking” in the provisions related to electric resistance welded pipe.

Following the discussion, the committee voted 12–0 that the provisions related to IM clarifications regarding manufacturing and construction defects were technically feasible, reasonable, cost-effective, and practicable if PHMSA made the changes it proposed during the meeting, created a new, stand-alone section for addressing pipeline cracking within the IM regulations, deleted the phrase related to “pipe body cracking,” and considered allowing other test procedures for determining whether manufacturing- and construction-related defects were stable.

MAOP Exceedances (§§ 191.23, 191.25)

In the NPRM, PHMSA proposed requiring operators to report each exceedance of the MAOP that exceeds the build-up allowed for the operation of pressure-limiting or control devices per the congressional mandate provided in the 2011 Pipeline Safety Act, which requires operators to report such exceedances on or before the 5th day

following the date on which the exceedance occurs.

During the public comment period of the June 7, 2017, meeting, a commenter expressed concern that being required to report an exceedance within 5 days might be problematic where an ongoing investigation might preclude an operator from being able to complete a full safety-related condition report. The GPAC considered this viewpoint but noted that the 5-day reporting requirement was prescribed by statute, and PHMSA does not have discretion when implementing that deadline. The GPAC, echoing another comment from the public, discussed whether the provision would be applicable to gathering lines. PHMSA, in response, noted that the requirement would be limited to gas transmission lines only. Following the discussion, the GPAC voted 11–0 that the provision was technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified that this provision does not apply to gathering lines.

Verification of Pipeline Material Properties and Attributes (§ 192.607)

In the NPRM, PHMSA proposed a process for operators to re-establish material properties on pipelines where those attributes may be unknown. The process was an opportunistic sampling approach that did not require any mandatory excavations and allowed operators to verify material properties of pipelines as opportunities presented themselves during normal operations and maintenance, such as excavations for the repair of anomalies.

The GPAC had a robust discussion on the proposed material properties verification requirements and wanted to clarify that two separate activities—MAOP reconfirmation and the application of IM principles—drive the need for material properties verification and should be addressed separately. Overall, the GPAC was supportive of PHMSA's opportunistic approach for verifying material properties. During the public comment period, members representing the pipeline industry suggested PHMSA allow a statistical sampling plan developed by operators instead of prescribing a specific number of samples needed. PHMSA clarified that it expected a 1 pipe-per-mile sampling standard in most cases.

At the December 2017 GPAC meeting, some GPAC members expressed concern with the specific attributes PHMSA was proposing operators collect and verify. There was also some discussion regarding how the notification procedure PHMSA proposed might be cumbersome if operators would be

required to wait on a response or action from PHMSA every time an operator wanted to submit an alternative plan. The GPAC suggested adding language where, if PHMSA was to object to an operator notification, they would have to object within 90 days. If PHMSA did not object within 90 days, the operator would be free to go forward with the intended action.

Following the discussion, the GPAC voted 12–0 that the provisions related to material properties verification were technically feasible, reasonable, cost-effective, and practicable if the following changes were made:

- Clarify that material properties verification applies to onshore steel transmission lines only, and not distribution or gathering lines.
- Remove the applicability criteria of the section and make the material properties verification provisions a procedure that operators can use for obtaining missing or inadequate records or verifying pipeline attributes if required by the MAOP reconfirmation provisions or other code sections. The committee agreed to address the applicability of the material properties verification requirements under each of the MAOP reconfirmation methods and other sections as appropriate.
- Delete the requirements for creating a material properties verification program plan.
- Drop the list of mandatory attributes operators would be required to verify but require that operators keep any records developed through this material properties verification method.
- Retain the opportunistic approach of obtaining unknown or undocumented material properties when excavations are performed for repairs or other reasons, using a one-per-mile standard proposed by PHMSA, but allow operators to use their own statistical approach and submit a notification to PHMSA with their method. Establish a minimum standard of a 95% confidence level for operator statistical methods submitted to PHMSA.
- Retain flexibility to allow either destructive or non-destructive tests when verification is needed.
- Incorporate language stating that, if an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA of an alternative sampling approach, the operator can proceed with their method. PHMSA will notify the operator if additional review time is needed.
- Revise the paragraph to accommodate situations where a single material properties verification test is needed (*e.g.*, additional information is

needed for an anomaly evaluation/repair).

- Drop accuracy specifications (retain requirement that test methods must be validated and that calibrated equipment be used).
- Drop mandatory requirements for multiple test locations for large excavations (multiple joints within the same excavation).
- Reduce number of quadrants at which NDE tests must be made from 4 to 2.
- Delete specified program requirements for how to address sampling failures and replace with a requirement for operators to determine how to deal with sample failures through an expanded sample program that is specific to their system and circumstances. Require notification to provide expanded sample program to PHMSA, and require operators establish a minimum standard that sampling programs must be based on a minimum 95% confidence level.
- Clarify the applicability of § 192.607 (d)(3)(i).

Strengthened Assessment Requirements (Appendix F, §§ 192.493, 192.506, 192.921(a))

In the NPRM, PHMSA proposed to clarify the selection and conduct of ILI tools per updated industry standards that would be incorporated by reference, clarify the consideration of uncertainties in ILI reported results, add additional assessment methods to allow greater flexibility to operators, and allow direct assessment as a method only if the pipeline was not piggable. PHMSA also proposed to explicitly allow guided wave ultrasonic testing (GWUT) in the list of integrity assessment methods by codifying in a new Appendix F the current guidelines operators use for submitting GWUT inspection procedures.

For the updated ILI standards, some GPAC members requested PHMSA delete the “requirements and recommendations” language in § 192.493 and other places where standards are incorporated by reference to avoid the consequence that non-mandatory recommendations in the standards would become regulatory requirements. Following the discussion, the GPAC voted 10–0 that the provisions related to strengthened assessment requirements pertaining to in-line assessment standards were technically feasible, reasonable, cost-effective, and practicable if PHMSA struck the phrase “the requirements and recommendations of” from the appropriate paragraph in § 192.493.

Regarding the usage of assessment methods, certain committee members recommended PHMSA allow the direct assessment method whenever appropriate (*i.e.*, do not restrict the use of direct assessments to unpiggable pipeline segments or when other methods are impractical) and incorporate better language to clarify when it is appropriate for operators to use direct assessments. Similarly, the GPAC suggested PHMSA clarify the regulatory language so that it was clear operators must select the appropriate assessment method based on the applicable threats. The clarification would avoid the implication that operators need to run certain tools against certain threats when there is no evidence or susceptibility of that threat for that particular pipeline segment.

The GPAC also recommended that PHMSA delete the proposed requirement in the baseline assessment method that required a review of ILI results by knowledgeable individuals, since it is duplicative with other existing requirements elsewhere in the regulations. Further, some GPAC members expressed concern that all tools cannot meet the 90 percent tool tolerance that is specified in the referenced industry standard. PHMSA representatives noted that the rule would not require that every tool perform within a 90 percent specification rate, but that actual tool performance should be verified and applied when ILI data is interpreted. As in other sections of the proposed regulations, the committee also requested PHMSA adopt the same objection procedure that the GPAC discussed and approved under the material properties verification provisions for any notification under this section.

Following the discussion, the GPAC voted 10–0 that the provisions related to strengthening the conduct of a baseline integrity assessment were technically feasible, reasonable, cost-effective, and practicable if PHMSA revised the requirements to clarify that operators must select assessment methods based on the threats to which the pipeline is susceptible and removed language in the provision that is duplicative with requirements elsewhere in the regulations; clarified that direct assessment is allowed where appropriate but may not be used to assess threats for which the method is not suitable; and incorporated the same objection procedure the committee approved for the material properties verification provisions and with a PHMSA review timeframe of 90 days.

In discussing the provisions related to the “spike” hydrostatic pressure test method, the committee had several comments and recommendations. Specifically, some GPAC members recommended that the spike test should be performed at a pressure level of 100 percent SMYS, and not 105 percent, to account for varying elevations and test segment lengths. They also suggested that the 30-minute hold time was too long and requested PHMSA consider minimizing the duration of the spike pressure to avoid growing subcritical cracks. Further, the GPAC recommended PHMSA clarify that spike testing should be performed against the threat of “time-dependent cracking” and remove instances in other sections of the regulations where PHMSA listed the threats for which a spike pressure test is appropriate. Following the discussion, the committee voted 10–0 that the provisions related to the “spike” hydrostatic pressure test method were technically feasible, reasonable, cost-effective, and practicable if PHMSA changed the minimum spike pressure to whichever is lesser: 100 percent SMYS or 1.5 times MAOP, reduced the spike hold time to a minimum of 15 minutes after the spike pressure stabilizes, referred to “time-dependent cracking” in the section, incorporated the same objection procedure the committee approved for the material properties verification provisions and with a PHMSA review timeframe of 90 days, and incorporated the term “qualified technical subject matter expert” (SME) at the SME requirements.

The GPAC did not have major concerns with incorporating the GWUT procedures into the regulations and voted 13–0 that the provisions related to the GWUT process were technically feasible, reasonable, cost-effective, and practicable if PHMSA revised the objection procedure as recommended by GPAC members during the discussion on the proposed material properties verification requirements and considering certain minor technical recommendations made by the GPAC members.

Moderate Consequence Area Definition (§ 192.3)

In the NPRM, PHMSA proposed a new definition for “Moderate Consequence Areas” (MCA) which would be areas operators would have to assess per the proposed requirements for performing integrity assessments outside of HCAs. PHMSA proposed to define an MCA as an area in a “potential

impact circle”⁸⁴ with 5 or more buildings intended for human occupancy; an “occupied site;” or the right-of-way of an interstate, freeway, expressway, and other principal 4-lane arterial roadway. PHMSA proposed the definition of an “occupied site” to be areas or buildings occupied by 5 or more persons, which was the same as an “identified site” under the HCA definitions at § 192.903, except that the occupancy threshold was lowered from 20 persons to 5 persons.

The GPAC, based on a comment made by a member of the public, asked if PHMSA could provide more guidance on what a “piggable” line is, for the purposes of this definition. The GPAC asked whether PHMSA believed that a qualifier applies to pipelines that can be fully assessed by a traditional, free-swimming ILI tool without further modification to the pipeline, and PHMSA noted during the meeting that a “piggable” line would be one without physical or operational modifications. The GPAC then suggested PHMSA clarify that definition in the preamble of this final rule.

GPAC members representing the public were concerned about PHMSA’s proposal during the meeting to eliminate the concept of an “occupied site” from the MCA definition. Industry members argued that, from a practicability standpoint, determining whether five people were in a location at any given time could be difficult, and there was significant overlap between “occupied sites” and the class locations that would need to be assessed per the proposal. The GPAC discussed whether some of these sites would be included within an operator’s HCA identification program already and, if not, whether operators would be able to otherwise incorporate “occupied sites” into their identification and assessment programs.

Several GPAC members discussed whether PHMSA should create a database or provide other guidance on which highways should be included in the MCA definition for consistency between PHMSA, State regulators, and operators. Those comments regarding highways were made following a public comment asking whether certain elevated highways needed to be included.

Following the discussion, the GPAC voted 10–0 that the MCA definition was technically feasible, reasonable, cost-effective, and practicable if PHMSA

⁸⁴ A “potential impact circle” is defined under § 192.903 as “a circle of radius equal to the potential impact radius,” where the “potential impact radius” is the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property.

changed the highway description to remove the reference to “rights-of-way” and added language so that the highway description includes “any portion of the paved surface, including shoulders;” clarified that highways with 4 or more lanes are included within the definition; discussed in the preamble what the definition of “piggable” is; and worked with the Federal Highway Administration to provide operators with clear information and discuss it in the preamble of this final rule. Additionally, the GPAC recommended PHMSA modify the term “occupied sites” in the definition by removing “5 or more persons” and the occupancy timeframe of 50 days, and tie the requirement into the HCA survey for “identified sites” as discussed by members and PHMSA at the meeting. Such identification could be made through publicly available databases and class location surveys, and PHMSA was to consider the sites and enforceability per direction by the committee members.

Assessments Outside of HCAs (§ 192.710)

In the NPRM, PHMSA proposed to require operators perform integrity assessments of certain pipelines outside of HCAs. Specifically, operators would perform an initial assessment within 15 years and periodic assessments 20 years thereafter of pipelines in Class 3 and Class 4 locations as well as piggable pipelines in newly-defined “moderate consequence areas” as discussed above.

The GPAC, based on a public comment during the meeting, questioned whether the timeframes for the initial assessment and periodic assessments were appropriate. Members debated shortening the time frames and suggested a few timeframes that could be based on a risk-based prioritization and taking into account timeframes for HCA assessments.

Following the discussion, the GPAC voted 10–0 that the provisions related to assessments outside of HCAs were technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified that direct assessment can be used as an assessment method only if appropriate for the threat being assessed but cannot be used to assess threats for which direct assessment is not suitable; revised the initial assessment and reassessment intervals from 15 years and 20 years, respectively, to 14 years and 10 years, respectively, and with a risk-based prioritization; revised the applicability requirements to apply to lines with MAOPs of 30 percent SMYS or greater; and removed the provisions related to low-stress assessments.

MAOP Reconfirmation (§ 192.624)

In the NPRM, PHMSA proposed a testing regime for (1) pipelines in HCAs, Class 3 or Class 4 locations, or “piggable” MCAs that experienced a reportable in-service incident due to certain types of defects since its most recent successful subpart J pressure test, (2) pipelines in HCAs or Class 3 or Class 4 locations that lacked the traceable, verifiable, and complete pressure test records necessary to substantiate the current MAOP, and (3) pipelines in HCAs, Class 3 or Class 4 locations, or piggable MCAs where the operator established the MAOP using the “grandfather” clause pursuant to § 192.619(c). PHMSA proposed operators of these pipelines re-confirm the MAOP of those pipelines by choosing and executing one of a variety of methods. Those methods are discussed in more detail in individual sections below.

MAOP Reconfirmation Scope and Completion Date

During the discussion on MAOP reconfirmation, some GPAC members suggested PHMSA revise the applicability of the provisions to remove pipeline segments with prior crack or seam incidents, as those issues would be dealt with in an operator’s IM program. Certain committee members recommended PHMSA restrict the scope of the MAOP reconfirmation provisions to pipeline segments with MAOPs of 30 percent SMYS or greater. These members argued that threshold was explicit in the congressional mandate as it pertained to previously untested pipe, and that it was based on the concept that lower-stress lines leak rather than rupture. Members further suggested that the benefit in addressing low-stress lines was not commensurate with the cost of doing so. Other committee members supported retaining the scope of PHMSA’s proposals in the NPRM in order to address specific NTSB recommendations.

Following the discussion, the committee voted 13–0 that the provisions related to the scope for MAOP reconfirmation were technically feasible, reasonable, cost-effective, and practicable if PHMSA removed pipelines with previous reportable incidents due to crack defects from the applicability paragraph; addressed pipeline segments with crack incident history in a new paragraph under the IM requirements; withdrew the definitions for “modern pipe,” “legacy pipe,” and “legacy construction techniques;” revised a reference to necessary records within the applicability paragraph to

refer to records needed for MAOP determination and not subpart J pressure test records; and revised the applicability of the requirements for grandfathered lines to apply only to those lines with MAOPs of 30 percent or greater of SMYS. The committee also recommended PHMSA review the costs and benefits of making the requirements applicable to Class 3 and Class 4 non-HCA pipe operating below 30 percent SMYS.

As for the completion date for the MAOP reconfirmation requirements, the GPAC voted 13–0 that the related provisions were technically feasible, reasonable, cost-effective, and practicable if PHMSA addressed how the completion plan and completion dates required by the section would apply to pipelines that currently do not meet the applicability conditions but may in the future. The committee suggested PHMSA could add a phrase stating that operators must complete all actions required by the section on 100 percent of the applicable pipeline mileage 15 years after the effective date of the rule or, as soon as practicable but not to exceed 4 years after the pipeline segment first meets the applicability conditions, whichever date is later. The GPAC also recommended that PHMSA consider a waiver or no-objection procedure for extending that timeline past 4 years, if necessary.

MAOP Reconfirmation: Methods 1 and 2 (Pressure Test and Pressure Reduction)

In the NPRM, PHMSA proposed six methods an operator could use if needing to reconfirm MAOP. Method 1, a hydrostatic pressure test, would be conducted at 1.25 times MAOP or the MAOP times the class location test factor, whichever is greater. PHMSA proposed operators use a “spike” test method on pipeline segments with reportable in-service incidents due to known manufacturing or construction issues, and PHMSA also proposed operators estimate the remaining life of pipeline segments with crack defects. Method 2, a pressure reduction, would allow operators to reduce the pipeline segment’s MAOP to the highest operating pressure divided by 1.25 times MAOP or the class location test factor times MAOP, whichever is greater. Similar to Method 1, PHMSA proposed operators taking a pressure reduction to reconfirm MAOP be required to estimate the remaining life of pipeline segments with crack defects.

The GPAC members representing the industry argued that a “spike” test is more appropriate to include under IM requirements and that it is not

appropriate for MAOP reconfirmation. During the meeting, PHMSA noted that if the scope of the MAOP reconfirmation provisions was to be revised to delete lines with crack-like defects, the spike test requirement would not be needed. However, PHMSA would expect the spike test provisions to be utilized when otherwise required by the regulations. GPAC members also suggested adding language to address material properties verification requirements with respect to the information that is needed to conduct a pressure test. At the meeting, PHMSA suggested that the GPAC consider explicitly requiring that any information an operator does not have to perform a successful pressure test in accordance with subpart J (or that is not documented in traceable, verifiable, and complete records) be verified in accordance with the material properties verification provisions.

Following the discussion, the GPAC voted 12–0 that the provisions related to the pressure test method for MAOP reconfirmation were technically feasible, reasonable, cost-effective, and practicable if PHMSA deleted the spike hydrostatic testing component for pipelines with suspected crack defects and referred to subpart J more broadly instead of certain sections within subpart J. The GPAC also recommended that if the pressure test segment does not have traceable, verifiable, and complete MAOP records, operators should use the best available information upon which the MAOP is currently based to perform the pressure test. The committee recommended PHMSA require operators of such pipeline segments add those segments to its plan for opportunistically verifying material properties in accordance with the material properties verification requirements, noting that most pressure tests will present at least two opportunities for material properties verification at the test manifolds.

As for the pressure reduction method of MAOP reconfirmation, the GPAC voted 12–0 that the related provisions were technically feasible, reasonable, cost-effective, and practicable if PHMSA increased the look-back period from 18 months to 5 years and removed the requirement for operators to perform fracture mechanics analysis on those pipeline segments where the pressure is being reduced to reconfirm the MAOP.

MAOP Reconfirmation: Method 3 (Engineering Critical Assessment and Fracture Mechanics)

In the NPRM, PHMSA proposed allowing operators to use an engineering critical assessment (ECA) analysis in

conjunction with an ILI assessment to reconfirm a pipeline segment's MAOP where the segment's MAOP would be based upon the lowest predicted failure pressure (PFP) of the segment. This method would require specific technical documentation and material properties verification, and it would require operators analyze crack, metal loss, and interacting defects remaining in the pipe, or that could remain in the pipe, to determine the PFP. The pipeline segment's MAOP would then be established at the lowest PFP divided by 1.25 or by the applicable class location factor listed under the MAOP determination provisions, whichever of those derating factors is greater.

Most of the GPAC discussion on this portion of MAOP reconfirmation related to the specific values used in the fracture mechanics analysis portion of the ECA and whether those requirements would best be located in a section independent from the MAOP reconfirmation requirements. During the meetings, PHMSA noted it would consider creating a stand-alone fracture mechanics section that could be referenced when the procedure is needed or required by other sections of the regulations. PHMSA clarified that fracture mechanics would be needed in the context of MAOP reconfirmation only for the ECA method and "other technology" usage under Method 6 where the applicable pipeline segments have cracks or crack-like defects.

Following the discussion, the GPAC voted 12–0 that the provisions related to the ECA method of MAOP reconfirmation and fracture mechanics were technically feasible, reasonable, cost-effective, and practicable if PHMSA moved the fracture mechanics requirements to a stand-alone section in the regulations. The GPAC recommended the section not specify when, or for which pipeline segments, fracture mechanics analysis would be required, but instead provide a procedure by which operators needing to perform fracture mechanics analysis could do so.

The GPAC recommended several changes to the fracture mechanics requirements, including striking cross-references to the MAOP reconfirmation requirements and spike hydrostatic testing requirements, as well as striking the sensitivity analysis requirements and replacing them with a requirement that operators account for model inaccuracies and tolerances.

Additionally, the GPAC recommended PHMSA add a paragraph specifying that any records created through the performance of a fracture mechanics analysis must be retained.

There were several technical GPAC recommendations related to the use of Charpy V-notch toughness values in the fracture mechanics analysis. Specifically, the GPAC recommended operators have the ability to use a conservative Charpy V-notch toughness value based on the sampling requirements of the material properties verification provisions, and that operators could use Charpy V-notch toughness values from similar or the same vintage pipe until the properties are obtained through an opportunistic testing program. Further, the GPAC recommended that the default Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperature) of 13-ft.-lbs. (body) and 4-ft.-lbs. (seam) only apply to pipe with suspected low-toughness properties or unknown toughness properties. Additionally, the GPAC recommended PHMSA include a requirement for operators of pipeline segments with a history of leaks or failures due to cracks to work diligently to obtain toughness data if unknown and use Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperature) of 5-ft.-lbs. (body) and 1-ft.-lbs. (seam) in the interim. Further, the GPAC suggested PHMSA allow operators to request the use of different default Charpy V-notch toughness values via a 90-day notification to PHMSA.

For the ECA method itself, the committee recommended PHMSA add a requirement to verify material properties in accordance with the material properties verification requirements if the information needed to conduct an ECA is not documented in traceable, verifiable, and complete records. Further, the GPAC recommended that PHMSA not include default Charpy V-notch toughness values or other technical fracture mechanics requirements in the ECA method, as those items would be specified in the new stand-alone fracture mechanics section. Similarly, the GPAC recommended removing ILI tool performance specifications and replacing them with a requirement to verify tool performance using unity plots or equivalent technologies.

MAOP Reconfirmation: Methods 4, 5, and 6 (Pipe Replacement, Small-Diameter & Potential Impact Radius Pressure Reduction, and Other Technology)

In the NPRM, PHMSA proposed three additional methods operators could use to reconfirm a pipeline's MAOP. Method 4, pipe replacement, would require operators to replace pipe for

which they have inadequate records or pipe that was not previously tested due to the grandfather clause in § 192.619(c). Method 5, as proposed, was applicable to low-stress, small diameter, and small potential impact radius (PIR) lines,⁸⁵ and would require operators to take a 10 percent pressure cut as well as perform more frequent patrols and leak surveys. Method 6, “other technology,” would allow operators to use an alternative method, with notification to PHMSA, to reconfirm the MAOP of their applicable pipeline segments.

The GPAC had no major comments regarding Method 4, pipe replacement. For Method 5, GPAC members representing the industry questioned the need for the compensatory safety measures, such as the additional patrols and leak surveys, in conjunction with the 10 percent pressure reduction. They also supported public comments that promoted expanding the applicability of Method 5 beyond the prescribed pipe diameter of less than or equal to 8 inches and the operating pressure of below 30 percent SMYS. During the meeting, PHMSA noted it could drop the diameter and operating pressure requirements from the applicability and use the prescribed PIR of 150 feet or less as a proxy for those risk factors. Additionally, PHMSA noted it would expand the look-back period to 5 years to be consistent with committee and public comments regarding the pressure reduction method (Method 2) of MAOP reconfirmation discussed earlier. With regard to the “other technology” method, committee members suggested using the notification procedure developed for the material properties verification requirements, and PHMSA acknowledged it could be included here as well.

Following the discussion, the committee voted 11–0 that the provisions related to the pipe replacement, pressure reduction for small PIR and diameter lines, and “other technology” methods of MAOP reconfirmation were technically feasible, reasonable, cost-effective, and practicable if PHMSA made certain changes. For Method 4, pipe replacement, the committee had no significant comments or changes. For Method 5, the small PIR and diameter pressure reduction method, the GPAC recommended PHMSA delete the size and pressure criteria, limiting the requirement to those lines with a PIR of 150 feet or less; remove the external corrosion direct assessment, crack

analysis program, odorization, and fracture mechanics analysis requirements; and change the frequency of patrols and surveys to 4 times per year in Class 1 and Class 2 locations and 6 times per year in Class 3 and Class 4 locations. For Method 6, the “other technology” method, the GPAC recommended PHMSA incorporate the same 90-day notification and objection procedure the GPAC approved for the material properties verification requirements.

MAOP Reconfirmation: Recordkeeping and Notification

The GPAC also voted on the notification procedure and recordkeeping requirements of the MAOP reconfirmation requirements. As there were no substantial GPAC comments on these issues, the GPAC voted 11–0 that the provisions are technically feasible, reasonable, cost-effective, and practicable if PHMSA provided guidance regarding what “traceable, verifiable, and complete” records are in the preamble, and if the notification procedure is retained as it was proposed in the NPRM, but incorporating the same 90-day notification and objection procedure the committee approved for the material properties verification requirements into any notification required under the MAOP reconfirmation requirements.

Other MAOP Amendments (§§ 192.503, 192.605(b)(5), 192.619(a)(2), 192.619(a)(4), 192.619(e), 192.619(f))

PHMSA presented to the committee issues related to other portions of MAOP determination⁸⁶ that had cross-references to MAOP reconfirmation methods or other areas of the proposed regulations. More specifically, the GPAC was to consider recommending PHMSA eliminate duplications in scope between the MAOP determination provisions and the MAOP reconfirmation provisions, and eliminate a duplicative revision to the subpart J pressure test general requirements that was referenced adequately elsewhere in the proposal. PHMSA also proposed that the establishment of MAOP under § 192.619 should rely on traceable, verifiable, and complete records, and therefore cross-referenced the material properties verification provisions with the MAOP determination provisions. Similarly, PHMSA added a paragraph to the existing MAOP determination provisions to more clearly specify that operators must have records to substantiate the MAOP of their pipeline segments. To address an NTSB

recommendation from the PG&E incident, PHMSA also proposed requiring that the MAOP pressure limitation factor specified in the MAOP determination section of the regulations for Class 1 pipeline segments be based on the subpart J test pressure divided by 1.25, whereas the existing requirement was the test pressure divided by 1.1. Finally, PHMSA proposed adding a clarification that the requirement for overpressure protection applied to pipeline segments where the MAOP was established using one of the six methods under MAOP reconfirmation. However, PHMSA noted in response to public comment that the clarification seemed to be overly confusing and should be withdrawn.

The GPAC reviewed and discussed PHMSA’s proposed changes to the other MAOP-related provisions, voting 12–0 that the provisions are technically feasible, reasonable, cost-effective, and practicable if PHMSA considered editorially restructuring the applicability of the MAOP determination provisions; clarifying that the recordkeeping requirements specified under MAOP determination only apply to onshore, steel, gas transmission pipelines; and clarifying that the MAOP recordkeeping requirements are not retroactive. The GPAC suggested this be clarified by stating existing records for pipelines installed on or before the effective date of the rule must be kept for the life of the pipeline, that pipelines installed after the effective date of the rule must make and retain records as required for the life of the pipeline, and that MAOP records are required for any pipeline placed in service after the effective date of the rule. The GPAC noted that other sections, including the MAOP reconfirmation and material properties verification requirements, would require when and for which pipeline segments where MAOP records are not documented in a traceable, verifiable, and complete manner would need to be verified.

Changes From the GPAC Recommendations

In this final rule, PHMSA considered the recommendations of the GPAC and adopted them as PHMSA deemed appropriate. However, there were recommendations from the GPAC that PHMSA considered but did not adopt. To summarize, the major changes PHMSA made in this rule that deviate from the GPAC recommendations are as follows:

(1) When discussing the other proposed issues related to the MAOP requirements, the GPAC recommended

⁸⁵ These lines would be lines operating below 30 percent SMYS with diameters of 8 inches or less and PIRs of 150 feet or less.

⁸⁶ See § 192.619.

PHMSA consider moving § 192.619(e) to be a subsection of § 192.619(a) and consider referencing section § 192.624 in § 192.619(a). PHMSA did not implement this recommendation because MAOP reconfirmation for grandfathered segments is not applicable for new pipeline segments.

(2) When considering the IM clarifications at § 192.917, the GPAC recommended PHMSA consider removing the term “hydrostatic” from the testing requirements at § 192.917(e)(3), which deals with manufacturing and construction defects, and allow other authorized testing procedures. PHMSA is not implementing this recommendation because allowing pneumatic tests would be a safety concern to the public and operating personnel.

(3) When discussing the assessment requirements for non-HCAs under proposed § 192.710, the GPAC recommended PHMSA change the “discovery of condition” period allotted from 180 to 240 days. PHMSA is not implementing this suggestion from the GPAC and is retaining the 180-day timeframe for operators to determine whether a condition presents a potential threat to the integrity of the pipeline.

(4) PHMSA added a notification requirement for the use of other technology under the non-HCA assessment requirements at § 192.710. While the GPAC did not specifically request PHMSA make this change, the GPAC was generally supportive of incorporating the notification procedure the committee agreed to under the proposed material properties verification requirements for other applications.

(5) Regarding the requirements for the scope of MAOP reconfirmation, the GPAC recommended PHMSA review the costs and benefits of including Class 3 and Class 4 pipelines not located in HCAs and that operate at less than 30 percent SMYS. PHMSA did consider this as an alternative in the RIA but chose not to move forward with the proposal as suggested as it is outside the scope of the mandate.

(6) Regarding the MCA definition, the GPAC recommended PHMSA consider modifying the term “occupied sites” within the definition by removing reference to “5 or more persons” and the timeframe of 50 days and tying the requirement for identifying occupied sites to the HCA “identified sites” survey requirement as discussed by members and PHMSA at the meeting. In this final rule, PHMSA chose to delete the term “occupied sites” from the MCA definition and from the general definitions section of part 192.

(7) PHMSA moved the specific ECA requirements outside of the MAOP reconfirmation section into a new stand-alone § 192.632. The MAOP reconfirmation requirements regarding the ECA method at § 192.624(c)(3) and the ECA requirements in § 192.632 will cross-reference each other. PHMSA made this change to streamline the MAOP reconfirmation provisions and improve the readability of the requirements. No substantive changes were made to the procedure in connection with this reorganization; this was a stylistic change only.

V. Section-by-Section Analysis

§ 191.23 Reporting Safety-Related Conditions

Section 23 of the 2011 Pipeline Safety Act requires operators to report each exceedance of MAOP that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices. On December 21, 2012, PHMSA published advisory bulletin ADB-2012-11, which advised operators of their responsibility under section 23 of the 2011 Pipeline Safety Act to report such exceedances. PHMSA is revising § 191.23 to codify this statutory requirement.

§ 191.25 Filing Safety-Related Condition Reports

Section 23 of the 2011 Pipeline Safety Act requires operators to report each exceedance of the MAOP that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices. As described above, PHMSA is revising § 191.23 to codify this requirement. Section 191.25 is also revised to make conforming edits and comply with the mandatory 5-day reporting deadline specified in section 23 of the 2011 Pipeline Safety Act.

§ 192.3 Definitions

Section 192.3 provides definitions for various terms used throughout part 192. In support of other regulations adopted in this final rule, PHMSA is amending the proposed definition of “*Moderate consequence area*.” This change will define this term as it is used throughout part 192.

The definition of a “*moderate consequence area*,” or MCA, is based on similar methodology used to define “*high consequence area*,” or HCA in § 192.903. Moderate consequence areas will define the subset of non-HCA locations where integrity assessments are required (§ 192.710) and where MAOP reconfirmation is required (§ 192.624). The criteria for determining MCA locations differs from the criteria

currently used to identify HCAs in that the threshold for buildings intended for human occupancy located within the potential impact radius is lowered from 20 to 5, and identified sites are excluded. In response to NTSB recommendation P-14-01, which was issued as a result of the incident near Sissonville, WV, the MCA definition also includes locations where interstate highways, freeways, expressways, and other principal 4-or-more-lane arterial roadways are located within the potential impact radius.

PHMSA is also adopting a definition of an “*engineering critical assessment*,” as that term will be used in §§ 192.624 and 192.632. More specifically, the ECA is a documented analytical procedure that operators can use to determine the maximum tolerable size for pipeline imperfections based on the MAOP of the particular pipeline segment. Operators can use an ECA in conjunction with an ILI inspection as one of the methods to reconfirm MAOP, if required.

§ 192.5 Class Locations

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that an important aspect of compliance with this requirement is to assure that pipeline class location records are complete and accurate. This final rule adds a new paragraph, § 192.5(d), to require each operator of transmission pipelines to maintain records documenting the current class location of each pipeline segment and demonstrating how an operator determined each current class location in accordance with this section.

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

Section 192.7 lists documents that are incorporated by reference in part 192. PHMSA is making conforming amendments to § 192.7 in the rule text to reflect other changes adopted in this final rule.

§ 192.9 What requirements apply to gathering lines?

This final rule codifies new standards for gas transmission pipelines, most of which are not intended to be applied to gas gathering pipelines. PHMSA is making conforming amendments to § 192.9 to clarify which provisions

apply only to gas transmission pipelines and not to gas gathering pipelines.

§ 192.18 How To Notify PHMSA

This final rule allows operators to notify PHMSA of proposed alternative approaches to achieving the objective of the minimum safety standards in several different regulatory sections. These notification procedures for alternative actions are comparable to the existing notification requirements in subpart O for the integrity management regulations. Because PHMSA is expanding the use of notifications to pipeline segments for which subpart O does not apply (*i.e.*, to non-HCA pipeline segments), PHMSA is adding a new § 192.18 in subpart A that contains the procedure for submitting such notifications for any pipeline segment.

§ 192.67 Records: Material Properties

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipeline material properties records are complete and accurate. This final rule moves the original § 192.67 to § 192.69 and adds in its place a new § 192.67 that requires each operator of gas transmission pipelines installed after the effective date of this final rule to collect or make, and retain for the life of the pipeline, records that document the physical characteristics of the pipeline, including tests, inspections, and attributes required by the manufacturing specification in effect at the time the pipe was manufactured. The physical characteristics an operator must keep documented include diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition. These requirements also apply to any new materials or components that are put on existing pipelines. For pipelines installed prior to the effective date of this final rule, operators are required to retain for the life of the pipeline all such records in their possession as of the effective date of this final rule. These recordkeeping requirements apply to offshore gathering lines and Type A gathering lines in accordance with § 192.9.

Pipelines that lack the traceable, verifiable, and complete records needed to substantiate MAOP may be subject to the MAOP reconfirmation requirements at § 192.624, as specified in that section.

§ 192.69 Storage and Handling of Plastic Pipe and Associated Components

Previous § 192.67, titled “Storage and handling of plastic pipe and associated components,” was created as a part of the Plastic Pipe rule, which was published on November 20, 2018 (83 FR 58716). PHMSA is redesignating that section in this final rule to a new § 192.69. No other changes have been made to the section.

§ 192.127 Records: Pipe Design

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipe design records are complete and accurate. For pipelines installed after the effective date of this final rule, this final rule adds a new § 192.127 to require each operator of gas transmission pipelines to collect or make, and retain for the life of the pipeline, records documenting pipe design to withstand anticipated external pressures and determination of design pressure for steel pipe. For pipelines installed prior to the effective date of this final rule, operators are required to retain for the life of the pipeline all such records in their possession as of the effective date of this final rule. Pipelines that lack the traceable, verifiable, and complete records needed to substantiate MAOP may be subject to the MAOP reconfirmation requirements at § 192.624, as specified in that section.

§ 192.150 Passage of Internal Inspection Devices

The current pipeline safety regulations in § 192.150 require that pipelines be designed and constructed to accommodate in-line inspection devices. Prior to this rulemaking, part 192 was silent on technical standards or guidelines for implementing requirements to assure pipelines are designed and constructed for in-line inspection assessments. Previously, there was no consensus industry standard that addressed design and construction requirements for in-line inspection assessments. NACE Standard Practice, NACE SP0102–2010, “In-line Inspection of Pipelines,” has since been published and provides guidance on this issue in section 7. The incorporation of this standard into the Federal Pipeline Safety Regulations at § 192.150 will promote a higher level of

safety by establishing consistent standards for the design and construction of pipelines to accommodate in-line inspection devices.

§ 192.205 Records: Pipeline Components

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipeline component records are complete and accurate. For pipelines installed after the effective date of this final rule, this final rule adds a new § 192.205 to require each operator of gas transmission pipelines to collect or make, and retain for the operational life of the component, records documenting manufacturing and testing information for valves and other pipeline components. For pipelines installed prior to the effective date of this final rule, operators are required to retain for the life of the pipeline all such records in their possession as of the effective date of this final rule. Pipelines that lack the traceable, verifiable, and complete records needed to substantiate MAOP may be subject to the MAOP reconfirmation requirements at § 192.624, as specified in that section.

§ 192.227 Qualification of Welders

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipeline welding qualification records are complete and accurate. This final rule adds a new paragraph, § 192.227(c), to require each operator of gas transmission pipelines to make and retain records demonstrating each individual welder’s qualification in accordance with this section for a minimum of 5 years following construction. This requirement will apply to pipelines installed after one year from the effective date of the rule.

§ 192.285 Plastic Pipe: Qualifying Persons To Make Joints

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records to ensure they accurately reflect the physical and

operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that plastic pipeline qualification records are complete and accurate. This final rule adds a new paragraph, § 192.285(e), to require each operator of gas transmission pipelines to make and retain records demonstrating a person's plastic pipe joining qualifications in accordance with this section for a minimum of 5 years following construction. This requirement will apply to pipelines installed after one year from the effective date of the rule.

§ 192.493 In-Line Inspection of Pipelines

The current pipeline safety regulations at §§ 192.921 and 192.937 require that operators assess the material condition of pipelines in certain circumstances (e.g., IM assessments for pipelines in HCAs) and allow the use of ILI tools for these assessments. Operators of gas transmission pipelines are required to follow the requirements of ASME/ANSI B31.8S, "Managing System Integrity of Gas Pipelines," in conducting their IM activities. ASME B31.8S provides limited guidance for conducting ILI assessments. Presently, part 192 is silent on the technical standards or guidelines for performing ILI assessments or implementing these requirements. When the IM regulations were initially promulgated, there were no uniform industry standards for ILI assessments. Three related standards have since been published:

- API STD 1163–2013, "In-Line Inspection Systems Qualification Standard." This Standard serves as an umbrella document to be used with and as a complement to the NACE and ASNT standards below, which are incorporated by reference in API STD 1163.
- NACE Standard Practice, NACE SP0102–2010, "In-line Inspection of Pipelines."
- ANSI/ASNT ILI–PQ–2005 (2010), "In-line Inspection Personnel Qualification and Certification."

API 1163–2013 is more comprehensive and rigorous than the current requirements in 49 CFR part 192. The incorporation of this standard into the Federal Pipeline Safety Regulations will promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes, and software utilized by the ILI industry. The API standard addresses in detail each of the following aspects of ILI inspections, most of

which are not currently addressed in the regulations:

- Systems qualification process.
 - Personnel qualification.
 - ILI system selection.
 - Qualification of performance specifications.
 - System operational validation.
 - System results qualification.
 - Reporting requirements.
 - Quality management system.
- The NACE standard covers in detail each of the following aspects of ILI assessments, most of which are not currently addressed in part 192 or in ASME B31.8S:
- Tool selection.
 - Evaluation of pipeline compatibility with ILI.
 - Logistical guidelines, which includes survey acceptance criteria and reporting.
 - Scheduling.
 - New construction (planning for future ILI in new lines).
 - Data analysis.
 - Data management.

The NACE standard provides a standardized questionnaire and specifies that the completed questionnaire should be provided to the ILI vendor. The questionnaire lists relevant parameters and characteristics of the pipeline section to be inspected. PHMSA determined that the consistency, accuracy, and quality of pipeline in-line inspections would be improved by incorporating the consensus NACE standard into the regulations.

The NACE standard applies to "free swimming" inspection tools that are carried down the pipeline by the transported product. It does not apply to tethered or remotely controlled ILI tools, which can also be used in special circumstances (e.g., examination of laterals). While their use is less prevalent than free-swimming tools, some pipeline IM assessments have been conducted using tethered or remotely controlled ILI tools. PHMSA determined that many of the provisions in the NACE standard can be applied to tethered or remotely controlled ILI tools. Therefore, PHMSA is amending the Federal Pipeline Safety Regulations to allow the use of these tools, provided they comply with the applicable sections of the NACE standard.

The ANSI/ASNT standard provides for qualification and certification requirements that are not addressed by 49 CFR part 192. The incorporation of this standard into the regulations will promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes and software utilized by the

ILI industry. The ANSI/ASNT standard addresses in detail each of the following aspects, which are not currently addressed in the regulations:

- Requirements for written procedures.
- Personnel qualification levels.
- Education, training and experience requirements.
- Training programs.
- Examinations (testing of personnel).
- Personnel certification and recertification.
- Personnel technical performance evaluations.

The final rule adds a new § 192.493 to require compliance with the three consensus standards discussed above when conducting ILI of pipelines.

§ 192.506 Transmission Lines: Spike Hydrostatic Pressure Test

A pressure test that incorporates a short duration "spike" pressure is a proven means to confirm the strength of pipe with known or suspected threats of cracks or crack-like defects (e.g., stress corrosion cracking, longitudinal seam defects, etc.). Currently, part 192 does not include minimum standards for such a spike hydrostatic pressure test. This final rule adds a new § 192.506 to codify the minimum standards for performing spike hydrostatic pressure tests when operators are required to, or elect to, use this assessment method. Under the spike hydrostatic pressure test requirements, an operator may use other technologies or processes equivalent to a spike hydrostatic pressure test with justification and notification in accordance with § 192.18.

§ 192.517 Records: Tests

Section 192.517 prescribes the recordkeeping requirements for each test performed under §§ 192.505 and 192.507. PHMSA is making conforming amendments to § 192.517 to add the recordkeeping requirements for the new § 192.506.

§ 192.607 Verification of Pipeline Material Properties and Attributes: Onshore Steel Transmission Pipelines

Section 23 of the 2011 Pipeline Safety Act mandates the Secretary of Transportation to require operators of gas transmission pipelines in Class 3 and Class 4 locations and Class 1 and Class 2 locations in HCAs to verify records to ensure the records accurately reflect the physical and operational characteristics of the pipelines and confirm the MAOP of the pipelines established by the operator (49 U.S.C. 60139). PHMSA issued Advisory Bulletin 11–01 on January 10, 2011 (76

FR 1504), and Advisory Bulletin 12-06 on May 7, 2012 (77 FR 26822), to inform operators of this requirement. Operators have submitted information in their Annual Reports (starting for calendar year 2012) indicating that a portion of transmission pipeline segments do not have adequate records to establish MAOP and that some operators do not have traceable, verifiable, and complete records that accurately reflect the physical and operational characteristics of the pipeline. Therefore, PHMSA has determined that additional regulations are needed to implement the 2011 Pipeline Safety Act. This final rule promulgates specific criteria for determining which pipeline segments must undergo examinations and tests to understand and document physical and material properties and reconfirm a proper MAOP. For operators that do not have traceable, verifiable, and complete documentation for the physical pipeline characteristics and attributes of a pipeline segment, PHMSA is adding a new § 192.607 that contains the procedure for verifying and documenting pipeline physical properties and attributes that are not documented in traceable, verifiable, and complete records and to establish standards for performing these actions. For operators of certain pipelines lacking the necessary records to substantiate MAOP, PHMSA is also adding § 192.624, which provides operators several methods for reconfirming a pipeline segment's MAOP.

The new material properties verification requirements at § 192.607 include the scope of information needed and the methodology for verifying material properties and attributes of pipelines. The most difficult information to obtain, from a technical perspective, is the strength of the pipeline's steel. Conventional techniques to obtain that data would include cutting out a piece of pipe and destructively testing it to determine the yield and ultimate tensile strength. In this final rule, PHMSA is providing operators with flexibility by allowing the use of non-destructive techniques that have been validated to produce accurate results for the grade and type of pipe being evaluated (see § 192.624).

Another issue regarding material properties verification is the cost associated with excavating the pipeline to verify material properties and determining how much pipeline needs to be exposed and tested to have assurance of the accuracy of the verification. PHMSA addresses these issues within this final rule by specifying that operators can take

advantage of opportunities when the pipeline is already being exposed, such as when maintenance activity is occurring and when anomaly repairs are being made, to verify material properties that are not documented in traceable, verifiable, and complete records. For example, PHMSA considers excavations associated with the direct examination of anomalies, pipeline relocations at road crossings and river or stream crossings, pipe upgrades for class location changes, pipe cut-outs for hydrostatic pressure tests, and excavations where pipe is replaced due to anomalies to be opportunities to perform material properties verification.

Over time, pipeline operators will develop a substantial set of traceable, verifiable, and complete material properties data, which will provide assurance that material properties are reliably known for the population of segments that did not have pipeline physical properties and attributes documented in traceable, verifiable, and complete records previously. Through this final rule, PHMSA is requiring that operators continue this opportunistic material properties verification process until the operator has completed enough verifications to obtain a high level of confidence that only a small percentage of pipeline segments have physical pipeline characteristics and attributes that are not verified or are otherwise inconsistent with all available information or operators' past assumptions. This final rule specifies the number of excavations required for operators to achieve this level of confidence.

Operators may use an alternative sampling approach that differs from the sampling approach specified in the requirements if they notify PHMSA in advance of using an alternative sampling approach in accordance with § 192.18.

Requirements are also included in the material properties verification section to ensure that operators document the results of the material properties verification process in records that must be retained for the life of the pipeline.

§ 192.619 Maximum Allowable Operating Pressure: Steel or Plastic Pipelines

The NTSB report on the PG&E incident included a recommendation (P-11-15) that PHMSA amend its regulations so that manufacturing and construction-related defects can only be considered "stable" if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the MAOP. This final rule revises the test pressure factors in

§ 192.619(a)(2)(ii) to correspond to at least 1.25 times MAOP for pipelines installed after the effective date of this rule.

The NTSB also recommended repealing § 192.619(c), commonly referred to as the "grandfather clause," and requiring that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test (recommendation P-11-14). Similarly, section 23 of the 2011 Pipeline Safety Act requires that selected pipeline segments in certain locations with previously untested pipe (*i.e.*, the MAOP is established under § 192.619(c)) or without MAOP records be tested with a pressure test or equivalent means to reconfirm the pipeline's MAOP. These requirements are addressed in the new § 192.624 and are described in more detail in the following section. This final rule also makes conforming changes to § 192.619 to require that operators of pipeline segments to which § 192.624 applies establish and document the segment's MAOP in accordance with § 192.624.

§ 192.624 Maximum Allowable Operating Pressure Reconfirmation: Onshore Steel Transmission Pipelines

Section 23 of the 2011 Pipeline Safety Act requires the verification of records for pipe in Class 3 and Class 4 locations, and high-consequence areas in Class 1 and Class 2 locations, to ensure they accurately reflect the physical and operational characteristics of the pipelines and confirm the established MAOP of the pipelines. Operators have submitted information in annual reports (beginning in calendar year 2012) indicating that some gas transmission pipeline segments do not have adequate material properties records or testing records to confirm physical and operational characteristics and to establish MAOP. For these pipelines, the 2011 Pipeline Safety Act requires that PHMSA promulgate regulations to require operators to reconfirm MAOP as expeditiously as economically feasible. The statute also requires PHMSA to issue regulations that require previously untested pipeline segments located in HCAs and operating at greater than 30 percent SMYS be tested to confirm the material strength of the pipelines. Such tests must be performed by pressure testing or other methods determined by the Secretary to be of equal or greater effectiveness.

As a result of its investigation of the PG&E incident, the NTSB issued two related recommendations. NTSB recommended that PHMSA repeal § 192.619(c), commonly referred to as

the “grandfather clause,” and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test (P-11-14). The NTSB also recommended that PHMSA amend the Federal Pipeline Safety Regulations so that manufacturing- and construction-related defects can only be considered stable if a pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the MAOP (P-11-15).

Through this final rule, PHMSA is finalizing a new § 192.624 to address these mandates and recommendations. This final rule requires that operators reconfirm and document MAOP for certain onshore steel gas transmission pipelines located in HCAs or MCAs that meet one or more of the criteria specified in § 192.624(a). More specifically, this section applies to (1) pipelines in HCAs or Class 3 or Class 4 locations lacking traceable, verifiable, and complete records necessary to establish the MAOP (per § 192.619(a)) for the pipeline segment, including, but not limited to, hydrostatic pressure test records required by § 192.517(a); and (2) pipelines where the MAOP was established in accordance with § 192.619(c), the pipeline segment’s MAOP is greater than or equal to 30 percent of SMYS, and the pipeline is located in an HCA, a Class 3 or Class 4 location, or an MCA that can accommodate inspection by means of instrumented inline inspection tools (i.e., “smart pigs”). This approach implements the mandate in the 2011 Pipeline Safety Act for pipeline segments in HCAs and Class 3 and Class 4 locations (49 U.S.C. 60139). In addition, the scope includes pipeline segments in the newly defined MCAs. This approach is intended to address the NTSB recommendations and to provide increased safety in areas where a pipeline rupture would have a significant impact on the public or the environment. Though PHMSA is subjecting certain grandfathered pipeline segments to the MAOP reconfirmation requirements of § 192.624, PHMSA is not repealing § 192.619(c) for pipeline segments located outside of HCAs, Class 3 or Class 4 locations, or MCAs that can accommodate inspection by means of instrumented ILI tools. Previously grandfathered pipelines that reconfirm MAOP using one of the methods of § 192.624 that operate above 72 percent SMYS may continue to operate at the reconfirmed pressure.

The methods to reconfirm MAOP are specified in § 192.624 and are as follows:

Method 1—Pressure test. The pressure test method as specified in section 23 of the 2011 Pipeline Safety Act. Operators choosing to pressure test must also verify material property records in accordance with § 192.607. PHMSA notes that a pressure test requires the cutout of pipe at test manifold sites and those pipe cutouts would be a prime example of pipe that could and should be tested through the material properties verification procedure, if necessary. In accordance with the statute, PHMSA determined that the following methods (2) through (6) are equally effective as a pressure test for the purposes of reconfirming MAOP.

Method 2—Pressure reduction. Derating the pipeline segment so that the new MAOP is less than the historical actual sustained operating pressure by using a pressure test safety factor of 0.80 (for Class 1 and Class 2 locations) or 0.67 (for Class 3 and Class 4 locations) times the sustained operating pressure (equivalent to a pressure test using gas or water as the test medium with a test pressure of 1.25 times MAOP for Class 1 and Class 2 locations and 1.5 times MAOP for Class 3 and Class 4 locations).

Method 3—Engineering critical assessment. An in-line inspection, previously performed pressure test, or alternative technology and engineering critical assessment process using technical analysis with acceptance criteria to establish a safety margin equivalent to that provided by a new pressure test. PHMSA organized the ECA process requirements under a new § 192.632 and established the technical requirements for analyzing the predicted failure pressure as a part of the ECA analysis in a new § 192.712. If an operator chooses the ECA method for MAOP reconfirmation but does not have any of the material properties necessary to perform an ECA analysis (diameter, wall thickness, seam type, grade, and Charpy V-notch toughness values, if applicable), the operator must include the pipeline segment in its program to verify the undocumented information in accordance with the material properties verification requirements at § 192.607.

Method 4—Pipe replacement. Replacement of the pipe, which would require a new pressure test that conforms with subpart J before the pipe is placed into service.

Method 5—Pressure reduction for pipeline segments with small potential impact radii. For pipeline segments with a potential impact radius of less than or equal to 150 feet, a pressure reduction using a safety factor of 0.90 times the sustained operating pressure is allowed (equivalent to a pressure test

of 1.11 times MAOP), supplemented with additional preventive and mitigative measures specified in this final rule.

Method 6—Alternative technology. Other technology that the operator demonstrates provides an equivalent or greater level of safety, provided PHMSA is notified in advance in accordance with § 192.18.

Lastly, this final rule includes a new paragraph, § 192.624(f), to clearly specify that records created while reconfirming MAOP must be retained for the life of the pipeline.

§ 192.632 Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Onshore Steel Transmission Pipelines

The requirements for reconfirming MAOP in the new § 192.624 include an option for operators to perform an engineering critical assessment, or ECA, to reconfirm MAOP in lieu of pressure testing and the other methods provided. The requirements for conducting such an ECA were proposed under the MAOP reconfirmation requirements at § 192.624(c)(3); however, PHMSA has moved the ECA requirements to a new, stand-alone section and cross-referenced those requirements in order to improve the readability of the MAOP reconfirmation requirements.

Operators choosing the ECA method for MAOP reconfirmation may perform an in-line inspection and a technical analysis with acceptance criteria to establish a safety margin equivalent to that provided by a pressure test. PHMSA established the technical requirements for analyzing the predicted failure pressure as a part of the ECA analysis in a new § 192.712, and those requirements are cross-referenced within this ECA process.

Although PHMSA expects that most operators will use an ECA in conjunction with in-line inspection, PHMSA would also allow operators with past, valid pressure tests to calculate the largest defects that could have survived the pressure test and analyze the postulated defects to calculate a predicted failure pressure with which to establish MAOP. This approach might be desirable for operators in certain circumstances, such as for line segments that have valid pressure test records, but that lack other records (such as material strength or pipe wall thickness) necessary to determine design pressure and establish MAOP under the existing § 192.619(a). Another situation for which operators could use this approach would be if the operator has a valid pressure test, but it was not conducted at a test pressure that

was high enough to establish the current MAOP.

Operators with pressure test records meeting the subpart J test requirements may use an ECA by calculating the largest defect that could have survived the pressure test and estimating the flaw growth between the date of the test and the date of the ECA. The ECA is then performed using these postulated defect sizes. In addition, operators must calculate the remaining life of the most severe defects that could have survived the pressure test and establish an appropriate re-assessment interval in accordance with new § 192.712.

If an operator chooses to use ILI to characterize the defects remaining in the pipe segment and the ECA method for MAOP reconfirmation but does not have one or more of the material properties necessary to perform an ECA analysis (diameter, wall thickness, seam type, grade, and Charpy V-notch toughness values, if applicable), the operator must use conservative assumptions and include the pipeline segment in its program to verify the undocumented information in accordance with the material properties verification requirements at § 192.607.

§ 192.710 Transmission Lines: Assessments Outside of High Consequence Areas

Section 5 of the 2011 Pipeline Safety Act requires, if appropriate, the Secretary of Transportation to issue regulations expanding IM system requirements, or elements thereof, beyond HCAs. Currently, part 192 does not contain any requirement for operators to conduct integrity assessments of onshore transmission pipelines that are not HCA segments, as defined in § 192.903, and are therefore not subject to subpart O. However, only approximately 7 percent of onshore gas transmission pipelines are located in HCAs. Through this final rule, operators are required to periodically assess Class 3 locations, Class 4 locations, and MCAs that can accommodate inspection by means of an instrumented inline inspection tool. The periodic assessment requirements under this section apply to pipelines in these locations with MAOPs greater than or equal to 30 percent of SMYS.

Industry has, as a practical matter, assessed portions of pipelines in non-HCA segments coincident with integrity assessments of HCA pipeline segments. For example, INGAA has noted in comment submissions that approximately 90 percent of Class 3 and Class 4 mileage not in HCAs are presently assessed during IM assessments. This is because, in large

part, ILI or pressure testing, by their nature, assess large continuous pipeline segments that may contain some HCA segments but that could also contain significant amounts of non-HCA segments.

While INGAA does not represent all pipeline operators subject to part 192, it does represent the majority of gas transmission operators. PHMSA has determined that, given this level of assessment, it is appropriate and consistent with industry direction to codify requirements for operators to periodically assess certain gas transmission pipelines outside of HCAs to monitor for, detect, and remediate pipeline defects and anomalies. Additionally, to achieve the desired outcome of performing assessments in areas where people live, work, or congregate, while minimizing the cost of identifying such locations, PHMSA is basing the requirements for identifying those locations on processes already being implemented by pipeline operators. More specifically, the MCA definition assumes a similar process used for identifying HCAs, with the exception that the threshold for buildings intended for human occupancy located within the potential impact circle is reduced from 20 to 5.

Because significant non-HCA pipeline mileage has been previously assessed in conjunction with the regular assessment of HCA pipeline segments, PHMSA is allowing operators to count those prior assessments as compliant with the new § 192.710 for the purposes of assessing non-HCAs if those assessments were conducted, and threats remediated, in conjunction with an integrity assessment required by subpart O.

This final rule also requires that the assessment required by the new § 192.710 be conducted using the same methods as adopted for HCAs (see § 192.921, below). Operators may use “other technology” as an assessment method, provided the operator notifies PHMSA in accordance with § 192.18.

§ 192.712 Analysis of Predicted Failure Pressure

The new requirements for reconfirming MAOP in the new § 192.624 include an option for operators to perform an engineering critical assessment, or ECA, to reconfirm MAOP in lieu of pressure testing and the other methods provided. A key aspect of the ECA analysis is the detailed analysis of the remaining strength of pipe with known or assumed defects. The current Federal Pipeline Safety Regulations in subparts I and O refer to methods for predicting the failure pressure for pipe with corrosion

metal loss defects. However, the regulations are silent on performing such analysis for pipe with cracks (including crack-like defects such as selective seam weld corrosion). Therefore, in this final rule, PHMSA is inserting a new section to address the techniques and procedures for analyzing the predicted failure pressures for pipe with corrosion metal loss and cracks or crack-like defects. Examples of technically proven models for calculating predicted failure pressures include: For the brittle failure mode, the Newman-Raju Model⁸⁷ and PipeAssess PIT[™] software;⁸⁸ and for the ductile failure mode, Modified Log-Secant Model,⁸⁹ API RP 579–1⁹⁰—Level II or Level III, CorLas[™] software,⁹¹ PAFFC Model,⁹² and PipeAssess PIT[™] software. All failure models used for the ECA analysis must be used within its technical parameters for the defect type and the pipe or weld material properties. Conforming changes are being made to applicable sections in subparts I and O to refer to this new section, for consistency, but the basic techniques are unchanged.

As a part of this section, PHMSA is including a new paragraph to address cracks and crack-like defects, which as stated above is a critical function of the ECA analysis. The ECA analysis requires the conservative analysis of any in-service cracks, crack-like defects remaining in the pipe, or the largest possible crack that could remain in the pipe, including crack dimensions (length and depth) to determine the predicted failure pressure (PFP) of each defect; the failure mode (ductile, brittle, or both) for the microstructure; the defect's location and type; the pipeline's operating conditions (including pressure cycling); and failure stress and

⁸⁷ Newman, J.C., and Raju; “Stress Intensity Factors for Cracks in Three Dimensional Finite Bodies Subjected to Tension and Bending Loads,” *Computational Methods in the Mechanics of Fracture*; Elsevier; 1986; pp. 311–334.

⁸⁸ Interim Report for Phase II—Task 5 of the Comprehensive Study to Understand Longitudinal ERW Seam Failures, “Summary Report for an Integrity Management Software Tool,” May 2017. <https://primis.phmsa.dot.gov/matrix/FilGet.rdm?fil=11469>.

⁸⁹ ASTM International, ASTM STP 536, “Failure Stress Levels of Flaws in Pressurized Cylinders,” 1973.

⁹⁰ American Petroleum Institute and American Society of Mechanical Engineers, API 579–1/ASME FFS–1, “Fitness-For-Service,” Second Edition, June 2007.

⁹¹ NACE International, NACE Corrosion 96 Paper 255, “Effect of Stress Corrosion Cracking on Integrity and Remaining Life of Natural Gas Pipelines,” March 1996.

⁹² Pipeline Research Council International, Inc., Topical Report NG–18 No. 193, “Development and Validation of a Ductile Flaw Growth Analysis for Gas Transmission Line Pipe,” June 1991.

crack growth analysis to determine the remaining life of the pipeline. An ECA must use the techniques and procedures developed and confirmed through the research findings provided by PHMSA and other reputable technical sources for longitudinal seam and crack growth, such as the Comprehensive Study to Understand Longitudinal ERW Seam Research & Development study task reports: Battelle Final Reports (“Battelle’s Experience with ERW and Flash Weld Seam Failures: Causes and Implications”—Task 1.4), Report No. 13–002 (“Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams”—Subtask 2.4), Report No. 13–021 (“Predicting Times to Failure for ERW Seam Defects that Grow by Pressure-Cycle-Induced Fatigue”—Subtask 2.5), and “Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1”—Task 4.5), which can be found online at: <https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390>. Operators wanting to use assumed Charpy V-notch toughness values differing from the prescribed values as a part of fracture mechanics analysis must notify PHMSA in accordance with § 192.18.

§ 192.750 *Launcher and Receiver Safety*

PHMSA has determined that more explicit requirements are needed for safety when performing maintenance activities that use launchers and receivers to insert and remove maintenance tools and devices, as such facilities are subject to pipeline system pressures. The current regulations for hazardous liquid pipelines at 49 CFR part 195 have, since 1981, contained such safety requirements for scraper and sphere facilities (§ 195.426). However, the regulations for natural gas pipelines do not similarly require controls or instrumentation to protect against inadvertent breaches of system integrity due to the incorrect operation of launchers and receivers for ILI tools, scraper, and sphere facilities. Accordingly, this final rule is adding a new § 192.750 to require a suitable means to relieve pressure in the barrel and either a means to indicate the pressure in the barrel or a means to prevent opening if pressure has not been relieved.

§ 192.805 *Qualification Program*

PHMSA is revising the Federal Pipeline Safety Regulations to include a new § 192.18 that provides instructions for submitting notifications to PHMSA whenever required by part 192. PHMSA

is making conforming changes to § 192.805 to refer to the new § 192.18.

§ 192.909 *How can an operator change its integrity management program?*

PHMSA is revising the Federal Pipeline Safety Regulations to include a new § 192.18 that provides instructions for submitting notifications to PHMSA whenever required by part 192. PHMSA is making conforming changes to § 192.909 to refer to the new § 192.18.

§ 192.917 *How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?*

Section 29 of the 2011 Pipeline Safety Act requires operators to consider seismicity when evaluating threats. Accordingly, PHMSA is revising § 192.917(a)(3) to include seismicity of the area in evaluating the threat of outside force damage. To address NTSB recommendation P–11–15, PHMSA is also revising the criteria in § 192.917(e)(3) for addressing the threat of manufacturing and construction defects by requiring that a pipeline segment must have been pressure tested to a minimum of 1.25 times MAOP to conclude latent defects are stable. Section 192.917(e)(4) has additional requirements for the assessment of low-frequency ERW pipe with seam failures. It now requires usage of the appropriate technology to assess low-frequency ERW pipe, including seam cracking and selective seam weld corrosion. Pipe with seam cracks must be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipe in accordance with § 192.712.

Lastly, the integrity management requirements to address specific threats in § 192.917(e) include requirements for the major causes of pipeline incidents, such as corrosion, third-party damage, cyclic fatigue, manufacturing and construction defects, and electric resistance welded pipe. However, § 192.917(e) does not address cracks and crack-like defects. Therefore, PHMSA is adding a new paragraph, § 192.917(e)(6), to include specific IM requirements for addressing the threat of cracks and crack-like defects (including, but not limited to, stress corrosion cracking or other environmentally assisted cracking, seam defects, selective seam weld corrosion, girth weld cracks, hook cracks, and fatigue cracks) comparable to the other types of threats addressed in § 192.917(e).

§ 192.921 *How is the baseline assessment to be conducted?*

Section 192.921 requires that pipelines subject to the IM regulations have an integrity assessment. The current regulations allow operators to use ILI tools; pressure testing in accordance with subpart J; direct assessment for the threats of external corrosion, internal corrosion, and stress corrosion cracking; and other technology that the operator demonstrates provides an equivalent level of understanding of the condition of the pipeline. Following the PG&E incident, PHMSA determined that the baseline assessment methods should be clarified and strengthened to emphasize ILI use and pressure testing over direct assessment. At San Bruno, PG&E relied heavily on direct assessment under circumstances for which direct assessment was not effective nor appropriate for the pipeline seam type and the threats to the pipeline. Therefore, this final rule requires that direct assessment only be allowed to assess the threats for which the specific direct assessment process is appropriate.

This final rule also adds three additional assessment methods for operators to use: (1) A “spike” hydrostatic pressure test, which is particularly well-suited to address time-dependent threats, such as stress corrosion cracking and other cracking or crack-like defects that can include manufacturing- and construction-related defects; (2) guided wave ultrasonic testing (GWUT), which is particularly appropriate in cases where short pipeline segments, such as road or railroad crossings, are difficult to assess; and (3) excavation with direct *in situ* examination. Based upon the threat assessed, examples of appropriate non-destructive examination methods for *in situ* examination can include ultrasonic testing, phased array ultrasonic testing, inverse wave field extrapolation, radiography, or magnetic particle inspection.

The current regulations indicate that ILI tools are an acceptable assessment method for the threats that the particular ILI tool type can assess. PHMSA is clarifying in this final rule that the use of ILI tools is appropriate for threats such as corrosion, deformation and mechanical damage (including dents, gouges, and grooves), material cracking and crack-like defects (e.g., stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), and hard spots with cracking. As discussed above, this final rule

strengthens guidance in this area by adding a new § 192.493 to require compliance with the requirements and recommendations of API STD 1163–2005, NACE SP0102–2010, and ANSI/ASNT ILI–PQ–2005 when conducting in-line inspection of pipelines. Accordingly, PHMSA revises § 192.921(a)(1) in this final rule to require compliance with § 192.493 instead of ASME B31.8S for baseline ILI assessments for covered segments.

GWUT has been used by pipeline operators for several years. Previously, operators were required by § 192.921(a)(4) to submit a notification to PHMSA as an “other technology” assessment method to use GWUT. In 2007, PHMSA developed guidelines for how it would evaluate notifications for the use of GWUT. These guidelines have been effectively used for over 9 years, and PHMSA has confidence that operators can use GWUT to assess the integrity of short segments of pipe against corrosion threats. In this final rule, PHMSA is incorporating these guidelines into a new Appendix F, which is referenced in § 192.921. Therefore, operators would no longer be required to notify PHMSA to use GWUT.

ASME B31.8S, section 6.1, describes both excavation and direct *in situ* examination as specialized integrity assessment methods applicable to particular circumstances:

It is important to note that some of the integrity assessment methods discussed in para. 6 only provide indications of defects. Examination using visual inspection and a variety of nondestructive examination (NDE) techniques are required, followed by evaluation of these inspection results in order to characterize the defect. The operator may choose to go directly to examination and evaluation for the entire length of the pipeline segment being assessed, in lieu of conducting inspections. For example, the operator may wish to conduct visual examination of aboveground piping for the external corrosion threat. Since the pipe is accessible for this technique and external corrosion can be readily evaluated, performing in-line inspection is not necessary.

PHMSA is clarifying its requirements to explicitly add excavation and direct *in situ* examination as an acceptable assessment method. As previously discussed under § 192.710, PHMSA intends for operators to assess non-HCA pipe with the same methods as HCA pipe. Therefore, PHMSA has standardized the assessment methods between both the IM and non-IM sections. Operators wishing to use “other technology” differing from the prescribed acceptable assessment

methods must notify PHMSA in accordance with § 192.18.

§ 192.933 What actions must be taken to address integrity issues?

PHMSA is revising the Federal Pipeline Safety Regulations to include a new § 192.18 that provides instructions for submitting notifications to PHMSA whenever required by part 192. PHMSA is making conforming changes to § 192.933 to refer to the new § 192.18.

§ 192.935 What additional preventive and mitigative measures must an operator take?

Section 29 of the 2011 Pipeline Safety Act requires operators to consider seismicity when evaluating threats. Accordingly, PHMSA is revising § 192.935(b)(2) to include seismicity of the area when evaluating preventive and mitigative measures with respect to the threat of outside force damage.

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

Section 192.937 requires that operators continue to periodically assess HCA pipeline segments and periodically evaluate the integrity of each covered pipeline segment. PHMSA determined that conforming amendments would be needed to implement, and be consistent with, the changes discussed above for § 192.921. Accordingly, this final rule requires that reassessments use the same assessment methods specified in § 192.921. Operators wishing to use “other technology” differing from the prescribed acceptable assessment methods must notify PHMSA in accordance with § 192.18.

§ 192.939 What are the required reassessment intervals?

Section 192.939 specifies reassessment intervals for pipelines subject to IM requirements. Section 5 of the 2011 Pipeline Safety Act includes a technical correction that clarified that periodic reassessments must occur at a minimum of once every 7 calendar years, but that the Secretary may extend such deadline for an additional 6 months if the operator submits written notice to the Secretary with sufficient justification of the need for the extension. PHMSA expects that any justification, at a minimum, must demonstrate that the extension does not pose a safety risk. In this final rule, PHMSA is codifying this technical correction.

As explained in PHMSA IM FAQ–41, the maximum interval for reassessment may be set using the specified number of calendar years. The use of calendar

years is specific to gas pipeline reassessment interval years and does not alter the actual year interval requirements which appear elsewhere in the code for various inspection and maintenance requirements.

Additionally, PHMSA is revising § 192.939 to include a new § 192.18 that provides instructions for submitting notifications to PHMSA whenever required by part 192. PHMSA is making conforming changes to § 192.939 to refer to the new § 192.18.

§ 192.949 How does an operator notify PHMSA? (Removed and Reserved)

This rulemaking includes several requirements that allow operators to notify PHMSA of proposed alternative approaches to achieving the objective of the minimum safety standards. This is comparable to existing notification requirements in subpart O for pipelines subject to the IM regulations. Because PHMSA is expanding the use of notifications to pipeline segments for which subpart O does not apply (*i.e.*, to non-HCA pipeline segments), PHMSA is adding a new § 192.18 that contains the procedure for submitting such notifications. As such, § 192.949 is no longer needed and is being removed and reserved.

Appendix F to Part 192—Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)

As discussed under § 192.921 above, a new Appendix F to part 192 is needed to provide specific requirements and acceptance criteria for the use of GWUT as an integrity assessment method. Operators must apply all 18 criteria defined in Appendix F to use GWUT as an integrity assessment method. If an operator applies GWUT technology in a manner that does not conform with the guidelines in Appendix F, it would be considered “other technology” for the purposes of §§ 192.710, 192.921, and 192.937.

VI. Standards Incorporated by Reference

A. Summary of New and Revised Standards

Consistent with the amendments in this document, PHMSA is incorporating by reference several standards as described below. Some of these standards are already incorporated by reference into the Federal Pipeline Safety Regulations and are being extended to other sections of the regulations. Other standards provide a technical basis for corresponding regulatory changes in this final rule.

• API STD 1163, “In-Line Inspection Systems Qualification,” Second edition, April 2013, Reaffirmed August 2018.

This standard covers the use of ILI systems for onshore and offshore gas and hazardous liquid pipelines. This includes, but is not limited to, tethered, self-propelled, or free-flowing systems for detecting metal loss, cracks, mechanical damage, pipeline geometries, and pipeline location or mapping. The standard applies to both existing and developing technologies. This standard is an umbrella document that provides performance-based requirements for ILI systems, including procedures, personnel, equipment, and associated software. The incorporation of this standard into the Federal Pipeline Safety Regulations will provide rigorous processes for qualifying the equipment, people, processes, and software used in in-line inspections.

• ANSI/ASNT ILI-PQ-2005(2010), “In-line Inspection Personnel Qualification and Certification,” Reapproved October 11, 2010.

This standard establishes minimum requirements for the qualification and certification of in-line inspection personnel whose jobs demand specific knowledge of the technical principles of in-line inspection technologies, operations, regulatory requirements, and industry standards as those are applicable to pipeline systems. The employer-based standard includes qualification and certification for Levels I, II, and III. The incorporation of this standard into the Federal Pipeline Safety Regulations provides for certification and qualification requirements that are not otherwise addressed in part 192 and will promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes, and software used in in-line inspections.

• NACE Standard Practice 0102-2010, “In-Line Inspection of Pipelines,” Revised 2010-03-13.

This standard outlines a process of related activities that a pipeline operator can use to plan, organize, and execute an ILI project, and it includes guidelines pertaining to ILI data management and data analysis. This standard is intended for individuals and teams, including engineers, O&M personnel, technicians, specialists, construction personnel, and inspectors, involved in planning, implementing, and managing ILI projects and programs. The incorporation of this standard into the Federal Pipeline Safety Regulations would promote a higher level of safety by establishing consistent standards to qualify the equipment, people,

processes, and software used in in-line inspections.

PHMSA is also extending the applicability of the following three currently incorporated-by-reference standards to new sections of the Federal Pipeline Safety Regulations:

• ASME/ANSI B16.5-2003, “Pipe Flanges and Flanged Fittings,” October 2004, IBR approved for § 192.607(f).

This standard covers pressure-temperature ratings, materials, dimensions, tolerances, marking, testing, and methods of designating openings for pipe flanges and flanged fittings. The standard includes requirements and recommendations regarding flange bolting, flange gaskets, and flange joints. This standard is intended for manufacturers, owners, employers, users, and others concerned with the specification, buying, maintenance, training, and safe use of valves with pressure equipment. The incorporation of this standard promotes industry best practices and operational, cost, and safety benefits.

• ASME/ANSI B31G-1991 (Reaffirmed 2004), “Manual for Determining the Remaining Strength of Corroded Pipelines,” 2004, IBR approved for §§ 192.632(a) and 192.712(b).

This document provides guidance for the evaluation of metal loss in pressurized pipelines and piping systems. It is applicable to all pipelines and piping systems that are part of the scope of the transportation pipeline codes that are part of ASME B31 Code for Pressure Piping, namely: ASME B31.4, Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids; ASME B31.8, Gas Transmission and Distribution Piping Systems; ASME B31.11, Slurry Transportation Piping Systems; and ASME B31.12, Hydrogen Piping and Pipelines, Part PL.

• AGA, Pipeline Research Committee Project, PR-3-805, “A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe,” (December 22, 1989), IBR approved for §§ 192.632(a) and 192.712(b).

This document was developed from the Modified B31G method to allow assessment of a river bottom profile of a corroded area on a pipeline to provide more accurate predictions of the pipeline’s remaining strength, and it was adapted into a software program known as RSTRENG. Pipeline operators can use RSTRENG to calculate a pipeline’s predicted failure pressure and safe pressure when determining operating pressures and anomaly response times.

The incorporation by reference of ASME/ANSI B31.8S was approved for

§§ 192.921 and 192.937 as of January 14, 2004. That approval is unaffected by the section revisions in this final rule.

B. Availability of Standards Incorporated by Reference

PHMSA currently incorporates by reference into 49 CFR parts 192, 193, and 195 all or parts of more than 60 standards and specifications developed and published by standard developing organizations (SDO). In general, SDOs update and revise their published standards every 2 to 5 years to reflect modern technology and best technical practices. ASTM often updates some of its more widely used standards every year, and sometimes multiple editions of standards are published in a given year.

In accordance with the National Technology Transfer and Advancement Act of 1995 (Pub. L. 104-113), PHMSA has the responsibility for determining which currently referenced standards should be updated, revised, or removed, and which standards should be added to 49 CFR parts 192, 193, and 195. Revisions to incorporated by reference materials in parts 192, 193, and 195 are handled via the rulemaking process, which allows for the public and regulated entities to provide input. During the rulemaking process, PHMSA must also obtain approval from the Office of the Federal Register to incorporate by reference any new materials.

On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Public Law 112-90. Section 24 of that law states: “Beginning 1 year after the date of enactment of this subsection, the Secretary may not issue guidance or a regulation pursuant to this chapter that incorporates by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge, on an internet website.” 49 U.S.C. 60102(p).

On August 9, 2013, Public Law 113-30 revised 49 U.S.C. 60102(p) to replace “1 year” with “3 years” and remove the phrases “guidance or” and, “on an internet website.” This resulted in the current language in 49 U.S.C. 60102(p), which now reads as follows:

Beginning 3 years after the date of enactment of this subsection, the Secretary may not issue a regulation pursuant to this chapter that incorporates by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge.

On November 7, 2014, the Office of the Federal Register issued a final rule that revised 1 CFR 51.5 to require that Federal agencies include a discussion in the preamble of the final rule “the ways the materials it incorporates by reference are reasonably available to interested parties and how interested parties can obtain the materials.” 79 FR 66278. In relation to this rulemaking, PHMSA has contacted each SDO and has requested free public access of each standard that has been incorporated by reference. The SDOs agreed to make viewable copies of the incorporated standards available to the public at no cost. Pipeline operators interested in purchasing these standards can contact the individual and applicable standards organizations. The contact information is provided in this rulemaking action, see § 192.7.

In addition, PHMSA will provide individual members of the public temporary access to any standard that is incorporated by reference that is not otherwise available for free. Requests for access can be sent to the following email address: PHMSAHPStandards@dot.gov.

VII. Regulatory Analysis and Notices

A. Statutory/Legal Authority for This Rulemaking

This final rule is published under the authority of the Federal Pipeline Safety Statutes (49 U.S.C. 60101 *et seq.*). Section 60102 authorizes the Secretary of Transportation to issue regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and

maintenance of pipeline facilities, as delegated to the PHMSA Administrator under 49 CFR 1.97.

PHMSA is revising the “Authority” entry for parts 191 and 192 to include a citation to a provision of the Mineral Leasing Act (MLA), specifically, 30 U.S.C. 185(w)(3). Section 185(w)(3) provides that “[p]eriodically, but at least once a year, the Secretary of the Department of Transportation shall cause the examination of all pipelines and associated facilities on Federal lands and shall cause the prompt reporting of any potential leaks or safety problems.” The Secretary has delegated this responsibility to PHMSA (49 CFR 1.97). PHMSA has traditionally complied with § 185(w)(3) through the issuance of its pipeline safety regulations, which require annual examinations and prompt reporting for all or most of the pipelines they cover. PHMSA is making this change to be consistent with and make clear its long-standing position that the agency complies with the MLA through the issuance of pipeline safety regulations.

B. Executive Orders 12866 and 13771, and DOT Regulatory Policies and Procedures

Executive Order 12866 requires agencies to regulate in the “most cost-effective manner,” to make a “reasoned determination that the benefits of the intended regulation justify its costs,” and to develop regulations that “impose the least burden on society.” This action has been determined to be significant under Executive Order 12866. It is also considered significant under the Regulatory Policies and Procedures of the Department of Transportation

because of substantial congressional, State, industry, and public interest in pipeline safety. The final rule has been reviewed by the Office of Management and Budget in accordance with Executive Order 12866 (Regulatory Planning and Review) and is consistent with the Executive Order 12866 requirements and 49 U.S.C. 60102(b)(5)–(6). Pursuant to the Congressional Review Act (5 U.S.C. 801 *et seq.*), the Office of Information and Regulatory Affairs designated this rule as not a “major rule,” as defined by 5 U.S.C. 804(2). This final rule is considered an Executive Order 13771 regulatory action. Details on the estimated costs of this final rule can be found in the rule’s RIA.

The table below summarizes the annualized costs for the provisions in the final rule. These estimates reflect the timing of the compliance actions taken by operators and are annualized, where applicable, over 21 years and discounted to 2017 using rates of 3 percent and 7 percent. PHMSA estimates incremental costs for the final requirements in Section 5 of the RIA. PHMSA finds that the other final rule requirements will not result in an incremental cost. Additionally, PHMSA did not quantify the cost savings from the material properties verification provisions under this final rule compared to the existing regulations. The costs of this final rule reflect incremental integrity assessments, MAOP reconfirmation actions, and ILI launcher and receiver upgrades; PHMSA estimates the annualized cost of this rule is \$32.7 million at a 7 percent discount rate.

SUMMARY OF ANNUALIZED COSTS, 2019–2039

[\$2017 thousands]

Provision	Annualized cost	
	3% Discount rate	7% Discount rate
1. MAOP Reconfirmation & Material Properties Verification	\$25.9	\$27.9
2. Seismicity	0	0
3. Six-Month Grace Period for Seven Calendar-Year Reassessment Intervals	0	0
4. In-Line Inspection Launcher/Receiver Safety	0.03	0.04
5. MAOP Exceedance Reports	0	0
6. Strengthening Requirements for Assessment Methods	0	0
7. Assessments Outside HCAs	5.48	4.71
8. Related Records Provisions	0	0
Total	31.4	32.7

The benefits of the final rule will depend on the degree to which compliance actions result in additional safety measures, relative to the current baseline, and the effectiveness of these

measures in preventing or mitigating future pipeline releases or other incidents. For the final rule RIA, PHMSA did not monetize benefits. The

rule’s benefits are discussed qualitatively instead.

For more information, please see the RIA in the docket for this rulemaking.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Flexibility Fairness Act of 1996, requires Federal regulatory agencies to prepare a Final Regulatory Flexibility Analysis (FRFA) for any final rule subject to notice-and-comment rulemaking under the Administrative Procedure Act unless the agency head certifies that the rule will not have a significant economic impact on a substantial number of small entities. PHMSA prepared a FRFA which is available in the docket for the rulemaking.

D. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

PHMSA analyzed this final rule per the principles and criteria in Executive Order 13175, "Consultation and Coordination with Indian Tribal Governments." Because this final rule would not significantly or uniquely affect the communities of the Indian tribal governments or impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13175 do not apply.

E. Paperwork Reduction Act

Pursuant to 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests. On April 18, 2016, PHMSA published an NPRM seeking public comments on the revision of the Federal Pipeline Safety Regulations applicable to the safety of gas transmission pipelines and gas gathering pipelines. During that time, PHMSA proposed changes to information collections that are no longer included in this final rule. PHMSA determined it would be more effective to advance a rulemaking that focuses on the mandates from the 2011 Pipeline Safety Act and split out the other provisions contained in the NPRM into two other separate rules. As such, PHMSA has removed all references to those collections previously contained in the NPRM and will submit information collection revision requests to OMB based on the requirements solely contained within this final rule.

PHMSA estimates that the proposals in this final rule will impact the information collections described below. These information collections are contained in the PSR, 49 CFR parts 190–199. The following information is provided for each information collection: (1) Title of the information

collection, (2) OMB control number, (3) Current expiration date, (4) Type of request, (5) Abstract of the information collection activity, (6) Description of affected public, (7) Estimate of total annual reporting and recordkeeping burden, and (8) Frequency of collection. The information collection burden for the following information collections are estimated to be revised as follows:

1. *Title:* Recordkeeping Requirements for Gas Pipeline Operators.

OMB Control Number: 2137–0049.

Current Expiration Date: 09/30/2021.

Abstract: A person owning or operating a natural gas pipeline facility is required to maintain records, make reports, and provide information to the Secretary of Transportation at the Secretary's request. Based on the proposed revisions in this rule, 25 new recordkeeping requirements are being added to the pipeline safety regulations for owners and operators of natural gas pipelines. Therefore, PHMSA expects to add 24,609 responses and 3,740 hours to this information collection because of the provisions in this final rule.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 3,861,470.

Total Annual Burden Hours:

1,674,810.

Frequency of Collection: On occasion.

2. *Title:* Notification Requirements for Gas Transmission Pipeline Operators.

OMB Control Number: New Collection. Will Request from OMB.

Current Expiration Date: TBD.

Abstract: A person owning or operating a natural gas pipeline facility is required to provide information to the Secretary of Transportation at the Secretary's request. Based on the proposed revisions in this rule, 10 new notification requirements are being added to the pipeline safety regulations for owners and operators of natural gas pipelines. Therefore, PHMSA expects to add 721 responses and 1,070 hours because of the notification requirements in this final rule.

Affected Public: Gas Transmission operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 721.

Total Annual Burden Hours: 1,070.

Frequency of Collection: On occasion.

3. *Title:* Annual Reports for Gas Pipeline Operators.

OMB Control Number: 2137–0522.

Current Expiration Date: 8/31/2020.

Abstract: This information collection covers the collection of annual report data from natural gas pipeline operators.

PHMSA is revising the Gas Transmission and Gas Gathering Annual Report (form PHMSA F7 100.2–1) to collect additional information including mileage of pipe subject to the MAOP reconfirmation and MCA criteria. Based on the proposed revisions, PHMSA estimates that the Annual Report will take an additional 5 hours per report to complete to include the newly required data, increasing the burden for each report to 47 burden hours for an overall burden increase of 7,200 burden hours across all operators.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 10,852.

Total Annual Burden Hours: 83,151.

Frequency of Collection: On occasion.

4. *Title:* Incident for Natural Gas Pipeline Operators.

OMB Control Number: 2137–0635.

Current Expiration Date: 4/30/2022.

Abstract: This information collection covers the collection of incident report data from natural gas pipeline operators. PHMSA is revising the Gas Transmission Incident Report to have operators indicate whether incidents occur inside Moderate Consequence Areas. PHMSA does not expect there to be an increase in burden for the reporting of Gas Transmission incident data.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 301.

Total Annual Burden Hours: 3,612.

Frequency of Collection: On occasion.

Requests for copies of these information collections should be directed to Angela Hill or Cameron Satterthwaite, Office of Pipeline Safety (PHP–30), Pipeline Hazardous Materials Safety Administration (PHMSA), 2nd Floor, 1200 New Jersey Avenue SE, Washington, DC 20590–0001, Telephone (202) 366–4595.

Comments are invited on:

(a) The need for the proposed collection of information for the proper performance of the functions of the agency, including whether the information will have practical utility;

(b) The accuracy of the agency's estimate of the burden of the revised collection of information, including the validity of the methodology and assumptions used;

(c) Ways to enhance the quality, utility, and clarity of the information to be collected; and

(d) Ways to minimize the burden of the collection of information on those

who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques.

Those desiring to comment on these information collections should send comments directly to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attn: Desk Officer for the Department of Transportation, 725 17th Street NW, Washington, DC 20503. Comments should be submitted on or prior to October 31, 2019. Comments may also be sent via email to the Office of Management and Budget at the following address: oir_submissions@omb.eop.gov. OMB is required to make a decision concerning the collection of information requirements contained in this final rule between 30 and 60 days after publication of this document in the **Federal Register**. Therefore, a comment to OMB is best assured of having its full effect if received within 30 days of publication.

F. Unfunded Mandates Reform Act of 1995

An evaluation of Unfunded Mandates Reform Act (UMRA) considerations is performed as part of the Final Regulatory Impact Assessment. PHMSA determined that this final rule does not impose enforceable duties on State, local, or tribal governments or on the private sector of \$100 million or more, adjusted for inflation, in any one year and therefore does not have implications under Section 202 of the UMRA of 1995. A copy of the RIA is available for review in the docket.

G. National Environmental Policy Act

PHMSA analyzed this final rule in accordance with the National Environmental Policy Act (42 U.S.C. 4332) and determined this action will not significantly affect the quality of the human environment. The Environmental Assessment for this final rule is in the docket.

H. Executive Order 13132: Federalism

PHMSA analyzed this final rule in accordance with Executive Order 13132 ("Federalism"). The final rule does not have a substantial direct effect on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government. This rulemaking action does not impose substantial direct compliance costs on State and local governments. The pipeline safety laws, specifically 49 U.S.C. 60104(c), prohibits State safety regulation of interstate pipelines. Under the pipeline

safety law, States have the ability to augment pipeline safety requirements for intrastate pipelines regulated by PHMSA, but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility PHMSA does not regulate. It is these statutory provisions, not the rule, that govern preemption of State law. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

I. Executive Order 13211

This final rule is not a "significant energy action" under Executive Order 13211 (Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use). It is not likely to have a significant adverse effect on supply, distribution, or energy use. Further, the Office of Information and Regulatory Affairs has not designated this final rule as a significant energy action.

J. Privacy Act Statement

Anyone may search the electronic form of all comments received for any of our dockets. You may review DOT's complete Privacy Act Statement, published on April 11, 2000 (65 FR 19476), in the **Federal Register** at: <https://www.govinfo.gov/content/FR-2000-04-11/pdf/00-8505.pdf>.

K. Regulation Identifier Number (RIN)

A regulation identifier number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. The RIN number contained in the heading of this document can be used to cross-reference this action with the Unified Agenda.

List of Subjects

49 CFR Part 191

MAOP exceedance, Pipeline reporting requirements.

49 CFR Part 192

Incorporation by reference, Integrity assessments, Material properties verification, MAOP reconfirmation, Pipeline safety, Predicted failure pressure, Recordkeeping, Risk assessment, Safety devices.

In consideration of the foregoing, PHMSA is amending 49 CFR parts 191 and 192 as follows:

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL, INCIDENT, AND OTHER REPORTING

■ 1. The authority citation for part 191 is revised to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5121, 60101 *et. seq.*, and 49 CFR 1.97.

■ 2. In § 191.23, paragraph (a)(6) is revised, paragraph (a)(10) is added, and paragraph (b)(4) is revised to read as follows:

§ 191.23 Reporting safety-related conditions.

(a) * * *

(6) Any malfunction or operating error that causes the pressure—plus the margin (build-up) allowed for operation of pressure limiting or control devices—to exceed either the maximum allowable operating pressure of a distribution or gathering line, the maximum well allowable operating pressure of an underground natural gas storage facility, or the maximum allowable working pressure of an LNG facility that contains or processes gas or LNG.

* * * * *

(10) For transmission pipelines only, each exceedance of the maximum allowable operating pressure that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices as specified in the applicable requirements of §§ 192.201, 192.620(e), and 192.739. The reporting requirement of this paragraph (a)(10) is not applicable to gathering lines, distribution lines, LNG facilities, or underground natural gas storage facilities (See paragraph (a)(6) of this section).

(b) * * *

(4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report. Notwithstanding this exception, a report must be filed for:

- (i) Conditions under paragraph (a)(1) of this section, unless the condition is localized corrosion pitting on an effectively coated and cathodically protected pipeline; and
- (ii) Any condition under paragraph (a)(10) of this section.

* * * * *

■ 3. Section 191.25 is revised to read as follows:

§ 191.25 Filing safety-related condition reports.

(a) Each report of a safety-related condition under § 191.23(a)(1) through (9) must be filed (received by the Associate Administrator) in writing

within 5 working days (not including Saturday, Sunday, or Federal holidays) after the day a representative of an operator first determines that the condition exists, but not later than 10 working days after the day a representative of an operator discovers the condition. Separate conditions may be described in a single report if they are closely related. Reporting methods and report requirements are described in paragraph (c) of this section.

(b) Each report of a maximum allowable operating pressure exceedance meeting the requirements of criteria in § 191.23(a)(10) for a gas transmission pipeline must be filed (received by the Associate Administrator) in writing within 5 calendar days of the exceedance using the reporting methods and report requirements described in paragraph (c) of this section.

(c) Reports must be filed by email to InformationResourcesManager@dot.gov or by facsimile to (202) 366-7128. For a report made pursuant to § 191.23(a)(1) through (9), the report must be headed "Safety-Related Condition Report." For a report made pursuant to § 191.23(a)(10), the report must be headed "Maximum Allowable Operating Pressure Exceedances." All reports must provide the following information:

- (1) Name, principal address, and operator identification number (OPID) of the operator.
- (2) Date of report.
- (3) Name, job title, and business telephone number of person submitting the report.
- (4) Name, job title, and business telephone number of person who determined that the condition exists.
- (5) Date condition was discovered and date condition was first determined to exist.
- (6) Location of condition, with reference to the State (and town, city, or county) or offshore site, and as appropriate, nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.
- (7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.
- (8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 4. The authority citation for part 192 is revised to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et. seq.*, and 49 CFR 1.97.

■ 5. In § 192.3, the definitions for "Engineering critical assessment (ECA)" and "Moderate consequence area" are added in alphabetical order to read as follows:

§ 192.3 Definitions.

Engineering critical assessment (ECA) means a documented analytical procedure based on fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), operating history, operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections based upon the pipeline segment maximum allowable operating pressure.

Moderate consequence area means:

- (1) An onshore area that is within a potential impact circle, as defined in § 192.903, containing either:
 - (i) Five or more buildings intended for human occupancy; or
 - (ii) Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, as defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1* (see: https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classifications/fcauab.pdf), and that does not meet the definition of high consequence area, as defined in § 192.903.
- (2) The length of the moderate consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle containing either 5 or more buildings intended for human occupancy; or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, to the outermost edge of the last contiguous potential impact circle that contains either 5 or more buildings

intended for human occupancy, or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes.

■ 6. In § 192.5, paragraph (d) is added to read as follows:

§ 192.5 Class locations.

(d) An operator must have records that document the current class location of each pipeline segment and that demonstrate how the operator determined each current class location in accordance with this section.

■ 7. Amend § 192.7 as follows:

- a. Revise paragraph (a)(1)(ii);
- b. Add paragraph (b)(12);
- c. Revise paragraphs (c)(2) and (4);
- d. Re-designate paragraphs (d) through (j) as paragraphs (e) through (k), respectively;
- e. Add new paragraphs (d) and (h)(2); and
- f. Revise newly redesignated paragraph (j)(1).

The revisions and additions read as follows:

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

- (a) * * *
- (1) * * *
- (ii) The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, email fedreg.legal@nara.gov or go to www.archives.gov/federal-register/cfr/ibr-locations.html.
- (b) * * *
- (12) API STANDARD 1163, "In-Line Inspection Systems Qualification," Second edition, April 2013, Reaffirmed August 2018, (API STD 1163), IBR approved for § 192.493.
- (c) * * *
- (2) ASME/ANSI B16.5-2003, "Pipe Flanges and Flanged Fittings," October 2004, (ASME/ANSI B16.5), IBR approved for §§ 192.147(a), 192.279, and 192.607(f).
- (4) ASME/ANSI B31G-1991 (Reaffirmed 2004), "Manual for Determining the Remaining Strength of Corroded Pipelines," 2004, (ASME/ANSI B31G), IBR approved for §§ 192.485(c), 192.632(a), 192.712(b), and 192.933(a).
- (d) American Society for Nondestructive Testing (ASNT), P.O. Box 28518, 1711 Arlinggate Lane, Columbus, OH 43228, phone: 800-222-2768, website: <https://www.asnt.org/>.

(1) ANSI/ASNT ILI-PQ-2005(2010), "In-line Inspection Personnel Qualification and Certification," Reapproved October 11, 2010, (ANSI/ASNT ILI-PQ), IBR approved for § 192.493.

(2) [Reserved]

* * * * *

(h) * * *

(2) NACE Standard Practice 0102-2010, "In-Line Inspection of Pipelines," Revised 2010-03-13, (NACE SP0102), IBR approved for §§ 192.150(a) and 192.493.

* * * * *

(j) * * *

(1) AGA, Pipeline Research Committee Project, PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," (December 22, 1989), (PRCI PR-3-805 (R-STRENG)), IBR approved for §§ 192.485(c); 192.632(a); 192.712(b); 192.933(a) and (d).

* * * * *

■ 8. In § 192.9, paragraphs (b), (c), and (d)(1), (2), and (6) are revised to read as follows:

§ 192.9 What requirements apply to gathering lines?

* * * * *

(b) Offshore lines. An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §§ 192.150, 192.285(e), 192.493, 192.506, 192.607, 192.619(e), 192.624, 192.710, 192.712, and in subpart O of this part.

(c) *Type A lines*. An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§ 192.150, 192.285(e), 192.493, 192.506, 192.607, 192.619(e), 192.624, 192.710, 192.712, and in subpart O of this part. However, operators of Type A regulated onshore gathering lines in a Class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

(d) * * *

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines except the requirements in §§ 192.67, 192.127, 192.205, 192.227(c), 192.285(e), and 192.506;

(2) If the pipeline is metallic, control corrosion according to requirements of

subpart I of this part applicable to transmission lines except the requirements in § 192.493;

* * * * *

(6) Establish the MAOP of the line under § 192.619(a), (b), and (c);

* * * * *

■ 9. Section 192.18 is added to read as follows:

§ 192.18 How to notify PHMSA.

(a) An operator must provide any notification required by this part by—

(1) Sending the notification by electronic mail to *InformationResourcesManager@dot.gov*; or

(2) Sending the notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22-321, 1200 New Jersey Ave. SE, Washington, DC 20590.

(b) An operator must also notify the appropriate State or local pipeline safety authority when an applicable pipeline segment is located in a State where OPS has an interstate agent agreement, or an intrastate applicable pipeline segment is regulated by that State.

(c) Unless otherwise specified, if the notification is made pursuant to § 192.506(b), § 192.607(e)(4), § 192.607(e)(5), § 192.624(c)(2)(iii), § 192.624(c)(6), § 192.632(b)(3), § 192.710(c)(7), § 192.712(d)(3)(iv), § 192.712(e)(2)(i)(E), § 192.921(a)(7), or § 192.937(c)(7) to use a different integrity assessment method, analytical method, sampling approach, or technique (*i.e.*, "other technology") that differs from that prescribed in those sections, the operator must notify PHMSA at least 90 days in advance of using the other technology. An operator may proceed to use the other technology 91 days after submittal of the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposed use of other technology or that PHMSA requires additional time to conduct its review.

§ 192.67 [Redesignated as § 192.69]

■ 10. Redesignate § 192.67 as § 192.69.

■ 11. Section 192.67 is added to read as follows:

§ 192.67 Records: Material properties.

(a) For steel transmission pipelines installed after [July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records that document the physical characteristics of the pipeline, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical

composition of materials for pipe in accordance with §§ 192.53 and 192.55. Records must include tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed.

(b) For steel transmission pipelines installed on or before July 1, 2020], if operators have records that document tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition in accordance with §§ 192.53 and 192.55, operators must retain such records for the life of the pipeline.

(c) For steel transmission pipeline segments installed on or before July 1, 2020], if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.

■ 12. Section 192.127 is added to read as follows:

§ 192.127 Records: Pipe design.

(a) For steel transmission pipelines installed after July 1, 2020], an operator must collect or make, and retain for the life of the pipeline, records documenting that the pipe is designed to withstand anticipated external pressures and loads in accordance with § 192.103 and documenting that the determination of design pressure for the pipe is made in accordance with § 192.105.

(b) For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting pipe design and the determination of design pressure in accordance with §§ 192.103 and 192.105, operators must retain such records for the life of the pipeline.

(c) For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.

■ 13. In § 192.150, paragraph (a) is revised to read as follows:

§ 192.150 Passage of internal inspection devices.

(a) Except as provided in paragraphs (b) and (c) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line, must

be designed and constructed to accommodate the passage of instrumented internal inspection devices in accordance with NACE SP0102, section 7 (incorporated by reference, *see* § 192.7).

* * * * *

■ 14. Section 192.205 is added to read as follows:

§ 192.205 Records: Pipeline components.

(a) For steel transmission pipelines installed after July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records documenting the manufacturing standard and pressure rating to which each valve was manufactured and tested in accordance with this subpart. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches must have records documenting the manufacturing specification in effect at the time of manufacture, including yield strength, ultimate tensile strength, and chemical composition of materials.

(b) For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting the manufacturing standard and pressure rating for valves, flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches, operators must retain such records for the life of the pipeline.

(c) For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.

■ 15. In § 192.227, paragraph (c) is added to read as follows:

§ 192.227 Qualification of welders.

* * * * *

(c) For steel transmission pipe installed after July 1, 2021, records demonstrating each individual welder qualification at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.

■ 16. In § 192.285, paragraph (e) is added to read as follows:

§ 192.285 Plastic pipe: Qualifying persons to make joints.

* * * * *

(e) For transmission pipe installed after July 1, 2021, records demonstrating each person's plastic pipe joining qualifications at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.

■ 17. Section 192.493 is added to read as follows:

§ 192.493 In-line inspection of pipelines.

When conducting in-line inspections of pipelines required by this part, an operator must comply with API STD 1163, ANSI/ASNT ILI-PQ, and NACE SP0102, (incorporated by reference, *see* § 192.7). Assessments may be conducted using tethered or remotely controlled tools, not explicitly discussed in NACE SP0102, provided they comply with those sections of NACE SP0102 that are applicable.

■ 18. Section 192.506 is added to read as follows:

§ 192.506 Transmission lines: Spike hydrostatic pressure test.

(a) *Spike test requirements.* Whenever a segment of steel transmission pipeline that is operated at a hoop stress level of 30 percent or more of SMYS is spike tested under this part, the spike hydrostatic pressure test must be conducted in accordance with this section.

(1) The test must use water as the test medium.

(2) The baseline test pressure must be as specified in the applicable paragraphs of § 192.619(a)(2) or § 192.620(a)(2), whichever applies.

(3) The test must be conducted by maintaining a pressure at or above the baseline test pressure for at least 8 hours as specified in § 192.505.

(4) After the test pressure stabilizes at the baseline pressure and within the first 2 hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.5 times MAOP or 100% SMYS. This spike hydrostatic pressure test must be held for at least 15 minutes after the spike test pressure stabilizes.

(b) *Other technology or other technical evaluation process.* Operators may use other technology or another process supported by a documented engineering analysis for establishing a spike hydrostatic pressure test or equivalent. Operators must notify PHMSA 90 days in advance of the assessment or reassessment requirements of this subchapter. The notification must be made in accordance with § 192.18 and must include the following information:

(1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;

(2) Procedures and processes to conduct tests, examinations, assessments, perform evaluations, analyze defects, and remediate defects discovered;

(3) Data requirements, including original design, maintenance and operating history, anomaly or flaw characterization;

(4) Assessment techniques and acceptance criteria;

(5) Remediation methods for assessment findings;

(6) Spike hydrostatic pressure test monitoring and acceptance procedures, if used;

(7) Procedures for remaining crack growth analysis and pipeline segment life analysis for the time interval for additional assessments, as required; and

(8) Evidence of a review of all procedures and assessments by a qualified technical subject matter expert.

■ 19. In § 192.517, paragraph (a) introductory text is revised to read as follows:

§ 192.517 Records: Tests.

(a) An operator must make, and retain for the useful life of the pipeline, a record of each test performed under §§ 192.505, 192.506, and 192.507. The record must contain at least the following information:

* * * * *

■ 20. Section 192.607 is added to read as follows:

§ 192.607 Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines.

(a) *Applicability.* Wherever required by this part, operators of onshore steel transmission pipelines must document and verify material properties and attributes in accordance with this section.

(b) *Documentation of material properties and attributes.* Records established under this section documenting physical pipeline characteristics and attributes, including diameter, wall thickness, seam type, and grade (e.g., yield strength, ultimate tensile strength, or pressure rating for valves and flanges, etc.), must be maintained for the life of the pipeline and be traceable, verifiable, and complete. Charpy v-notch toughness values established under this section needed to meet the requirements of the ECA method at § 192.624(c)(3) or the fracture mechanics requirements at § 192.712 must be maintained for the life of the pipeline.

(c) *Verification of material properties and attributes.* If an operator does not have traceable, verifiable, and complete records required by paragraph (b) of this section, the operator must develop and implement procedures for conducting nondestructive or destructive tests, examinations, and assessments in order to verify the material properties of aboveground line pipe and components, and of buried line pipe and components when excavations occur at the following opportunities: Anomaly direct examinations, *in situ* evaluations, repairs, remediations, maintenance, and excavations that are associated with replacements or relocations of pipeline segments that are removed from service. The procedures must also provide for the following:

(1) For nondestructive tests, at each test location, material properties for minimum yield strength and ultimate tensile strength must be determined at a minimum of 5 places in at least 2 circumferential quadrants of the pipe for a minimum total of 10 test readings at each pipe cylinder location.

(2) For destructive tests, at each test location, a set of material properties tests for minimum yield strength and ultimate tensile strength must be conducted on each test pipe cylinder removed from each location, in accordance with API Specification 5L.

(3) Tests, examinations, and assessments must be appropriate for verifying the necessary material properties and attributes.

(4) If toughness properties are not documented, the procedures must include accepted industry methods for verifying pipe material toughness.

(5) Verification of material properties and attributes for non-line pipe components must comply with paragraph (f) of this section.

(d) *Special requirements for nondestructive Methods.* Procedures developed in accordance with paragraph (c) of this section for verification of material properties and attributes using nondestructive methods must:

(1) Use methods, tools, procedures, and techniques that have been validated by a subject matter expert based on comparison with destructive test results on material of comparable grade and vintage;

(2) Conservatively account for measurement inaccuracy and uncertainty using reliable engineering tests and analyses; and

(3) Use test equipment that has been properly calibrated for comparable test materials prior to usage.

(e) *Sampling multiple segments of pipe.* To verify material properties and

attributes for a population of multiple, comparable segments of pipe without traceable, verifiable, and complete records, an operator may use a sampling program in accordance with the following requirements:

(1) The operator must define separate populations of similar segments of pipe for each combination of the following material properties and attributes: Nominal wall thicknesses, grade, manufacturing process, pipe manufacturing dates, and construction dates. If the dates between the manufacture or construction of the pipeline segments exceeds 2 years, those segments cannot be considered as the same vintage for the purpose of defining a population under this section. The total population mileage is the cumulative mileage of pipeline segments in the population. The pipeline segments need not be continuous.

(2) For each population defined according to paragraph (e)(1) of this section, the operator must determine material properties at all excavations that expose the pipe associated with anomaly direct examinations, *in situ* evaluations, repairs, remediations, or maintenance, except for pipeline segments exposed during excavation activities pursuant to § 192.614, until completion of the lesser of the following:

(i) One excavation per mile rounded up to the nearest whole number; or

(ii) 150 excavations if the population is more than 150 miles.

(3) Prior tests conducted for a single excavation according to the requirements of paragraph (c) of this section may be counted as one sample under the sampling requirements of this paragraph (e).

(4) If the test results identify line pipe with properties that are not consistent with available information or existing expectations or assumed properties used for operations and maintenance in the past, the operator must establish an expanded sampling program. The expanded sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an expanded sampling approach in accordance with § 192.18.

(5) An operator may use an alternative statistical sampling approach that differs from the requirements specified in paragraph (e)(2) of this section. The alternative sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an alternative sampling approach in accordance with § 192.18.

(f) *Components.* For mainline pipeline components other than line pipe, an operator must develop and implement procedures in accordance with paragraph (c) of this section for establishing and documenting the ANSI rating or pressure rating (in accordance with ASME/ANSI B16.5 (incorporated by reference, *see* § 192.7)),

(1) Operators are not required to test for the chemical and mechanical properties of components in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, valve operator piping, or cross-connections with isolation valves from the mainline pipeline.

(2) Verification of material properties is required for non-line pipe components, including valves, flanges, fittings, fabricated assemblies, and other pressure retaining components and appurtenances that are:

(i) Larger than 2 inches in nominal outside diameter,

(ii) Material grades of 42,000 psi (Grade X-42) or greater, or

(iii) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.

(3) Procedures for establishing material properties of non-line pipe components must be based on the documented manufacturing specification for the components. If specifications are not known, usage of manufacturer's stamped, marked, or tagged material pressure ratings and material type may be used to establish pressure rating. Operators must document the method used to determine the pressure rating and the findings of that determination.

(g) *Upgrading.* The material properties determined from the destructive or nondestructive tests required by this

section cannot be used to raise the grade or specification of the material, unless the original grade or specification is unknown and MAOP is based on an assumed yield strength of 24,000 psi in accordance with § 192.107(b)(2).

■ 21. In § 192.619, the introductory text of paragraphs (a) introductory text and (a)(2) and (4) are revised and paragraphs (e) and (f) are added to read as follows:

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure (MAOP) determined under paragraph (c), (d), or (e) of this section, or the lowest of the following:

(2) The pressure obtained by dividing the pressure to which the pipeline

segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 psi (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the Table 1 to paragraph (a)(2)(ii):

TABLE 1 TO PARAGRAPH (a)(2)(ii)

Class location	Installed before (Nov. 12, 1970)	Factors, ¹ segment—		
		Installed after (Nov. 11, 1970) and before July 1, 2020	Installed on or after July 1, 2020	Converted under § 192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

¹ For offshore pipeline segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For pipeline segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

* * * * *

(4) The pressure determined by the operator to be the maximum safe pressure after considering and accounting for records of material properties, including material properties verified in accordance with § 192.607, if applicable, and the history of the pipeline segment, including known corrosion and actual operating pressure.

* * * * *

(e) Notwithstanding the requirements in paragraphs (a) through (d) of this section, operators of onshore steel transmission pipelines that meet the criteria specified in § 192.624(a) must establish and document the maximum allowable operating pressure in accordance with § 192.624.

(f) Operators of onshore steel transmission pipelines must make and retain records necessary to establish and document the MAOP of each pipeline segment in accordance with paragraphs (a) through (e) of this section as follows:

(1) Operators of pipelines in operation as of July 1, 2020 must retain any existing records establishing MAOP for the life of the pipeline;

(2) Operators of pipelines in operation as of July 1, 2020 that do not have records establishing MAOP and are required to reconfirm MAOP in accordance with § 192.624, must retain the records reconfirming MAOP for the life of the pipeline; and

(3) Operators of pipelines placed in operation after July 1, 2020 must make and retain records establishing MAOP for the life of the pipeline.

■ 22. Section 192.624 is added to read as follows:

§ 192.624 Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.

(a) *Applicability.* Operators of onshore steel transmission pipeline segments must reconfirm the maximum allowable operating pressure (MAOP) of all pipeline segments in accordance with the requirements of this section if either of the following conditions are met:

(1) Records necessary to establish the MAOP in accordance with § 192.619(a), including records required by § 192.517(a), are not traceable, verifiable, and complete and the pipeline is located in one of the following locations:

(i) A high consequence area as defined in § 192.903; or

(ii) A Class 3 or Class 4 location.

(2) The pipeline segment's MAOP was established in accordance with § 192.619(c), the pipeline segment's MAOP is greater than or equal to 30 percent of the specified minimum yield strength, and the pipeline segment is located in one of the following areas:

(i) A high consequence area as defined in § 192.903;

(ii) A Class 3 or Class 4 location; or

(iii) A moderate consequence area as defined in § 192.3, if the pipeline segment can accommodate inspection by means of instrumented inline inspection tools.

(b) *Procedures and completion dates.* Operators of a pipeline subject to this

section must develop and document procedures for completing all actions required by this section by July 1, 2021. These procedures must include a process for reconfirming MAOP for any pipelines that meet a condition of § 192.624(a), and for performing a spike test or material verification in accordance with §§ 192.506 and 192.607, if applicable. All actions required by this section must be completed according to the following schedule:

(1) Operators must complete all actions required by this section on at least 50% of the pipeline mileage by July 3, 2028.

(2) Operators must complete all actions required by this section on 100% of the pipeline mileage by July 2, 2035 or as soon as practicable, but not to exceed 4 years after the pipeline segment first meets a condition of § 192.624(a) (e.g., due to a location becoming a high consequence area), whichever is later.

(3) If operational and environmental constraints limit an operator from meeting the deadlines in § 192.624, the operator may petition for an extension of the completion deadlines by up to 1 year, upon submittal of a notification in accordance with § 192.18. The notification must include an up-to-date plan for completing all actions in accordance with this section, the reason for the requested extension, current status, proposed completion date, outstanding remediation activities, and

any needed temporary measures needed to mitigate the impact on safety.

(c) *Maximum allowable operating pressure determination.* Operators of a pipeline segment meeting a condition in paragraph (a) of this section must reconfirm its MAOP using one of the following methods:

(1) *Method 1: Pressure test.* Perform a pressure test and verify material properties records in accordance with § 192.607 and the following requirements:

(i) *Pressure test.* Perform a pressure test in accordance with subpart J of this part. The MAOP must be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in § 192.619(a)(2)(ii).

(ii) *Material properties records.* Determine if the following material properties records are documented in traceable, verifiable, and complete records: Diameter, wall thickness, seam type, and grade (minimum yield strength, ultimate tensile strength).

(iii) *Material properties verification.* If any of the records required by paragraph (c)(1)(ii) of this section are not documented in traceable, verifiable, and complete records, the operator must obtain the missing records in accordance with § 192.607. An operator must test the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. If there is a failure during the pressure test, the operator must test any removed pipe from the pressure test failure in accordance with § 192.607.

(2) *Method 2: Pressure Reduction.* Reduce pressure, as necessary, and limit MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by the greater of 1.25 or the applicable class location factor in § 192.619(a)(2)(ii). The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period. The value used as the highest actual sustained operating pressure must account for differences between upstream and downstream pressure on the pipeline by use of either the lowest maximum pressure value for

the entire pipeline segment or using the operating pressure gradient along the entire pipeline segment (*i.e.*, the location-specific operating pressure at each location).

(i) Where the pipeline segment has had a class location change in accordance with § 192.611, and records documenting diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and pressure tests are not documented in traceable, verifiable, and complete records, the operator must reduce the pipeline segment MAOP as follows:

(A) For pipeline segments where a class location changed from Class 1 to Class 2, from Class 2 to Class 3, or from Class 3 to Class 4, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by 1.39 for Class 1 to Class 2, 1.67 for Class 2 to Class 3, and 2.00 for Class 3 to Class 4.

(B) For pipeline segments where a class location changed from Class 1 to Class 3, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by 2.00.

(ii) Future uprating of the pipeline segment in accordance with subpart K is allowed if the MAOP is established using Method 2.

(iii) If an operator elects to use Method 2, but desires to use a less conservative pressure reduction factor or longer look-back period, the operator must notify PHMSA in accordance with § 192.18 no later than 7 calendar days after establishing the reduced MAOP. The notification must include the following details:

(A) Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in § 192.624(c)(2);

(B) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with § 192.712;

(C) Justification that establishing MAOP by another method allowed by this section is impractical;

(D) Justification that the reduced MAOP determined by the operator is safe based on analysis of the condition of the pipeline segment, including material properties records, material properties verified in accordance with § 192.607, and the history of the pipeline segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned; and

(E) Planned duration for operating at the requested MAOP, long-term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts.

(3) *Method 3: Engineering Critical Assessment (ECA).* Conduct an ECA in accordance with § 192.632.

(4) *Method 4: Pipe Replacement.* Replace the pipeline segment in accordance with this part.

(5) *Method 5: Pressure Reduction for Pipeline Segments with Small Potential Impact Radius.* Pipelines with a potential impact radius (PIR) less than or equal to 150 feet may establish the MAOP as follows:

(i) Reduce the MAOP to no greater than the highest actual operating pressure sustained by the pipeline during 5 years preceding October 1, 2019, divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during one continuous 30-day period. The reduced MAOP must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire pipeline segment or the operating pressure gradient (*i.e.*, the location specific operating pressure at each location);

(ii) Conduct patrols in accordance with § 192.705 paragraphs (a) and (c) and conduct instrumented leakage surveys in accordance with § 192.706 at intervals not to exceed those in the following table 1 to § 192.624(c)(5)(ii):

TABLE 1 TO § 192.624(c)(5)(ii)

Class locations	Patrols	Leakage surveys
(A) Class 1 and Class 2	3½ months, but at least four times each calendar year	3½ months, but at least four times each calendar year.
(B) Class 3 and Class 4	3 months, but at least six times each calendar year	3 months, but at least six times each calendar year.

(iii) Under Method 5, future uprating of the pipeline segment in accordance with subpart K is allowed.

(6) *Method 6: Alternative Technology.* Operators may use an alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP. If an operator elects to use alternative technology, the operator must notify PHMSA in advance in accordance with § 192.18. The notification must include descriptions of the following details:

(i) The technology or technologies to be used for tests, examinations, and assessments; the method for establishing material properties; and analytical techniques with similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the pipeline segment being evaluated;

(ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects and flaws, and remediate defects discovered;

(iii) Pipeline segment data, including original design, maintenance and operating history, anomaly or flaw characterization;

(iv) Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of the predicted failure pressure quantified as a fraction of specified minimum yield strength;

(v) If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.712;

(vi) Operational monitoring procedures;

(vii) Methodology and criteria used to justify and establish the MAOP; and

(viii) Documentation of the operator's process and procedures used to implement the use of the alternative technology, including any records generated through its use.

(d) *Records.* An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

■ 23. Section 192.632 is added to read as follows:

§ 192.632 Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Onshore steel transmission pipelines.

When an operator conducts an MAOP reconfirmation in accordance with § 192.624(c)(3) "Method 3" using an ECA to establish the material strength and MAOP of the pipeline segment, the ECA must comply with the requirements of this section. The ECA must assess: Threats; loadings and operational circumstances relevant to those threats, including along the pipeline right-of-way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; and initial and final defect size relevance. The ECA must quantify the interacting effects of threats on any defect in the pipeline.

(a) *ECA Analysis.* (1) The material properties required to perform an ECA analysis in accordance with this paragraph are as follows: Diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and Charpy v-notch toughness values based upon the lowest operational temperatures, if applicable. If any material properties required to perform an ECA for any pipeline segment in accordance with this paragraph are not documented in traceable, verifiable and complete records, an operator must use conservative assumptions and include the pipeline segment in its program to verify the undocumented information in accordance with § 192.607. The ECA must integrate, analyze, and account for the material properties, the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with this section, along with other pertinent information related to pipeline integrity, including close interval surveys, coating surveys, interference surveys required by subpart I of this part, cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by §§ 192.617, 192.710, and subpart O of this part.

(2) The ECA must analyze and determine the predicted failure pressure for the defect being assessed using procedures that implement the appropriate failure criteria and justification as follows:

(i) The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure of each defect in accordance with § 192.712.

(ii) The ECA must analyze any metal loss defects not associated with a dent, including corrosion, gouges, scrapes or other metal loss defects that could remain in the pipe, to determine the predicted failure pressure. ASME/ANSI B31G (incorporated by reference, see § 192.7) or R-STRENG (incorporated by reference, see § 192.7) must be used for corrosion defects. Both procedures and their analysis apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations' procedures. The ECA must use conservative assumptions for metal loss dimensions (length, width, and depth).

(iii) When determining the predicted failure pressure for gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, appropriate failure criteria and justification of the criteria must be used and documented.

(iv) If SMYS or actual material yield and ultimate tensile strength is not known or not documented by traceable, verifiable, and complete records, then the operator must assume 30,000 p.s.i. or determine the material properties using § 192.607.

(3) The ECA must analyze the interaction of defects to conservatively determine the most limiting predicted failure pressure. Examples include, but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process.

(4) The MAOP must be established at the lowest predicted failure pressure for any known or postulated defect, or interacting defects, remaining in the pipe divided by the greater of 1.25 or the applicable factor listed in § 192.619(a)(2)(ii).

(b) *Assessment to determine defects remaining in the pipe.* An operator must utilize previous pressure tests or develop and implement an assessment program to determine the size of defects remaining in the pipe to be analyzed in accordance with paragraph (a) of this section.

(1) An operator may use a previous pressure test that complied with subpart J to determine the defects remaining in the pipe if records for a pressure test meeting the requirements of subpart J of this part exist for the pipeline segment. The operator must calculate the largest defect that could have survived the pressure test. The operator must predict how much the defects have grown since the date of the pressure test in

accordance with § 192.712. The ECA must analyze the predicted size of the largest defect that could have survived the pressure test that could remain in the pipe at the time the ECA is performed. The operator must calculate the remaining life of the most severe defects that could have survived the pressure test and establish a re-assessment interval in accordance with the methodology in § 192.712.

(2) Operators may use an inline inspection program in accordance with paragraph (c) of this section.

(3) Operators may use “other technology” if it is validated by a subject matter expert to produce an equivalent understanding of the condition of the pipe equal to or greater than pressure testing or an inline inspection program. If an operator elects to use “other technology” in the ECA, it must notify PHMSA in advance of using the other technology in accordance with § 192.18. The “other technology” notification must have:

(i) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments, including characterization of defect size used in the crack assessments (length, depth, and volumetric); and

(ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects, and remediate defects discovered.

(c) *In-line inspection.* An inline inspection (ILI) program to determine the defects remaining the pipe for the ECA analysis must be performed using tools that can detect wall loss, deformation from dents, wrinkle bends, ovalities, expansion, seam defects, including cracking and selective seam weld corrosion, longitudinal, circumferential and girth weld cracks, hard spot cracking, and stress corrosion cracking.

(1) If a pipeline has segments that might be susceptible to hard spots based on assessment, leak, failure, manufacturing vintage history, or other information, then the ILI program must include a tool that can detect hard spots.

(2) If the pipeline has had a reportable incident, as defined in § 191.3, attributed to a girth weld failure since its most recent pressure test, then the ILI program must include a tool that can detect girth weld defects unless the ECA analysis performed in accordance with this section includes an engineering evaluation program to analyze and account for the susceptibility of girth weld failure due to lateral stresses.

(3) Inline inspection must be performed in accordance with § 192.493.

(4) An operator must use unity plots or equivalent methodologies to validate the performance of the ILI tools in identifying and sizing actionable manufacturing and construction related anomalies. Enough data points must be used to validate tool performance at the same or better statistical confidence level provided in the tool specifications. The operator must have a process for identifying defects outside the tool performance specifications and following up with the ILI vendor to conduct additional in-field examinations, reanalyze ILI data, or both.

(5) Interpretation and evaluation of assessment results must meet the requirements of §§ 192.710, 192.713, and subpart O of this part, and must conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length and depth) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the defect types and pipe material vintage being evaluated. Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations.

(6) Anomalies detected by ILI assessments must be remediated in accordance with applicable criteria in §§ 192.713 and 192.933.

(d) *Defect remaining life.* If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with § 192.712.

(e) *Records.* An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

■ 24. Section 192.710 is added to read as follows:

§ 192.710 Transmission lines: Assessments outside of high consequence areas.

(a) *Applicability:* This section applies to onshore steel transmission pipeline

segments with a maximum allowable operating pressure of greater than or equal to 30% of the specified minimum yield strength and are located in:

(1) A Class 3 or Class 4 location; or

(2) A moderate consequence area as defined in § 192.3, if the pipeline segment can accommodate inspection by means of an instrumented inline inspection tool (*i.e.*, “smart pig”).

(3) This section does not apply to a pipeline segment located in a high consequence area as defined in § 192.903.

(b) *General—(1) Initial assessment.*

An operator must perform initial assessments in accordance with this section based on a risk-based prioritization schedule and complete initial assessment for all applicable pipeline segments no later than July 3, 2034, or as soon as practicable but not to exceed 10 years after the pipeline segment first meets the conditions of § 192.710(a) (*e.g.*, due to a change in class location or the area becomes a moderate consequence area), whichever is later.

(2) *Periodic reassessment.* An operator must perform periodic reassessments at least once every 10 years, with intervals not to exceed 126 months, or a shorter reassessment interval based upon the type of anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety.

(3) *Prior assessment.* An operator may use a prior assessment conducted before July 1, 2020 as an initial assessment for the pipeline segment, if the assessment met the subpart O requirements of part 192 for in-line inspection at the time of the assessment. If an operator uses this prior assessment as its initial assessment, the operator must reassess the pipeline segment according to the reassessment interval specified in paragraph (b)(2) of this section calculated from the date of the prior assessment.

(4) *MAOP verification.* An integrity assessment conducted in accordance with the requirements of § 192.624(c) for establishing MAOP may be used as an initial assessment or reassessment under this section.

(c) *Assessment method.* The initial assessments and the reassessments required by paragraph (b) of this section must be capable of identifying anomalies and defects associated with each of the threats to which the pipeline segment is susceptible and must be performed using one or more of the following methods:

(1) *Internal inspection.* Internal inspection tool or tools capable of detecting those threats to which the

pipeline is susceptible, such as corrosion, deformation and mechanical damage (e.g., dents, gouges and grooves), material cracking and crack-like defects (e.g., stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493;

(2) *Pressure test.* Pressure test conducted in accordance with subpart J of this part. The use of subpart J pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms; manufacturing and related defect threats, including defective pipe and pipe seams; and stress corrosion cracking, selective seam weld corrosion, dents and other forms of mechanical damage;

(3) *Spike hydrostatic pressure test.* A spike hydrostatic pressure test conducted in accordance with § 192.506. A spike hydrostatic pressure test is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;

(4) *Direct examination.* Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all applicable threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), Inverse Wave Field Extrapolation (IWEX), radiography, and magnetic particle inspection (MPI);

(5) *Guided Wave Ultrasonic Testing.* Guided Wave Ultrasonic Testing (GWUT) as described in Appendix F;

(6) *Direct assessment.* Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and

with the applicable requirements specified in §§ 192.925, 192.927 and 192.929; or

(7) *Other technology.* Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with § 192.18.

(d) *Data analysis.* An operator must analyze and account for the data obtained from an assessment performed under paragraph (c) of this section to determine if a condition could adversely affect the safe operation of the pipeline using personnel qualified by knowledge, training, and experience. In addition, when analyzing inline inspection data, an operator must account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.

(e) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that 180 days is impracticable.

(f) *Remediation.* An operator must comply with the requirements in §§ 192.485, 192.711, and 192.713, where applicable, if a condition that could adversely affect the safe operation of a pipeline is discovered.

(g) *Analysis of information.* An operator must analyze and account for all available relevant information about a pipeline in complying with the requirements in paragraphs (a) through (f) of this section.

■ 25. Section 192.712 is added to read as follows:

§ 192.712 Analysis of predicted failure pressure.

(a) *Applicability.* Whenever required by this part, operators of onshore steel transmission pipelines must analyze anomalies or defects to determine the predicted failure pressure at the location of the anomaly or defect, and the

remaining life of the pipeline segment at the location of the anomaly or defect, in accordance with this section.

(b) *Corrosion metal loss.* When analyzing corrosion metal loss under this section, an operator must use a suitable remaining strength calculation method including, ASME/ANSI B31G (incorporated by reference, *see* § 192.7); R-STRENG (incorporated by reference, *see* § 192.7); or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result.

(c) [Reserved]

(d) *Cracks and crack-like defects—(1) Crack analysis models.* When analyzing cracks and crack-like defects under this section, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other).

(2) *Analysis for crack growth and remaining life.* If the pipeline segment is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law (for example, Paris Law) or other technically appropriate engineering methodology. For other degradation processes that can cause crack growth, appropriate engineering analysis must be used. The above methodologies must be validated by a subject matter expert to determine conservative predictions of flaw growth and remaining life at the maximum allowable operating pressure. The operator must calculate the remaining life of the pipeline by determining the amount of time required for the crack to grow to a size that would fail at maximum allowable operating pressure.

(i) When calculating crack size that would fail at MAOP, and the material toughness is not documented in traceable, verifiable, and complete records, the same Charpy v-notch toughness value established in paragraph (e)(2) of this section must be used.

(ii) Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other).

(iii) An operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired. The operator must determine and document if further pressure tests or use of other assessment

methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired.

(3) *Cracks that survive pressure testing.* For cases in which the operator does not have in-line inspection crack anomaly data and is analyzing potential crack defects that could have survived a pressure test, the operator must calculate the largest potential crack defect sizes using the methods in paragraph (d)(1) of this section. If pipe material toughness is not documented in traceable, verifiable, and complete records, the operator must use one of the following for Charpy v-notch toughness values based upon minimum operational temperature and equivalent to a full-size specimen value:

(i) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;

(ii) A conservative Charpy v-notch toughness value to determine the toughness based upon the material properties verification process specified in § 192.607;

(iii) A full size equivalent Charpy v-notch upper-shelf toughness level of 120 ft.-lbs.; or

(iv) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of the crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in accordance with § 192.18.

(e) *Data.* In performing the analyses of predicted or assumed anomalies or defects in accordance with this section, an operator must use data as follows.

(1) An operator must explicitly analyze and account for uncertainties in reported assessment results (including tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses, unless the defect dimensions have been verified using *in situ* direct measurements.

(2) The analyses performed in accordance with this section must utilize pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607.

Until documented material properties are available, the operator shall use conservative assumptions as follows:

(i) *Material toughness.* An operator must use one of the following for material toughness:

(A) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;

(B) A conservative Charpy v-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in § 192.607;

(C) If the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 13.0 ft.-lbs. for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects;

(D) If the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 5.0 ft.-lbs. for body cracks and 1.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion; or

(E) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in advance in accordance with § 192.18 and include in the notification the bases for demonstrating that the Charpy v-notch toughness values proposed are appropriate and conservative for use in analysis of crack-related conditions.

(ii) *Material strength.* An operator must assume one of the following for material strength:

(A) Grade A pipe (30,000 psi), or

(B) The specified minimum yield strength that is the basis for the current maximum allowable operating pressure.

(iii) *Pipe dimensions and other data.* Until pipe wall thickness, diameter, or other data are determined and documented in accordance with § 192.607, the operator must use values upon which the current MAOP is based.

(f) *Review.* Analyses conducted in accordance with this section must be reviewed and confirmed by a subject matter expert.

(g) *Records.* An operator must keep for the life of the pipeline records of the investigations, analyses, and other actions taken in accordance with the requirements of this section. Records must document justifications, deviations, and determinations made for the following, as applicable:

(1) The technical approach used for the analysis;

(2) All data used and analyzed;

(3) Pipe and weld properties;

(4) Procedures used;

(5) Evaluation methodology used;

(6) Models used;

(7) Direct in situ examination data;

(8) In-line inspection tool run

information evaluated, including any multiple in-line inspection tool runs;

(9) Pressure test data and results;

(10) In-the-ditch assessments;

(11) All measurement tool,

assessment, and evaluation accuracy specifications and tolerances used in technical and operational results;

(12) All finite element analysis results;

(13) The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method;

(14) The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods;

(15) Safety factors used for fatigue life and/or predicted failure pressure calculations;

(16) Reassessment time interval and safety factors;

(17) The date of the review;

(18) Confirmation of the results by qualified technical subject matter experts; and

(19) Approval by responsible operator management personnel.

■ 26. Section 192.750 is added to read as follows:

§ 192.750 Launcher and receiver safety.

Any launcher or receiver used after July 1, 2021, must be equipped with a device capable of safely relieving pressure in the barrel before removal or opening of the launcher or receiver barrel closure or flange and insertion or removal of in-line inspection tools, scrapers, or spheres. An operator must use a device to either: Indicate that pressure has been relieved in the barrel; or alternatively prevent opening of the barrel closure or flange when pressurized, or insertion or removal of in-line devices (e.g. inspection tools, scrapers, or spheres), if pressure has not been relieved.

■ 27. In § 192.805, paragraph (i) is revised to read as follows:

§ 192.805 Qualification Program.

* * * * *

(i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if an operator significantly modifies the program after the administrator or state agency has verified that it complies

with this section. Notifications to PHMSA must be submitted in accordance with § 192.18.

■ 28. In § 192.909, paragraph (b) is revised to read as follows:

§ 192.909 How can an operator change its integrity management program?

* * * *

(b) *Notification.* An operator must notify OPS, in accordance with § 192.18, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must provide notification within 30 days after adopting this type of change into its program.

■ 29. In § 192.917, paragraphs (a)(3) and (e)(2) through (4) are revised, and paragraph (e)(6) is added to read as follows:

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) * * *

(3) Time independent threats such as third party damage, mechanical damage, incorrect operational procedure, weather related and outside force damage to include consideration of seismicity, geology, and soil stability of the area; and

* * * *

(e) * * *

(2) *Cyclic fatigue.* An operator must analyze and account for whether cyclic fatigue or other loading conditions (including ground movement, and suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, crack, or other defect in the covered segment. The analysis must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the analysis together with the criteria used to determine the significance of the threat(s) to the covered segment to prioritize the integrity baseline assessment or reassessment. Failure stress pressure and crack growth analysis of cracks and crack-like defects must be conducted in accordance with § 192.712. An operator must monitor operating pressure cycles and periodically, but at least every 7 calendar years, with intervals not to exceed 90 months, determine if the cyclic fatigue analysis remains valid or if the cyclic fatigue analysis must be revised based on changes to operating pressure cycles or other loading conditions.

(3) *Manufacturing and construction defects.* An operator must analyze the covered segment to determine and account for the risk of failure from manufacturing and construction defects (including seam defects) in the covered segment. The analysis must account for the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to hydrostatic pressure testing satisfying the criteria of subpart J of at least 1.25 times MAOP, and the covered segment has not experienced a reportable incident attributed to a manufacturing or construction defect since the date of the most recent subpart J pressure test. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high-risk segment for the baseline assessment or a subsequent reassessment.

(i) The pipeline segment has experienced a reportable incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, or a construction-, installation-, or fabrication-related defect;

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) *Electric Resistance Welded (ERW) pipe.* If a covered pipeline segment contains low frequency ERW pipe, lap welded pipe, pipe with longitudinal joint factor less than 1.0 as defined in § 192.113, or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure (including seam cracking and selective seam weld corrosion), or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding 5 years (including abnormal operation as defined in § 192.605(c)), or MAOP has been increased, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high-risk segment for the baseline assessment or a subsequent reassessment. Pipe with seam cracks must be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis to estimate the

remaining life of the pipe in accordance with § 192.712.

* * * *

(6) *Cracks.* If an operator identifies any crack or crack-like defect (e.g., stress corrosion cracking or other environmentally assisted cracking, seam defects, selective seam weld corrosion, girth weld cracks, hook cracks, and fatigue cracks) on a covered pipeline segment that could adversely affect the integrity of the pipeline, the operator must evaluate, and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar characteristics associated with the crack or crack-like defect. Similar characteristics may include operating and maintenance histories, material properties, and environmental characteristics. An operator must establish a schedule for evaluating, and remediating, as necessary, the similar pipeline segments that is consistent with the operator's established operating and maintenance procedures under this part for testing and repair.

■ 30. In § 192.921, revise paragraph (a) and add paragraph (i) to read as follows:

§ 192.921 How is the baseline assessment to be conducted?

(a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* § 192.917).

(1) Internal inspection tool or tools capable of detecting those threats to which the pipeline is susceptible. The use of internal inspection tools is appropriate for threats such as corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (e.g., stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. In addition, an operator must analyze and account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool

performance) in identifying and characterizing anomalies;

(2) Pressure test conducted in accordance with subpart J of this part. The use of subpart J pressure testing is appropriate for threats such as internal corrosion; external corrosion and other environmentally assisted corrosion mechanisms; manufacturing and related defects threats, including defective pipe and pipe seams; stress corrosion cracking; selective seam weld corrosion; dents; and other forms of mechanical damage. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7) to justify an extended reassessment interval in accordance with § 192.939.

(3) Spike hydrostatic pressure test conducted in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;

(4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), radiography, and magnetic particle inspection (MPI);

(5) Guided wave ultrasonic testing (GWUT) as described in Appendix F. The use of GWUT is appropriate for internal and external pipe wall loss;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and the pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927 and 192.929; or

(7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using

the other technology in accordance with § 192.18.

* * * * *

(i) *Baseline assessments for pipeline segments with a reconfirmed MAOP.* An integrity assessment conducted in accordance with the requirements of § 192.624(c) may be used as a baseline assessment under this section.

■ 31. In § 192.933, paragraphs (a)(1) and (2) are revised to read as follows:

§ 192.933 What actions must be taken to address integrity issues?

(a) * * *

(1) *Temporary pressure reduction.* If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, *see* § 192.7); R-STRENG (incorporated by reference, *see* § 192.7); or by reducing the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. An operator must notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or through another action.

(2) *Long-term pressure reduction.* When a pressure reduction exceeds 365 days, an operator must notify PHMSA under § 192.18 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

* * * * *

■ 32. In § 192.935, paragraph (b)(2) is revised to read as follows:

§ 192.935 What additional preventive and mitigative measures must an operator take?

* * * * *

(b) * * *

(2) *Outside force damage.* If an operator determines that outside force (e.g., earth movement, loading, longitudinal, or lateral forces, seismicity of the area, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include increasing the frequency of aerial, foot

or other methods of patrols; adding external protection; reducing external stress; relocating the line; or inline inspections with geospatial and deformation tools.

* * * * *

■ 33. In § 192.937, revise paragraph (c) and add paragraph (d) to read as follows:

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

* * * * *

(c) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified on the covered segment (*see* § 192.917).

(1) *Internal inspection tools.* When performing an assessment using an in-line inspection tool, an operator must comply with the following requirements:

(i) Perform the in-line inspection in accordance with § 192.493;

(ii) Select a tool or combination of tools capable of detecting the threats to which the pipeline segment is susceptible such as corrosion, deformation and mechanical damage (e.g. dents, gouges and grooves), material cracking and crack-like defects (e.g. stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible; and

(iii) Analyze and account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.

(2) *Pressure test conducted in accordance with subpart J of this part.* The use of pressure testing is appropriate for threats such as: Internal corrosion; external corrosion and other environmentally assisted corrosion mechanisms; manufacturing and related defects threats, including defective pipe and pipe seams; stress corrosion cracking; selective seam weld corrosion; dents; and other forms of mechanical damage. An operator must use the test

pressures specified in table 3 of section 5 of ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7) to justify an extended reassessment interval in accordance with § 192.939.

(3) *Spike hydrostatic pressure test in accordance with § 192.506.* The use of spike hydrostatic pressure testing is appropriate for time-dependent threats such as: Stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;

(4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), radiography, or magnetic particle inspection (MPI);

(5) Guided wave ultrasonic testing (GWUT) as described in Appendix F. The use of GWUT is appropriate for internal and external pipe wall loss;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927, and 192.929;

(7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with § 192.18; or

(8) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than 7 calendar years. An operator using this reassessment method must comply with § 192.931.

(d) *MAOP reconfirmation assessments.* An integrity assessment conducted in accordance with the requirements of § 192.624(c) may be used as a reassessment under this section.

■ 34. In § 192.939, paragraphs (a) introductory text, (b) introductory text, and (b)(1) are revised to read as follows:

§ 192.939 What are the required reassessment intervals?

* * * * *

(a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is 7 calendar years. Operators may request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to OPS, in accordance with § 192.18, with sufficient justification of the need for the extension. If an operator establishes a reassessment interval that is greater than 7 calendar years, the operator must, within the 7-calendar-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with § 192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.

* * * * *

(b) *Pipelines Operating below 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is 7 calendar years. Operators may request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to OPS in accordance with § 192.18. The notice must include sufficient justification of the need for the extension. An operator must establish reassessment by at least one of the following—

(1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than 7 calendar years, an operator must conduct by the seventh calendar year of the interval either a confirmatory direct assessment in accordance with § 192.931, or a low stress reassessment in accordance with § 192.941.

* * * * *

§ 192.949 [Removed and Reserved]

■ 35. Remove and reserve § 192.949.

■ 36. Appendix F is added to read as follows:

Appendix F to Part 192—Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)

This appendix defines criteria which must be properly implemented for use of guided wave ultrasonic testing (GWUT) as an integrity assessment method. Any application of GWUT that does not conform to these criteria is considered “other technology” as described by §§ 192.710(c)(7), 192.921(a)(7), and 192.937(c)(7), for which OPS must be notified 90 days prior to use in accordance with §§ 192.921(a)(7) or 192.937(c)(7). GWUT in the “Go-No Go” mode means that all indications (wall loss anomalies) above the testing threshold (a maximum of 5% of cross sectional area (CSA) sensitivity) be directly examined, in-line tool inspected, pressure tested, or replaced prior to completing the integrity assessment on the carrier pipe.

I. *Equipment and Software: Generation.* The equipment and the computer software used are critical to the success of the inspection. Computer software for the inspection equipment must be reviewed and updated, as required, on an annual basis, with intervals not to exceed 15 months, to support sensors, enhance functionality, and resolve any technical or operational issues identified.

II. *Inspection Range.* The inspection range and sensitivity are set by the signal to noise (S/N) ratio but must still keep the maximum threshold sensitivity at 5% cross sectional area (CSA). A signal that has an amplitude that is at least twice the noise level can be reliably interpreted. The greater the S/N ratio the easier it is to identify and interpret signals from small changes. The signal to noise ratio is dependent on several variables such as surface roughness, coating, coating condition, associated pipe fittings (T’s, elbows, flanges), soil compaction, and environment. Each of these affects the propagation of sound waves and influences the range of the test. It may be necessary to inspect from both ends of the pipeline segment to achieve a full inspection. In general, the inspection range can approach 60 to 100 feet for a 5% CSA, depending on field conditions.

III. *Complete Pipe Inspection.* To ensure that the entire pipeline segment is assessed there should be at least a 2 to 1 signal to noise ratio across the entire pipeline segment that is

inspected. This may require multiple GWUT shots. Double-ended inspections are expected. These two inspections are to be overlaid to show the minimum 2 to 1 S/N ratio is met in the middle. If possible, show the same near or midpoint feature from both sides and show an approximate 5% distance overlap.

IV. *Sensitivity*. The detection sensitivity threshold determines the ability to identify a cross sectional change. The maximum threshold sensitivity cannot be greater than 5% of the cross sectional area (CSA).

The locations and estimated CSA of all metal loss features in excess of the detection threshold must be determined and documented.

All defect indications in the "Go-No Go" mode above the 5% testing threshold must be directly examined, in-line inspected, pressure tested, or replaced prior to completing the integrity assessment.

V. *Wave Frequency*. Because a single wave frequency may not detect certain defects, a minimum of three frequencies must be run for each inspection to determine the best frequency for characterizing indications. The frequencies used for the inspections must be documented and must be in the range specified by the manufacturer of the equipment.

VI. *Signal or Wave Type: Torsional and Longitudinal*. Both torsional and longitudinal waves must be used and use must be documented.

VII. *Distance Amplitude Correction (DAC) Curve and Weld Calibration*. The distance amplitude correction curve accounts for coating, pipe diameter, pipe wall and environmental conditions at the assessment location. The DAC curve must be set for each inspection as part of establishing the effective range of a GWUT inspection. DAC curves provide a means for evaluating the cross-sectional area change of reflections at various distances in the test range by assessing signal to noise ratio. A DAC curve is a means of taking apparent attenuation into account along the time base of a test signal. It is a line of equal sensitivity along the trace which allows the amplitudes of signals at different axial distances from the collar to be compared.

VIII. *Dead Zone*. The dead zone is the area adjacent to the collar in which the transmitted signal blinds the received signal, making it impossible to obtain reliable results. Because the entire line must be inspected, inspection procedures must account for the dead zone by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid

readings in the dead zone is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

IX. *Near Field Effects*. The near field is the region beyond the dead zone where the receiving amplifiers are increasing in power, before the wave is properly established. Because the entire line must be inspected, inspection procedures must account for the near field by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the near field is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

X. *Coating Type*. Coatings can have the effect of attenuating the signal. Their thickness and condition are the primary factors that affect the rate of signal attenuation. Due to their variability, coatings make it difficult to predict the effective inspection distance. Several coating types may affect the GWUT results to the point that they may reduce the expected inspection distance. For example, concrete coated pipe may be problematic when well bonded due to the attenuation effects. If an inspection is done and the required sensitivity is not achieved for the entire length of the pipe, then another type of assessment method must be utilized.

XI. *End Seal*. When assessing cased carrier pipe with GWUT, operators must remove the end seal from the casing at each GWUT test location to facilitate visual inspection. Operators must remove debris and water from the casing at the end seals. Any corrosion material observed must be removed, collected and reviewed by the operator's corrosion technician. The end seal does not interfere with the accuracy of the GWUT inspection but may have a dampening effect on the range.

XII. *Weld Calibration to set DAC Curve*. Accessible welds, along or outside the pipeline segment to be inspected, must be used to set the DAC curve. A weld or welds in the access hole (secondary area) may be used if welds along the pipeline segment are not accessible. In order to use these welds in the secondary area, sufficient distance must be allowed to account for the dead zone and near field. There must not be a weld between the transducer collar and the calibration weld. A conservative estimate of the predicted amplitude for the weld is 25% CSA (cross sectional area) and can be used if welds are not accessible.

Calibrations (setting of the DAC curve) should be on pipe with similar properties such as wall thickness and coating. If the actual weld cap height is different from the assumed weld cap height, the estimated CSA may be inaccurate and adjustments to the DAC curve may be required. Alternative means of calibration can be used if justified by a documented engineering analysis and evaluation.

XIII. *Validation of Operator Training*. Pipeline operators must require all guided wave service providers to have equipment-specific training and experience for all GWUT Equipment Operators which includes training for:

- A. Equipment operation,
- B. field data collection, and
- C. data interpretation on cased and buried pipe.

Only individuals who have been qualified by the manufacturer or an independently assessed evaluation procedure similar to ISO 9712 (Sections: 5 Responsibilities; 6 Levels of Qualification; 7 Eligibility; and 10 Certification), as specified above, may operate the equipment. A senior-level GWUT equipment operator with pipeline specific experience must provide onsite oversight of the inspection and approve the final reports. A senior-level GWUT equipment operator must have additional training and experience, including training specific to cased and buried pipe, with a quality control program which that conforms to Section 12 of ASME B31.8S (for availability, see § 192.7).

XIV. *Training and Experience Minimums for Senior Level GWUT Equipment Operators*:

- Equipment Manufacturer's minimum qualification for equipment operation and data collection with specific endorsements for casings and buried pipe
- Training, qualification and experience in testing procedures and frequency determination
- Training, qualification and experience in conversion of guided wave data into pipe features and estimated metal loss (estimated cross-sectional area loss and circumferential extent)
- Equipment Manufacturer's minimum qualification with specific endorsements for data interpretation of anomaly features for pipe within casings and buried pipe.

XV. *Equipment: Traceable from vendor to inspection company*. An operator must maintain documentation of the version of the GWUT software used and the serial number of the other

equipment such as collars, cables, etc., in the report.

XVI. *Calibration Onsite.* The GWUT equipment must be calibrated for performance in accordance with the manufacturer's requirements and specifications, including the frequency of calibrations. A diagnostic check and system check must be performed on-site each time the equipment is relocated to a different casing or pipeline segment. If on-site diagnostics show a discrepancy with the manufacturer's requirements and specifications, testing must cease until the equipment can be restored to manufacturer's specifications.

XVII. *Use on Shorted Casings (direct or electrolytic).* GWUT may not be used to assess shorted casings. GWUT operators must have operations and

maintenance procedures (*see § 192.605*) to address the effect of shorted casings on the GWUT signal. The equipment operator must clear any evidence of interference, other than some slight dampening of the GWUT signal from the shorted casing, according to their operating and maintenance procedures. All shorted casings found while conducting GWUT inspections must be addressed by the operator's standard operating procedures.

XVIII. *Direct examination of all indications above the detection sensitivity threshold.* The use of GWUT in the "Go-No Go" mode requires that all indications (wall loss anomalies) above the testing threshold (5% of CSA sensitivity) be directly examined (or

replaced) prior to completing the integrity assessment on the cased carrier pipe or other GWUT application. If this cannot be accomplished, then alternative methods of assessment (such as hydrostatic pressure tests or ILI) must be utilized.

XIV. *Timing of direct examination of all indications above the detection sensitivity threshold.* Operators must either replace or conduct direct examinations of all indications identified above the detection sensitivity threshold according to the table below. Operators must conduct leak surveys and reduce operating pressure as specified until the pipe is replaced or direct examinations are completed.

REQUIRED RESPONSE TO GWUT INDICATIONS

GWUT criterion	Operating pressure less than or equal to 30% SMYS	Operating pressure over 30 and less than or equal to 50% SMYS	Operating pressure over 50% SMYS
Over the detection sensitivity threshold (maximum of 5% CSA).	Replace or direct examination within 12 months, and instrumented leak survey once every 30 calendar days.	Replace or direct examination within 6 months, instrumented leak survey once every 30 calendar days, and maintain MAOP below the operating pressure at time of discovery.	Replace or direct examination within 6 months, instrumented leak survey once every 30 calendar days, and reduce MAOP to 80% of operating pressure at time of discovery.

Issued in Washington, DC, on September 16, 2019, under authority delegated in 49 CFR part 1.97.

Howard R. Elliott,
Administrator.

[FR Doc. 2019-20306 Filed 9-30-19; 8:45 am]

BILLING CODE 4910-60-P

U21806-AG-CE-0385

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Question:

98. Refer to Table 2 on page 38 of Ms. Pascarello's direct testimony on the miles of EIRP main pipe retired. Please expand this table to show the annual miles retired for each category of pipe from 2012 to 2020 and include 2024 actual numbers with the updated remaining miles at end of 2024. Provide this information in Excel.

Response:

Please see U21806-AG-CE-0385_Pascarello_Attachment_1. The data in Table 2 has been updated for 2021, 2022, and 2023 to reflect additional information that identifies whether the Coated and Wrapped pipe quantities are part of the Standard Pressure or Medium Pressure system.

Witness: Kristine A. Pascarello

Date: March 12, 2025

Case No: U-21806
Exhibit: AG-7
April 23, 2025
Page 2 of 6

CECo Response to AG-CE-0385

[illegible]

U21806-AG-CE-0386

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Question:

99. Refer to Table 3 on page 40 of Ms. Pascarello's direct testimony on EIRP project work. Please expand this table to include annual numbers for 2021-2024 and forecasted for 2025 and 2026. Provide it in Excel.

Response:

Please see U21806-AG-CE-0386_Pascarello_Attachment_1.

Witness: Kristine A. Pascarello

Date: March 10, 2025

CECo Response to AG-CE-0386

U21806-AG-CE-0386_Pascarello_Attachment_1																
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Grid Projects																
# of Projects		0	0	0	0	0	0	0	0	5	8	9	13	11	17	17
Installed Miles		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.77	148.36	161.08	105.43	100.46	113.11	119.30
Service Counts		0	0	0	0	0	0	0	0	4,673	13,651	14,025	9,587	10,080	11,425	9,490
Segment Projects																
# of Projects		27	52	39	50	57	42	29	26	26	1	0	0	1	9	6
Installed Miles		10.63	56.79	51.55	80.27	79.50	76.67	47.42	48.52	30.29	2.02	0.00	0.00	6.07	5.34	16.61
Service Counts		0	0	0	0	0	0	0	0	0	0	0	0	471	569	866
Steel/ TOD Projects																
# of Projects		2	2	4	5	2	0	2	1	3	1	1	1	1	10	7
Installed Miles		1.00	6.67	9.71	4.31	1.47	0.00	5.44	2.23	4.17	6.84	1.03	6.82	8.66	21.05	14.46
Service Counts		4	8	104	1	5	0	9	29	42	72	49	0	10	264	198
Total																
# of Projects		29	54	43	55	59	42	31	27	34	10	10	14	13	36	30
Installed Miles		11.62	63.45	61.25	84.58	80.97	76.67	52.86	50.75	71.24	157.22	162.11	112.25	115.19	139.50	150.37
Service Counts		4	8	104	1	5	0	9	29	4,715	13,723	14,074	9,587	10,561	12,258	10,554

U21806-AG-CE-0390

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Question:

103. Refer to Table 7 on page 49 of Ms. Pascarello's direct testimony on the scope and cost of the EIRP. Please:

- a. Expand the table to include the same information for each year 2015 to 2024 actual and provide in Excel.
- b. Provide the ratio of new pipe to old replaced pipe used in forecasting the number of miles of new pipe to be installed in 2024 through 2026.
- c. By prorating three months of 2024 forecasted capital expenditures and nine months from 2025 forecasted capital costs included in the table results in \$236.6 million of capital expenditures that are likely to be incurred in the 12 months ending September 2025. Explain why the Company is exceeding the \$215.3 million of capital expenditures agreed to in the settlement of Case U-21490 for the 12 months ending September 2025 by approximately \$20 million.

Response:

- a. Please see U21806-AG-CE-0390_Pascarello_Attachment_1.
- b. The Company uses 20% to forecast the amount of new pipe miles to be installed to retired miles.
- c. The Company developed the projected 2024 and 2025 expenditures for approval in this case based on the planned services and miles of main installed as shown in Exhibit A-84 (KAP-6), including significant increases to planned work in 2025 and a decrease in the cost per mile. While this request assumes likely expenditures for the 12 months ending September 2025 based on prorating the annual projections, actual expenditures may not match the prorated amounts and will not be known until the completion of the U-21490 test year.

Witness: Kristine A. Pascarello

Date: March 13, 2025

CECo Response to AG-CE-0390

U21806-AG-CE-0390_Pascarello_Attachment_1

Table 7: EIRP 2015-2026 Scope and Cost

	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Preliminary Actual	Projected	Projected	Projected	Projected	Projected
Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2024	2025 ³	2026	10 months 1/1/25- 10/31/25 ³	Test Year 11/1/25 – 10/31/26 ³
Installed Pipe (Miles) ¹	84.6	81.0	76.7	52.9	50.8	71.2	157.2	162.1	108.9	127.5	134.6	139.6	150.3	115.9	148.5
Service Counts ¹	9,846	9,930	7,884	4,632	4,951	8,556	13,880	14,074	8,649	11,247	12,114	12,528	11,903	8,748	9,175
Capital Cost (\$Millions) ²	\$82.5	\$79.6	\$81.9	\$86.8	\$78.4	\$118.5	\$230.8	\$248.1	\$181.9	\$193.0	\$195.6	\$247.0	\$251.6	\$204.6	\$250.8

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

³ The 2025 projected miles and cost have been corrected from the original filing to reflect an error in converting feet to miles. The 10 months ending 10/31/25 and the test year projections have also been reduced to reflect the 2025 changes.

U21806-AG-CE-0430

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Question:

143. Refer to page 3 of Exhibit A-82 (KAP-4) on Material Condition. For each project over \$5 million in the 10 months ending October 2025 and 12 months ending October 2026, please provide the current phase of project development.

Response:

Please see U21806-AG-CE-0430_Pascarello_Attachment_1.

Witness: Kristine A. Pascarello

Date: March 10, 2025

U21806-AG-CE-0430_Pascarello_Attachment_1		
EIRP - Distribution		Current Phase
	Name	Design Status
OWS2 - Ph 1,2 Corruna	NGDP OWS2 Phase 1	Designed
	NGDP OWS2 Phase 2	Released for Construction
ALM2 - Ph 4, 7 and 6 St. Louis	NGDP ALM2 Phase 4	Under Construction
	NGDP ALM2 Phase 6	Design 90%
	NGDP ALM2 Phase 7	Released for Construction
SAG6 - TOD Line 1087g	NGDP SAG6 TOD LINE1087g	Designed
SAG8 Frankenmuth(Junction Rd)	NGDP SAG8 HP JUNCTION RD	Released for Construction
LIV4 - Ph 1,2	NGDP LIV4 Phase 1	Designed
	NGDP LIV4 Phase 2	Design 90%
ROK4 - Ph 2,3,5,6	NGDP ROK4 Phase 2	Design 90%
	NGDP ROK4 Phase 3	Design 90%
	NGDP ROK4 Phase 5	Designed
	NGDP ROK4 Phase 6	Under Construction
ROK13 - Ph 1	NGDP ROK13 Phase 1	Designed
KAL2 - Ph 1,2,4,5,10 HP	NGDP KAL2 PHASE 1	Under Construction
	NGDP KAL2 PHASE 2	Design 90%
	NGDP KAL2 PHASE 4	Released for Construction
	NGDP KAL2 PHASE 5	Design 90%
	NGDP KAL2 PHASE 10	Design 90%
LAN4 - Ph 4,5,6,7,8 ²	NGDP LAN4 Phase 4	Under Construction
	NGDP LAN4 Phase 5	Under Construction
	NGDP LAN4 Phase 6	Released for Construction
	NGDP LAN4 Phase 7	Design 90%
	NGDP LAN4 Phase 8	Design 90%
MAC12 - Ph 1,2,3,4,5,6,7,8 ³	NGDP MAC12 PHASE1	Design 90%
	NGDP MAC12 PHASE2	Design 90%
	NGDP MAC12 PHASE3	Design 90%
	NGDP MAC12 PHASE4	Design 90%
	NGDP MAC12 PHASE5	Design 90%
	NGDP MAC12 PHASE6	Design 90%
	NGDP MAC12 PHASE7	Under Construction
	NGDP MAC12 PHASE8	Released for Construction
FLT5 - Ph 1,2,3	NGDP FLT5 Phase 1 Center Rd	Under Construction
	NGDP FLT5 Phase 2 Bristol Rd	Design 90%
	NGDP FLT5 Phase 3 Atherton Rd	Design 30%
MAC14 - Ph 2	NGDP MAC14 Phase 2	Design 90%
ALM5 - PH1 Line 1070g	NGDP ALM5 LINE1070g	Released for Construction
FLT11 - Ph 1,2,3,4,5,6	NGDP FLT11 Phase 1 Lapeer East	Design in Progress
	NGDP FLT11 Phase 2 Lapeer South	Design in Progress
	NGDP FLT11 Phase 3 Lapeer Downtown	Design Not Started
	NGDP FLT11 Phase 4 Davison North	Design in Progress
	NGDP FLT11 Phase 5 Davison South	Design in Progress
	NGDP FLT11 Phase 6 Davison Lapeer Rd	Design in Progress

CECo Response to AG-CE-0430

OWS3 - Ph 1,2	NGDP OWS3 Phase 1	Design in Progress
	NGDP OWS3 Phase 2	Design 30%
SAG4 - Ph 1,2,3	NGDP SAG4 PHASE1	Design Not Started
	NGDP SAG4 PHASE2	Design Not Started
	NGDP SAG4 PHASE3	Design Not Started
BCY2 - Ph 2	NGDP BCY2 Phase 2	Design Not Started
ALM2 - Ph 1,7,8	NGDP ALM2 Phase 1	Design Not Started
	NGDP ALM2 Phase 7	Released for Construction
	NGDP ALM2 Phase 8	Design 60%
ALM5 - Ph 2 Line 1070g	NGDP ALM5 PH 2 LINE1070g	Design Not Started
MAC11 - Ph 2,3,5,6,7,11	NGDP MAC11 PHASE 2	Design 60%
	NGDP MAC11 PHASE 3	Design 30%
	NGDP MAC11 PHASE 5	Design 30%
	NGDP MAC11 PHASE 6	Design 30%
	NGDP MAC11 PHASE 7	Design in Progress
	NGDP MAC11 PHASE 11	Design 30%
ROK12 - Ph 1,2	NGDP ROK12 Segment Project Phase 1	Design 30%
	NGDP ROK12 Segment Project Phase 2	Design in Progress
ROK10 - Ph 1,2,3,4,5,6	NGDP ROK10 Phase 1	Design Not Started
	NGDP ROK10 Phase 2	Design Not Started
	NGDP ROK10 Phase 3	Design Not Started
	NGDP ROK10 Phase 4	Design Not Started
	NGDP ROK10 Phase 5	Design Not Started
	NGDP ROK10 Phase 6	Design in Progress
ROK7 - Ph 4,5,6,7,8	NGDP ROK7 Phase 4	Design Not Started
	NGDP ROK7 Phase 5	Design Not Started
	NGDP ROK7 Phase 6	Design Not Started
	NGDP ROK7 Phase 7	Design Not Started
	NGDP ROK7 Phase 8	Design Not Started
KAL3 - Ph 8,9,10	NGDP KAL3 PHASE 8	Design Not Started
	NGDP KAL3 PHASE 9	Design Not Started
	NGDP KAL3 PHASE 10	Design Not Started
KAL11 - Ph 1,2,3 Bangor	NGDP KAL11 PHASE 1	Design in Progress
	NGDP KAL11 PHASE 2	Design 90%
	NGDP KAL11 PHASE 3	Design in Progress
LAN14 - Mt Hope & Chippewa	NGDP LAN14 (Mount Hope and Chippewa)	Design in Progress
KAL7 - Michigan Ave Galesburg	NGDP KAL7 HP GALESBURG	Design in Progress
KAL8 - VW Ave (east of Schoolcraft)	NGDP KAL8 HP VICKSBURG	Design in Progress
LAN13 - Thornapple Lake Rd at M66	NGDP LAN13 HP Thornapple Lake Rd	Design in Progress
LAN10 Ph1 & Ph2 TOD Line 1022	NGDP LAN10 TOD LINE1022 PH1	Design 30%
	NGDP LAN10 TOD LINE1022 PH2	Design in Progress

U21806-AG-CE-0802

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Question:

365. Refer to ATT_1 To discovery response AG-CE-0430 on the development phase of large projects. Does "Design in Progress" mean that less than 30% of the design has completed? If no, provide the percentage completed.

Response:

Yes, "Design in Progress" means that the survey is completed, and the design has started but has not reached the 30% complete milestone.

Witness: Kristine A. Pascarello

Date: April 7, 2025

U21806-AG-CE-0389

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Question:

102. Refer to lines 3-4 on page 48 of Ms. Pascarello's direct testimony on the 2035 EIRP completion date. Please:

- a. State what significant increase in risk the Company would anticipate if the program completion date for the remaining pipe replacement was extended by five years to 2040.
- b. Provide any engineering analysis that the Company has performed in the past five years that determined all remaining vintage pipe needs to be replaced by 2035 due increased degradation occurring with the existing pipe in the ground.

Response:

- a. While leak data on Company mains shows a downward trend, as provided in response U21806-AG-CE-0406, the Company expects more leaks due to the continued deterioration of the remaining aging pipe if the program completion date is extended to 2040. The current pace of the EIRP will continue to lead to an overall reduction in leaks. As shown in Figure 20 in Exhibit A-42 (NPD-1), page 47, much of the remaining vintage pipe was installed between 1920 and 1950. At approximately 75 years and older, this pipe has reached the end of its useful life. Continuing prolonged use increases the likelihood of incidents occurring as the pipe continues to deteriorate due to factors such as soil conditions and ground movement. The Company continues to experience emergent incidents, including two within the FLT4 grid project in early 2024. This system experienced issues in different locations while EIRP crews were replacing pipe in other parts of this grid. In January 2024, water infiltrated a 4" cast iron main on the standard pressure system. The water froze and blocked the flow of gas to customers. In February 2024, a leak occurred in another section of this grid, leading the Company to cut out the section of leaking pipe. These incidents, occurring as the Company was starting to replace vintage mains in the area, support the project's pace and prioritization.
- b. The Company's Engineering department runs the Distribution Risk Analysis Modeling ("DRAM") annually. The DRAM uses inputs such as pipe material type, pipe age, soil conditions, and leak data to risk rank 7,000 segments of distribution pipe. The DRAM risk ranking for 2025 and 2026 are included in WP-KAP-3. Risk models are essential tools in engineering analysis because they provide a structured approach to identifying, assessing, and managing potential risks.

Witness: Kristine A. Pascarello

Date: March 13, 2025

U21806-AG-CE-0391

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Question:

104. Refer to Table 7 on page 49 of Ms. Pascarello's direct testimony on the scope and the cost of the EIRP for 2023. Please provide the end year of the EIRP if the same pace of pipe replacement in 2023 continued into future years.

Response:

Based on the following assumptions:

1. EIRP continues at the same pace as 2023 for remainder of program.
2. Vintage main retired by other programs continues at current pace and retires approximately 50 miles per year (total: 300 miles) by 2030.
3. Cast Iron pipe, Wrought Iron pipe, and the Standard Pressure system are eliminated by 2030.
4. All miles after 2030 would be retired exclusively by EIRP.

The Company projects the end year of EIRP would be 2038.

Witness: Kristine A. Pascarello

Date: March 12, 2025

U21806-AG-CE-0780

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Question:

343. Refer to discovery response AG-CE-0389 on the EIRP versus gas leak trends. Please:

- a. In response to subpart (a), you state that the Company expects more leaks due to the continued deterioration of the remaining aging pipe. Is this simply a general expectation or is it based on an engineering analysis. If based on an engineering analysis, provide a copy of the analysis.
- b. In response to subpart (a), you state that the Company experienced infiltration of water in a 4" cast iron main in January 2024 and In February 2024 a gas leak occurred in another segment. Is this the first time that these types of incidents have occurred or have they have occurred multiple times in the past ten years.
- c. With regard to the pipeline segments experiencing the two incidents described in subpart (b), why were these pipe segments not identified for replacement as priority projects within the Company's selection model? Is there a weakness within the model that needs to be addressed?

Response:

- a. The expectation is based on historical incidents and the characteristics of aging pipelines. Over time, the materials used in older pipelines, such as cast iron or early steel, naturally degrade. This degradation is accelerated by factors like corrosion, which is common in buried pipelines due to soil and environmental conditions. Pipelines that have been in service for many decades experience wear and tear from continuous use. This includes physical stresses from internal pressure and external forces, which can lead to cracks and leaks. Additionally, older pipelines were constructed with the technology and materials available at the time, which may not meet current standards for durability and safety. Historically, the deterioration of vintage materials occurring on the distribution system is causing emergent work due to gas leaking from pipes and/or water infiltration into pipes.
- b. In addition to the incidents included in AG-CE-0389, examples of other incidents include:
 1. Hemphill (Flint area): Immediate action leak occurring May 2022. This is a 12" bare steel medium pressure line that has deteriorated to the point that this pipe cannot be welded on, forcing at a minimum 4800 feet of emergent 12" medium pressure pipe replacement to find newer pipe that can be welded to complete the tie-in.
 2. Grand River replacement (Howell area): Leak that occurred in August 2021. This leak was on 4" steel high pressure pipe that was installed in 1928. Details of this incident include:
 - Integrity Digs results: 15+ holes, 25-80' apart. No "usable" pipe found.
 - Additional leak found near original proposed tie-in point (currently venting)
 - Shallow pipe in farmer's field
 - Exposed pipe in ditch

U21806-AG-CE-0780

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- Main located 18" away from a residential house
 - Whole isolated segment being placed on regulation trailer. Grain Dryer being put on temporary regulation trailer
 - Replacement of nearly 10,000 feet of pipe
3. The Company has experienced, and continues, to experience water infiltration due to deterioration of vintage mains, particularly in the standard pressure system where cast iron main is in service. One example started in January 2020 until January 2022 (3 heating seasons) in the 3000 block of W. Genesee Ave in Saginaw. Customers experienced 70 gas outages caused by water in their services and meters. The water infiltration combined with low temperatures caused frozen lock wings, risers, meters, and water entering customer fuel lines.

Customer Impacts:

- Average outage length: 10 hours
 - No heat and hot water during outage
 - In total, customers were without natural gas service for over 700 hours
 - Safety concerns including use of alternate heating methods which could increase risk of fire or carbon monoxide incidents; flooding in the home; and lack of hot water for personal needs.
- c. Consumers Energy uses a relative risk model for calculating risk on its distribution system. The Company's selection model prioritizes pipeline segments based on a comprehensive risk assessment that includes factors such as historical leak data, pipe properties, corrosion, cathodic protection, and environmental conditions. The EIRP focuses on replacing vintage pipe materials based on the Company's risk model and plans projects approximately three years in advance. These segments in question had a risk score which was high enough to be included with other high risk ranked segments and were included in the three-year planning cycle. As described in AG-CE-0389, the FLT4 incidents occurring as the Company was starting to replace vintage mains in the area, support the project's pace and prioritization.

Witness: Kristine A. Pascarello

Date: April 7, 2025

U21806-AG-CE-0781

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Question:

344. Refer to discovery response AG-CE-0391 on the EIRP completion date. Please confirm that your conclusion of a 2038 completion date for the EIRP, based on the assumptions outlined, includes also replacement of all the targeted HP/Steel Distribution mains. If no, provide a date when those mains would be fully replaced based on the same assumptions.

Response:

The response provided in AG-CE-0391 is based on the preliminary remaining 1,443 miles of vintage pipe as of January 1, 2025. The assumption includes that 308 miles will be retired by other programs and 1,135 miles will be retired by EIRP at the 2023 pace of 84 miles retired per year. It does include HP Steel but does not include the remaining 67 miles of TOD steel pipe or 79 miles of Standard Pressure coated and wrapped steel pipe included in the EIRP scope. If those miles were added, the estimated completion would be 2040. Additionally, AG-CE-0391 requested using the same pace of pipe replacement, so the estimation does not include keeping the same capital expenditure level as 2023.

Witness: Kristine A. Pascarello

Date: April 7, 2025

U21806-AG-CE-0393

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Question:

106. Refer to lines 18-25 on page 51 of Ms. Pascarello's direct testimony on the Material Condition Non-Modeled Program. Please:

- a. Explain whether the wrought iron replacement, the HP waterway crossing, and the leak mitigation projects are included in the capital expenditures for the Material Condition Non-Model Program or in the Renewal Program given the statement on lines 23-24.
- b. Explains why the wrought iron replacement, the HP waterway crossing, and the leak mitigation projects would be included in the Material Condition Non-Model Program when they do not seem to fit the five criteria on lines 3-11 and seem to be planned programs that should fall under other construction programs.

Response:

- a. The capital expenditures for the wrought iron replacement, the HP waterway crossing, and the leak mitigation projects described in the referenced section of my direct testimony are included in the Material Condition Non-Modeled program. As described on page 50, line 22 of my direct testimony, the projects in the Material Condition Non-Modeled program are Company-initiated projects, planned and designed by the Distribution Engineering team. The leaks and meter replacements included in the Material Condition Renewals program are field initiated projects focused on addressing urgent issues as described on page 59, line 20 of my direct testimony. Planned and engineered projects are in the Material Condition Non-Modeled program, while field-initiated immediate replacement projects are in the Material Condition Renewals program.
- b. The projects do fit in the criteria described on page 51:
 - Wrought iron replacements: criteria (iv), described on page 54, lines 7 through 14.
 - HP waterway crossing: criteria (ii), described on page 57, lines 15 through 23.
 - Leak mitigation projects: criteria (i), on page 51, leaks or temporary repairs that need to be resolved within the year.

Witness: Kristine A. Pascarello

Date: March 12, 2025

U21806-AG-CE-0397
Page 1 of 1

Question:

110. Refer to lines 1-7 on page 55 of Ms. Pascarello’s direct testimony on the replacement of the remaining 12 miles of wrought iron through the Material Condition Non-Modeled Program. Please provide the Company replacement plan by year with related miles and capital expenditures.

Response:

The Material Condition Non-Modeled program plans to replace 7.64 miles of the remaining 12 miles of wrought iron. The remaining miles are included in the 2026 EIRP KAL11 Bangor project. The replacement plan by year with related miles and capital expenditures planned in Material Condition Non-Modeled is:

Year	Miles Replaced	\$
2025	1.3	\$ 1,500,000.00
2026	4.5	\$ 5,000,000.00
2027	1.84	\$ 2,000,000.00

Witness: Kristine A. Pascarello
Date: March 12, 2025

CECo Response to AG-CE-0398

U21806-AG-CE-0398

Page 1 of 1

Question:

111. Refer to lines 17-20 on page 56 of Ms. Pascarello's direct testimony on the Line 1010 MAOP pipeline project. Please provide the forecasted capital expenditures for the 10 months ending October 2025 and 12 months ending October 2026.

Response:

10 months ending October 2025: \$10,300,000

12 months ending October 2026: \$9,300,000

Witness: Kristine A. Pascarello

Date: March 12, 2025

U21806-AG-CE-0782

Page 1 of 1

Question:

345. Refer to discovery response AG-CE-0393 on the material condition non-modeled program. Please:

- a. Confirm that the key distinguishing factor between the modeled program and the non-modeled program is that the modeled program includes projects that have been pre-planned and the non-modeled program includes projects that generally arise during the course of the year. If not confirming, explain further and why the non-modeled program also includes pre-planned projects.
- b. For each of the Wrought Iron Pipe replacements, HP Waterway crossing projects, Leak Mitigation work projects, and Obsolete Meter Replacements, provide the units or projects completed each year 2021-2024 and forecasted for 2025 and 2026 and the related dollar amount.

Response:

- a. Using AG-CE-0393 referenced in the question, this response assumes the modeled program in the question is referring to the Material Condition Renewals program. The Material Condition Renewals program involves field-initiated replacement projects that require immediate remediation. These projects are not planned or designed by the Company's Distribution Engineering team. In contrast, the Material Condition Non-Modeled program includes both planned and emergent projects, which are planned and designed by the Distribution Engineering team.

b.

	Wrought Iron		HP Waterway		Leak Mitigation		Obsolete Meters	
	Projects/Units	\$	Projects/Units	\$	Projects/Units	\$	Projects/Units	\$
2021	0	\$ -	0	\$ -	0	\$ -	0	\$ -
2022	1	\$ 415,757	0	\$ -	0	\$ -	0	\$ -
2023	0	\$ -	0	\$ -	0	\$ -	0	\$ -
2024	2	\$ 539,982	2	\$ 637,933	517	\$ 2,970,587	0	\$ -
2025	2	\$ 1,500,000	3	\$ 2,500,000	50	\$ 250,000	0	\$ -
2026	6	\$ 3,000,000	8	\$ 3,000,000	800	\$ 4,000,000	5500	\$ 3,700,000

Witness: Kristine A. Pascarello

Date: April 7, 2025

U21806-AG-CE-0785

Page 1 of 1

Question:

348. Refer to discovery response AG-CE-0397 on the replacement of wrought iron mains. Why are these remaining mains replaced under the non-modeled program instead of the EIRP modeled segment replacement program? Is the Company using the non-modeled program to supplement the EIRP program?

Response:

As described on page 51, line 10 of my direct testimony, the Non-Modeled program includes projects based on operational improvements that may not be represented effectively in risk model results. The risk model used for EIRP projects does not account for whether the main is weldable, so wrought iron segments are not prioritized in the risk ranking. If the Company waits for the risk to become high enough to become an EIRP segment, there is a significant chance of a leak occurring before the project starts. This would result in an emergent project that needs to be constructed quickly without a planned design, due to the inability to weld on the main. For example, in Bangor, a project expanded from a short 300-foot section to 1,172 feet to find a weldable main.

Vintage miles that are replaced under the Non-Modeled program are removed from the scope of the EIRP project. This approach allows for a balanced mix of EIRP and Non-Modeled work to continue with the long-term plan and address system issues as they arise.

Witness: Kristine A. Pascarello

Date: April 7, 2025

U21806-AG-CE-0787

Page 1 of 1

Question:

350. Refer to discovery response AG-CE-0400 on HP waterway crossing pipeline projects. Please:

- a. Explain how the Company plans to remediate the pipelines listed in ATT_1, feet of pipe installed, depth of cover, etc.
- b. At what depth under the river bed were each of the pipelines in ATT_1 initially installed?
- c. Explain why it was not obvious to the Company when it installed pipelines under a river bed that erosion would occur over time and the pipeline were not buried at a deeper depth?
- d. At what depth below the river bed will be the new pipeline segments installed now?
- e. Expand ATT_1 to show the cost for each of the pipelines for each year 2024 to completion and provide the current phase of the project. Provide the expanded attachment in Excel.

Response:

- a. Each of these segments will be replaced with new high-pressure steel mains. Current Company boring standards require a depth of at least 10 feet below the solid bottom of the waterway being crossed. Each project will be somewhat unique, and the final feet to be installed will be calculated once detailed design is fully complete.
- b. The Company is not able to provide this data, as the depth of cover is not an attribute that was historically captured as part of the as-built documentation process.
- c. As shown in the ATT_1, all but one of the pipelines in question were installed between 1948 and 1968, a period during which the understanding of long-term environmental impacts, such as erosion, was not as advanced as it is today. The potential for significant erosion over decades may not have been fully anticipated or understood. Additionally, industry standards and regulations reflecting a greater awareness of environmental factors and the need for more robust safety measures have evolved since then.
- d. New lines will be installed at least 10' below the riverbed, according to current standards.
- e. Please see U21806-AG-CE-0787_Pascarello_Attachment_1.

Witness: Kristine A. Pascarello

Date: April 7, 2025

CECo Response to AG-CE-0787

Case No: U-21806
Exhibit: AG-10
April 23, 2025
Page 7 of 7

[illegible]

U21806-AG-CE-0793
Page 1 of 1

Question:

356. Refer to discovery response AG-CE-0410 on the VSR program. Please provide the table in Excel.

Response:

Please see U21806-AG-CE-0793_Pascarello_Attachment_1.

Witness: Kristine A. Pascarello

Date: April 7, 2025

CECo Response to AG-CE-0793

U21806-AG-CE-0793_Pascarello_Attachment_1												
	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Projected 2024	Preliminary Actual 2024	Projected 2025	Projected 2026	Projected 12 Mos Ending 10/31/2026
VSR Program Units	6,307	9,381	5,571	5,456	5,056	2,176	1,228	2,875	2,564	4,194	5,913	5,827
VSR Unit Cost	\$5,322	\$6,037	\$7,260	\$7,848	\$6,518	\$7,888	\$9,246	\$6,493	\$7,547	\$6,671	\$7,389	\$7,296
VSR Program Spend (\$000)	\$33,564	\$56,634	\$40,443	\$42,818	\$32,955	\$17,165	\$11,354	\$18,666	\$19,352	\$27,978	\$43,689	\$42,513
EIRP/Other Programs	5,169	4,042	4,064	4,291	5,245	8,235	3,576	3,476	4,313	3,172	2,622	2,677
Total Services Replaced	11,476	13,423	9,635	9,747	10,301	10,411	4,804	6,351	6,877	7,366	8,535	8,504
Total Services Remaining	170,478	157,055	147,420	137,673	127,372	116,961	112,157	105,806	105,280	98,440	89,905	81,401

U21806-AG-CE-0405

Page 1 of 1

Question:

118. Refer to lines 10-19 on page 64 of Ms. Pascarello's direct testimony on Leak Detection and Repair regulations. Please provide the actual issue date or the latest expected issue date.

Response:

Please see the response U21806-CE-CUB-0100.

Witness: Kristine A. Pascarello

Date: March 10, 2025

U21806-CUB-CE-0100

Page 1 of 1

Question:

19. Refer to the Testimony of Kristine A. Pascarello, Page 64, Line 12.

- a. Please provide the current status of the mentioned NPRM regarding LDAR.

Response:

- a. LDAR has not been published in the Federal Register at this time. It is the Company's understanding that the regulation is impacted by Presidential Executive Order "Regulatory Freeze Pending Review."

Witness: Kristine A. Pascarello

Date: February 4, 2025

U21806-AG-CE-0414

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Question:

127. Refer to lines 12-19 on page 74 of Ms. Pascarello's direct testimony on the AMD program. Is the Company replacing all of its existing leak detection equipment with new equipment? Explain the Company's plans in detail and why existing leak detection equipment cannot still be used to avoid the purchase of new equipment.

Response:

Equipment purchased through the Advanced Methane Detection Program is not intended to replace existing traditional leak detection equipment.

Advanced Methane Detection tools can detect leaks from a distance and measure the emission rates of leaks. Additionally, the tools are used to identify a general area where a leak might be occurring.

Traditional leak detection equipment is used on the ground to pinpoint the exact location of a leak. These tools do not have the capability to detect leaks from a distance or measure emission rates.

The Company plans to use both types of equipment together. The advanced tools help locate the general area of a leak, and then the traditional tools are used to find the precise location of the leak.

Witness: Kristine A. Pascarello

Date: March 10, 2025

U21806-AG-CE-0417

Page 1 of 1

Question:

130. Refer to page 76 of Ms. Pascarello's direct testimony on the AMD program. In Phase 1 of the AMD project, did the Company test the new equipment versus the existing equipment to determine how many more Grade 1, Grade 2, and Grade 3 leaks the new equipment detected that the existing equipment had not detected? If yes, provide a copy of that test and evaluation. If no, explain why not and how the Company concluded that the new equipment was reliable and cost-effective.

Response:

The Company evaluated AMD equipment and methods compared to existing traditional equipment and methods by comparing above and below ground leak find rates for both. The study showed that for below ground leaks, AMD surveys resulted in 1 below ground leak for every 4.8 miles of main surveyed compared to traditional leak survey at 1 below ground leak for every 33.3 miles of main surveyed. This shows nearly a 7x higher below ground leak find rate with AMD. For above ground leaks, AMD surveys resulted in 1 above ground leak for every 28.4 services surveyed compared to traditional leak survey at 1 above ground leak for every 29.9 services surveyed. This shows a 5% higher above ground leak find rate with AMD. The attachment U21806-AG-CE-417-Pascarello_ATT_1 provides the results of the evaluation.

Witness: Kristine A. Pascarello

Date: March 10, 2025

CECo Response to AG-CE-0417

U21806-AG-CE-0417-Pascarello_ATT_1						
2024 Leak Find Rate Comparison (AMD vs. Traditional)						
		Below Ground Leaks	1 Below ground leak per x miles of			
Below Ground	Miles of Main Surveyed	Confirmed	main surveyed			
Traditional	9,931	298	33.3			0.03
AMD	370	77	4.8	6.9	x more effective	0.21
		Above Ground Leak	1 Above ground leak per x services			
Above Ground	# of Services Surveyed	Confirmed	surveyed			
Traditional	356,356	11,908	29.9			0.03
AMD	7,100	250	28.4	1.05	x more effective	0.04

U21806-AG-CE-0418

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Question:

131. Refer to lines 1-7 on page 77 of Ms. Pascarello's direct testimony on the AMD program. Please provide a copy of the comparative data and evaluation by leak grade 1-3 for below and above ground gas leaks separately.

Response:

Comparative data does not exist for this study. The study was performed using Advanced Methane Detection (AMD) tools first to survey for leaks. Traditional leak detection methods were then used to check for any leaks that might have been missed by the AMD survey. The traditional methods did not find any additional leaks that AMD had missed, so no exceptions were documented.

Witness: Kristine A. Pascarello

Date: March 10, 2025

U21806-AG-CE-0419

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Question:

132. Refer to lines 1-7 on page 77 of Ms. Pascarello's direct testimony on the AMD program. Please:

- a. Explain what a possible leak is versus an actual gas leak.
- b. Does the AMD equipment find only possible gas leaks? How does the Company then determine whether there is an actual leak?
- c. What percentage of the possible leaks detected by the AMD equipment are actual leaks versus false readings?

Response:

- a. A possible leak is an indication of methane in the air detected by AMD technology. An actual gas leak is confirmed by a qualified leak investigator.
- b. AMD technology does not confirm whether a leak exists or not. It provides a Leak Indication Search Area ("LISA") when it detects methane in the air. A qualified leak investigator is then dispatched to the LISA to perform a leak investigation and confirm the presence of an actual leak.
- c. 82% of LISAs result in at least one confirmed leak in the search area.

Witness: Kristine A. Pascarello

Date: March 10, 2025

U21806-AG-CE-0421

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Question:

134. Refer to lines 9-18 on page 78 of Ms. Pascarello's direct testimony on the AMD program for Phase 2. Please:

- a. Explain how gas leaks are found and how this process differs from current procedures.
- b. Provide a copy of the leak detection program in place in 2023 and of the new comprehensive program, process, and procedures that will be implemented with the AMD equipment.
- c. Provide a description of the various grades of gas leaks.

Response:

- a. Gas leaks are found through a leak survey process. Existing traditional leak survey involves a foot or mobile patrol using leak detection devices on a specific set of gas assets based on a compliance schedule. If a surveyor detects a leak on one of the in-scope assets, the leak is graded and escalated for remediation based on the grade given. With AMD, all gas distribution assets within a designated area are surveyed with the AMD mobile technology. When the technology detects methane in the air, it places a search area on a map. A leak investigator is then dispatched to that search area to confirm whether a leak exists. If a leak is confirmed, the same standards and procedures apply for grading and escalation of those leaks.
- b. Leak Survey schedules vary each year due to the different inspection cycles of 1, 3, or 5 years, driven by varying compliance requirements for the natural gas system. These cycles ensure that assets are monitored at appropriate intervals based on regulatory standards, risk assessment and system integrity needs. Leak Surveys are conducted from April to November each year and will begin using a combination of walking and driving inspections depending on survey type. Inspections are performed using handheld or mobile detection equipment to identify and investigate suspected leaks. Please see U21806-AG-CE-0421_Pascarello_Attachment_1 and U21806-AG-CE-0421_Pascarello_Attachment_2 for a copy of the procedures.
- c. The current leak remediation process is described in the Company's Natural Gas Delivery Plan, Exhibit A-42 (NPD-1) beginning on page 55. There are three grades given to a gas leak. The grading system is based on the nature of the potential hazard and considers things like gas concentration within proximity to a building among other factors. A grade 1 leak is considered an immediate action leak and is escalated for immediate remediation. A grade 2 leak is scheduled for remediation within 6 months. A grade 3 leak is either remediated within 12 months or monitored annually to ensure the leak has not increased in severity where it would pose a safety risk.

Witness: Kristine A. Pascarello

Date: March 13, 2025

U21806-AG-CE-0794

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Question:

357. Refer to discovery response AG-CE-0417 on the AMD program.

- a. The calculations in the attachment seem to indicate that the traditional approach discovered more leaks per mile. Your conclusion in the discovery response seems to state the opposite. Please explain this contradiction.
- b. The request was for the Company to identify the leaks discovered by grade under each method. Please provide this information.
- c. Did the AMD equipment identify any more grade 1 and 2 gas leaks than the traditional equipment identified? If yes, provide the numbers.

Response:

- a. The calculations do not portray how many leaks per mile or per service, but rather 1 below ground leak per "x" number of miles and 1 below ground leak per "x" number of services. Portrayed this way, the smaller number results in a greater leak rate.
- b. The study compared find rates for above and below ground leaks and did not track by leak grading.
- c. The study compared find rates for above and below ground leaks and did not track by leak grading.

Witness: Kristine A. Pascarello

Date: April 7, 2025

U21806-AG-CE-0425

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Question:

138. Refer to page 81 of Ms. Pascarello's direct testimony on the ECAP system implementations. Please:

- a. Explain specifically what each of the four phases have accomplished or are intended to accomplish.
- b. Identify specifically what the systems in Table 12 are used for and have accomplished or will accomplish with specific benefits for each year 2021-2025.

Response:

- a. Phase 1 included implementation of the Corrective and Preventative Action (CAPA) system and onboarding Gas Operations, Gas Engineering, and Gas Regulatory business areas to collect information, analyze data, identify issues, and take appropriate, effective, and timely actions to resolve and sustain resolutions. Phases 2-4 expanded onboarding across key business areas – Electric Operations and Electric Engineering (Phase 2), Generation Operations and Electric Supply Engineering (Phase 3), Corporate Safety & Health and Environmental (Phase 4).
- b. The ECAP organization has successfully accomplished each element of the CAPA system implementation plan as outlined in Table 12. The ECAP organization is responsible for facilitating problem solving after issues are identified either internally or by regulatory agencies. The CAPA system collects and analyzes all incident information and manages the timely implementation of all corrective and preventive actions after problem solving. The ECAP organization then validates the effectiveness of actions to reduce the potential for repeat issues. Examples include but are not limited to regulatory compliance, failure investigations, and damage prevention.

Witness: Kristine A. Pascarello

Date: March 13, 2025

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Question:

140. Refer to page 85 of Ms. Pascarello's direct testimony on the Utility Network project. Please:

- a. Expand Table 14 to include actual amounts for 2024 and any remaining costs from inception to completion by year in Excel. If this system will also be used by the electric business, provide the total company cost by year from inception to completion in Excel.
- b. Explain in detail what the Utility Network system will actually do.
- c. Provide the current phase of the project and the month and year when the detailed system requirements phase will be completed.
- d. Provide the month and year when the GIS platform will become unsupported.
- e. What is the additional functionality that the Company needs?
- f. How much of the additional features listed on lines 16-21 on page 85 and lines 1-10 on page 86 are critically necessary and not provided by the current system.
- g. Provide a copy of the cost/benefit analysis for this project with calculations in Excel with formulas intact and all assumptions explained and data cited to a source.

Response:

- a. Please see U21806-AG-CE-0427_Pascarello_Attachment_1. The costs represented in Table 14 support the gas business. A separate project is planned for the electric business, which will have separate financial projections. The Gas Utility Network project experienced less actual vs projected spend in 2024. This change in expenditure was in part due to both a delayed project start along with slightly higher planning than initially anticipated. Subsequently, the project was delayed in transitioning from the design phase into the build phase. The delay in project start within 2024 is projected to result in an increase in spend in 2025 as reflected in the attachment.
- b. As referenced on page 84, lines 21 through 24 of my direct testimony, the Utility Network project will transform the Company's current GIS geometric network data model and platform to the Environmental Systems Research Institute ("ESRI") Utility Network Model. This will establish a unified gas transmission, distribution, and stations data model in support of optimizing the core engineering and operational processes, technologies, and data. The project will implement the Utility and Pipeline Data Model (UPDM), which is a standard GIS data model designed to manage all distribution and transmission gas assets. The three-component model defines schemas specifically designed to manage assets, compliance/integrity, and inspection data. Leveraging a standard model will better allow Consumers Energy to simplify processes and improve analytics. This will reduce multiple processes currently in place to maintain the same data in two different locations. It will increase accuracy for analysis and maintenance of High Consequence Areas (HCAs). The integrity and inspection components of Utility and Pipeline Data Model (UPDM) will also facilitate the Company's

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direction toward tracking and traceability compliance with or without the federal regulation going into effect. The transformation will allow the Company to geospatially enable the organization to support workflows, data insights, and analytics to uncover information related to location to support more informed decision making.

- c. The Gas Utility Network project is being divided up into multiple go lives to accomplish the entire intended scope. The first Go Live for the Landbase GIS and ArcGIS Enterprise is in the execute phase. Detailed system requirements have already been compiled and completed. The second phase of the project is for the Gas Go Live, which is currently within the define phase. This phase is where the team has begun compiling the detailed system requirements. These requirements are projected to continue to be updated through November 2025, as the project iteratively designs the many interfaces.
- d. There are several different components within the GIS platform, each with unique obsolescence dates. The Gas Distribution GIS is using ESRI ArcMap 10.8.1 (Geometric Network), which becomes unsupported starting March 2026. Gas Transmission GIS is using ESRI ArcMap 10.6.1 (Geometric Network), which has already reached an unsupported state.
- e. This transformation is in support of optimizing the core engineering and operational processes, technologies, and data. The functionality that the Company needs is an important part of the Company's Gas Safety Management System ("GSMS"). It is required to support the growing business requirements for advanced analytics and business challenges presented from regulatory mandates and requirements to support a strong pipeline safety management system, which necessitate geospatial insight on a more granular asset level than what is currently available. The growing requirements of the GIS data are needed to support several aspects of a strong Pipeline Safety Management System ("PSMS") - American Petroleum Institute (API) Recommended Practice 1173. The Pipeline Safety Management impacted areas include but are not limited to:
 - Risk Management - accurate inventory of assets, therefore enabling the ability to appropriately identify and assess risk,
 - Management Review & Continuous Improvement - improve the effectiveness of the PSMS through technology that can enhance pipeline safety,
 - Emergency Preparedness and Response - applying lessons learned and improved processes to ensure the Company can effectively respond to a pipeline incident, and
 - Documentation & Record Keeping - ensuring required records are legible, identifiable, and readily available to workers performing an activity.

To effectively support these requirements, the Company is working to enable the ability to:

- Support near real time systems
- Perform quicker information delivery with large datasets
- More accurately define and depict exactly how each part of a utility system is connected

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- View geographically clustered assets
 - Detect any logically inconsistent associations among features
 - Enforce stronger data integrity
 - Streamline data workflows
 - Enhance geospatial reports without the need for intensive manual analysis processes or generated with 3rd party solution tools
 - Geospatially enable the organization to support workflows, data insights, and analytics to uncover information related to location to support more informed decision making
 - Manage and analyze all distribution and transmission gas assets together
 - Set the foundation to support tracking and traceability capabilities
 - Better manage, route and event data effectively and efficiently.
- f. As referenced on page 85, lines 10 through 12 of my testimony, the vendor will no longer build additional functionality on the soon to be unsupported platform. All software development needed to meet the growing needs of utilities, as referenced in subpart e to this response, have been transitioned to the new platform and related tools and applications. The capabilities listed on page 85, lines 16 through 21 will collectively be required to overcome challenges of modeling the gas system more accurately and more representative of actual system configuration. The result of this transformation is critical in maturing core engineering and operational processes such as Risk Management and Emergency Preparedness. In the current geometric network, it is challenging to represent complex and clustered assets such as regulator stands, stations, and city gates. Equipment is currently depicted as point features and relies on related tables, spreadsheets, and CAD drawings to fully define and accurately reflect how assets are installed in the field. This creates challenges with being able to effectively analyze the assets and see the network from production to end user. Modeling within the Utility Network will allow the Company to incorporate non spatial assets within stations and city gates and integrate them into the network process. Managing the distribution and transmission data in different models continues to be a challenge, particularly with meeting the requirements associated with transmission operated by distribution ("TOD") assets. In addition to the above listed business needs, it is critically important to move to a GIS platform that will be supported and extended long term where the architectural components are better positioned to support today's computing, technology, and security requirements.
- g. Many of the benefits related to the Utility Network project relate to risk avoidance and are not representative in an Excel formula-based spreadsheet. This project is being undertaken to address technology obsolescence. Please see WP-KAP-14 for more information.

Witness: Kristine A. Pascarello

Date: March 13, 2025

U21806-AG-CE-0427_Pascarello_Attachment_1								
a.								
Table 14: Utility Network Actual and Projected Costs								
Utility Network								
	2022 Actual	2023 Actual	2024 Projected	Preliminary 2024 Actual	2025 Projected	2026 Projected	Project Total	Test Year
O&M	\$	\$352,679	\$722,781	\$745,093	\$1,815,114	\$196,068	\$3,108,954	\$517,408
Capital	\$	\$	\$2,888,200	\$1,552,199	\$12,306,368	\$4,865,563	\$18,724,130	\$7,513,271

U21806-AG-CE-0316 Revised
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Question:

30. Refer to lines 3-15 on page 22 of Mr. Griffin's direct testimony. Please explain why capital expenditures for TOD Pipeline Integrity projects increase in the projected test year when they decline in 2024 and for the 10 months ending October 2025. Provide the number of miles remediated in each year 2021 to 2024 actual and forecasted for 2024, 2025, and 2026 along with any other metrics that support the capital expenditures for each year.

Response:

The costs for this program are driven by the type of assessments scheduled to be performed that year and the number and type of digs that need to be completed in order to assess the pipe. The table below provides a summary of the WP-MPG-13, MPG-15, MPG-17, and MPG-19 showing expenditure fluctuations.

	2023 (MPG 13)	2024 (MPG 15)	2025 (MPG 17)	2026 (MPG 19)
ECDA Assessments	\$ 2,440,660	\$ 1,605,992	\$ 1,702,000	\$ 874,000
Casing Assessments	\$ 0	\$ 178,444	\$ 2,000,000	\$ 2,000,000
Risk Mitigation Assessments	\$ 0	\$ 1,665,473	\$ 661,167	\$ 4,865,585
ICDA Assessments	\$ 4,647,405	\$ 2,670,092	\$ 3,000,000	\$ 3,000,000
Pipe Replacement	\$ 2,185,551	\$ 0	\$ 0	\$ 0
Tool Program	\$ 0	\$ 0	\$ 50,000	\$ 100,000
Total	\$ 9,273,616	\$ 6,120,000	\$ 7,413,167	\$ 10,839,585

In 2023, a larger number of ICDA digs were completed to assess the pipe than typical due to the new requirements from Safety of Gas Transmission Pipelines, including Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments ("RIN2"). Additionally, pipe replacements needed to address MAOP exceedances on the pipe were completed. In 2024, the ICDA excavations were at a more typical level and pipe replacements were not required which led to the drop in costs in 2024 compared to 2023. The rise in expenses in 2025 and 2026 is driven by two main factors. The scheduled assessment of casings and performing Risk Mitigation assessments. The casing assessments are to address pipe inside casings within an HCA, which are completed every seven years as required by code. The Risk Mitigation Assessments are to evaluate and assess non-HCA pipe within the system. Performing these assessments help the Company evaluate the condition of the non-HCA pipe and remediate any corrosion issues necessary. This is typically pipe that is between HCAs and allows us to assess the pipe along with the HCA segments. This also gives the Company a better understanding of the cathodic protection of the HCA and non-HCA pipe and allows the Company to

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address deficiencies in the cathodic protection systems more holistically. Further explanation of these assessments is explained in responses U21806-AG-CE-329 and U21806-AG-CE-330.

The miles of HCA assessed are provided below:

	2021	2022	2023	2024	2025	2026
HCA Miles assessed	26.51	21.34	14.8	15.6	23.1	11.8

These assessments are performed by excavating the pipe (digs), performing an examination of its condition, repairing any pipe in bad condition, and installing UT sensors, UT coupons, or anodes for future monitoring and cathodic protection. This work is done in conjunction with O&M survey and digs that are also necessary to complete the assessments and are covered in the Pipeline Integrity TOD program O&M expenses.

Witness: MICHAEL P. GRIFFIN
Date: April 1, 2025

MICHIGAN PUBLIC SERVICE COMMISSION

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Question:

43. Refer to WP-MPG-17 on TOD Pipeline Integrity projects for 2025. Please provide the following information for each project with capital expenditures of \$500,000 and greater:

- a. When the pipeline segment was found to be deficient and requiring remediation.
- b. Explain what remediation is being done.
- c. How many feet or miles are being remediated.
- d. Provide the basis for the cost forecast.
- e. Provide the average cost per mile or foot to remediate similar projects in 2022, 2023, and 2024.
- f. Provide the current phase of development for the project.

Response:

Casings:

- a. The two casings to be inspected were identified in the fall of 2024.
- b. The two casings are scheduled to be inspected using a robotic ILI tool in August of 2025. After the inspection, the condition of the pipe inside the casing will be determined and remediation performed if required.
- c. The two casings are 60 and 106 feet long.
- d. The \$2,000,000 forecast is based on two projects being performed at an estimated cost of \$1,000,000 per project. The in-line inspection cost is projected to be an additional \$800,000.
- e. There weren't any similar casing projects performed in 2022, 2023 or 2024. Casings are assessed every 6 to 7 years.
- f. Currently these casing are in the planning and scheduling phase. The ILI tool vendor is being scheduled along with construction crews to perform excavation and construction.

Risk Mitigation:

- a. Survey for the lines was performed in the fall of 2024. The results of the survey was then analyzed and inspection locations selected during the winter of 2024.
- b. Excavation/inspection of the pipe will be performed at selected locations as well as installation of a new rectifier and groundbed to address low potential areas.
- c. A total of 14.4 miles of pipe will be assessed as part of this work. After the inspection, the condition of the pipe will be determined and remediation performed.
- d. The \$661,167 forecast is based on performing one dig per mile at a cost of \$46,000 per dig.
- e. The average dig cost for 2022 to 2024 was \$46,000
- f. Currently the Risk Mitigation work is in the planning and scheduling phase. The dig locations and rectifier installations are being determined. Additionally, permits are being applied for where necessary.

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ICDA Digs

- a. Survey for the lines was performed in the fall of 2024. The results of the survey were then analyzed, and inspection and remediation locations selected during the winter and will be finalized in April 2025.
- b. Excavation/inspection of the pipe will be performed at selected locations as well as installation of a UT sensor.
- c. Approximately 20 locations will be inspected as part of this work. After the inspection, the condition of the pipe will be determined and remediation performed.
- d. The \$3,000,000 forecast is based on performing twenty digs at a cost of \$150,000 per dig.
- e. The average dig cost is based on historical (2022-2024) digs costs of \$150,000 per dig.
- f. Currently the ICDA Dig work is in the planning and scheduling phase. The dig locations are being determined and their location verified in the field.

Witness: MICHAEL P. GRIFFIN

Date: March 7, 2025

CECo Response to AG-CE-0748

U21806-AG-CE-0748

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Question:

319. Refer to discovery response AG-CE-0316 on capital expenditures for TOD pipeline integrity work. Please:

- a. Expand the table to include actual amounts for each year 2021, 2022, and 2024, and provide it in Excel.
- b. Provide a similar table with the number miles or other units (specify the units) for each year 2021-2024 actual and forecasted for 2025 and 2026 and provide in Excel.
- c. Explain why the 2024 total amount of \$4,276,084 does not match to the \$6,119,000 shown on line 6 of page 22 of Mr. Griffin's direct testimony.
- d. Explain why the cost for assessments is capitalized and not expensed. Identify the accounting authority that permits capitalization and provide a copy of it.
- e. Describe what ECDA and Risk Mitigation assessment entail and why Risk Mitigation assessments begin in 2025.
- f. Is there a duplication in work between Risk Mitigation Assessments, HCA, and non-HCA pipeline assessments? If yes, how will it be avoided and by what amount should the forecasted costs for 2025 and 2026 be adjusted down?
- g. Was the \$2,185,551 pipe replacement cost in 2023 related to the Company's inability to re-establish MAOP on the pipeline segment and for not having traceable, verifiable, and complete records for the pipeline?

Response:

- a. See attachment U21806-AG-CE-748-Griffin_ATT_1.
- b. See attachment U21806-AG-CE-748-Griffin_ATT_1.
- c. The 2024 total amount \$4,276,084 only included the HCA assessment costs and erroneously omitted the Non-HCA/Moderate Consequence Area ("MCA") and Casing Assessment costs. The corrected table is shown below:

	2023 Actual	2024 Projected	2025 Projected	2026 Projected
ECDA Assessments	\$ 2,440,660	\$ 1,605,992	\$ 1,702,000	\$ 874,000
Casing Assessments	\$ 0	\$ 178,444	\$ 2,000,000	\$ 2,000,000
Risk Mitigation Assessments	\$ 0	\$ 1,665,473	\$ 661,167	\$ 4,865,585
ICDA Assessments	\$ 4,647,405	\$ 2,670,092	\$ 3,000,000	\$ 3,000,000
Pipe Replacement	\$ 2,185,551	\$ 0	\$ 0	\$ 0
Tool Program	\$ 0	\$ 0	\$ 50,000	\$ 100,000
Total	\$ 9,273,616	\$ 6,119,000	\$ 7,413,167	\$ 10,839,585

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- d. The cost for assessment digs can be capitalized when a retirement unit is installed per FERC Uniform System of Accounts Code of Federal Regulations (CFR) 18 Part 201. A link to this document is here: [eCFR :: 18 CFR Part 201 -- Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act](#). The UT sensors and UT coupons installed during assessment digs are considered retirement units according to the above rule. During an assessment dig, the dig can be capitalized when a UT sensor or UT coupon is installed. Similarly, if a retirement unit is not installed during an assessment dig, it is expensed and accounted for in the digs for the Pipeline Integrity-TOD program O&M expenses.
- e. External Corrosion Direct Assessment ("ECDA") and Risk mitigation assessments are similar but assess different segments of pipe. The ECDA assessments refer to pipe that is in HCA and/or MCA. The Risk Mitigation assessments refer to pipe that is outside of HCA/MCA. The Risk Mitigation assessments are performed to assess and evaluate the condition of the pipe outside of the code required HCA and MCA's.
- f. Risk Mitigation and non-HCA assessments are essentially the same. Prior to the new Safety of Gas Transmission Pipelines, including Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments ("RIN2") rule, which established the MCA requirements, the Company referred to pipe outside of HCA as non-HCA. Today, the Company assesses the HCA and MCA pipe the same way and schedule it at the same time and refer to it as the ECDA assessment. The Risk Assessment pipe now refers to any pipe outside of an HCA or MCA. There is no duplication of work between the Risk Assessment and HCA assessments. The O&M surveys are performed at the same time since the pipe segments connect to each other and are part of the same pipeline, but there is not a duplication of work between the two assessments.
- g. The pipe replacements in 2023 were to address a potentially instable seam issue caused by an over pressurization of the pipe and had nothing to do with traceable verifiable and complete records.

Witness: MICHAEL P. GRIFFIN

Date: April 1, 2025

CECo Response to AG-CE-0748

U21806-AG-CE-748-Griffin_ATT_1							
	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2024 Projected	2025 Projected	2026 Projected
ECDA	\$ 2,161,470	\$ 1,410,432	\$ 2,440,660	\$ 1,096,446	\$ 1,605,992	\$ 1,702,000	\$ 874,000
Casings			\$ -	\$ -	\$ 178,444	\$ 2,000,000	\$ 2,000,000
Risk Mitigation			\$ -	\$ 577,849	\$ 1,665,473	\$ 661,167	\$ 4,865,585
ICDA	\$ 2,280,725	\$ 2,341,353	\$ 4,647,405	\$ 2,660,049	\$ 2,670,092	\$ 3,000,000	\$ 3,000,000
Pipe Replacement	\$ 8,294,240	\$ 17,823,309	\$ 2,185,551	\$ 1,569,359	\$ -		\$ -
Tool Program	\$ 174,251	\$ 161,201	\$ -		\$ -	\$ 50,000	\$ 100,000
Total	\$ 12,910,686	\$ 21,736,295	\$ 9,273,616	\$ 5,903,703	\$ 6,120,001	\$ 7,413,167	\$ 10,839,585
	2021	2022	2023	2024 Actual	2024 Projected	2025 Projected	2026 Projected
HCA Miles assessed	30.91	22.06	14.8	15.6	15.6	23.1	11.8
Risk Mitigation Miles			7.77	17.91	17.91	34.27	105

MICHIGAN PUBLIC SERVICE COMMISSION										Case No. U-21806
Consumers Energy Company										WP-MPG-2
Regulatory Compliance Program Capital										Page 1 of 1
MAOP Pipeline Projects										
Project ID	Project Description	Project Summary & Reason	Location	2023 Actual	2024 Projection	2025 Projection	2026 Projection	10 Months Ending 10/30/2025 Projection	12 Months Ending 10/30/2026 Projection	Internal Approval? Y/N
GL-01280	SAG-100A Alma-St Louis Pipe Repl			0	-240,224					Y
GL-02042	KZO-1300 STA730+07-732+54 Pipe Repl	Final reconciliation costs of prior years project.	Kalamazoo, MI	-29,494	0					Y
GL-02046	STC-Lahser Lateral Pipe Repl	Final reconciliation costs of prior year project.	Southfield, MI	-5,783	0					Y
GL-02048	SAG-300 MdInd Rd at Kchvie Pipe Repl	Order cancelled and moved to O&M Original Scope: Replace 1,103 ft of 12" pipeline on Midland Rd. (STA 843+48 to 854+51). Scope changed to the replacement of 6 elbows within 1,103' segment (no MAOP gap on pipe). Must be funded as O&M.	Midland, MI	-36,231	0					Y
GL-02112	FDM-3070 2.4 Miles Pipe Repl	Reconciliation of prior years project	Blissfield, MI	0	-6,599					Y
GL-03042	SAG-LN 1900-REM MAOP	On the Line 1900 piping at Grand Blanc, the pressure test was conducted too low to meet class 3 requirements on the Launcher/Receiver and associated piping.	Flint, MI	1,692	1,799					Y
GL-03181	NVL-1400 Pontiac Trail VS Pipe Repl	Replacement of transmission pipeline segment with incomplete MAOP records. The MAOP Gap is located at Pontiac Trail Valve Site on Line 1400 and the crossover piping that connects to Line 2020.	Milford, MI	436,236	-402,801					Y
GL-03197	SAG-LN 100A Mt Pleasant Vs MAOP X Gap	Replacement of transmission pipeline segment with incomplete MAOP records. The MAOP Gap is located on the crossover piping that connects Line 100A to Line 100B at Mt. Pleasant Valve Site.	Mt Pleasant, MI	1,408,098	-8,073					Y
GL-03210	SAG-100A Mt. Pleasant VS-16in Vlvs	Replacement of transmission pipeline segment with incomplete MAOP records. The MAOP Gap is located on the crossover valves at Mt. Pleasant Valve Site. This work aligns with Pipeline Integrity direct assessment planned for 2023. Not completing this gap closure with the Integrity work will result in duplicate work to draw down the line again in a later year.	Mt Pleasant, MI	1,205,591	52,930					Y
GL-03261	NVL Ln 1400 Milford Rd Pipe Repl	Replacement of transmission pipeline segment with incomplete MAOP records. The MAOP Gap is located under Milford Road on Line 1400.	Milford, MI	1,806,050	5,247					Y
GL-03431	STC - Line 1060 - Mt. Clemens CG - LR Dr	On Line 1060 at Mt Clemens City Gate, the Launcher/Receiver piping has pressure test documentation that does not meet the TVC (Traceable, Verifiable, Complete) requirements per 192.624.	Mt Clemens, MI	0	385,631					Y
GL-03461	STC-1900 Metamora CG Hot Tap Repl	Replacement of transmission pipeline segment with incomplete MAOP records that cannot be resolved through pressure testing. This MAOP Gap is located at Metamora City Gate. On Line 1900 at Metamora City Gate, the hot tap piping is missing pressure test documentation to meet the TVC (Traceable, Verifiable, Complete) requirements per 192.624.	Metamora, MI	0	240,518	2,592,099	0	2,409,173	182,926	Y
GL-03462	STC-Ln 1060 4" BD Repl	On the L1060 line at Mt Clemens CG, 2003 L/R piping has a pressure test does that not meet TVC requirements per 192.624, therefore we are required to reconfirm MAOP. 4 in BD material was not specified on original construction drawing (4" plug valve and 12x4 tee) - material verifying sample would necessitate full removal of the BD, so it will be replaced with new material instead.	Mt Clemens, MI	0	22,812		289,000	0	268,605	Y
B-GL-00289	2026 project for Capital MAOP Replacement	Scope to be determined by ongoing MAOP records validation effort by Consumers Energy MSEA project.				0	2,758,800	0	2,564,110	Y
TOTAL EXPENDITURE				4,786,160	51,240	2,592,099	3,047,800	2,409,173	3,015,641	

Business cases have not been conducted on these projects as the projects in this program are in response to the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which required the PHMSA to direct each owner or operator of a natural gas transmission pipeline and associated features to provide verification that their records accurately reflect a pipeline's MAOP.

U21806-AG-CE-0319

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Question:

33. Refer to page 27 of Mr. Griffin's direct testimony on MAOP Transmission projects. For each MAOP project undertaken in 2023 through the end of the projected test year, please identify the missing records that required replacement of the pipeline, pipeline segment, and other facilities and equipment. Identify also what other less costly alternatives the Company explored before deciding on pipeline or facility replacement.

Response:

See attachment U21806-AG-CE-319-Griffin_ATT_1 for the requested information.

Witness: MICHAEL P. GRIFFIN

Date: March 7, 2025

U21806-AG-CE-0331

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Question:

45. Refer to WP-MPG-2 on MAOP projects. Please confirm that project B-GL-00289 for \$2,564,110 in capital expenditures in the projected test year pertain to currently- unknown future projects and not to any currently known specific projects. If not confirming, provide evidence otherwise.

Response

The project B-GL-00289 for \$2,564,110 in capital expenditures in the projected test year does pertain to currently unknown future projects.

Witness: MICHAEL P. GRIFFIN

Date: March 4, 2025

U21806-AG-CE-0750

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Question:

321. Refer to ATT_1 to discovery response AG-CE-0319 on MAOP projects for transmission pipelines. Please:

a. Regarding project GL-03042:

i. When was the pressure test conducted that was too low and why was it conducted at a low-pressure level?

ii. With the Company planning to perform an O&M pressure test in 2027, does it mean this capital project is not necessary at this time? If no, explain why it is still necessary.

b. Regarding project GL-03197, what is the seam threat? How is replacement of the pipeline less disruptive than hydrotesting?

c. What does 192.624 require?

d. For each project, identify the number of feet or miles to be replaced and explain why only this segment of the pipeline does not meet MAOP requirements and the remaining portion is not a problem.

Response:

a.

i. The pressure test in question was conducted 9/16/2009. During the test, the pressure recording fell below the minimum pressure allowed to support an MAOP of 960 PSI; it is unknown why the test was at that level.

ii. Yes, the capital project in question is not required at this time.

b. The 1950 piping replaced was of low frequency Electric Resistance Welding construction. Regulation requires the Company to assess this material, as it is known by industry to have manufacturing defects that can lead to potential seam failures. Corrosion interaction with pipe seams cannot be assessed by direct assessment; it can only be assessed via in-line inspection. Because the segments identified were on crossover lines, an inline inspection tool was not feasible to use, therefore, the Company chose to replace the segments. The new piping installed will be able to be assessed by direct assessment in the future, as it is constructed with piping made from modern manufacturing processes. Additionally, the Company needed to remediate the pressure test on these segments, as the MAOP was non-commensurate due to a class location change.

These crossover segments are between the company's L100A and L100B pipelines and gas deliverability cannot be maintained while taking an outage on both lines. Pressure testing all the piping at once was not feasible operationally. The replacement was constructed in a phased approach to accommodate only one line being out at a time. This replacement was also done in conjunction with a valve replacement and direct assessment remediation project at this location; both were funded out of different programs. This allowed for some costs to be shared among the projects.

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c. The requirements can be accessed via this link: [49 CFR § 192.624 - Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines. | Electronic Code of Federal Regulations \(e-CFR\) | US Law | LII / Legal Information Institute](#)

d. For GL-03042 approximately 40 feet will be replaced, for GL-03210 184 feet will be replaced. The Company's pipelines are made up of various vintages of material that have their own pressure test records. The records or conditions addressed by each project only apply to that segment, and not the whole pipeline.

Witness: MICHAEL P. GRIFFIN

Date: March 31, 2025

CECo Response to AG-CE-0319

U21806-AG-CE-319_Griffin_ATT_1				
Project ID	Project Description	Project Summary & Reason	Identify missing records	Identify what other less costly alternatives were considered.
GL-03042	SAG-LN 1900-REM MAOP	On the Line 1900 piping at Grand Blanc, the pressure test was conducted too low to meet class 3 requirements on the Launcher/Receiver and associated piping.	The segments of pipe for GL-03042 were identified by the Standard Engineering Analysis to have a pressure test that is non-commensurate with the MAOP of the System that it is coupled. Project is not eligible for 192.624, as pressure test was determined to be TVC by Standard Engineering Analysis.	Pressure reduction is not feasible as no pressure protection equipment nearby. Company plans to execute O+M pressure test in 2027, and costs will be expensed at that time.
GL-03181	NVL-1400 Pontiac Trail VS Pipe Repl	Replacement of transmission pipeline segment with incomplete MAOP records. The MAOP Gap is located at Pontiac Trail Valve Site on Line 1400 and the crossover piping that connects to Line 2020.	The segments of pipe for GL-03181 were identified by the Standard Engineering Analysis to have a pressure test that is non-commensurate with the MAOP of the System that it is coupled. Project is not eligible for 192.624, as pressure test was determined to be TVC by Standard Engineering Analysis.	Pressure reduction is not feasible as no pressure protection equipment nearby. Company executed O+M pressure test in 2023, and remaining costs were for capital grading of site to achieve proper depth of cover over the pipeline.
GL-03197	SAG-LN 100A Mt Pleasant Vs MAOP X Gap	Replacement of transmission pipeline segment with incomplete MAOP records. The MAOP Gap is located on the crossover piping that connects Line 100A to Line 100B at Mt. Pleasant Valve Site.	The segments of pipe for GL-03197 were identified by the Standard Engineering Analysis to have a pressure test that is non-commensurate with the MAOP of the System that it is coupled. Project is not eligible for 192.624, as pressure test was determined to be TVC by Standard Engineering Analysis.	Pressure reduction is not feasible as no pressure protection equipment nearby. Replacement eliminated seam threat on 1950's pipe. Replacement was less disruptive to system operation and simpler project execution than hydrotesting.
GL-03210	SAG-100A Mt. Pleasant VS-16in Vlvs	Replacement of transmission pipeline segment with incomplete MAOP records. The MAOP Gap is located on the crossover valves at Mt. Pleasant Valve Site. This work aligns with Pipeline Integrity direct assessment planned for 2023. Not completing this gap closure with the Integrity work will result in duplicate work to draw down the line again in a later year.	The segments of pipe for GL-03210 were identified by the Standard Engineering Analysis to have a pressure test that is non-commensurate with the MAOP of the System that it is coupled. Project is not eligible for 192.624, as pressure test was determined to be TVC by Standard Engineering Analysis.	Pressure reduction is not feasible as no pressure protection equipment nearby. Replacement eliminated seam threat on 1950's pipe. Replacement was less disruptive to system operation and simpler project execution than hydrotesting.
GL-03261	NVL Ln 1400 Milford Rd Pipe Repl	Replacement of transmission pipeline segment with incomplete MAOP records. The MAOP Gap is located under Milford Road on Line 1400.	The segments of pipe for GL-03210 were identified by the Standard Engineering Analysis to have a pressure test that is non-commensurate with the MAOP of the System that it is coupled. Project is not eligible for 192.624, as pressure test was determined to be TVC by Standard Engineering Analysis.	Pressure reduction is not feasible as no pressure protection equipment nearby. Replacement was chosen as existing pipe was not designed for current class.
GL-03431	STC - Line 1060 – Mt. Clemens CG – LR Dr	On Line 1060 at Mt Clemens City Gate, the Launcher/Receiver piping has pressure test documentation that does not meet the TVC (Traceable, Verifiable, Complete) requirements per 192.624.	The segments of pipe for Project ID GL-03431 were identified by the Standard Engineering Analysis to have a pressure test that is not Traceable, Verifiable, and Complete.	Company has investigated the other options available in 192.624 and has chosen retirement as the most practicable option to comply. Pressure reduction is not feasible as no pressure protection equipment nearby. Piping is not utilized anymore by operations in lieu of a more efficient way of liquids disposal.

CECo Response to AG-CE-0319

GL-03461	STC-1900 Metamora CG Hot Tap Repl	Replacement of transmission pipeline segment with incomplete MAOP records that cannot be resolved through pressure testing. This MAOP Gap is located at Metamora City Gate. On Line 1900 at Metamora City Gate, the hot tap piping is missing pressure test documentation to meet the TVC (Traceable, Verifiable, Complete) requirements per 192.624.	The segments of pipe for Project GL-03461 were identified by the Standard Engineering Analysis to have a pressure test that is not Traceable, Verifiable, and Complete.	Company has investigated the other options available in 192.624 and has chosen replacement as the most practicable and beneficial option to comply. Pressure reduction is not feasible as no pressure protection equipment nearby. Segments will be remediated in conjunction with a mainline valve installation which will allow for outage flexibility and allow compliance with valve
GL-03462	STC-Ln 1060 4" BD Repl	On the L1060 line at Mt Clemens CG, 2003 L/R piping has a pressure test does that not meet TVC requirements per 192.624, therefore we are required to reconfirm MAOP. 4 in BD material was not specified on original construction drawing (4" plug valve and 12x4 tee) - material verifying sample would necessitate full removal of the BD, so it will be replaced with new material instead.	The segments of pipe for Project GL-03462 were identified by the Standard Engineering Analysis to have a pressure test that is not Traceable, Verifiable, and Complete.	Company has investigated the other options available in 192.624 and has chosen replacement as the most practicable option to comply. Pressure reduction is not feasible as no pressure protection equipment nearby. Gap segment is small enough that obtaining a material sample and pressure testing is impracticable. Replacement is occurring in conjunction with other work at the site.
B-GL-00289	2026 project for Capital MAOP Replacement	Scope to be determined by ongoing MAOP records validation effort by Consumers Energy MSEA project.	N/A	N/A

CECo Response WP-MPG-1

MICHIGAN PUBLIC SERVICE COMMISSION														Case No. U-21806	
Consumers Energy Company														WP-MPG-1	
Asset Relocation Transmission Capital Projects														Page 1 of 2	
Project ID	Project Description	Project Summary & Reason	Location	Qty. & Size Pipe Removed	Qty. & Size Pipe Installed	2023 Actual	2024 Projection	2025 Projection	2026 Projection	10 Months Ending 10/30/2025 Projection	12 Months Ending 10/30/2026 Projection	Start Date	Completion Date	Internal Approval? Y/N	
GL-00976	SAG-100ALn Lwrg-Co Drain-197 *CNCL*	Project cancelled, moved to O&M				-4,158	0							Y	
GL-00978	SAG-100BLn Lwrg Co Drain-197 *CNCL*	Project cancelled, moved to O&M				-4,110	0							Y	
GL-00981	KZO - L1200A McKale Rd LL	Final settlement costs: Replace and lower approximately 600 feet of 26" piping in farm area near McKale Road. Design and construction of new replacement section to comply with 49 CFR 192.327(a) requiring transmission pipeline to be installed with at least 36" cover.	Burr Oak, MI	564 ft. of 26" pipe	564 ft. of 26" pipe	55,200	0					7/8/2022	10/6/2022	Y	
GL-00982	KZO-1200A Wetland BR038 Ln Lwrg	Replace and lower approximately 1200 feet of 26" piping at wetland BRO38 along Line 1200A as a measure to protect it from possible contact and damage as result of its shallow depth and comply with 49 CFR 192.327(a).	Hodunk, MI	759 ft. of 26" pipe	1193 ft. of 26" pipe	36,806	-106,954					7/12/2021	9/1/2021	Y	
GL-00983	KZO-1200A Wetland BR032 Ln Lwrg	Replace and lower approximately 1300 feet of 26" pipeline in wetlands near Mauer Road on Line 1200A. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Union, MI	1300 ft. of 26" pipe	1300 ft. of 26" pipe	52,139	49,524					4/1/2031	11/1/2031	Y	
GL-00984	KZO-1200A Wetland BR030 Ln Lwrg	Project Cancelled, consolidated within scope for GL-00983 above for improved efficiency				662	0							Y	
GL-00985	KZO-1200A Uni Bat Drain Ln Lwrg	Final settlement costs: Replace and lower approximately 120 feet of 26" pipeline at Union-Batavia Drain on Line 1200A. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR 192.327(a) and company requirements.	Union, MI	111 ft. of 26" pipe	113 ft. of 26" pipe	66,756						7/8/2022	10/6/2022	Y	
GL-00987	KZO-1200A 26" Langwell Rd. LL	Replace and lower approximately 2200 feet of 26" pipeline in cultivated area E. of Babcock Rd, N. of Langwell Rd, Matteson Twp, Branch County (S12, T6S, R8W) on Line 1200A. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR 192.327(a) and company requirements.	Matteson Township, MI	2191 ft. of 26" pipe	2192 ft. of 26" pipe	46,429	0					7/8/2022	10/6/2022	Y	
GL-00988	KZO-1200A Wetland BR017 Ln Lwrg	Replace and lower approximately 1200 feet of 26" pipeline in wetland near M-86 and Farrand Road on Line 1200A. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Matteson Township, MI	1,200 ft. of 26" pipe	1,200 ft. of 26" pipe	94,075	84,191	31,447	7,576,396	30,145	7,264,087	4/1/2026	11/1/2026	Y	
GL-00990	KZO-1200A Wetland BR014 Ln Lwrg	Replace and lower approximately 350 feet of 26" pipeline in wetland between Cornn Road and M-86 on Line 1200A. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Matteson Township, MI	350 ft. of 26" pipe	350 ft. of 26" pipe	21,700	84,191	44,924	3,278,501	43,064	3,144,653	4/1/2026	11/1/2026	Y	
GL-00991	KZO-1200A Townline Rd Ln Lwrg	Replace and lower approximately 2,800 feet of 26" pipeline in private drain located south of Townline Road. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Burr Oak Township, MI	2,800 ft. of 26" pipe	2,800 ft. of 26" pipe	0	84,191	44,924	10,965,079	43,064	10,513,060	4/1/2026	11/1/2026	Y	
GL-02083	FDM-2200 Toma Rd Line Lwrg	Replace and lower approximately 350 feet of 36" pipeline near Toma Road. Reduce risk of potential contact and damage as result of its shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Putnam Township, MI	350 ft. of 36" pipe	350 ft. of 36" pipe	4,022	0				0	4/1/2031	11/1/2031	Y	
GL-02085	KZO-1200A Crooked Creek Rd Line Lwrg	Final settlement costs: Replace and lower approximately 500 feet of 26" piping at Crooked Creek, along Line 1200A, as a measure to protect it from possible contact and damage as result of its shallow depth. And also to comply with 49 CFR 192.327(a).	White Pigeon, MI	503 ft. of 26" pipe	507 ft. of 26" pipe	44,559	106,934				0	7/12/2021	9/1/2021	Y	
GL-02086	KZO-1200A Needham Rd Line Lwrg	Replace and lower approximately 300 feet of 26" pipeline in cultivated area approximately 600' east of Needham Road. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Burr Oak Township, MI	300 ft. of 26" pipe	300 ft. of 26" pipe	0	84,191	44,924	1,873,429	43,064	1,797,742	4/1/2026	11/1/2026	Y	
GL-02087	KZO-1300 E Ave Line Lwrg	Project deferred to future date. Historical costs expensed.	Kalamazoo, MI	300 ft. of 12" pipe	300 ft. of 12" pipe	-8,814	0	44,924	31,826	43,064	32,368	4/1/2030	11/1/2030	Y	
GL-02647	NVL-1600 Lake Park Dr Ln Lwrg	Line lowering of Line 1600 at Lake Park Drive, City of Farmington Hills. Moved forward in LTRP per System Integrity risk evaluation. Meetings held in 2019 with City of Farmington Hills to discuss and plan.	Farmington Hills, MI	200 ft. of 16" pipe	196 ft. of 16" pipe	50,045	0				0	5/26/2020	6/10/2020	Y	
GL-02658	NVL-2800 Sutton Rd Reroute	Final settlement costs: Re-route the pipeline to resolve encroachment and protect pipeline from external stress.	Northfield Township, MI	26 ft. of 18" pipe	541 ft. of 18" pipe	52,358	0				0	4/14/2021	5/14/2021	Y	
GL-02673	NVL-L1020 Currie Rd Relocation	Final settlement costs: Oakland County and Washtenaw County are collaborating on a road improvement project. This road project will result in conflicts with Line 1020, requiring relocation of the line, which resides in road right-of-way.	Salem Township, MI	2247 ft. of 16" pipe	2133 ft. of 16" pipe	41,440	0				0	4/14/2021	5/12/2021	Y	
GL-02774	OVS-1300 25th St Ln Lwrg	Final settlement costs: Allegan County reconstructing 25th street and reducing the grade of the road considerably where Line 1300 currently crosses.	Allegan Township, MI	152 ft. of 12" pipe	240 ft. of 12" pipe	22,391	0				0	10/5/2020	10/23/2020	Y	
GL-02782	STC-1600 Eldridge & 13 Mile Ln Lwrg	Final settlement costs: Line lowering of Line 1600 along 13 Mile Road at Eldridge Lane, Village of Beverly Hills for civic improvement project.	Southfield Township, MI	724 ft. of 16" pipe	712 ft. of 16" pipe	16,217	0				0	6/11/2020	7/2/2020	Y	

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GL-03021	SAG-100B Sleepy Hollow Re-route	Re-route of Line 100B through the Sleepy Hollow State Park area would potentially eliminate the HCA and reduce the risk to the public through the park/beach area. Installing the 26" pipe during the Line 100A replacement, through the proposed re-route would minimize the disturbance to the park area, while taking advantage of utilizing the contractor that will already be on site to install the new 36" 100A pipe. Additional benefits will be gained by utilizing the consultant designer who is performing the design for the new/replacement 100A pipe as well.	Laingsburg, MI	3,000 ft. of 26" pipe	3,000 ft. of 26" pipe	1,741,965	13,237,811	152,740	95,667	146,418	98,030	4/1/2024	11/1/2024		Y
GL-03173	NVL-1600 Taft Rd Ln Lwrng	Replace and lower approximately 915 feet of 16" pipeline along Taft Road in Novi on Line 1600. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR 192.327(a) and company requirements.	Novi, MI	915 ft. of 16" pipe	915 ft. of 16" pipe	3,108,125	168,382			0		5/15/2023	6/15/2023		Y
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Asset Relocation Transmission Capital Projects														Page 2 of 2	
Project ID	Project Description	Project Summary & Reason	Location	Qty. & Size Pipe Removed	Qty. & Size Pipe Installed	2023 Actual	2024 Projection	2025 Projection	2026 Projection	10 Months Ending 10/30/2025 Projection	12 Months Ending 10/30/2026 Projection	Start Date	Completion Date	Internal Approval? Y/N	
GL-03194	600 Lwr Bald Mtn Rd	Replace and lower approximately 100 feet of 22" piping at Bald Mountain Rd identified as shallow in April 2022, resulting in the immediate closure of Bald Mountain Rd. Design and construction of new replacement section to comply with 49 CFR 192.327(a) requiring transmission pipeline to be installed with at least 36" of cover.	Orion Township, MI	100 ft. of 22" pipe	94 ft. of 22" pipe	94,525	0			0		10/3/2022	10/31/2022		Y
GL-03195	SAG-300 Parker Drn Lwr	Replace and lower approximately 100 feet of 12" pipeline in Parker Swamp Drain on Line 300. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR 192.327(a) and company requirements.	Tittabawassee Township, MI	100 ft. of 12" pipe	100 ft. of 12" pipe	114,297	2,025,000	149,888	0	143,684	6,204	4/1/2024	11/1/2024		Y
GL-03326	SAG-100A Chippewa River Line Lwrng	Replace and lower approximately 1200 feet of 22" pipeline in the Chippewa River on Line 100A. Reduce risk of potential contact and damage as result of shallow depth, comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	St. Pleasant, MI	1,200 ft. of 22" pipe	1,200 ft. of 22" pipe	104,766	50,000	3,757,314	283,605	3,601,788	427,393	4/1/2025	11/1/2025		Y
GL-03327	SAG-100C Chippewa River Line Lwrng	Replace and lower approximately 1400 feet of 16" pipeline in the Chippewa River on Line 100C. Reduce risk of potential contact and damage as result of shallow depth, comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	St. Pleasant, MI	1,400 ft. of 16" pipe	1,400 ft. of 16" pipe	118,686	50,000	3,411,558	154,583	3,270,343	289,399	4/1/2025	11/1/2025		Y
GL-03348	SAG-100B Chippewa River Ln Lwrng	Replace and lower approximately 1100 feet of 26" pipeline in the Chippewa River on Line 100B. Reduce risk of potential contact and damage as result of shallow depth, comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	St. Pleasant, MI	1,100 ft. of 26" pip	1,100 ft. of 26" pip	43,904	49,524	4,699,611	154,583	4,505,079	342,716	4/1/2025	11/1/2025		Y
GL-03351	OVS-LN 1300 114th Ave Ln Lwrng	Replace and lower approximately 750 feet of 12" pipeline near 114th Ave on Line 1300. Reduce risk of potential contact and damage as result of shallow depth, comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Watson, MI	750 ft. of 12" pipe	750 ft. of 12" pipe	25,636	1,301,000	152,740	0	146,418	6,322	4/1/2024	11/1/2024		Y
GL-03353	OVS-1100 Rabbit River Ln Lwrng	Replace and lower approximately 1920 feet of 24" pipeline crossing the Rabbit River on Line 1100. Reduce risk of potential contact and damage as result of shallow depth, comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Overisel Township, MI	1,920 ft. of 24" pipe	1,920 ft. of 24" pipe	179,395	121,000	7,295,007	154,583	6,993,044	450,147	4/1/2025	11/1/2025		Y
GL-03397	100A-100B Surrey & Old State Bridgln	Placement on protective concrete bridging atop existing Lines 100A and 100B at the Surrey Rd crossing in Clare Co as a measure of additional protection from external loading. Project done in conjunction with municipal roadwork with Clare Co., modified road maintains minimum depth of coverage requirements.	Surrey Township, MI	N/A	N/A	58,930	0			0		4/1/2023	11/1/2023		Y
GL-03142	KZO-Line 1200A-26" Lowering-E of Webb Rd	Replace and lower approximately 1000 feet of 26" piping east of Webb Road along Line 1200A. Aligned with other project outages planned for Line 1200A in 2031.	Batavia Township, MI	1,000 ft. of 26" pipe	1,000 ft. of 26" pipe			0	90,357	0	86,617	4/1/2031	11/1/2031		Y
B-GL-00091	STC - Line 600 22" Lowering/Relocation - Console St	Prioritizing per 2024 System Integrity risk analysis. Replace and lower approximately 1100 feet of 22" piping along Console St along Line 600.	Independence Charter Township, MI	1,100 ft. of 22" pipe	1,100 ft. of 22" pipe			44,924	45,466	43,064	45,443	4/1/2027	11/1/2027		Y
B-GL-00093	OVS - Line 1300 12" Lowering - north of 138th Ave	Prioritizing per 2024 System Integrity risk analysis. Replace and lower approximately 250 feet of 12" piping near 138th Ave. on Line 1300.	Hamilton, MI	250 ft. of 12" pipe	250 ft. of 12" pipe			0	45,466	0	43,584	4/1/2028	11/1/2028		Y
GL-03468	STC - Line 600 22" Lowering - Stevens Rd Line Lwrng	Replace and lower approximately 100 feet of 22" piping at Stevens Rd along Line 600.	Independence Charter Township, MI	100 ft. of 22" pipe	100 ft. of 22" pipe			44,924	45,466	43,064	45,443	4/1/2027	11/1/2027		Y
GL-03470	STC - Line 600 22" Lowering - South of Judah Rd, East of Baldwin Rd	Replace and lower approximately 300 feet of 22" piping near Judd and Baldwin Roads along Line 600.	Lake Orion, MI	300 ft. of 22" pipe	300 ft. of 22" pipe			44,924	45,466	43,064	45,443	4/1/2027	11/1/2027		Y
GL-03466	STC 1900 26" North Ave Line Lwrng	Replace and lower approximately 350 feet of 26" piping near North Ave along Line 1900.	Armada, MI	350 ft. of 26" pipe	350 ft. of 26" pipe			0	45,466	0	43,584	4/1/2028	11/1/2028		Y
GL-03342	KZO-1800 Al Sabo 20" Ln Lwr	Replace and lower approximately 1700 feet of 20" piping within the Al Sabo Land Preserve along Line 1800.	Kalamazoo, MI	1,700 ft. of 20" pipe	1,700 ft. of 20" pipe			0	45,466	0	43,584	4/1/2028	11/1/2028		Y
						6,177,945	17,388,985	19,964,771	24,931,405	19,138,368	24,725,821				
Business cases have not been conducted on these projects as they are required due to civic improvement activities, due to depth of cover issues or to eliminate conflicts with other utilities. GL-03021 received a Certificate of Necessity to Operate and Construct in MPSC Case No. U-21179															

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Question:

40. Refer to WP-MPG-1 on Transmission asset relocations. For the projects GL-00988, GL-00990, GL-00991, GL-02086, GL-03326, GL-03327, GL-03348, and GL-03353, please provide the following information:

- a. The current phase of development for the project (i.e., preliminary assessment, scoping, preliminary design, engineering, construction, etc.).
- b. Provide the current depth of soil cover or whether the pipe is currently exposed.
- c. The actual length of pipe not compliant with the required depth of cover.
- d. When the problem of insufficient depth of cover was first discovered by the Company.
- e. What caused the insufficient depth of cover.
- f. Why the required depth of cover cannot be re-established by adding more soil on top of the pipe at a lower expense than pipe replacement. Provide evidence that this option was evaluated for each project.
- g. If the pipe is located in wetlands, identify who is likely to access and damage the pipe.
- h. For project GL-00991, is the private drain responsible for the loss of soil cover? Who is the private party? Is the Company holding the responsible party accountable for the cost to re-establish dept of cover? If yes, provide details. If no, explain why not.

Response:

- a. The current phase of development for each project identified is as follows:
 - **GL-00988 KZO 1200A Wetland BR017 Ln Lwrng:** engineering in-progress, construction scheduled for 2026.
 - **GL-00990 KZO 1200A Wetland BR014 Ln Lwrng:** preliminary design in-progress, construction scheduled for 2026.
 - **GL-00991 KZO 1200A Townline Rd Ln Lwrng:** preliminary design in-progress, construction scheduled for 2026.
 - **GL-02086 KZO 1200A Needham Rd Ln Lwrng:** preliminary design in-progress, construction scheduled for 2026.
 - **GL-03326 SAG 100A Chippewa River Ln Lwrng:** engineering in-progress, construction scheduled for 2025.
 - **GL-03327 SAG 100C Chippewa River Ln Lwrng:** engineering in-progress, construction scheduled for 2025.
 - **GL-03348 SAG 100B Chippewa River Ln Lwrng:** engineering in-progress, construction scheduled for 2025.

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- **GL-03353 OVS 1100 Rabbit River Ln Lwrng:** engineering in-progress, construction scheduled for 2025.
- b. The shallowest depth of cover for each project identified is as follows:
 - **GL-00988 KZO 1200A Wetland BR017 Ln Lwrng:** 6" of cover within Wetland BR017.
 - **GL-00990 KZO 1200A Wetland BR014 Ln Lwrng:** 18" of cover within Wetland BR014 and agricultural farmland.
 - **GL-00991 KZO 1200A Townline Rd Ln Lwrng:** 10" of cover within a drain and agricultural farmland.
 - **GL-02086 KZO 1200A Needham Rd Ln Lwrng:** 21" of cover within agricultural farmland.
 - **GL-03326 SAG 100A Chippewa River Ln Lwrng:** exposed within the Chippewa River.
 - **GL-03327 SAG 100C Chippewa River Ln Lwrng:** exposed within the Chippewa River.
 - **GL-03348 SAG 100B Chippewa River Ln Lwrng:** acceptable cover per 49 CFR 192.327 and Company standards currently, however, project completion in conjunction with GL-03326 and GL-03327 to remediate identified bend strain issue adjacent to river crossing with same Contractor and general construction window. The bend strain issue will be remediated using Horizontal Directional Drilling ("HDD") beneath the Chippewa River, like 100A and 100C under GL-03326 and GL-03327, respectively, but to also mitigate future exposure risk given the other exposures adjacent in this location.
 - **GL-03353 OVS 1100 Rabbit River Ln Lwrng:** exposed within the Rabbit River.
- c. The actual length of shallow piping for each project identified is as follows:
 - **GL-00988 KZO 1200A Wetland BR017 Ln Lwrng:** 1200 ft segment containing multiple shallow locations in wetland per topographic survey, including the shallowest depth indicated in response to part b, above. Replacement by HDD within wetland in compliance with minimum depth requirements.
 - **GL-00990 KZO 1200A Wetland BR014 Ln Lwrng:** 350 ft segment containing multiple shallow locations in wetland and agricultural farmland per topographic survey, including the shallowest depth indicated in response to part b, above. Replacement in compliance with minimum depth requirements.
 - **GL-00991 KZO 1200A Townline Rd Ln Lwrng:** 2800 ft segment containing multiple shallow locations in agricultural farmland and a drain per topographic survey, including the shallowest depth indicated in response to part b, above. Replacement in compliance with minimum depth requirements.
 - **GL-02086 KZO 1200A Needham Rd Ln Lwrng:** 300 ft segment containing multiple shallow locations in agricultural farmland per topographic survey, including the shallowest depth indicated in response to part b, above. Replacement in compliance with minimum depth requirements.
 - **GL-03326 SAG 100A Chippewa River Ln Lwrng:** 37 ft of exposed pipe per topographic survey, replacement footage driven by HDD design and minimum EGLE permit depth requirements for the Chippewa River.

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- **GL-03327 SAG 100C Chippewa River Ln Lwrng:** 10 ft of exposed pipe per topographic survey, replacement footage driven by HDD design and minimum EGLE permit depth requirements for the Chippewa River.
 - **GL-03348 SAG 100B Chippewa River Ln Lwrng:** not applicable, see response for part b, above. Replacement footage driven by HDD design and minimum EGLE permit depth requirements for the Chippewa River.
 - **GL-03353 OVS 1100 Rabbit River Ln Lwrng:** 6 ft of exposed pipe in western riverbank per topographic survey, replacement footage driven by HDD design, minimum EGLE permit depth requirements for the Rabbit River and federal flood plain designation for access from the east.
- d. For each identified project, insufficient depth was first discovered, evaluated and documented for remediation following appropriate prioritization within the Asset Relocation program, as shown below. Projects are prioritized based on risk. Projects carrying higher risk are conducted along with or other municipal/3rd party requests which causes other projects within the workplan to be moved to a later date based on available resources and funding, and to align with gas control on outage availability on the line.
- **GL-00988 KZO 1200A Wetland BR017 Ln Lwrng:** July 2014
 - **GL-00990 KZO 1200A Wetland BR014 Ln Lwrng:** July 2014
 - **GL-00991 KZO 1200A Townline Rd Ln Lwrng:** July 2014
 - **GL-02086 KZO 1200A Needham Rd Ln Lwrng:** July 2014
 - **GL-03326 SAG 100A Chippewa River Ln Lwrng:** December 6, 2022
 - **GL-03327 SAG 100C Chippewa River Ln Lwrng:** December 6, 2022
 - **GL-03348 SAG 100B Chippewa River Ln Lwrng:** December 6, 2022
 - **GL-03353 OVS 1100 Rabbit River Ln Lwrng:** June 13, 2023
- e. The following explains the anticipated cause of cover degradation for each identified project:
- **GL-00988 KZO 1200A Wetland BR017 Ln Lwrng:** gradual soil erosion associated with stormwater runoff, seasonal wetland water level fluctuation.
 - **GL-00990 KZO 1200A Wetland BR014 Ln Lwrng:** gradual soil erosion associated with stormwater runoff, seasonal wetland water level fluctuation and annual agricultural activity within the area.
 - **GL-00991 KZO 1200A Townline Rd Ln Lwrng:** gradual soil erosion associated with stormwater runoff and annual agricultural activity within the area.
 - **GL-02086 KZO 1200A Needham Rd Ln Lwrng:** gradual soil erosion associated with stormwater runoff and annual agricultural activity within the area.
 - **GL-03326 SAG 100A Chippewa River Ln Lwrng & GL-03327 SAG 100C Chippewa River Ln Lwrng:** gradual scouring since time of installation within the river crossing; attributed to changing river bottom dynamics associated with seasonal water velocities and flow characteristics. The remediated segment will be installed via means of HDD at a depth well below the river bottom and per engineering requirements. HDDs offer an improved, less invasive, installation technology that was not available when the segment was installed originally.

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- **GL-03348 SAG 100B Chippewa River Ln Lwrng:** while cover is currently acceptable, the project will be completed to remediate an adjacent bend strain issue. Further, this line will ultimately experience the same scouring and seasonal changes noted for GL-03326 and GL-0332, above, given the proximity to the other projects at this location. This will ultimately save money as the Company will have to mobilize/demobilize crews remediate the bend strain issue and will have crews on site for the other two nearby projects.
 - **GL-03353 OVS 1100 Rabbit River Ln Lwrng:** gradual scouring since time of installation within the river crossing; attributed to changing river bottom dynamics associated with seasonal water velocities and flow characteristics. The remediated segment will be installed via means of HDD at a depth well below the river bottom and per engineering requirements. HDDs offer an improved, less invasive, installation technology that was not available when the segment was installed originally.
- f. Response for each identified project involving the option to remediate shallow depth of cover via means of placing fill atop the existing line is as follows:
- **GL-00988 KZO 1200A Wetland BR017 Ln Lwrng:** evaluated option during scoping, unable to add fill in wetlands without appropriate permitting and is not advisable if remediation can be completed otherwise. Fill addition is not successful long-term in locations subject to seasonal water fluctuations, the best option for remediation is to lower the pipe well beneath the wetland via HDD.
 - **GL-00990 KZO 1200A Wetland BR014 Ln Lwrng:** evaluated option during scoping, unable to add fill in wetlands without appropriate permitting and is not advisable if remediation can be completed otherwise. Fill addition is not successful long-term in locations subject to seasonal water fluctuations or within agricultural areas.
 - **GL-00991 KZO 1200A Townline Rd Ln Lwrng:** evaluated option during scoping, unable to successfully, long-term, establish additional fill in agricultural areas subject to farming operation. Placement of fill in this location would require additional action in the future once added cover has degraded. Location also includes crossing of a drain; therefore, remediation must lower the line to prevent negatively impacting the hydraulics of the existing drain.
 - **GL-02086 KZO 1200A Needham Rd Ln Lwrng:** evaluated option during scoping, unable to successfully, long-term, establish additional fill in agricultural areas subject to farming operation. Placement of fill in this location would require additional action in the future once added cover has degraded.
 - **GL-03326 SAG 100A Chippewa River Ln Lwrng, GL-03327 SAG 100C Chippewa River Ln Lwrng, GL-03348 SAG 100B Chippewa River Ln Lwrng & GL-03353 OVS 1100 Rabbit River Ln Lwrng:** option not evaluated given location geography being a river crossing, fill addition is neither permissible in river crossings nor will it be successful long term as flow velocities will immediately scour and remove added material added from atop the pipeline. The only viable remediation option available for long-term success is to replace via means of HDD, to depths well below the river bottom and protect from future exposure.

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- g. The following projects contain pipe located in wetlands and identify the party most likely to access and damage the pipe:
- **GL-00988 KZO 1200A Wetland BR017 Ln Lwrng:** the landowner is most likely to encounter and potentially damage the existing shallow pipe. The Company must protect its assets from any contact or damage resulting from any 3rd party though compliance with 49 CFR 192.317 and be mindful of the potential for trespass or other unauthorized activity near the existing line. Additionally, seasonal water level fluctuation in this wetland allows potential access to the shallow depth location, which increases the potential for contact or damage.
 - **GL-00990 KZO 1200A Wetland BR014 Ln Lwrng:** the landowner and/or tenant farmer is the most likely to encounter and potentially damage the existing shallow pipe in wetland and adjacent farm field, as well as any other 3rd party given proximity of the project location to state highway. The Company must protect its assets from any contact or damage resulting from any 3rd party though compliance with 49 CFR 192.317 and be mindful of the potential for trespass or other unauthorized activity near the existing line. Seasonal water level fluctuation in this area also increases the risk of access from 3rd parties, which increases the potential for contact or damage.
- h. For **GL-00991 KZO 1200A Townline Rd Ln Lwrng**, the existing drain is not a regulated, county-maintained drain. Instead, the drain property is owned by the landowner and maintained appropriately. With cover degradation being gradual over time since the pipeline's installation in 1960, the Company has no ability to demonstrate the landowner for being strictly responsible for cover loss in this location. Instead, cover loss has occurred naturally, over time, as result of stormwater runoff which has resulted in the existing depth, 65 years following the original installation.

Witness: MICHAEL P. GRIFFIN

Date: March 4, 2025

CECo Response WP-MPG-3

MICHIGAN PUBLIC SERVICE COMMISSION Consumers Energy Company Deliverability Base Field Measurement Program										Case No. U-21806 WP-MPG-3 Page 1 of 2
Project ID	Project	Location	Project Reason	2023 Actual	2024 Projection	2025 Projection	2026 Projection	10 Months Ending 10/30/2025 Projection	12 Months Ending 10/30/2026 Projection	Internal Approval Y/N
GL-02402	MAR-Blue Lake 36 Site Upgrds	Blue Lake	Improve measurement accuracy	0	34,130					Y
GL-02403	MAR-Goose Creek Site Upgrds	Goose Creek	Improve measurement accuracy	1,454	-23,560					Y
GL-03451	STC-2070 Dutton Rd Meter Run Viv Repl	Dutton RD Valve Site	Valve replacement, modifications to the meter runs, and modifications to the site to ensure uniform design pressure at the site	0	3,077,516					Y
GM-00387	SAG-Coleman CG Meter Repl	Coleman-Beaverton CG	Improve measurement accuracy	1,048	0					Y
GM-00542	RAY-Run Cntrl Repl, RTU Inst	Ray Compressor	Failed Valve Replacement	-17,071	0					Y
GM-00547	SAG-Summerton Rd GC Upgrade	Summerton Rd	Cancelled order	-287	0					Y
GM-00554	NVL-Gas Sampling System Upgrd	Northville Compressor	Improve Gas Quality Readings	-17,693	0					Y
GM-00555	OVS-FGU Meter Inst (2018)		Settlement costs for prior year project	-80,324	0					Y
GM-00564	JXN-Strg Orifice Mtr Rmvl	Ira Storage	Reclassify old order to O&M/COR at closeout	-1,490,292	0					Y
GM-00596	NVL-500 GrandBlancJnct Meter Repl	Grand Blanc In 500 to 2800	Improve measurement accuracy	39,337	0					Y
GM-00597	NVL-ClarkstonInt USM Inst	Clarkston Jct Interchange	Improve measurement accuracy	15,561	0					Y
GM-00664	KZO-Plainwell VS GC Install	Plainwell VS	Improve measurement accuracy	870	0					Y
GM-00666	JXN-T&S Transducer Repl (2019)	Ray Compression Plant 3	Cancelled order	0	40					Y
GM-00668	JXN-FGU Meter Inst (2019)	Marion Winterfield Storage Field	Improve measurement accuracy	-24,290	-12,053					Y
GM-00670	OVS-Dorr CG Mtr Repl	Dorr CG	Improve measurement accuracy	1,249	1,183					Y
GM-00682	FDM-Spring Arbor CG H2O, H2S Inst	Spring Arbor	Improve measurement accuracy	0	-2,989					Y
GM-00693	NVL-Lyon 29-34 Liquid Handling Ugrd	Lyon	Project Moved to Storage Prg	370	0					Y
GM-00748	OVS-Salem GC, H2O, H2S Inst	Salem CG	Improve Gas Quality Readings	0	-13,762					Y
GM-00754	FDM 34 -Dewitt Township	Dewitt 34 TMS	System Improvements	-17,853	0					Y
GM-00773	MAR - CG H2O & H2S Install	Marion CG	Improve Gas Quality Readings	-119,717	0					Y
GM-00774	MAR - McBain CG H2O & H2S Inst	McBain CG	Improve Gas Quality Readings	-23,079	0					Y
GM-00852	FDM-4070 Vector Ray Msrmt	Ray Compressor	Improve measurement accuracy	202,787	29,372					Y
GM-00853	FDM-4060 Vector Hartland Msrmt	Hartland	Improve measurement accuracy	697,703	581					Y
GM-00878	MAR-Falmouth CG Meter Repl	Falmouth CG	Improve measurement accuracy	15,775	-338					Y
GM-00923	SAG Summerton Rd. Meter Site Rebuild	Summerton RD	Failed Valve Replacement	3,793,918	-18,378					Y
GM-00950	FDM-Chelsea Ln 100A Metering	Chelsea 100A	Improve measurement accuracy	1,480,847	15,684					Y
GM-00964	GRN-Novilla RNG MS Inst	Keene TWP	TMS Site	-211,319	-2,678					Y
GM-00969	JXN-Mosherville CG Meter Run Repl	Mosherville	Improve measurement accuracy	346,418	47,389					Y
GM-00987	FNT-Measurement Training Facility	Bay City Consumers Facility	Training lab for field workers	242,938	79,708					Y
GM-00995	SAG-Grand Blanc Mtr Run Repl	Grand Blanc Junction (Ln 500 to Ln 1900 metering)	Meters that are inoperable. Improve Measurement accuracy and LAUF. Asset life is past its reasonable lifespan. Concrete supports are crumbling and orifice meter is not serviceable anymore. In order to get reliable measurement again and ensure the site remains in a safe condition going forward, this work will need to happen.	12,620	1,285,717	4,844,049		4,320,223	523,827	Y
GM-01024	KZO-1200A White Pigeon ROM	White Pigeon Compressor Station	Improve measurement accuracy and add sectionalized LAUF monitoring on the line. A new meter installation at this valve site will allow us to diagnose and troubleshoot losses on LN 1200A should there ever be losses incurred on this line.	37,698	40,000					Y
GM-01025	KZO- White Pigeon Fuel Meter	White Pigeon Compressor Station	Fuel metering upgrade for emissions monitoring.	26,944	479,463					Y
GM-01047	JXN-Lainsburg Jnc. Meter Inst.	Lainsburg JCT	Improve measurement accuracy and add sectionalized LAUF monitoring on the line. A new meter installation at this valve site will allow us to diagnose and troubleshoot losses on LN 1100 should there ever be losses incurred on this line.	0	899,820	3,497,232	0	3,119,048	378,184	Y
GM-01068	FDM 34- 2024 SVD Cntr Pnl Mod, Inlet Ins	Dewitt 34 TMS	Dewitt 34 TMS customer reimbursable project	0	4,436					Y

CECo Response WP-MPG-3

GM-01084	Perry Morrice Meter Replacement	Perry Morrice	Upgrading is the only option to ensure safe and reliable operating conditions. When an asset is beyond it's lifecycle, the meter will be required to be upgraded to ensure accurate system LAUF measurement. This will also ensure proper odorization based on the flow rate.	0	2,315	866,799	0	773,065	93,734	Y
GM-95000	JXN-FGU Meter Program	Marion Winterfield Storage Field	Improve measurement accuracy.	10,783	9,533					Y
GM-95001	JXN-Transducer Repl Program	Various	Improve measurement accuracy. Capital replacement of measurement transducers that are in disrepair or beyond lifecycle	119,769	-38,564					Y
GM-95004	JXN- 2024 Tranducer Repl Progam	Various	Improve measurement accuracy. Capital replacement of measurement transducers that are in disrepair or beyond lifecycle	0	195,163	453,507	458,682	404,466	458,123	Y
GM-95309	JXN-2023 Measurement Capital Tools	Various	Improve measurement accuracy. Capital replacement of measurement transducers that are in disrepair or beyond lifecycle	273,792	494,072					Y
MICHIGAN PUBLIC SERVICE COMMISSION										Case No. U-21806
Consumers Energy Company										WP-MPG-3
Deliverability Base Field Measurement Program										Page 2 of 2
Project ID	Project	Location	Project Reason	2023 Actual	2024 Projection	2025 Projection	2026 Projection	10 Months Ending 10/30/2025 Projection	12 Months Ending 10/30/2026 Projection	Internal Approval Y/N
B-GM-00037	Measurement Reliability Capital Tools (2025-2029)	Various	Measurement Reliability Capital Tools that are used for a variety of new technology and and tools to support measurement. This could be analyzers for spot sampling to comply with gas tariff, methane detectors for methane surveys, or other tools for compliance related tasks			378,210	382,525	337,311	382,059	Y
GM-95208	Field Measurement		Closeout	-1,281	0					Y
GM-00897	JXN-Grand Ledge CG Building Install (write off)	Grand Ledge	Final reconciliation		-10,000					Y
GM-01089	Williamston Transmission Meter Proving Station	Webberville	Installation of a new testing facility to prove and test transmission meters before installation for compliance with API-1164.		200,000	253,534	8,932,012	226,117	7,993,537	Y
B-GM-00041	Rose Center Meter Replacement	Rose Center City Gate	Upgrading is the only option to ensure safe and reliable operating conditions. When an asset is beyond it's lifecycle, the meter will be required to be upgraded to ensure accurate system LAUF measurement. This will also ensure proper odorization based on the flow rate.			338,799	875,802	302,162	817,731	Y
B-GM-00042	SCADA Gas Quality Hydraulic modeling	Various	SCADA Gas Quality Hydraulic modeling. This will provide an alternative to installation of on-line gas chromatography throughout the system. There will still be a need to install chromatographs at strategic locations.			0	2,264,283	0	2,019,428	Y
B-GM-00043	Northville CS Line 1200 A Meter and Chromatograph Install	Northville Compressor Station	Improve measurement accuracy and add sectionalized LAUF monitoring on the line. A new meter installation at this valve site will allow us to diagnose and troubleshoot losses on LN 1200A should there ever be losses incurred on this line.			0	5,481,969	0	4,889,158	Y
B-GM-00044	Chrysler Tech Meter Replacement	Chrysler Tech	Upgrading is the only option to ensure safe and reliable operating conditions. When an asset is beyond it's lifecycle, the meter will be required to be upgraded to ensure accurate system LAUF measurement. This will also ensure proper odorization based on the flow rate.			0	876,244	0	781,489	Y

Business cases have not been conducted on these projects as field measurement projects are associated with remote gas measurement equipment monitoring, gas volume calculations, gas transmission metering, Transport Metering Station ("TMS"), Interstate Interconnection sites, gas quality improvement and processing, gas sampling systems, and other ancillary equipment. These investments directly impact the Company's ability to conform to the MPSC technical standards concerning natural gas quality, measurement accuracy, and Lost and Unaccounted For ("LAUF") gas.

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Question:

46. Refer to WP-MPG-3 on the Deliverability Base Field Measurement program For projects GM-00995, GM-01047, GM-01089, B-GM-00041, B-GM-00042, BGM-00043, B-GM-00044, B-GM-00045, B-GM-0046, B-GM-00047, B-GM-00048, and GM-01085, please provide the following information for each project:

- a. Provide the current phase of development for the project.
- b. For project 1047, explain the necessity for this project and provide the cost/benefit analysis with calculation in Excel that supports undertaking the project.
- c. For project GM-01089:
 - (i) Identify what the money will be spent on.
 - (ii) Explain fully what the project entails and why it is necessary.
 - (iii) Explain what testing facility is currently being used and why it cannot continue to be used.
 - (iv) Provide the cost/benefit analysis with calculation in Excel that supports undertaking the project.
- d. For projects B-GM-00041, B-GM-00044, B-GM-00045, and GM-01085, identify the problems experienced in the past three years.
- e. For projects B-GM-00042 and B-GM-00043:
 - (i) Identify what the money will be spent on.
 - (ii) Explain fully what the project entails and why it is necessary.
 - (iii) Provide the cost/benefit analysis with calculation in Excel that supports undertaking the project.
- f. For project B-GM-00043, explain the basis and rationale for forecasting spending \$5.5 million for a new meter installation on the expectation that potential gas losses could be incurred in the future on Line 1200A.
- g. For projects B-GM-00046, B-GM-00047, and B-GM-00048, explain the necessity to undertake the initiative for on-line chromatography and provide the cost/benefit analysis with calculation in Excel that supports undertaking the projects.

Response:

- a. See attachment U21806-AG-CE-332-Griffin_ATT_1.
- b. See attachment U21806-AG-CE-332-Griffin_ATT_1.
- c. See attachments U21806-AG-CE-332-Griffin_ATT 1 and U21806-AG-CE-332-Griffin_ATT_2.
- d. See attachment U21806-AG-CE-332-Griffin_ATT_1.

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- e. See attachment U21806-AG-CE-332-Griffin_ATT_1.
- f. See attachment U21806-AG-CE-332-Griffin_ATT_1.
- g. See attachment U21806-AG-CE-332-Griffin_ATT_1.

Witness: MICHAEL P. GRIFFIN

Date: March 10, 2025

CECo Response AG-CE-0332

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Project ID	Project	Project Reason/Necessity	Current Phase	Further Questions/Necessity/Problems Experienced	Project Benefit
GM-00995	SAG-Grand Blanc Mtr Run Repl	Meters that are inoperable. Improve Measurement accuracy and LAUF. Asset life is past its reasonable lifespan. Concrete supports are crumbling and orifice meter is not serviceable anymore. In order to get reliable measurement again and ensure the site remains in a safe condition going forward, this work will need to happen.	Engineering design complete. Contractor bid event in progress.		Orifice meters are not functioning any longer. The Company has been unable to change out the orifice plates. Completing this work will continue to provide interstage flow data to evaluate LAUF. Improvements in measurement accuracy by going with an Ultrasonic meter.
GM-01047	JXN-Lainsburg Jnc. Meter Inst.	Improve measurement accuracy and add sectionalized LAUF monitoring on the line. A new meter installation at this valve site will allow the Company to diagnose, troubleshoot and remediate losses on LN 1100 should there ever be losses incurred on this line.	Engineering design in progress		This is a new Interstage meter installation. Losses in the system are evaluated at a system wide level and a sectionalized level. The reported losses are based on the overall system. If there are losses in the system, sectionalized areas are evaluated to try to solve losses in the system as they occur. A new meter installation at this valve site will allow the Company to diagnose and troubleshoot losses on LN 1100 should there ever be losses incurred on this line.
GM-01089	Williamston Transmission Meter Proving Station	Installation of a new testing facility to prove and test transmission meters before installation for compliance with API-1164.	Engineering design in progress	i. Money will be invested on building a facility that has a lab, live measurement proving area, and associated gas site works. ii. This station will allow a testing environment for gas transmission measurement technology to comply with API-1164, which requires any new protocol, application, or software proposed to be added to the SCADA network should be run in a test-bed or development environment to evaluate the potential for impairing the performance of the SCADA system. Further, the Transportation Security Administration ("TSA") requires the management of software/credentials on measurement devices and a physical testing laboratory with functional versions of all equipment subject to hardware/firmware upgrades to enable testing/validation of firmware in a controlled/non-production environment. The Company currently does not have a test environment for transmission meters or gas analytical equipment. iii. Currently, metering equipment is tested/evaluated for deployment live in the field or at a 3rd party testing facility. Protocol, firmware and cyber security are evaluated at existing facilities. This facility will allow the Company to deploy new equipment in a controlled environment to do extended testing that one cannot get at a third party testing facility without paying a premium price. The facility will also be used for R&D to leverage field support and eliminate vendor costs for commissioning and troubleshooting measurement devices.	This project will allow for capital efficiencies by having a facility that can be utilized for repurposing meters, building gas analysis enclosures/buildings, completing acceptance testing before field deployment, and allow for more robust analysis sampling in an effort to eliminate third party testing facilities. The capital efficiencies are estimated at greater than \$1,000,000 per year after construction is complete. The R&D opportunity will be realized as the Company adapts to new technology and can have a full functioning test bed in house. The projected annual benefits that begin after construction are shown in attachment U21806-AG-CE-332-Griffin_ATT_2.
B-GM-00041	Rose Center Meter Replacement	Upgrading is the only option to ensure safe and reliable operating conditions. When an asset is beyond its lifecycle, the meter will be required to be upgraded to ensure accurate system LAUF measurement. This will also ensure proper odorization based on the flow rate.	Design planned to kick off at end of Q2 2025	The asset has reached the end of its useful life. This site has an orifice meter. Orifice meters are acceptable forms of measurement but not optimal given their age. Operationally, the plates are required to be changed out by operations more periodically. When there are swings in the weather and gas usage is fluctuating, the plates are required to be changed out more frequently. There are a number of orifices at similar age that have been inoperable where plates have not been able to be removed. This is a site that is nearing that timeframe where there will be challenges. This is part of being a proactive steward of the asset and moving to a less maintenance intensive measurement device (Ultrasonic meter measurement)	This project is at a city gate in which having accurate measurement will impact the amount of odorant injected. The meter at this site is nearing the end of its useful life. This project is proactively upgrading metering before failure.
B-GM-00042	SCADA Gas Quality Hydraulic modeling	SCADA Gas Quality Hydraulic modeling. This will provide an alternative to installation of on-line gas chromatography throughout the system. There will still be a need to install chromatographs at strategic locations.	Engineering planned towards the end of 2025	i. Money will be spent to add functionality/additional software to the gas SCADA system by taking inputs of gas quality in the system, building a live gas model of the system, and application of modeled gas quality to sites where there is no gas analysis. ii. At custody transfer sites, high volume stations, and stations with limited gas quality data, gas analysis/gas chromatography is installed. Other operators have been installing analysis equipment at all points of distribution and every measurement site. Currently, the Company takes a system average and applies that to sites with no chromatography data. The LAUF can be negatively impacted by assuming a system average vs having online analysis at each site or a more accurate representative or modeled data. This project plans to deliver more representative gas quality data at each site without having to install live analysis at every site.	See information in the previous column
B-GM-00043	Northville CS Line 1200 A Meter and Chromatograph Install	Improve measurement accuracy and add sectionalized LAUF monitoring on the line. A new meter installation at this valve site will allow the Company to diagnose and troubleshoot losses on LN 1200A should there ever be losses incurred on this line.	Design planned to kick off before the end of Q3 2025	i. Money will be spent to install new Ultrasonic meters and removal of the older orifice meters ii. This site has orifice meters that have reached the end of their useful life. Orifice meters are acceptable forms of measurement but not optimal given their age. Operationally, the plates are required to be changed out by operations more periodically. When there are swings in the weather and gas usage is fluctuating, the plates are required to be changed out more frequently. There are a number of orifices at similar age that have been inoperable where plates have not been able to be removed. This is a site that is nearing that timeframe where there will be challenges. This is part of being a proactive steward of the asset and moving to a less maintenance intensive measurement device (Ultrasonic meter measurement)	See information in the previous column

CECo Response AG-CE-0332

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B-GM-00044	Chrysler Tech Meter Replacement	Upgrading is the only option to ensure safe and reliable operating conditions. When an asset is beyond it's lifecycle, the meter will be required to be upgraded to ensure accurate system LAUF measurement. This will also ensure proper odorization based on the flow rate.	Design planned to kick off in April of 2025	The asset has reached the end of it's useful life. This site has an orifice meter. Orifice meters are acceptable forms of measurement but not optimal given their age. Operationally, the plates are required to be changed out by operations more periodically. When there are swings in the weather and gas usage is fluxuating, the plates are required to be changed out more frequently. There are a number of orifices at similar age that have been inoperable where plates have not been able to be removed. This is a site that is nearing that timeframe where there will be challenges. This is part of being a proactive steward of the asset and moving to a less maintenance intensive measurement device (Ultrasonic meter measurement)	This is at a city gate in which having accurate measurement will impact the amount of odorant injected. The meter at this site is nearing the end of it's useful life. This project is proactively upgrading metering before failure.
B-GM-00045	Eureka CG Meter Replacement	Upgrading is the only option to ensure safe and reliable operating conditions. When an asset is beyond it's lifecycle, the meter will be required to be upgraded to ensure accurate system LAUF measurement. This will also ensure proper odorization based on the flow rate.	Engineering planned to kick off in 2026	The asset has reached the end of it's useful life. This site has an orifice meter. Orifice meters are acceptable forms of measurement but not optimal given their age. Operationally, the plates are required to be changed out by operations more periodically. When there are swings in the weather and gas usage is fluxuating, the plates are required to be changed out more frequently. There are a number of orifices at similar age that have been inoperable where plates have not been able to be removed. This is a site that is nearing that timeframe where there will be challenges. This is part of being a proactive steward of the asset and moving to a less maintenance intensive measurement device (Ultrasonic meter measurement)	This is at a city gate in which having accurate measurement will impact the amount of odorant injected. The meter at this site is nearing the end of it's useful life. This project is proactively upgrading metering before failure.
B-GM-00046	Williamston CG Gas Chromatograph Installation	Initiative to have on-line chromatography data, representative data, or modeled data at every site. This is a site on a targeted list for on-line chromatography	Engineering planned to kick off in 2026	A cost/benefit analysis has not been performed. On line chromatography provides real time energy content and gas compressibility values for the gas. Our program goal is to have real time or representative energy content for every site in order to help in our effort of reducing LAUF. Site selection for real time data is based on high volume stations, custody transfer locations, and areas where there is not good information on the system. All of these sites selected will help provide real time data at these particular measurement sites and representative gas quality to other near by sites. The plan going forward is to utilize gas chromatography installation projects in conjunction with "B-GM-0004" to build representative gas quality throughout the system.	Project benefit explained in previous column.
B-GM-00047	Winterfield 12 Gas Chromatograph Installation	Initiative to have on-line chromatography data, representative data, or modeled data at every site. This is a site on a targeted list for on-line chromatography	Engineering planned to kick off in 2026	A cost/benefit analysis has not been performed. On line chromatography provides real time energy content and gas compressibility values for the gas. Our program goal is to have real time or representative energy content for every site in order to help in our effort of reducing LAUF. Site selection for real time data is based on high volume stations, custody transfer locations, and areas where there is not good information on the system. All of these sites selected will help provide real time data at these particular measurement sites and representative gas quality to other near by sites. The plan going forward is to utilize gas chromatography installation projects in conjunction with "B-GM-0004" to build representative gas quality throughout the system.	Project benefit explained in previous column.
B-GM-00048	Ovid CG Gas Chromatograph Installation	Initiative to have on-line chromatography data, representative data, or modeled data at every site. This is a site on a targeted list for on-line chromatography	Engineering planned to kick off in 2026	A cost/benefit analysis has not been performed. On line chromatography provides real time energy content and gas compressibility values for the gas. Our program goal is to have real time or representative energy content for every site in order to help in our effort of reducing LAUF. Site selection for real time data is based on high volume stations, custody transfer locations, and areas where there is not good information on the system. All of these sites selected will help provide real time data at these particular measurement sites and representative gas quality to other near by sites. The plan going forward is to utilize gas chromatography installation projects in conjunction with "B-GM-0004" to build representative gas quality throughout the system.	Project benefit explained in previous column.
GM-01085	STC-Lahser CG Meter Upgrade	Upgrading is the only option to ensure safe and reliable operating conditions. When an asset is beyond it's lifecycle, the meter will be required to be upgraded to ensure accurate system LAUF measurement. This will also ensure proper odorization based on the flow rate.	Engineering design complete.	The asset has reached the end of it's useful life. This site has an orifice meter. Orifice meters are acceptable forms of measurement but not optimal given their age. Operationally, the plates are required to be changed out by operations more periodically. When there are swings in the weather and gas usage is fluxuating, the plates are required to be changed out more frequently. There are a number of orifices at similar age that have been inoperable where plates have not been able to be removed. This is a site that is nearing that timeframe where there will be challenges. This is part of being a proactive steward of the asset and moving to a less maintenance intensive measurement device (Ultrasonic meter measurement)	This is at a city gate in which having accurate measurement will impact the amount of odorant injected. The meter at this site is nearing the end of it's useful life. This project is proactively upgrading metering before failure.

CECo Response to AG-CE-0332

U21806-AG-CE-332-Griffin_ATT_2								
Williamston Proving/Testing R&D Facility								
Project Benefit Analysis								
<u>Assumptions</u>	1st Year Anticipated Capital Efficiencies							
a) CE to build (1) Gas Analysis Building with internal CE resources		\$ (100,000)						
b) CE-Measurement to build a Gas Sampling Site to eliminate the need for utilization of a 3rd Party Sampling Lab for Manual Gas Sampling		\$ (50,000)						
c) CE to leverage the Facility to standardize and centralize the construction of Gas Analysis by 3rd Party Integrator. The Facility would be equipped with tools, equipment and resources to construct multiple Gas Analysis Bldgs.		\$ (750,000)						
d) Eliminate the need for out-of-state Factory Acceptance Testing "FAT". Current State: CE utilizes (2) Integrators: one in Indiana and the other in West Virginia		\$ (108,000)						
Net 1st Year Efficiencies - Total		\$ (1,008,000)						
Legend								
FAT	CE attends approximately (2) FAT per GA-Bldg./ Assumption is (3) GA-Bldgs. per year							

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Question:

37. Refer to lines 5-23 on page 39 of Mr. Griffin's direct testimony on the Deliverability Base Field Measurement program. Please:

- a. Explain why the capital expenditures for this program are increasing four-fold between 2023 and the projected test year. Provide units, metrics and other information with related dollar amount supporting the increase in spending.
- b. With the large propose spending on field measurement improvements and expected reductions in LAUF, please provide the reduction in LAUF volumes or an approximate percentage reduction expected in the projected test year or by 2026 versus LAUF volumes in 2023.

Response:

- a. There are fluctuations from year to year in the program to account for available resources and scope variances. For instance, a meter build project on a 26" pipeline may have multiple meters with a much higher cost than a meter build project at a city gate site with a single meter at a much smaller size. Larger pipeline meter build projects may have additional scope such as temporary compression instead of venting gas to the atmosphere. All the variances in scope account for some of the variance year to year. The other variance compared to 2023 is the fact that the Company is building a testing and proving facility that will allow a testing environment for gas transmission measurement technology to comply with API-1164, which requires any new protocol, application, or software proposed to be added to the Supervisory Control and Data Acquisition ("SCADA") network should be run in a test-bed or development environment to evaluate the potential for impairing the performance of the SCADA system. My workpaper WP-MPG-3 provides all projects and other information concerning each project along with the associated expenditures for 2023- 2026. See the response to U21806-AG-CE-332 which provides for more information on benefits and project information.
- b. LAUF gas is the loss or gain of gas volumes calculated as the difference between the volumes delivered into the transmission and distribution system less the volumes delivered out of those systems. Factors such as gas leaks, customer billing issues, customer theft, meter and measurement accuracy, and gas vented for operational, maintenance, and safety purposes all contribute to the causes of LAUF gas volumes. Due to the many factors impacting LAUF, the test year volumes related to LAUF are calculated based on a five-year average of actual LAUF volumes, as established by Commission orders. Actions to reduce and circumstances that increase LAUF will be incorporated into the LAUF calculation over time.

Witness: MICHAEL P. GRIFFIN
Date: March 7, 2025

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Question:

329. Refer to ATT_2 to discovery responses AG-CE-0332 on transmission field measurement projects. Please:

- a. Explain what you mean by capital efficiencies. Are the amounts listed in the schedule reductions in capital expenditures or O&M expenses and in which future year or years will they occur?
- b. Explain what item (c) means and how this cost saving would be achieved.
- c. Explain how item (d) is different from item (b).

Response:

- a. Capital efficiencies will be realized primarily by leveraging internal Company resources to perform most of the integration work that is now being conducted by 3rd Party Integrators. The Company will be able to institute stricter quality cost controls and oversight. Currently 3rd Party Integration companies are out of state. The Company will also be able to standardize and employ lean construction methods to build new Gas Analysis-Buildings and re-purpose Legacy Ultrasonic Metering and Gas Analysis-Buildings.

All the amounts are capital expenditure reductions, except for item b) CE Measurement- Gas Sampling Analysis Site. This is a direct O&M expense reduction. Currently, Operations travels to a vendor in Traverse City to obtain lab analysis for Manual Gas Samples. Centralizing at the Williamston site would reduce travel and provide a quicker lab analysis turnaround.

Gas Sampling Analysis Site O&M reductions would be in 2027. The capital reductions would begin in 2027. Besides the efficiencies, as described in my direct testimony, this station will allow a testing environment for gas transmission measurement technology to comply with API-1164, which requires any new protocol, application, or software proposed to be added to the Supervisory Control and Data Acquisition ("SCADA") network should be run in a test-bed or development environment to evaluate the potential for impairing the performance of the SCADA system. Further, the Transportation Security Administration ("TSA") requires the management of software/credentials on measurement devices and a physical testing laboratory with functional versions of all equipment subject to hardware/firmware upgrades to enable testing/validation of firmware in a controlled/non-production environment. The Company currently does not have a test environment for transmission meters or gas analytical equipment.

- b. Currently the 3rd Party integrator performs 100% of the fabrication of the analytical equipment at their out-of-state facilities [Indiana or West Virginia]. The goal of the Williamston facility will be to have 100% of this work to take place in-state. The Company will stock all the required equipment, tools, and materials to construct the Gas Analysis-Buildings at our facility that is currently done at the vendor facility. The Company will also have an overhead crane, a gas analysis

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lab to support not only Factory Acceptance Testing ("FAT") but also Functional Performance Testing. Currently the 3rd Party integrators only provide FAT which confirms the buildings are built to specifications but does not validate that the equipment is functional. The Williamston facility will have "live" gas which will allow the Company to pre-commission the equipment prior to being delivered on site for start-up and commissioning. The vendor does not have "live" gas at their facility. This will allow the Company to use the option to contract the fabrication at the Company site or leverage internal Company resources. The capital cost reductions will be realized with the 3rd Party contractor/integrator only supplying labor.

- c. Item (d) is for the capital reductions realized by eliminating out-of-state travel/expenses. Currently between 3 and 6 employees typically attend the 50% and 100% FAT for each Gas Analysis-Building [estimated 3/year]. By centralizing integration at the Williamston facility, this would greatly reduce the travel/expenses on an annual basis.

Item [b] accounts only for the Gas Sampling Analysis Vendor lab expenses described above (Traverse City) and not the Gas Analysis-Buildings (which are fabricated in West Virginia or Indiana). Further, item [b] details the development of a Gas Sampling Analysis Lab solely dedicated to providing lab analysis for manual gas sampling. Currently the Company's Field Operations personnel collect manual gas samples from identified sites throughout the natural gas system. These samples are then transported to a 3rd Party Lab in Traverse City for analysis and the reporting is emailed to Measurement Reliability & Engineering's ("MR&E") designee and distributed to various internal stakeholders. By developing a Gas Sampling Analysis Site, the process would be streamlined and standardized. The manual gas samples would be bundled and transported to Williamston where MR&E would provide the lab analysis and distribute the reporting in an expedited process. Gas sampling is directly tied to MPSC Technical Standard for Gas Service by ensuring heating value, oxygen, hydrogen sulfide, and water are within tariffs limits.

Witness: MICHAEL P. GRIFFIN

Date: March 31, 2025

CECo WP-MPG-4

Consumers Energy Company										Case No. U-21806
Projected Capital Expenditures for the Capacity/Deliverability Program										WP-MPG-4
Deliverability Base Pipeline Program										Page 1 of 4
Project ID	Project	Location	Project Reason	2023 Actual	2024 Projection	2025 Projection	2026 Projection	10 Months Ending 10/30/2025 Projection	12 Months Ending 10/30/2026 Projection	Internal Approval Y/N
GL-02711	KZO-1200A Hackman Rd VS 1216A Repl	Sturgis	Project from prior years (2021) final reconciliation	22,975	0					Y
GL-02751	SAG-500 Ovid VS Vlv 501x20N Repl	Ovid	20" crossover Valve 501X20N has been determined to be inoperable. Valve does not operate by hand or by operator. Long-term compliance with 49 CFR 192.745(b) requires replacement of the valve. Short-term and medium-term negative impacts to outage execution and pipeline emergency response on Line 100A, Line 500, and Ovid City Gate.	-74,123	-54,663	2,275,786		1,983,070	292,716	Y
GL-02771	OVS-1100 Pipe Repl 24108-24679	Grand Ledge	Class location change on Line 1100 that results in 571' of pipe needing to be replaced. Between GIS Station 24108 and 24679. (49 CFR 192.611)	7,758	3,226					Y
GL-02773	STC-McmbVS Vlv 1715E,1714 Rep	Macomb	Project from prior years (2021) final reconciliation	239	255					Y
GL-02775	SAG-100A Pipe Repl 30454-30863	Rosebush	Project completed in 2022, asset in-service and restoration in 2023 Class location change on Line 100A that results in 408' of pipe needing to be replaced. Between GIS Station 30454 and 30863. (49 CFR 192.611)	-125,939	0					Y
GL-02776	SAG-100A Pipe Repl 95442-95924	Perry	Project from prior years (2021) final reconciliation	10,559	0					Y
GL-02777	SAG-100A Pipe Repl 9113-9750	Mt Pleasant	Project completed in 2022, asset in-service and restoration in 2023 Class location change on Line 100A that results in 637' of pipe needing to be replaced. Between GIS Station 9113 and 9750. (49 CFR 192.611)	114,253	5,196					Y
GL-02778	SAG-100C Pipe Repl 571095-571833	Mt Pleasant	Project completed in 2022, asset in-service and restoration in 2023 Class location change on Line 100C that results in 738' of pipe needing to be replaced. Between GIS Station 571095 and 571833. (49 CFR 192.611)	-282,956	16,234					Y
GL-02779	SAG-100C Pipe Repl 592488-592795	Clare	Class location change on Line 100C that results in 405' of pipe needing to be replaced. Between GIS Station 592488 and 592795. (49 CFR 192.611)	593,065	48,260					Y
GL-02837	STC-1600 Evergreen VS Vlv #1628 Rpl	Royal Oak	Project from prior years (2021) final reconciliation	-272,551	0					Y
GL-02838	NVL-1200A Northville CS Vlv #1273 Rpl	Northville	Valve #1273 could not hold gas pressure greater than 30 psig in a closed position last year. This leakage problem caused many leak calls and created masking problems. Replace Valve 1273 to allow for the replacement of Valve #1610.	7,647	5,639					Y
GL-02839	NVL-1600 Northville CS Vlv #1610 Rpl	Northville	Project from prior years (2021) final reconciliation	305,670	0					Y
GL-02851	SAG-700 Dutch Rd 6in LR Drain Vlv Repl	Saginaw	Project from prior years (2021) final reconciliation	0	351					Y
GL-02852	SAG-300 Woodcock Rd VS Vlv 309-12 Repl	Midland	Replace 12" mainline sectionalizing Valve 309-12 at Woodcock Road Valve Site, Line 300. Valve 309-12 has significant sealing issues and has caused isolation problems during planned outages.	1,106,354	1,052					Y
GL-02853	OVS-1300 Plainwell VS Vlv 6GSV3 Repl	Plainwell	Project from prior years (2020) final reconciliation	2,759	0					Y

CECo WP-MPG-4

Consumers Energy Company Projected Capital Expenditures for the Capacity/Deliverability Program Deliverability Base Pipeline Program										Case No. U-21806 WP-MPG-4 Page 2 of 4
Project ID	Project	Location	Project Reason	2023 Actual	2024 Projection	2025 Projection	2026 Projection	10 Months Ending 10/30/2025 Projection	12 Months Ending 10/30/2026 Projection	Internal Approval Y/N
B-GL-00245	Line 500 - Torrey Road VS - Valve 504-26 & Dual Tap Valve Replacement	Grand Blanc	Valve 504-26 has been identified as a difficult valve to isolate with. Recommended for replacement by operations. Replace mainline valve, tap valves and adjacent piping in conjunction with city gate rebuild.		159,398	929,821	0	810,225	119,595	Y
B-GL-00247	Line 2800 - Bridgeport VS Drain Vlv Repl	Bridgeport	Within the Problem Valve Database, a LR drain valve has been recommended for replacement by operations. This valve has been identified as leaking by.			21,133	0	18,415	2,718	Y
B-GL-00249	Line 300 - Muskegon River CS 301-T12 Replacement	Marion	Within the Problem Valve Database, Valve 301-T12 has been recommended for replacement by operations. It has been identified as leaking by.		159,398	489,294	0	426,360	62,934	Y
B-GL-00250	Line 300 - Coleman Beaverton LR Drain Vlv Replacement	Coleman	Within the Problem Valve Database, the drain valve at Coleman Beaverton has been recommended for replacement by operations. One of the Drain Valves on the Launcher/Receiver at Coleman Beaverton Valve Site has been identified as causing issues during the integrity inspections.			21,133	0	18,415	2,718	Y
B-GL-00251	Line 400 - FDM Laingsburg Int Vlv 401-24 Repl	Laingsburg	Within the Problem Valve Database, valve 401-24 at Laingsburg Interconnect has been recommended for replacement by operations. This valve have been identified as leaking by, and needs to be replaced.		159,398	1,791,281	0	1,560,883	230,398	Y
GL-03323	Line 400 - FDM Perry-Morrice Mainline Vlv and Dual Tap Inst.	Morrice	Perry-Morrice is a critical facility to improve the resiliency of. This site cannot take an outage at anytime in the year, and the load in fall, winter and spring is too high to reasonably supply temporary gas with a CNG or even LNG trailer. Installation of one 24" mainline valve, two 4" tap valves and associated piping at Perry Morrice City Gate in order to improve gas deliverability.		159,398	2,625,002	0	2,287,369	337,633	Y
GL-03473	Line 400 - FDM Bancroft VLV 402S-24 Repl and check valves	Morrice	Within the Problem Valve Database, valve 402S-24 has been recommended for replacement by operations. This valve have been identified as leaking by, and needs to be replaced.		159,398	1,463,005	0	1,274,830	188,175	Y
B-GL-00255	Line 1100 - FDM Laingsburg Valve 1162 and bypass removal	Laingsburg	Valve 1162 has been reported by operations as not sealing. This valve is redundant and can be cut out and replaced with a pup piece. Removal of the bypass installed with meter run project.			650,224	0	566,591	83,633	Y
B-GL-00259	Line 1200A - Chelsea to Hellner Valve Spacing VS INST (Valve Site Installation d	TBD	Valve spacing study has indicated a new sectionalizing block valve is needed between Chelsea and Hellner on Line 1200A. (49 CFR 192.179)			0	2,358,401	0	2,055,058	Y
B-GL-00260	Line 700 - St Louis 701-26 Repl, 701X20S Act Repl	St Louis	Within the Problem Valve Database, Valve 701-26 has been recommended for replacement by operations. This valve has been identified as leaking by, and needs to be replaced.			0	986,906	0	859,968	Y
B-GL-00261	Line 100B - St Louis VS Vlv 115-26N 8GSV2 and Drain Vlv Repl	St Louis	Within the Problem Valve Database, two gas supply valves and Valve 115-26N have been recommended for replacement by operations. These valves have been identified as leaking by, and need to be replaced to allow for integrity inspections.			0	1,572,267	0	1,370,039	Y
B-GL-00262	FDM 1200B Hanover Horton CG Vlv 1252B Repl and RCV	Horton	Within the Problem Valve Database, valve 1252B at Hanover Horton has been recommended for replacement by operations. This valve have been identified as leaking by, and needs to be replaced.		159,398	0	2,515,627	0	2,192,062	Y
B-GL-00263	Line 100A SAG Muskegon River CS Vlv 101x16 Repl, drain valve	Marion	Within the Problem Valve Database, valve 101x16 at Muskegon River CS has been recommended for replacement by operations. This valve have been identified as leaking by, and needs to be replaced.			0	1,886,721	0	1,644,047	Y
B-GL-00264	Line 100B - Mission Rd Vlv INST (Valve Site Installation due to valve spacing \$1	Mt Pleasant	Valve spacing study has indicated a new sectionalizing block valve is needed between Mt Pleasant and Herrick on Line 100B. (49 CFR 192.179)			0	1,572,267	0	1,370,039	Y
B-GL-00265	Line 100B - Farwell Mainline Inst (Valve Installation due to valve spacing \$192.	Farwell	Valve spacing study has indicated a new sectionalizing block valve is needed at Farwell VS on Line 100B. (49 CFR 192.179)			0	2,358,401	0	2,055,058	Y

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Projected Capital Expenditures for the Capacity/Deliverability Program										WP-MPG-4
Deliverability Base Pipeline Program										Page 4 of 4
Project ID	Project	Location	Project Reason	2023 Actual	2024 Projection	2025 Projection	2026 Projection	10 Months Ending 10/30/2025 Projection	12 Months Ending 10/30/2026 Projection	Internal Approval Y/N
8-GL-00266	Three Valve Replacements in 2026 due to inoperability	TBD	Valve Replacement projects due to inoperability (2026)			0	3,249,876	0	2,831,870	Y
8-GL-00267	2026 replacement due to MAOP Revision (Class Location Change - 192.611)	TBD	Replace piping in order to ensure pipeline can continue to operate at current MAOP despite increase in Class Location due to population density change. Line number and location TBD.			0	2,279,787	0	1,986,556	Y
8-GL-00270	OVS 1100 30th St VS Vlv 1116 & 1118 Repl and RCV	Hamilton	Within the Problem Valve Database, valves 1116 and 1118 at 30th St VS has been recommended for replacement by operations. These valves have been identified as leaking by, and needs to be replaced. These valves are also on the RCV program list and will become RCV capable at this time.			1,788,117	0	1,558,126	229,991	Y
8-GL-00276	Line 1200B Lutes Valve 1226B Cut out	Girard Twp	Within the Problem Valve Database, valve 1226B is inoperable, but redundant. Cut out the valve and replace with a pup piece.			0	314,453	0	274,008	Y
8-GL-00277	Line 2080 Thetford VS Drain Valve Repl	Thetford	Within the Problem Valve Database, the drain valve at Thetford VS has been recommended for replacement by operations. This valve has been identified as inoperable, and needs to be replaced.			0	20,440	0	17,811	Y
8-GL-00278	Line 1600 Novi Wixom Valve 1616 Repl	Novi	Within the Problem Valve Database, valve 1616 at Novi Wixom has been recommended for replacement by operations. This valve has been identified as leaking by, and needs to be replaced.			0	1,021,974	0	890,525	Y
8-GL-00280	SAG - Line 2100 Carpenter Rd. VS Valves 2114E, 2114, 8GSV2, 8" BDV Repl	Davison	Within the Problem Valve Database, valve 2114, 2114E, 8GSV2 and an 8" BDV have been identified to leak by. Short-term and medium-term negative impacts to inspection on Line 2100.			0	2,122,561	0	1,849,553	Y
GL-02101	OVS-1800 30th St VS Vlv 1810 Repl	Hamilton	Retire 20" mainline sectionalizing Valve 1810 at 30th Street Valve Site, Line 1800. Valve has sealing issues. Valve 1810 is redundant with Valve 1810S, and is a candidate for retirement and replacement with a spool piece.			832,287	0	725,237	107,050	Y
GL-03029	STC-Macomb VS Vlv 1528 Repl Inst RCV	Macomb	26" mainline sectionalizing Valve 1528 is inoperable in the open position. Long-term compliance with 49 CFR 192.745(b) requires replacement of the valve. Also operator issues have been identified on 26" 1526W; Short-term and medium-term negative impacts to outage execution and pipeline emergency response on Lines 1500 and 1700.			1,133,016	0	987,285	145,731	Y
GL-03047	KZO-1200A,B MndnLeon 4in Tap Vlv Repl	Bronson	Replacement of 1223A, 4" tap valves and associated piping from Lines 1200A and 1200B. In support of Mendon-Leonidas City Gate rebuild by M&R. To improve reliability and gas deliverability on Lines 1200A, 1200B, and Mendon-Leonidas City Gate. Valve 1223A does not seal and leaks by.			0	1,702,766	0	1,483,752	Y
GL-03289	STC- 1500 Valve Spacing VS Inst	New Baltimore	Valve spacing study has indicated a new sectionalizing block valve is needed between St Clair and Macomb on Line 1500. (49 CFR 192.179)			1,949,048	0	1,698,358	250,691	Y
GL-03313	FDM-1100 Clintonia VS Vlv 1148 1148E Repl	Portland	Within the Problem Valve Database, valves 1148 at Clintonia VS has been identified as inoperable and is recommended for replacement by operations. Valve 1148E has been identified as leaking by, and needs to be replaced.			0	1,466,926	0	1,278,247	Y
GL-03317	SAG-1900 Leonard Lkville Vlv & Dual Tap	Leonard	Replacement of one 26" mainline valve, two 12" tap valves and associated piping at Leonard-Lakeville City Gate in support of CG rebuild and in order to improve gas deliverability.			2,348,936	0	2,046,811	302,125	Y
GL-03319	SAG-2800 Grand Blanc Jct Viv Repl	Grand Blanc	Valve 506-26 has been identified as a difficult valve to isolate with. Both valve 506-26 and 8GSV2 recommended for replacement by operations.		159,398	1,524,777	0	1,328,657	196,120	Y
GL-03482	Line 1500 - STC Shelby VS Vlv 1522 Repl (GL-03482)	Shelby Twp	Within the Problem Valve Database, valve 1522 at Shelby VS has been recommended for replacement by operations. This valve have been identified as leaking by, and needs to be replaced.		159,398	798,150	0	695,491	102,660	Y
GL-03489	Line 700 - SAG Thomas Twp VS Vlv 705-26 Repl (GL-03489)	Thomas Twp	Within the Problem Valve Database, valve 705-26 at Thomas Twp VS has been recommended for replacement by operations. This valve have been identified as leaking by, and needs to be replaced.		159,398	1,625,561	0	1,416,478	209,083	Y
				18,756,525	18,173,004	22,266,570	25,429,371	19,402,599	25,022,565	

Business cases have not been conducted on projects. Projects in this program are in accordance with Michigan Gas Safety Standards as explained in my direct testimony.

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Question:

47. Refer to WP-MPG-4 on the Deliverability Base Pipeline program. For projects GL-02751, B-GL-00251, GL-03323, GL-03473, B-GL-00259, B-GL-00260, B-GL- 00261, B-GL-00262, B-GL-00263, B-GL-00264, B-GL-00265, B-GL-00266, B-GL-00267, B-GL-00270, B-GL-002678, B-GL-00280, GL-03047, GL-03289, GL-03313, GL-03317, GL-03482, and GL-03489, please:

- a. Provide the current phase of development for the project.
- b. For valves that are leaking, provide the month and year when the company first discovered that the valve was leaking.
- c. There are at least 13 valves that were reported to be leaking in WPMPG-4. Including the projects listed above. Has the Company evaluated repairing some or all of the valves being replaced at potentially a lower cost? If yes, provide the detailed analysis. If no, explain why not.
- d. Some of the projects identified above pertain to replacement of the inoperable valves. Explain why those valves are inoperable, how often the Company lubricated those valves, and what other preventive maintenance was performed to ensure valves would continue to be operable.
- e. With regard to project GL-03323, what is the current problem with the Perry-Morrice facility and when did it start? How does installation of the 24" valve solve the problem? What other less costly alternatives were evaluated?
- f. For project GL-03317, what is the current problem and how does replacement of the current 26" mainline valve with two 12" tap valves solves the problem. What other less costly alternatives were evaluated?

Response:

- a. See table below. In general, project work begins the year ahead of construction and allows for survey, engineering, and design to be completed. Construction is typically the second year of the project, and the year in which the greatest amount of spending occurs.
- b. See table below.

Project ID	Project	a. Project Phase	b. Month Reported
GL-02751	SAG-500 Ovid VS Vlv 501x20N Repl	This project is in the engineering and design phase, with construction planned for 2025.	N/A
B-GL-00251	Line 400 - FDM Laingsburg Int Vlv 401-24 Repl	This project has since been canceled and is being replaced with GL-03313 below. This was canceled due to a second round of repairs on the valve being successful.	
GL-03323	Line 400 - FDM Perry-Morrice Mainline Vlv and Dual Tap Inst.	This project is in the engineering and design phase, with construction planned for 2025.	N/A
GL-03473	Line 400 - FDM Bancroft VLV 402S-24 Repl and check valves	This project is in the engineering and design phase, with construction planned for 2025.	August 2023

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B-GL-00259	Line 1200A - Chelsea to Hellner Valve Spacing VS INST (Valve Site Installation)	Work has not begun for this project. Construction is planned for 2026 with engineering and design kicking off in summer of 2025.	N/A
B-GL-00260	Line 700 - St Louis 701-26 Repl, 701X20S Act Repl	Work has not begun for this project. Construction is planned for 2026 with engineering and design kicking off in summer of 2025.	April 2023
B-GL-00261	Line 100B - St Louis VS Vlv 115-26N 8GSV2 and Drain Vlv Repl	Work has not begun for this project. Construction is planned for 2026 with engineering and design kicking off in summer of 2025.	March 2021
B-GL-00262	FDM 1200B Hanover Horton CG Vlv 1252B Repl and RCV	Work has not begun for this project. Construction is planned for 2026 with engineering and design kicking off in summer of 2025.	May 2020
B-GL-00263	Line 100A SAG Muskegon River CS Vlv 101x16 Repl, drain valve	Work has not begun for this project. Construction is planned for 2026 with engineering and design kicking off in summer of 2025.	December 2021
B-GL-00264	Line 100B - Mission Rd Vlv INST (Valve Site Installation due to valve spacing §1	Work has not begun for this project. Construction is planned for 2026 with engineering and design kicking off in summer of 2025.	N/A
B-GL-00265	Line 100B - Farwell Mainline Inst (Valve Installation due to valve spacing §192.	Work has not begun for this project. Construction is planned for 2026 with engineering and design kicking off in summer of 2025.	N/A
B-GL-00266	Three Valve Replacements in 2026 due to inoperability	There is no current phase for this project. This funding is requested for critical valves discovered as inoperable	N/A

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		during the 2025 inspection season.	
B-GL-00267	2026 replacement due to MAOP Revision (Class Location Change - 192.611)	There is no current phase for this project. This funding is requested for class location change projects identified during the 2025 studies.	N/A
B-GL-00270	OVS 1100 30th St VS Vlvs 1116 & 1118 Repl and RCV	This project is in the engineering and design phase, with construction planned for 2025.	February 2022
B-GL-002678	There is no project with this number.	N/A	N/A
B-GL-00280	SAG - Line 2100 Carpenter Rd. VS Valves 2114E, 2114, 8GSV2, 8" BDV Repl	Work has not begun for this project. Construction is planned for 2026 with engineering and design kicking off in summer of 2025.	June 2020
GL-03047	KZO-1200A,B MndnLeon 4in Tap Vlvs Repl	Work has not begun for this project. Construction is planned for 2026 with engineering and design kicking off in summer of 2025.	N/A
GL-03289	STC- 1500 Valve Spacing VS Inst	This project is in the engineering and design phase, with construction planned for 2025.	N/A
GL-03313	FDM-1100 Clintonia VS Vlv 1148 1148E Repl	This project is in the engineering and design phase, with construction planned for 2025. This project was pulled forward with the cancellation of B-GL-00251 due to the high priority of the inoperable valve. B-GL-00274 has been pulled forward to fill this gap in 2026, which is also a replacement of a critical inoperable valve.	August 2020
GL-03317	SAG-1900 Leonard Lkville Vlv & Dual Tap	This project is in the engineering and design phase, with construction planned for 2025.	N/A

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GL-03482	Line 1500 - STC Shelby VS Vlv 1522 Repl (GL-03482)	This project is in the engineering and design phase, with construction planned for 2025.	April 2022
GL-03489	Line 700 - SAG Thomas Twp VS Vlv 705-26 Repl	This project is in the engineering and design phase, with construction planned for 2025.	March 2021
B-GL-00274	Line 2700/1700 - 31 Mile Rd VS 2710, 2712, 1712S Repl	Work has not begun for this project. Construction is planned for 2026 with engineering and design kicking off in summer of 2025. Project Reason: Valves 2710 and 2712 have been identified by operations to have sealing issues, and valve 1712S has been identified as inoperable. Projected 2026 cost: \$1,572,267 and \$1,370,039 in the test year 12 Months Ending October 31, 2026	July 2022

- c. Onsite repairs were attempted on these valves. Onsite repair options include flushing the valve with new grease, replacing grease fittings, and resetting the stops. Other than the repairs mentioned, the other option is to send the valve back to the manufacturer to attempt internal repairs. Sending a valve into a manufacturer to disassemble and repair valves from the inside has been deemed to have a low success rate and costly. This also requires a replacement of the current in-service valve while the manufacturer attempts a repair. Internal repairs cannot be done in-house because the company does not possess an API-6D monogram to recertify the valves once they have been modified. A replacement project was created once it was determined the repairs were unsuccessful.
- d. A valve is designated as inoperable once all attempts to maintain and repair the valve have been unsuccessful and the valve cannot be operated via an electric or pneumatic actuator, or by manual operation. The Company performs an annual inspection on each pipeline valve. During this annual inspection, the Company operates the valve, flushes out the grease, and/or adjusts the stops, as needed.
- e. Perry-Morrice CG is a critical facility that does not currently have a mainline valve or dual taps. When Line 400 is removed from service in this area, there is no way to maintain feed to Perry-Morrice CG. This CG cannot take an outage at any time in the year and would require temporary feed if an outage occurs on Line 400. The load in fall, winter and spring is too high to reasonably supply with temporary gas. This was a slow growing issue that has developed over time, as the demand grew with growth on the distribution system downstream of Perry Morrice CG. The

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installation of a mainline valve and dual taps will improve deliverability because it will give the Company the option to continue to feed Perry-Morrice CG if either portion of Line 400 needs an outage to the west or the east. The other alternatives evaluated, build a new city gate in the area to feed this distribution system or continue to use temporary gas each time that Line 400 needs to take an outage, were both more costly than installing a mainline and dual tap.

- f. This project is necessary to remove aging and unreliable assets on our system and improve system deliverability at Leonard-Lakeville CG. The Line 1900 valves at Leonard Lakeville CG were installed with the original 1900 pipeline installation back in 1968. The installation of a new mainline valve and dual taps will improve deliverability and reliability. This project will allow the company to rely on fully operational and sealing valves to continue to feed Leonard Lakeville CG if either portion of Line 1900 takes an outage to the west or the east. There is no alternative available for improving deliverability at this site by replacing these aging assets.

Witness: MICHAEL P. GRIFFIN

Date: March 7, 2025

CCECo WP-MPG-6

MICHIGAN PUBLIC SERVICE COMMISSION										Case No. U-21806	
Consumers Energy Company										WP-MPG-6	
Capacity/Deliverability Program - City Gate Projects										Page 1 of 3	
Project ID	Project Description	Order	Location	Reason for Project	2023 Actual	2024 Projection	2025 Projection	2026 Projection	10 Months Ending 10/30/2025 Projection	12 Months Ending 10/30/2026 Projection	Internal Approval Y/N
GM-00941	OVS-Dorr CG Rbld	39997759	Dorr	Planned 2024 rebuild, 1965 original build	503,990	2,578,000	50,000		44,412	5,588	Y
GM-00942	KZO- Galesburg CG Rbld	40213320	Kalamazoo	Planned 2024 rebuild, 60+ year old facility at the end of its designed life.	1,791,768	4,561,600	50,000		44,412	5,588	Y
GM-00943	STC-Orion CG Rbld	39924024	Lake Orion	2024 construction project, 1955 Build	887,891	11,941,758	50,000		44,412	5,588	Y
GM-00944	JXN-Park Rd CG ESD Inst	41700070	Jackson	2024 construction project, Installation of fail closed ESD valves for enhanced overpressure protection.	28,895	744,972	50,000		44,412	5,588	Y
GM-00951	JXN-PEPL-Blissfield CG Rbld	40187839	Riga	Planned 2024 rebuild, Installation of new city gate to serve our existing customers. Resolution to MPSC to own, operate and maintain the overpressure protection device which protects our distribution system.	1,216,665	9,478,994	50,000		44,412	5,588	Y
GM-00955	SAG M&R Temp Skid 2 Valve Repl	39995890	Various	Planned 2022 rebuild to support temporary regulation for future construction	7,842	0			0	0	Y
GM-00956	JXN-Reg Trailer 1 Build	40191448	Various	Planned 2023 to support temporary regulation for future construction	228,645	0			0	0	Y
GM-00957	JXN-Reg Trailer 2 Build	40191455	Various	Planned 2023 to support temporary regulation for future construction	40,250	7,211			0	0	Y
GM-00958	JXN-Reg Trailer 3 Build	40191453	Various	Planned 2023 to support temporary regulation for future construction	47,306	-1,221			0	0	Y
GM-00959	JXN-Reg Trailer 4 Build	40191452	Various	Planned 2023 to support temporary regulation for future construction	30,820	0			0	0	Y
GM-00960	JXN-Reg Trailer 5 Build	40191450	Various	Planned 2023 to support temporary regulation for future construction	33,250	0			0	0	Y
GM-00965	KZO-M Ave CG F-S Install	40116897	Oshtemo	Planned 2022 rebuild to support liquid removal and gas system health	63,391	0			0	0	Y
GM-00966	KZO-Climax CG Valve Repl	40563617	Climax	Planned 2022 rebuild of failed valves	5,697	156			0	0	Y
GM-00976	ALM-St. Louis VS RTU, Bldg Rep	40019478	St Louis	RTU-Elect Upgrade and safety related constructions associated with sinking building	1,249,972	6,698			0	0	Y
GM-00979	STC-Pontiac Wlton CG ESD Inst	40645212	Auburn Hills	Planned 2023 Rebuild to modernize overpressure protection	681,104	5,108			0	0	Y
GM-00994	STC-Leonard-Lakeville City Gate Rbld	41317268	Leonard	Planned 2024 Rebuild, 1970 build	671,526	8,857,383	301,293		267,622	33,671	Y
GM-00996	FDM-Bancroft CG Rbld	41332319	Morrice	Planned 2025 Rebuild, 1962 Build	155,938	1,214,079	8,412,078	305,166	7,471,975	1,211,165	Y
GM-00997	STC-Lasher CG ESD Vlv Inst	41332540	Beverly Hills	Planned 2025 Project, Installation of fail closed ESD valves for enhanced overpressure protection.	28,035	85,434	1,106,157	40,497	982,537	159,591	Y
GM-00999	STC- Pontiac Walton CG Cat Htr Repl	41345968	Auburn Hills	Planned 2024 catalytic heater installations to protect instrumentation to provide service	20,930	0			0	0	Y
GM-01000	STC-Metamora CG Cat Htr Inst	41345973	Oxford	Planned 2024 catalytic heater installations to protect instrumentation to provide service	5,232	0			0	0	Y
GM-01004	FDM-Dexter CG Reg Repl	41424130	Dexter	Planned 2024 replace obsolet regulator	47,460	565			0	0	Y
GM-01005	JXN-Grasslake CG Fence Driveway Inst	41382682	Grass Lake	Project cancelled in 2023	600	0			0	0	Y
GM-01006	OVS-Mid-Cal CG Vlv Repl	41564527	Middleville	Carry over from prior year project	12,780	245			0	0	Y
GM-01019	STC-Dixie-Waterford CG Vlv Repl	41858919	Clarkston	2026 construction project	872	40,636			0	0	Y
GM-01020	SAG-Flint CG-Branch Rd Vlv Repl	42865404	Flint	2024 valve replacement of failing valve	0	44,000			0	0	Y
GM-01021	FDM-Hanover Horton CG Valve Repl	41930157	Hanover	2024 valve replacement of failing valve	0	5,965			0	0	Y
GM-01052	JXN-Jxn Hart Rd CG Rbld	42496744	Jackson	2025 construction project 1968 Asset at the end of its designed life.	0	788,039	8,371,412	305,166	7,435,854	1,206,620	Y
GM-01054	FDM-Hanover Horton CG Rbld	42650854	Horton	2025 construction project 1963 Asset at the end of its designed life.	0	580,982	6,671,034	305,166	5,925,504	1,016,592	Y
GM-01055	SAG-Flint Torrey Rd CG Rebl	42653954	Flint	Planned 2025 rebuild, 1963 Asset at the end of its designed life.	0	1,061,827	7,655,511	305,166	6,799,959	1,126,614	Y
GM-01056	NVL-Highland CG, Odorizer Rbld	42707627	Highland	2025 construction project 1962 Asset at the end of its designed life.	0	880,156	8,747,804	305,166	7,770,182	1,248,684	Y

CCEo WP-MPG-6

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Capacity/Deliverability Program - City Gate Projects										Page 2 of 3	
Project ID	Project Description	Order	Location	Business Case	2023 Actual	2024 Projection	2025 Projection	2026 Projection	10 Months Ending 10/30/2025 Projection	12 Months Ending 10/30/2026 Projection	Internal Approval Y/N
GM-01061	FDM-Laingsburg CG ESD Vlv Inst	42824337	Laingsburg	Planned 2025 Modernization of overpressure protection	0	1,050,000	266,057	40,497	236,323	65,705	Y
GM-01078	STC-Macomb CG ESD Repl	43248849	Macomb	2025 construction project Modernization of overpressure protection	0	100,981	1,106,157	40,497	982,537	159,591	Y
GM-01088	GM-01088 STC-Holly CG Vlv H3 Repl		Holly	Replacement of failing valve		100,000			0	0	Y
B-GL-00300	2025 BMS Retrofits-Pinckney City Gate		Various	Modernization of heater relighters to provide consistant heating of gas			41,197	-	36,593	4,604	Y
B-GL-00301	MT. PLEASANT CG (M-9) RTU & BMS-2025		MT Pleasant	Modernization of heater relighters to provide consistant heating of gas			235,287	23,137	208,992	46,846	Y
B-GL-00302	2026-Livingston Rd VS RTU		Highland	Replacement of obsolete sixnet device			-	283,778	0	252,064	Y
B-GL-00304	2026 Novi Wixom CG ESD Valve & BMS		Novi	Modernization of heater relighters to provide consistant heating of gas			151,862	1,658,139	134,890	1,489,803	Y
B-GL-00305	2026 NORTHVILLE COMPRESSOR STATION RTU UPGRADE		Northville	Replacement of obsolete sixnet device and consolidation of multiple RTU systems			266,184	2,733,377	236,437	2,457,653	Y
B-GL-00306	2026 Spring Arbor CG - PEPL & Odorizer		Spring Arbor	Rebuild 1961 Asset at the end of its designed life.			987,100	8,725,866	876,786	7,861,010	Y
B-GL-00307	2026 Flint CG Irish & Odorizer		Flint	Rebuild 1973 asset at the end of its designed life.			987,100	8,320,811	876,786	7,501,222	Y
B-GL-00308	2026 Dixie Waterford ESD & RTU		Clarkston	Modernization of over pressure protection and electrical equipment			42,521	1,190,717	37,769	1,062,399	Y
B-GL-00309	2026 Climax CG - PEPL		Climax	rebuild of 1980 asset at the end of its designed life.			850,425	9,627,954	755,385	8,647,010	Y
B-GL-00310	2026 South Lyon - Whitmore Lake CG & Odorizer		South Lyon	rebuild of 1956 asset at the end of its designed life.			531,516	8,840,790	472,115	7,912,176	Y
B-GL-00311	2026 CLINTON (PEPL) (CP-1)		Clinton	Replacement of obsolete sixnet device			87,109	536,601	77,374	486,367	Y
B-GL-00312	2026 COLEMAN-BEAVERTON RTU & BMS		Coleman	Replacement of obsolete sixnet device & heater relighter moderinzation			75,931	410,456	67,445	373,071	Y
B-GL-00313	2026 COOLIDGE CG (C-9) RTU & BMS		Royal Oak	Replacement of obsolete sixnet device & heater relighter moderinzation			75,931	410,456	67,445	373,071	Y
B-GL-00314	2026 GRAND LEDGE CG (G-11) RTU & BMS		Grand Ledge	Replacement of obsolete sixnet device & heater relighter moderinzation			75,931	410,456	67,445	373,071	Y
B-GL-00315	2026 MIDLAND CG (M-7) RTU & BMS		Midland	Replacement of obsolete sixnet device & heater relighter moderinzation			75,931	410,456	67,445	373,071	Y
B-GL-00316	2026 NORTH LYON CG RTU & BMS		Wixom	Replacement of obsolete sixnet device & heater relighter moderinzation			75,931	410,456	67,445	373,071	Y
B-GL-00317	2026 Mendon Leonidas & Odorizer		Bronson	Rebuild of 1966 asset at the end of its designed life.			531,516	9,627,954	472,115	8,611,369	Y
B-GL-00318	2027 31 Mile Rd. VS		Ray	Replacement of obsolete sixnet device			-	76,841	0	68,254	Y
B-GL-00319	2027 MUSKEGON RIVER COMPR STA RTU UPGRADE		Marion	Replacement of obsolete sixnet device			-	130,869	0	116,244	Y
B-GL-00320	2027 Schoolcraft CG & Odorizer		Schoolcraft	Rebuild 1969 Asset at the end of its designed life			-	998,937	0	887,299	Y
B-GL-00321	2027 Sheldon ESD & MAOP Gap		Plymouth	Modernization of overpressure protection and recertification of MAOP			-	43,031	0	38,222	Y
B-GL-00322	2027 Mid-Cal ESD		Middleville	Modernization of overpressure protection			-	43,031	0	38,222	Y
B-GL-00323	2027 DCP MATTHEWS RD RTU			Replacement of obsolete sixnet device			-	72,576	0	64,465	Y
B-GL-00324	2027 DUTTON RD VS RTU		Rochester Hills	Replacement of obsolete sixnet device			-	72,576	0	64,465	Y
B-GL-00325	2027 Evon Rd. Valve Site RTU		Saginaw	Replacement of obsolete sixnet device			-	72,576	0	64,465	Y
B-GL-00326	2027 MIDDLEVILLE CG (M-6) RTU		Middleville	Replacement of obsolete sixnet device			-	72,576	0	64,465	Y
B-GL-00327	2027 Shepherd & Odorizer		Shephard	Rebuild of 1959 Asset at the end of its designed life			-	998,937	0	887,299	Y

U21806-AG-CE-0335

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Question:

49. Refer to WP-MPG-6 on City Gate projects. For projects GM-00996, GM-01052, GM-01054, GM-01055, GM-01056, B-GL-00304, B-GL-00305, B-GL-00306, BGL- 00307, B-GL-00308, B-GL-00309, B-GL-00310, and B-GL-00317, please provide the following information:

- a. The current phase of development for the project.
- b. Other than approaching end of life, is the gate station operating well? What problems are currently being experienced with the gate station.
- c. Provide the cost/benefit analysis with calculation in Excel that supports undertaking the project.

Response:

- a. See the attachment U21806-AG-CE-335_Griffin_ATT_1 for the current phase of each project.
- b. City gates that have operational issues are addressed in a prudent manner to ensure customer reliability. The primary driver of these investments, as discussed in the Natural Gas Delivery plan, is the age of the Company's city gate assets. Outdated equipment at city gates results in increased risk of equipment failure. Modern facilities have more reliable and efficient equipment, resulting in improved reliability, less safety risk and less maintenance. The age of each asset is shown on the attachment to this interrogatory.
- c. Cost Benefit analyses were not conducted for these projects. They are part of the City Gate modernization program as identified in the Natural Gas Delivery Plan (Exhibit A-42 (NPD-1)) at Section IV.C.2. The city gate fleet goal is to 'modernize' 90% of the Company's city gates within this 10-year plan. *Modernization* is defined as upgrading the following mechanisms: emergency shutoff system, bath heater system, separation systems, and the required SCADA transducers for each stage. After modernization is complete, city gates will be rebuilt on a cycle that will ensure the entire fleet is rebuilt within 50 years, or as required for safety, customer demand, and high-performance demand.

Witness: MICHAEL P. GRIFFIN

Date: March 10, 2025

CECo Response to AG-CE-0335

U21806-AG-CE-335-Griffin_ATT_1			
Capacity/Deliverability Program - City Gate Projects			
Project ID	Project Description	Problem/Necessity/Age	Current Phase
GM-00996	FDM-Bancroft CG Rbld	63 year old facility at the end of its designed life.	Engineering/Design
GM-01052	JXN-Jxn Hart Rd CG Rbld	57 year old facility at the end of its designed life.	Pre-Engineering/Design
GM-01054	FDM-Hanover Horton CG Rbld	62 year old facility at the end of its designed life.	Engineering/Design
GM-01055	SAG-Flint Torrey Rd CG Rebl	61 year old facility at the end of its designed life.	Engineering/Design
GM-01056	NVL-Highland CG, Odorizer Rbld	63 year old facility at the end of its designed life.	Engineering/Design
B-GL-00304	2026 Novi Wixom CG ESD Valve & BMS	Installation of Fail closed ESD valves for enhanced overpressure protection and Filter Separator	Engineering/Design
B-GL-00305	2026 NORTHVILLE COMPRESSOR STATION RTU Upgrade	Consolidation of multiple RIUs for a more streamlined and effective communication and instrumentation system	Engineering/Design
B-GL-00306	2026 Spring Arbor CG - PEPL & Odorizer	64 year old facility at the end of its designed life.	Pre-Engineering/Design
B-GL-00307	2026 Flint CG Irish & Odorizer	52 year old facility at the end of its designed life.	Pre-Engineering/Design
B-GL-00308	2026 Dixie Waterford ESD & RTU	Installation of fail closed ESD valves for enhanced overpressure protection.	Pre-Engineering/Design
B-GL-00309	2026 Climax CG - PEPL	45 year old facility at the end of its designed life.	Pre-Engineering/Design
B-GL-00310	2026 South Lyon - Whitmore Lake CG & Odorizer	69 year old facility at the end of its designed life.	Pre-Engineering/Design
B-GL-00317	2026 Mendon Leonidas & Odorizer	59 year old facility at the end of its designed life.	Pre-Engineering/Design

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Question:

324. Refer to discovery response AG-CE-0324 on transmission city gates. Please provide the dollar amount related modernization projects for each year in Excel.

Response:

See attachment U21806-AG-CE-753-Griffin_ATT_1 for the requested information. As described in the response to U21806-AG-CE-324, my workpaper WP-MPG-6 shows each project and project cost for 2023 through the test year. This program also includes other expenditures and activities as described in my direct testimony beginning on page 45, line 21 through page 48, line 20.

Witness: MICHAEL P. GRIFFIN

Date: April 2, 2025

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Discovery AG-CE-0753

U21806-AG-CE-753-Griffin_ATT_1											AG Calculations		
Proj ID	Site	Year	Notes	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Projection	2026 Projection	2027 Amount			
B-GL-00317	2026 Mendon Leonidas & Odorizer	2026		\$ -	\$ -	\$ -	\$ 1,000	\$ 531,516	\$ 9,627,954	\$ 305,166			
B-GL-00310	2026 South Lyon - Whitmore Lake CG & O	2026		\$ -	\$ -	\$ -	\$ 16,108	\$ 531,516	\$ 8,840,790	\$ 305,166			
B-GL-00308	2026 Dixie Waterford ESD & RTU	2026		\$ -	\$ -	\$ -	\$ -	\$ 42,521	\$ 1,190,717	\$ 49,177			
B-GL-00309	2026 Climax CG - PEPL	2026		\$ -	\$ -	\$ -	\$ -	\$ 850,425	\$ 9,627,954	\$ 305,166			
B-GL-00307	2026 Flint CG Irish & Odorizer	2026		\$ -	\$ -	\$ -	\$ -	\$ 987,100	\$ 8,320,811	\$ 305,166			
B-GL-00306	2026 Spring Arbor CG - PEPL & Odorizer	2026		\$ -	\$ -	\$ -	\$ -	\$ 987,100	\$ 8,725,866	\$ 305,166			
GM-00863	NVL-Novi-Wixom CG ESD, F-S Inst	2026	Project was deferred into 2026 from 2022	\$ 40,318	\$ 361,490	\$ (113,454)	\$ 128,691						
B-GL-00304	2026 Novi Wixom CG ESD Valve & BMS	2026						\$ 151,862	\$ 1,658,139	\$ 217,728	\$ 54,301,000	7	\$ 7,757,286
GM-01078	STC-Macomb CG ESD Repl	2025		\$ -	\$ -	\$ -	\$ 51,181	\$ 1,106,157	\$ 40,497	\$ -			
GM-01056	NVL-Highland CG, Odorizer Rbld	2025		\$ -	\$ -	\$ -	\$ 1,124,159	\$ 8,747,804	\$ 305,166	\$ -			
GM-01055	SAG-Flint Torrey Rd CG Rbld	2025		\$ -	\$ -	\$ -	\$ 1,698,708	\$ 7,655,511	\$ 305,166	\$ -			
GM-01052	JXN-Jxn Hart Rd CG Rbld	2025		\$ -	\$ -	\$ -	\$ 1,614,922	\$ 8,371,412	\$ 305,166	\$ -			
GM-01054	FDM-Hanover Horton CG Rbld	2025		\$ -	\$ -	\$ -	\$ 783,910	\$ 6,671,034	\$ 305,166	\$ -			
GM-00997	STC-Lasher CG ESD Vlv Inst	2025		\$ -	\$ -	\$ 28,035	\$ 514,911	\$ 1,106,157	\$ 40,497	\$ -			
GM-00996	FDM-Bancroft CG Rbld	2025		\$ -	\$ -	\$ 155,938	\$ 2,180,723	\$ 8,412,078	\$ 305,166	\$ -	\$ 51,829,000	7	\$ 7,404,143
GM-00941	OVS-Dorr CG Rbld	2024		\$ -	\$ 255,490	\$ 503,990	\$ 2,496,970	\$ 50,000	\$ -	\$ -			
GM-00942	KZO - Galesburg CG Rbld	2024		\$ -	\$ 167,840	\$ 1,791,768	\$ 4,470,219	\$ 50,000	\$ -	\$ -			
GM-00943	STC-Orion CG Rbld	2024		\$ -	\$ 16,680	\$ 887,891	\$ 12,637,190	\$ 50,000	\$ -	\$ -			
GM-00994	STC-Leonard-Lakeville City Gate Rbld	2024		\$ -	\$ -	\$ 671,526	\$ 7,525,000	\$ 301,293	\$ -	\$ -			
GM-00944	JXN-Park Rd CG ESD Inst	2024		\$ -	\$ -	\$ 28,895	\$ 714,204	\$ 50,000	\$ -	\$ -			
GM-01061	FDM-Laingsburg CG ESD Vlv Inst	2024		\$ -	\$ -	\$ -	\$ 746,794	\$ 266,057	\$ 40,497				
GM-00951	JXN-PEPL-Blissfield CG Rbld	2024		\$ -	\$ 15,364	\$ 1,216,665	\$ 7,171,118	\$ 50,000	\$ -	\$ -			
GL-03398	MAR-Bear Lk-Excelsior PL Inst	2024	Installation projects required to retire a City Gate. Considered 1 project	\$ -	\$ -	\$ 103,965	\$ 4,282,320	\$ -	\$ -	\$ -			
GM-00936	MAR-Excelsior Twp CG Ret-Vlv Inst	2024		\$ -	\$ -	\$ 46,378	\$ 188,361	\$ 50,000	\$ -	\$ -	\$ 46,846,000	8	\$ 5,855,750
GM-00979	STC-Pontiac Wlton CG ESD Inst	2023		\$ -	\$ 33,234	\$ 681,104	\$ 5,018	\$ -	\$ -	\$ -			
GM-00899	SAG-Akron CG Rbld	2023		\$ 393,716	\$ 2,585,887	\$ 7,544,837	\$ 4,287	\$ -	\$ -	\$ -			
GM-00794	KZO-M Ave CG Rbld	2023		\$ -	\$ 647,729	\$ 12,710,911	\$ 138,402	\$ -	\$ -	\$ -	\$ 24,745,000	3	\$ 8,248,333
GM-00514	STC-Greenfield CG Rbld	2022		\$ 2,236,224	\$ 6,340,439	\$ 106,028	\$ 119,429	\$ -	\$ -	\$ -			
GM-00902	KZO-Kzo CG-Nazareth Rd Rbld	2022		\$ 21,492	\$ 5,784,883	\$ 74,128	\$ 112,215	\$ -	\$ -	\$ -			
GM-00901	STC-Rochester CG Rbld	2022		\$ 798,290	\$ 7,499,386	\$ 46,234	\$ 3,319	\$ -	\$ -	\$ -			
GM-00900	JXN-Napoleon-Brooklyn CG Rbld	2022		\$ 94,374	\$ 6,275,876	\$ 40,208	\$ -	\$ -	\$ -	\$ -			
GM-00867	FDM-Lansing CG-Airport Rd Rbld	2022		\$ 68,899	\$ 8,082,082	\$ 122,875	\$ 206,885	\$ -	\$ -	\$ -			
GM-00898	MAR-Bear Lk Twp CG Rbld	2022		\$ 124,119	\$ 4,094,765	\$ (3,563)	\$ (47,180)	\$ -	\$ -	\$ -			
GM-00864	STC-Goodison CG ESD Inst	2022			\$ 811,394	\$ (22,915)	\$ -	\$ -	\$ -	\$ -			
GM-00965	KZO-M Ave CG F-S Install	2022		\$ -	\$ 1,130,961	\$ 63,391	\$ -	\$ -	\$ -	\$ -	\$ 44,184,000	8	\$ 5,523,000
GM-00803	KZO-Marshall-Lansing CG Rbld	2021		\$ 4,845,378	\$ 394,871	\$ (760)	\$ (3,708)	\$ -	\$ -	\$ -			
GM-00789	SAG-Mt Pleasant CG Rbld	2021		\$ 4,920,139	\$ 11,344	\$ 30,292	\$ 32,960	\$ -	\$ -	\$ -			
GM-00822	FDM-Lansing CG-Turner Rd Rbld	2021		\$ 7,107,170	\$ 47,060	\$ 4,655	\$ -	\$ -	\$ -	\$ -			
											2022-2024	\$ 115,775,000	19 \$ 6,093,421

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Project ID	Project Description	2023 Actual	2024 Projection	2025 Projection	2026 Projection	10 Months Ending 10/30/2025 Projection	12 Months Ending 10/30/2026 Projection	Internal Approval Y/N
GL-02076	STC-Wattles Rd VS Vlv 2074 RCV Inst	-13,644	0			0	0	Y
GL-02413	NVL-2800 S Lyon RCV Inst	124,440	116,065	1,071,865	0	1,061,147	10,719	Y
GL-02421	NVL-1600 W Wayne CG RCV Inst	0	1,999			0	0	Y
GL-02662	SAG-500 Vlv 504-26, 504T12E Act Inst		0	294,763	0	291,815	2,948	Y
GL-02663	KZO-1300 Vlv 1312, 1314 Act Inst	9,699	0			0	0	Y
GL-02664	SAG-500 Vlv 506-26 Act to RTU Inst		0	777,102	0	769,331	7,771	Y
GL-02667	STC-2700 Kern Rd to Clkstn Jct RCV Inst	-10,734	0			0	0	Y
GL-02668	STC-1700 Ray CS to Red Run RCV Ist	-9,268	321			0	0	Y
GL-02758	STC-2070 Coolidge RCV Inst	-10,702	0			0	0	Y
GL-02825	FDM-1200B Moscow VS Vlv 1252B Repl		0	0	1,084,230	0	1,073,387	Y
GL-02827	NVL-2300 NCS to Newbrg CG RCV Inst GL-02	7,427	0			0	0	Y
GL-02829	SAG-300 Midlnd CG to Zil Jct RCV Inst	-16,367	42			0	0	Y
GL-02830	SAG-500 Ovid to Grand Blanc RCV Inst	56,168	0			0	0	Y
GL-02831	SAG-700 StLou to Dutch Rd RCV Inst	-5,816	0			0	0	Y
GL-02832	SAG-2100 FlintCG to CrpntvRS RCV Inst	4,022	0			0	0	Y
GL-02833	STC-600 Clrkstn to SqrIRdVS RCV Inst	6,553	0			0	0	Y
GL-02834	KZO-1300 Olmstead VS RCV Inst	9,743	0			0	0	Y
GL-02835	OVS-1100 MidCal to Clntnia VS RCV Inst	10,925	0			0	0	Y
GL-02836	STC-1700 Vector, Canal Rd RCV Inst	32,920	0			0	0	Y
GL-02862	STC-1500/1700 Macomb VS RCV Inst	5,285	0			0	0	Y
GL-02863	SAG-100/250 Mt Pleasant CG RCV Inst	162	15,946			0	0	Y
GL-02941	NVL-1070 Sheldon Rd VS RCV Inst	15,260	7,679			0	0	Y
GL-02942	SAG-1900 Atlas, GrndBlnc RCV Inst	-7,758	0			0	0	Y
GL-02943	FDM-2800 FDM,Milr,Hdsn,Sutn RCV Inst	224,725	-85,690		3,252,688	0	3,220,161	Y
GL-02944	FDM-400 8 Sites RCV Inst	53,445	1,734	1,607,798	0	1,591,720	16,078	Y
GL-02945	KZO-1200B HH to Chelsea RCV's Inst	-3,021	0			0	0	Y
GL-02947	KZO-1300 Plnwl to Palmer RCV Inst	-162,414	-207,537			0	0	Y
GL-03016	KZO-1800 RCV's Inst	50,707	-62			0	0	Y
GL-03023	FDM-1100 Lansing CG Arpt Rd RCV Inst	37,376	0			0	0	Y
GL-03025	KZO-1800 MAve Check Valves Inst	38,596	1,580			0	0	Y
GL-03027	FDM-2200 Chelsea to Fenton RCV Inst	12,234	-12,283	406,782		402,714	4,068	Y
GL-03040	STC-600 Hillsboro VS RCV Inst	109,847	7,553			0	0	Y
GL-03041	STC-2700 Hillsboro VS RCV Inst	26,286	4,883			0	0	Y
GL-03049	SAG-250 MtPl to Zilwke RCV Inst	14,823	4,320	0	2,168,459	0	2,146,775	Y
GL-03050	OVS-1800 30thSt to Plnwl RCV Inst	53,944	1,902			0	0	Y
GL-03117	OVS-1100 Dorr CG to MidCal RCV Inst	997	0			0	0	Y
GL-03121	FDM-3200 VectrLesli to KnrMrgn RCV Inst	19,329	441			0	0	Y
GL-03123	SAG-100C Airport to Herrick RCV Inst	0	12,034	887,764	0	878,886	8,878	Y
GL-03125	NVL-LN 1020 V4018 & V4028 RCV Inst	47,180	330			0	0	Y
GL-03265	KZO-1200A 1207, 1208A, 1208C RCV	50,328	13,708			0	0	Y
GL-03268	SAG 100B Mt Pleasant VS 112-26 Repl	1,188,339	11,518			0	0	Y
GL-03267	STC- 1500 Vlv 1528 RCV Inst		0	214,373	0	212,229	2,144	Y
GL-03324	STC-2700 Squirrel Rd Vlv RCV Updt	278,251	272					Y
GL-03329	STC-1200A Chelsea VS RCV Inst	4,190	0					Y
GL-03480	TEDI Laingsburg Int. (GL-03480)		0	277,613	0	274,837	2,776	Y
B-GL-00110	TEDI- Clintonia VS		0	214,373	0	212,229	2,144	Y

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B-GL-00112	TEDI St. Clair VS		0	135,055	0	133,704	1,351	Y
B-GL-00114	TEDI Metamora CG		0	405,466	0	401,411	4,055	Y
B-GL-00115	TEDI Perry-Morrice CG		0	294,763	0	291,815	2,948	Y
B-GL-00116	TEDI New Haven VS		0	964,892	0	955,243	9,649	Y
B-GL-00117	TEDI- Leonard Lakeview CG		0	750,306	0	742,803	7,503	Y
B-GL-00118	TEDI-Highland CG		0	233,667	0	231,330	2,337	Y
B-GL-00119	TEDI-St Louis VS		0	0	889,068	0	880,178	Y
B-GL-00120	TEDI-Three Rivers Landfill		0	0	1,337,191	0	1,323,819	Y
B-GL-00121	TEDI-Brocker Rd VS		0	0	885,455	0	876,600	Y
B-GL-00122	TEDI- Campground VS		0	0	885,455	0	876,600	Y
B-GL-00123	TEDI-M-72 VS		0	0	325,269	0	322,016	Y
B-GL-00124	TEDI-Military VS		0	0	108,423	0	107,339	Y
B-GL-00129	TEDI-North Bradley VS (Coleman-Beaverton)		0	0	2,840,682	0	2,812,275	Y
B-GL-00132	TEDI-Carpenter Rd VS		0	0	135,529	0	134,173	Y
B-GL-00133	TEDI-State Rd VS		0	0	325,269	0	322,016	Y
B-GL-00134	TEDI-Fenton Int		0	0	325,269	0	322,016	Y
B-GL-00140	TEDI-Blanchard Rd VS		0	0	1,951,613	0	1,932,097	Y
B-GL-00160	Ovid VS		0	267,966	0	265,287	2,680	Y
B-GL-00214	Babcock VS		0	0	1,653,450	0	1,636,916	Y
TOTAL EXPENDITURE		2,253,476	-103,244	8,804,547	18,168,050	8,716,502	18,074,415	
Business cases have not been conducted on these projects.								
RCVs are being installed to reduce response time and to improve public safety. RCVs reduce the loss of natural gas should a pipeline failure occur and can be operated remotely by Gas Control for potential reduction in response times.								

U21806-AG-CE-0336

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Question:

50. Refer to WP-MPG-8 on TED-I Remote Closure Valve projects.

- a. For projects of \$1 million or greater in 2025 and 2026, please provide the current phase of development for the project.
- b. For each year 2021 to 2024, provide the number of RCV installations and the average cost for each installation.
- c. For 2025 and 2026, provide the average cost for RCV installations and explain the reasons for any variance of 10% or greater versus the average cost during the prior three years.

Response:

- a. For the projects in 2025 they are currently in the design and procurement phase of the project and for 2026 the projects are currently in the planning and scoping phase.

b.

1. For 2021, the number of RCVs installed were 31
2. For 2022, the number of RCVs installed were 26
3. For 2023, the number of RCVs installed were 14
4. For 2024, the number of RCVs installed were 4

The average installed cost over this time frame was \$610,445.

Note that the cost of RCVs vary due to amount of construction required, ability to share costs across other programs and projects as well as the need to install new electric services and new Remote Terminal Unit/Monitoring capability.

- c. For 2025 and 2026, the average cost of RCV installation projects will be \$817,351. The average cost for the prior three years (2022-2024) was \$822,792. This is a 1% variance.

Witness: MICHAEL P. GRIFFIN

Date: March 10, 2025

U21806-AG-CE-0506

Page 1 of 2

Question:

168. Refer to page 33 and 34 of Mr. Joyce's direct testimony on the Lyon 29/34 project. Please:

- a. Provide the cost of the project by year from inception to completion.
- b. Provide a copy of the analysis performed by the Company to justify undertaking this project.
- c. Explain what alternatives were evaluated, and what financial benefits will result from completion of the project. Provide a copy of the cost/benefit analysis performed in Excel with formulas intact and all assumptions explained.
- d. Provide the phases of project development with timeline and related cost and the phase that the project is currently in.
- e. Explain what has changed since the Company proposed this project in Case No. U-21490. Provide any updates to the responses to the Attorney General's discovery requests in that case for this project.
- f. Provide the actual moisture content per LB/MMCF experienced during each withdrawal in each year 2018 through 2024 in Excel.
- g. Provide the number of days that gas withdrawals occurred during each year in 2021 through 2024.
- h. Provide the volume of gas withdrawn on each occasion in 2021 through 2024 and as a percent of total field capacity.
- i. Provide the volume of gas withdrawn on each occasion in 2021 through 2024 as a percent of the total gas supply in pipeline system fed partially from the Northville storage field.

Response:

- a. Please reference U21806-AG-CE-0506-Joyce_ATT_1 for cost information the project.
- b. Please reference U21806-AG-CE-0506-Joyce_ATT_2 for a copy of the analysis performed by the Company to justify undertaking this project.
- c. Please reference U21806-AG-CE-0506-Joyce_ATT_2 for overview of the alternatives that were evaluated.
- d. Timeline for the Lyon 29-34 project is as follows: engineering and equipment procurement in 2023 and 2024, construction in 2025 and 2026, and in-service in 2026, and project close-out in 2027.
- e. Detailed engineering, construction and material procurement has progressed with construction scheduled to begin in 2025 and conclude in 2026.

U21490-AG-CE-0315 – Updates provided in the responses to this question.

U21490-AG-CE-0316 -Updates provided in the response to U21806-AG-CE-507

U21490-AG-CE-0476 – No updates

U21490-AG-CE-0477 – No updates

U21490-AG-CE-0478 – No updates

U21806-AG-CE-0506

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- f. Please reference U21806-AG-CE-0506-Joyce_ATT_3 for the actual moisture content per LB/MMCF experienced during each withdrawal in each year 2018 through 2024.
- g. Please reference U21806-AG-CE-0506-Joyce_ATT_4 for the number of days that gas withdrawals occurred during each year in 2021 through 2024.
- h. Please reference U21806-AG-CE-0506-Joyce_ATT_4 for the volume of gas withdrawn on each occasion in 2021 through 2024 and as a percent of total field capacity.
- i. Please reference U21806-AG-CE-0506-Joyce_ATT_4 for the volume of gas withdrawn on each occasion in 2021 through 2024 as a percent of the total gas supply in pipeline system fed partially from the Northville storage field.

Witness: Timothy K. Joyce

Date: March 17, 2025

CECo Response AG-CE-0506

Case No: U-21806
Exhibit: AG-22
April 23, 2025
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MICHIGAN PUBLIC SERVICE COMMISSION				U21806-AG-CE-0506-Joyce_ATT_1					Case No. U-21806		
Consumers Energy Company											
Gas Compression & Storage											
Northville Lyon 29/34 Liquid Handling Actuals and Projected Spend (\$000)											
For Gas Rate Case											
									</		

MICHIGAN PUBLIC SERVICE COMMISSION				U21806-AG-CE-0506-Joyce_ATT_3		
<u>Consumers Energy Company</u>					Case No. U-21806	
Gas Compression & Storage						
Northville Lyon 29/34 Liquid Handling actual moisture content per LB/MMCF experienced during each withdrawal in each year 2018 through 2024						
For Gas Rate Case						
					Test Date	Moisture Range
				Lyon 29 Field	January 2019	7 to 9
				Lyon 29-1	March 2020	1.9 to 7.8
				Lyon 29-2	March 2020	4.9 to 8.2
				Lyon 29-3	March 2020	5 to 7.9
				Lyon 34 Field	January 2019	10 to 12
				Lyon 2-34	March 2020	9 to 12
				Lyon 3-34	March 2020	11 to 14
				Lyon 4-34	March 2020	8 to 17
				Northville Reef Field	January 2019	7 to 14
				N-211	March 2020	5.7 to 6.8
				N-301A	March 2020	6.7 to 7.3
				N-302A	March 2020	8 to 13
				N-303	March 2021	2 to 56*

CECo Response AG-CE-0506

MICHIGAN PUBLIC SERVICE			U21806-AG-CE-0506-Joyce_ATT_4					
Consumers Energy Company								
Gas Compression & Storage								
Northville Lyon 29/34 Liquid Handling gas withdrawal data from 2021 through 2024.								
For Gas Rate Case								
Year	Field	Number of days that gas withdrawals occurred	Volume withdrawn, as a percent of total field capacity	Volume withdrawn, as a percent of total system send out	Withdrawal Volume (MMscf)	Notes	Total Field Capacity (MMscf)	Total system send out (MMscf)
2021	Lyon 29	0	0.00%	0.00%	0		2179.59	290,731
	Lyon 34	0	0.00%	0.00%	0		1358	290,731
	Northville Reef	1	2.00%	0.01%	24.6	Flow testing of new well N-303	1220	290,731
2022	Lyon 29	1	5.60%	0.04%	121.7	Flowed for ~12 hours before high moisture	2179.59	308,734
	Lyon 34	0	0.00%	0.00%	0	Flowed for <15 minutes due to valve	1358	308,734
	Northville Reef	1	0.30%	0.00%	3.9	Flowed for ~2 hours before high moisture	1220	308,734
2023	Lyon 29	0	0.00%	0.00%	0		2179.59	296,564
	Lyon 34	0	0.00%	0.00%	0		1358	296,564
	Northville Reef	0	0.00%	0.00%	0		1220	296,564
2024	Lyon 29	0	0.00%	0.00%	0		2179.59	277,138
	Lyon 34	0	0.00%	0.00%	0		1358	277,138
	Northville Reef	0	0.00%	0.00%	0		1220	277,138

U21806-AG-CE-0819

Page 1 of 3

Question:

369. Refer to discovery response AG-CE-0506 on the Lyon 29/34 dehydration project. Please:

- a. Explain what the technology factors on page 6 of the November 1, 2023 presentation in ATT_2 mean, how they relate to the project, and their relevance.
- b. Based on your proposal, identify what level of moisture in the gas flow the dehydration units will achieve at the outlet after processing of the gas and for injection into the transmission or distribution line connected to it.
- c. Explain how the "Status Quo-Operate As Is" option shown on page 8 of ATT_2 differs from gas blending. Explain how the Company has been able to utilize the gas from the storage field so far when needed without the dehydration units.
- d. For the "Status Quo-Operate As Is" option shown on page 8 of ATT_2:
 - i. Explain what "Replacement of S. Lyon CG 1/15 yrs" means, why it would be necessary, and on what basis and engineering evaluation.
 - ii. Explain what "Anticipate 2 cutouts every 10 years due to corrosion..." means, for which facility, why, and on what basis and engineering evaluation.
 - iii. Provide the frequency of ILI inspections done during the last five years. Provide the engineering study showing that corrosion exceeding the limit of 1 mil would occur each year and based on what frequency of operation of the field.
- e. Regarding Natural Gas Blending on page 9 of ATT_2. Please:
 - i. Explain what the problem is with the configuration of the 1020 transmission pipeline.
 - ii. Provide a copy of the engineering analysis performed by the Company that shows that gas blending from gas withdrawn from the storage wells during their limited operation would increase the moisture content of the gas delivered to customers in excess of 7lb/MMSCF at the customer meters.
- f. Regarding the Summary of Options on page 10 of ATT_2, please:
 - i. Explain why the comparative cost analysis was done over 41 years.
 - ii. Provide the calculations for each option and costs in Excel with formulas intact and all source data and assumptions explained and cited to a source.
 - iii. Did the Company assume that the new installed dehydration units and system would last 41 years or would they need to be replaced or overhauled multiple times over that timeframe. Explain fully.
 - iv. Explain why no financial evaluation of the Natural Gas Blending option was performed. Would this option be equivalent to the Status Quo option? If no, explain why not and provide a financial evaluation of the natural gas blending option in Excel.
 - v. Explain why the Dehydration option for individual facilities is the optimal solution at a levelized cost of \$6.8 million when the Status Quo option is by far the lowest cost option at \$1.4 million.
 - vi. How many dehydration units and facilities would need to be installed based on your proposal and where?
- g. Pages 8 and 11 of ATT_2 state that an Act 9 approval for building a new 1,200 feet 16-inch pipeline is necessary under your proposal. Explain why and whether the Act 9 filing has been made and under which case number.

Response:

- a. Please reference attachment U21806-AG-CE-0819_Joyce_ATT_2 which details the evaluation of each technology.

U21806-AG-CE-0819
Page 2 of 3

- b. Less than 5lb/MMSCF.
- c. Status quo is different than blending because the moisture level out of storage is monitored and shut in when it hits the tariff limit for moisture. Gas is blended when entering the transmission pipeline, however, is shut in when the storage gas hits the tariff level for moisture prior to blending, ensuring the moisture content of the mixed gas does not exceed the tariff limit.

d.

- i. The presence of wet gas above the tariff limit will contribute to internal corrosion growth and accelerate the need to replace the city gate which receives gas from the transmission line 1020. See answers d (ii. and iii.) for additional information on internal corrosion.
- ii. For internal corrosion, the NACE standard SP0775-2023 states that a general corrosion rate of 2mpy (0.002" per year) is a low corrosion rate. This equates to a pitting rate of 5mpy (0.005" per year). See Table 2 below. Utilizing a scenario where we have a low corrosion rate of 5 mpy in pitting rate (which is what an ILI tool measures), we could see approximately 0.050" of wall loss over a 10 year period between ILI runs. This equates to approximately 18% wall loss for line 1020. If this occurs at a location which presently shows 10% wall loss, which is a possibility, the internal corrosion could grow to 28% wall loss and may warrant being cut out to repair the location. Continued use of the Lyon 29 and Lyon 34 fields would likely increase this rate of corrosion due to contamination of the transmission line 1020 with wet gas.

Table 2
Qualitative Categorization of Carbon Steel Corrosion & Pitting Rates

Average General Corrosion Rate (See Paragraph 2.4)			Maximum Pitting Rate (See Paragraph 2.5)	
	mm/y ^(A)	mpy ^(B)	mm/y	mpy
Low 	< 0.05	< 2.0	< 0.13	< 5.0
Moderate 	0.05 – 0.2	2.0 – 8.0	0.13 – 0.3	5.0 – 12
High 	> 0.2	> 8.0	> 0.3	> 12

^(A) mm/y = millimeters per year
^(B) mpy = mils per year

- iii. In-Line Inspections of 1020 occurred in 2017 and 2024. In 2017 two areas of internal corrosion were found. One was cut out and had a maximum of 31.67% wall loss due to internal corrosion. The second location was identified to have 12% wall loss (0.034") due to internal corrosion, but was not severe enough to required additional evaluation. This location was also identified in the 2024 ILI run and showed to be 20% wall loss (0.056"). This 0.022" inch change over approximately 7 years equates to a corrosion rate of 0.003" per year. While NACE considers this a low corrosion pitting rate and correlates with the analysis explained in the prior question.

e.

- i. There is not a problem with the configuration of the 1020 transmission line. This is specific to the recognition that the connection delivers storage gas to the transmission line and is a typical pipeline connection and not in any way designed to mix gas to meet moisture content requirements.

U21806-AG-CE-0819

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ii. An engineering analysis was not done for the blending basis. As stated previously, the Company's position is that blending is not recognized as a competent process for ensuring compliance with the gas quality tariff.

f.

i. 41 years was used as it is the associated asset life for gas conditioning equipment (2017 Schedule of Gas Depreciation Rates by Functional Plant Case U-18127).

ii. Please reference attachment U21806-AG-CE-0819_Joyce_ATT_1.

iii. No replacements assumed within the 41 year lifespan.

iv. No financial evaluation was performed for blending due to the Company's interpretation that gas blending is not a competent means to meet the gas quality requirements of the tariff.

v. Cost is part of the evaluation and not the whole evaluation. Use of the field is limited by the condition that the new equipment will address and although the status quo option is the least cost option, it does not solve the problem and therefore is not a viable solution.

vi. Two desiccant hydration units are designed and will be installed on the same site as the Lyon 29 storage wells.

g. The Act 9 is required to construct the new pipeline and is necessary to connect the conditioned gas from the Lyon 29 site to the 1020 transmission line. The Act 9 was filed and approved, reference Case No. U-21589.

Witness: Timothy K. Joyce

Date: April 11, 2025

U21806-AG-CE-0820

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Question:

370. Refer to ATT_3 to discovery response AG-CE-0506 on the Lyon 29/34 dehydration project. Please:

- a. Expand the schedule in ATT_3 to show the moisture content of each test result encompassed in the moisture range shown in the table for each test date and well/field tested.
- b. Explain what the asterisk next to the number 56 on the last line refers to. Explain what occurred that made the moisture content increase significantly to 56 lbs./MMCF when all other tests show a level below 20 lbs./MMCF.
- c. Explain why no moisture reading were taken after March 2021 to present.

Response:

- a. Please reference attachment U21806-AG-CE-0820_Joyce_ATT_1.
The Northville Reef field flowed from all three wells in January 2019. The moisture content during this period would remain consistent at about 7 to 10 lb/MMcf for about 6 hours and then increased in moisture to about 14 lb/MMcf before decreasing back to 7 to 10 lb/MMcf over an approximately 4-hour time interval. It did reach greater than 14 lb/MMcf for a limited period.

The Lyon 29 field flowed from all three wells in January 2019. The moisture content during this period remained around 7 lb/MMcf, and for brief periods the content would be at or slightly above 7 lb/MMcf and in one instance approach 9 lb/MMcf.

The Lyon 34 field flowed from all three wells in January 2019. The moisture content during this period was recorded between about 10 to 12 lb/mmcf.

During the March 2021 flow testing, the N-303 had a gas moisture meter installed near the wellhead as multiple field configurations would be tested and the field moisture meter could not provide moisture for only the N-303 throughout the test period.

- b. The asterisk is noted with the following note: "Multiple periods of significantly high moisture may be due to the well flowing to the system for the first time since drilling".
The N-303 was newly drilled in 2020. The first time the well was brought online was in March 2021. The higher moisture may be attributed to any fluids injected into the well while drilling and the March 2021 was the first time the well flowed unrestricted back to the transmission system. The moisture decreased to an average of about 12 lb/MMcf during the testing. It is believed the moisture above the 20 lb/MMcf would be temporary but may require multiple withdrawal seasons to further confirm.
- c. There have been no readings taken because the fields were not put on withdrawal due to the inability to control the moisture content. These fields are currently last to be dispatched due the restrictions associated with the tariff and the inability to control the moisture of the gas when flowing to the system.

Witness: Timothy K. Joyce

Date: April 11, 2025

THE REMAINING 17 PAGES CONSIST OF A PROPOSAL PRESENTATION BY CONSUMERS ENERGY ON THE LYON 29 / 24
LIQUID HANDLING FACILITY DATED NOVEMBER 1, 2023

Lyon 29 / 34 Liquid Handling Facility

Chris Plawchan
November 1, 2023

Agenda

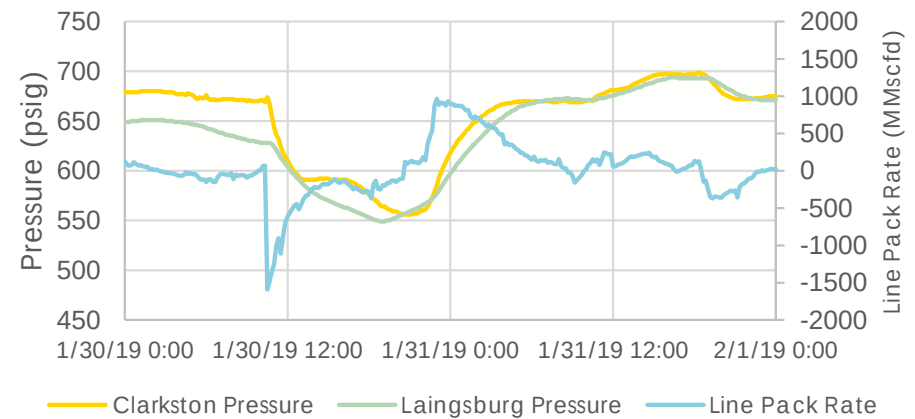
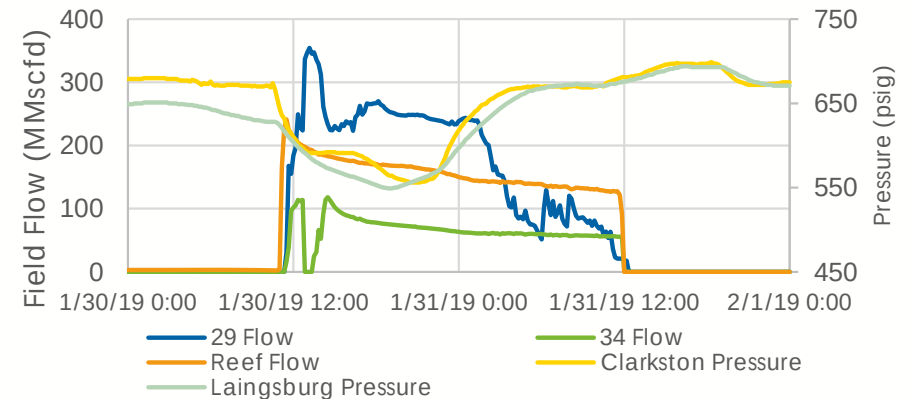
- Lyon 29/34 Purpose
- Project Objectives & Benefits
- Align With Gas Delivery Plan
- Technology Evaluation
- Technology Selection
- Options Evaluated
- Summary of Options
- Lyon 29 Site – Scope
- Lyon 34 Site – Scope
- Northville Reef Site - Scope
- Project Risk / Opportunity
- Project Milestones Schedule
- Project Funding Strategy
- Stakeholder Approval

Lyon 29/34 Purpose

Reduce reliance on Ray

- Diversification of peak day supply
- Ray Incident – Immediate system pressure stabilization
- “Insurance Policy” - Less expensive than FT contracts for equivalent pipeline deliverability

Ensure gas delivered to pipeline from Lyon 29, Lyon 34, Northville Reef meet tariff specification



Project Objectives & Benefits

Objectives

- Ensure gas delivered to pipeline from Lyon 29, Lyon 34, Northville Reef meet tariff specification
 - 7 lbs water / 1 million scf gas
- Sarbanes Oxley - process gas before metering – accurate accounting of energy
 - Reconfigure equipment to process all moisture prior to measurement

Benefits

- Reduce non-compliance
 - Avoid potential MPSC fines
 - Avoid customer freeze-offs
- Zero unplanned shut-in of Northville fields
- Reduce potential pipeline corrosion

Align With Gas Delivery Plan

Objective	Goal	Outcome	2030 Target
Safe	Zero Incidents	Reduce System Risk	2.1%
		Achieve GSMS maturity level	≥4.0
Reliable	Resilient and reliable system	Maintain Gas Flow Deliverability	95%
		Increase Resilience	>91.5%
Affordable	Competitive, predictable prices	Annual average of monthly residential bill	\$107
		Increase Customer satisfaction survey	85+
		Increase Energy Waste Reduction	1% year over year
Clean	Decrease air emissions footprint	Reduce Scope 1 system methane emissions from 2005 baseline	15,128MT
		Reduce Scope 3 customer carbon emissions from 2022 baseline	4 million MT

Technology Evaluation

Technology	Economics	Operation	Technical	Overall
Triethelyne Glycol (TEG) -e.g. Ray CS, Overisel CS	8.4	20.2	10.8	39.4
Mole Sieve	5.6	26.6	8.8	41.0
Deliquescent Desiccant	18	31.4	12.8	62.2
Gas Membrane	13.6	18.2	10.4	42.2

- Based on flow rates and frequency of use

Technology Selection – Deliquescent Desiccant

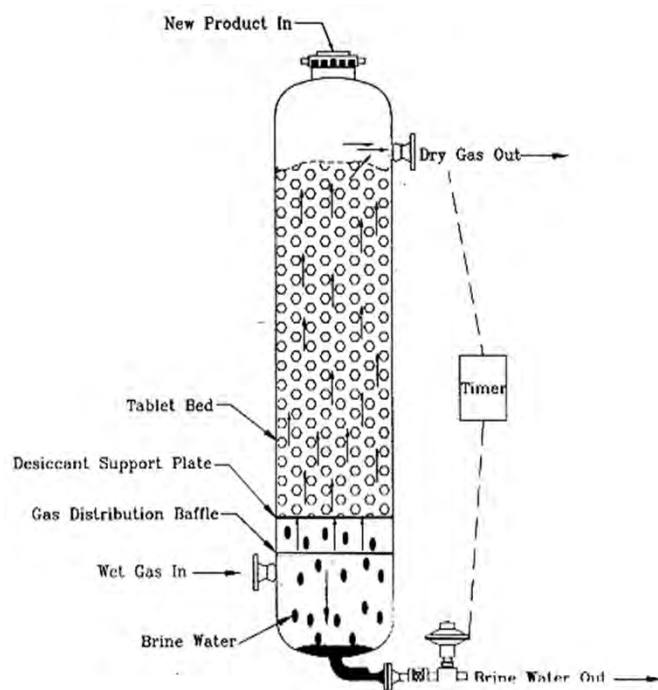
Re-evaluation Participates;

- Engineering
- Operations / M&R
- Gas System Planning

Technology

Recommendation;

- Orbital Engineering



System characteristics

Improved safety

- No fire hazard
- No pumps, burners, heat exchangers

Reduced facility capital

- Easy installation
- Small footprint – 9'x12' Vessel
- Low capital expense (vessels) - \$1.38MM

Reduced operating costs

- Simple unattended operation
- No costly disposal - Brine
- Low maintenance - \$8k/yr
- Low periodic costs - \$12/mmscf
- No “turndown” limitations

Lower compliance costs

- No BTEX vapor emissions

Restrictions

- May require maintaining desiccant above freezing temperature – Building recommended

Options Evaluated

Dehydration for Individual Facilities

- 3 Process Trains;
 - Bldgs / Knockout Pots / Dehydration Vessels / Filters / Meter / Regulators & PLDs
 - Brine storage Tanks / Offloading Containments
- ACT 9 to construct a new 1200' 16" pipeline from Lyon 29 Processing Facility to 1020 line
- Acquisition of an adjacent parcel; 9 MI and Griswold Rd.

Central Liquid Handling Facility

- 3 Process Trains (same equipment outlined for the Individual Option)
- ACT 9 to construct two new pipelines from the Lyon 34 site to the Northville Reef
- Acquisition of ROW for the new pipelines

Status Quo – Operate As-Is

- Replacement of S Lyon CG 1/15yrs
- Anticipate 2 cutouts every 10yrs due to corrosion wall thickness loss (.27mills/yr)
- Anticipate yearly ILI tool inspection due to corrosion exceeding the limit of 1mil/yr

Options Evaluated – Con't

3rd Party Storage Supply

- Lyon 29/34 deliverability is being replaced with NNS and FT service from 3rd party pipelines.
- Per the 2021 Storage Strategy Report, Lyon 29 & 34 have a target delivery of 390 MMcf/d that needs to be replaced.
- An average of ANR, PEPL, and Trunkline was used to establish the cost of replacement services. (Per Gas Supply team, no single company would likely have enough capacity available.)

Natural Gas Blending

- Due to the current configuration of the 1020 transmission pipeline and Consumer Energy's stance on blending natural gas streams in order to meet the moisture content tariff limit of 7lb/MMSCF deemed this approach a nonviable solution.

Summary of Options

Alternative (41 year timeline)	Capital Cost	O&M Cost	NPR of Revenue Required	Levelized Annual Revenue Required
Dehydration for Individual Facilities	\$59.1 Million	\$2.1 Million*	\$85.1 Million	\$6.8 Million
Central Liquid Handling Facility	\$70.0 Million	\$2.1 Million*	\$104.8 Million	\$8.3 Million
Status Quo – Continue Operating As-Is	\$20.0 Million	\$6.3 Million	\$17.2 Million	\$1.4 Million
3rd Party Storage Supply – On Demand	\$0 Million	\$2.7 Billion	\$1.1 Billion	\$89.6 Million
Natural Gas Blending	N/A	N/A	N/A	N/A

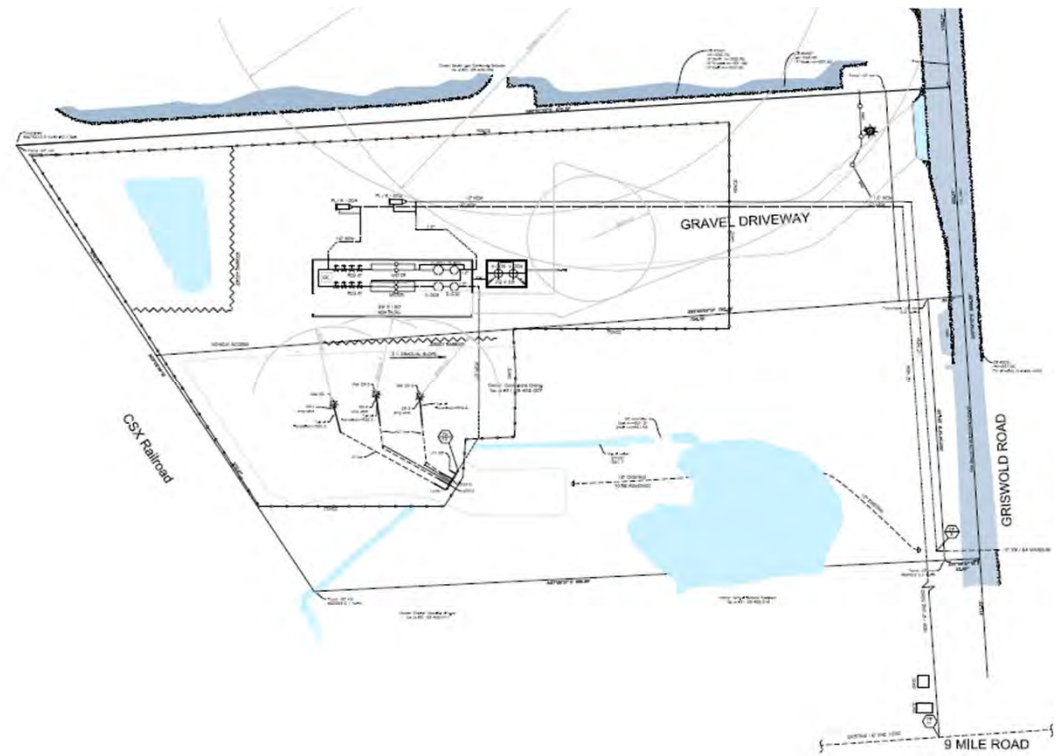
* \$8k/yr, \$12 per MMcf

- Although the Individual Dehydration Facilities is not the lowest capital cost option, when combined with the overall cost to maintain facilities (via O&M), it provides the optimal solution for the customer.

Lyon 29 Site - Scope

Site modifications entail:

- Acquire 1.5 acres (Griswold and 9mi Rd)
- Act 9 Certificate of Necessity
 - 1200' new 16" 5050 transmission line
 - Re-route 12" Lyon 29 line
 - 500' of new 12" piping
- 2 Process trains
 - Knockout drum
 - Dehydration vessel
 - Filters
 - Meters; (5) USM meter runs
 - PLD worker/monitor with RCV
- 50'x150' Process Bldg
- 2 - 100 bbl brine tanks
- Tie into 1020 line with 16" piggable wye
- Two Launcher/Receivers; 12" and 16"



Lyon 34 Site - Scope

Site modifications entail:

- A new cold weather enclosure w/ chromograph
- Replace 12" Launcher/Receiver
- Replace 8" Launcher/Receiver
- 4" USM to measure Lyon 34 injection
- Replace well lines

Removal of all existing surface equipment:

- Decommission the 4020 pipeline
- Removal of the 4020/1020 tie-in and block valve
- Removal of existing surface equipment
 - Separators
 - Brine storage tanks
 - PLDs/Regulators
 - 12" Meters / Headers



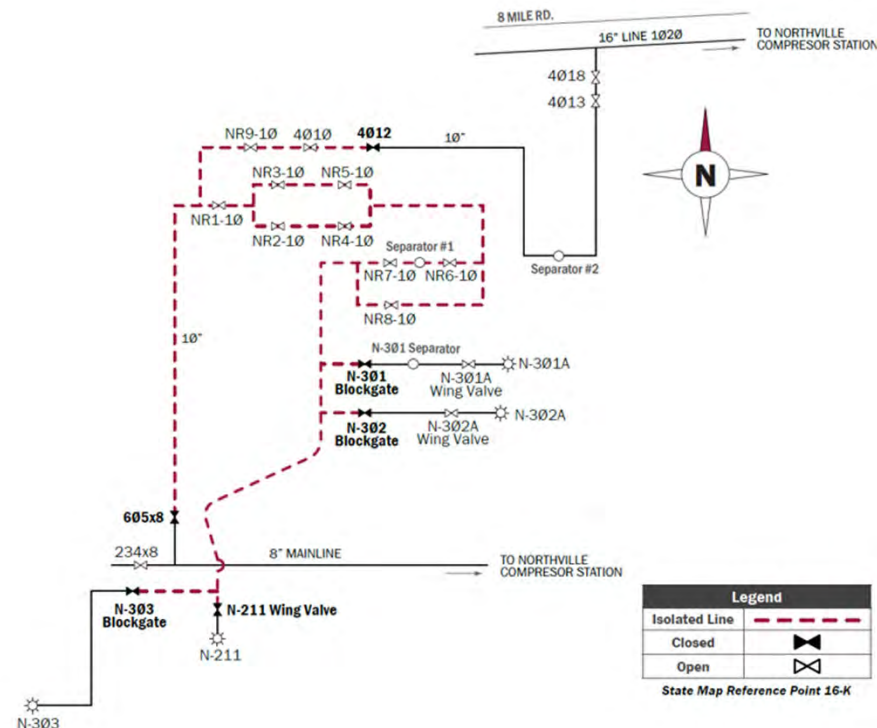
Northville Reef Site - Scope

Site modifications entail:

- 50'x150' Process Bldg
- New Process train
 - Knockout drum
 - Dehydration vessel
 - Filter / Meters
 - PLD worker/monitor with RCV
- New 2 - 100 bbl brine tanks
- New Launcher/Receivers

Removal of all existing surface equipment:

- Separators
- Brine storage tanks
- PLDs/Regulators
- Meter Headers
- Launcher/Receivers



Project Risk / Opportunities

Risks:

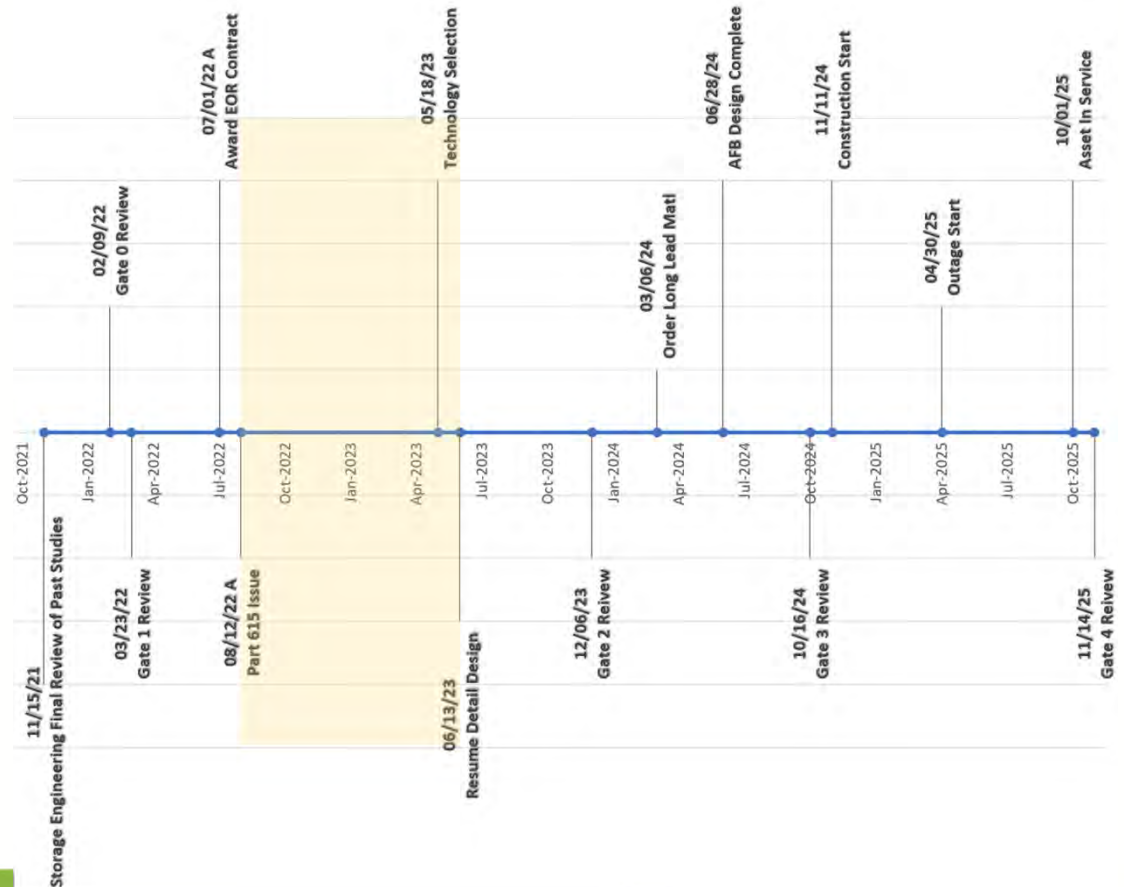
- Act 9 application and review process
- Public scrutiny

Opportunities:

- Effective utilization of Lyon 29 Storage Field
- Equipment located in light industrial zone
- Avoid brand damage – Do nothing option
- Avoid air permit

Project Milestone Schedule

- Part 615 alternate site inquiry: 8/24/22
- Technology issue identified: 11/17/22
- Resume EOR design: 6/13/2023



Project Funding Strategy

	*2022-Original	2022	2023	2024	2025	2026	Total
LTFP	\$24,145	\$1,139	\$8,013	\$11,671	\$25,246	\$75	\$46,144
CL's	\$(23,006)-Jan	\$005	\$(6,547)	\$0	\$0	\$0	\$(6,542)
Budget	\$1,139	\$1,144	\$1,466	\$11,671	\$25,246	\$75	\$39,602

*2022 Original shown above for reference only. LTFP table totals reflect 2024-2028

**Annual Variance due to minor underrun on EOR actuals in 2023.

Annual Summary	2023
Actuals to Date (9/30)	\$678
Annual Budget	\$1,466
FAC	\$1,420
**Variance	\$(046)

Assumptions:

- Budget “restarted” 2022 when costs transferred back to GS-00365
- Lyon 29 is final site selection, includes 16” 5050 pipeline / 4020 retire, Lyon 29 piping reconfiguration costs

Stakeholder Approval

Proceed to Gate 2:

- Implement a new dehydration facility at Lyon 29 site for Lyon 29 and Lyon 34 storage fields
- Implement a separate dehydration facility at Northville Reef for the Northville Reef storage field.

CECo Response AG-CE-0508

U21806-AG-CE-0508

Page 1 of 2

Question:

170. Refer to Table 7 on page 36 of Mr. Joyce's direct testimony on new well projects. Please:

a. Expand the table to include new well information for each year 2019 to 2022 and 2024 actual. Identify the well type and provide in Excel.

b. Explain what each well type entails.

Response:

a.

Table 7: Proposed New Well Drilling Plan

Drill Year	Location	Field	New Well ID	Projected Cost	Completed	Actual Cost thru 2024YE	Well Type
2019	Did Not Drill						
2020	Northville	Northville	N-303	-	Yes	\$4,930,220	New
	St. Clair	Ira	I-203	-	Yes	\$5,351,401	New
2021	Marion	Winterfield	W-1003	-	Yes	\$7,822,084	New
2022	St. Clair	Lenox	L-201	-	Yes	\$8,271,841	New
2023	Marion	Winterfield	W-994 (re-entry)	\$3,338,861	Yes	\$3,242,286	Re-entry
	Marion	Cranberry	C-995	\$6,300,178	Yes	\$6,229,757	New
	Marion	Cranberry	C-996	\$5,251,591	Yes	\$5,101,157	New
2024	Overisel	Overisel	O-305	\$9,759,300	Yes	\$9,832,810	New
	Marion	Cranberry	C-994	\$6,563,713	Yes	\$6,208,712	New
2025	Marion	Winterfield	W-1004	\$10,253,314	No	\$627,871	New
	Marion	Winterfield	W-1005	\$7,728,750	No		New
	Marion	Winterfield	W-1006	\$7,728,750	No		New
	Marion	Cranberry	C-1103	\$10,641,316	No	\$592,655	New
2026	St. Clair	Puttygut	P-301	\$8,237,405	No	\$402,285	New
	St. Clair	Puttygut	P-302	\$6,852,403	No		New
	St. Clair	Four Corners	FC-201 (re-entry)	\$3,537,775	No	\$7,375	Re-entry
	Ray	Ray	R-510	\$9,571,623	No	\$12,685	New
	Ray	Ray	R-511	\$7,102,411	No		New

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- b. A “new well” is drilled without any prior installed infrastructure and is completely new to the system. The description of well “re-entry” is discussed on page 36 lines 5-11 of my direct testimony. Both “new” and “re-entry” wells are drilled with horizontal drainholes to provide the efficient deliverability of gas into and out of the field.

Witness: Timothy K. Joyce

Date: March 17, 2025

U21806-AG-CE-0509

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Question:

171. Refer to Table 8 on page 41 of Mr. Joyce's direct testimony on storage pipeline replacement projects. Please:

- a. Expand the table to include the project number that matches with WPTKJ-6. Provide the amount to be spent by year for each project from inception to completion and provide the expanded table in Excel.
- b. Identify when the Act 9 filing for the Hessen Full Field project was made and provide the case number.

Response:

- a. Please reference the attachment U21806-AG-CE-0509-Joyce_ATT_1.
- b. The Act 9 filing for the Hessen Full Field project was filed on 12/18/2024 and is MPSC case number U21842.

Witness: Timothy K. Joyce

Date: March 17, 2025

CECo Response AG-CE-0509

U21806-AG-CE-0509-Joyce_ATT_1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21806
Page: 1 of 1
Witness: TKJoyce
Date: December 2024

Year	Location	Project Name/ID	Project Type*	Projected Cost	Length (ft)	Act 9 Required	Anticipated File Date	Complete	Actual Cost thru 2024 YE	2022 Actual Expense	2023 Actual Expense	2024 Actual Expense	Projected 2025 Expense	Projected 2026 Expense	Projected 2027 Expense
2023	Marion	Cranberry Lateral 67E- Launcher/Receiver (GS-00457)	Replacement	\$815,072	53	No	N/A	Yes	\$1,181,969	\$0	\$1,114,639	\$67,331	\$0	\$0	\$0
2023	St. Clair	Puttygut Mainline (GS-00464)	Replacement	\$3,649,000	1,426	No	N/A	Yes	\$3,357,248	\$35,789	\$3,288,830	\$32,629	\$0	\$0	\$0
2024	Overisel	Overisel Lateral 2 (GS-00385)	Replacement	\$8,899,720	5,095	No	N/A	Yes	\$8,769,439	\$80,995	\$40,834	\$8,647,610	\$50,000	\$0	\$0
2024	Marion	Cranberry Lateral 61W (GS-00493)	Replacement	\$4,620,000	1,785	No	N/A	Yes	\$2,405,977	\$0	\$30,465	\$2,375,512	\$0	\$0	\$0
2025	Overisel	Overisel Lateral 3 (GS-00514)	Replacement	\$8,281,000	5,227	No	N/A	No	\$190,151	\$0	\$0	\$190,151	\$7,833,000	\$50,000	\$0
2025	Marion	Winterfield Lateral 52SB (GS-00495)	Replacement	\$4,446,000	1,056	No	N/A	No	\$2,634	\$0	\$0	\$2,634	\$4,092,000	\$32,000	\$0
2025	St. Clair	Hessen Full field (GS-00489)	Replacement	\$14,708,988	33,898	Yes	Nov-24	No	\$541,980	\$0	\$234,345	\$307,635	\$15,703,000	\$57,000	\$0
2026	Overisel	Salem ML 2 (GS-00506)	Replacement	\$3,752,000	4,013	No	N/A	No	-	\$0	\$0	\$0	\$62,000	\$3,714,000	\$54,000
2026	Overisel	Salem ML 3 (GS-00505)	Replacement	\$2,942,000	2,800	No	N/A	No	-	\$0	\$0	\$0	\$62,000	\$2,890,000	\$54,000
2026	Overisel	Overisel ML -16" (GS-00515)	Replacement	\$12,675,000	13,707	No	N/A	No	-	\$0	\$0	\$0	\$62,000	\$12,891,000	\$54,000
2023	Marion	Cranberry Lateral 62W (GS-00470)	Retirement	\$1,645,798	9,768	No	N/A	Yes	\$586,370	\$0	\$596,735	(\$10,365)	\$0	\$0	\$0
2024	Overisel	Overisel ML - 10", ML - 12", Lateral 9, 8, 7E/W (GS-00382)	Retirement	\$5,594,252	42,451	No	N/A	Yes	\$6,882,912	\$0	\$141,922	\$6,740,989	\$50,000	\$0	\$0
2024	Marion	Cranberry Lateral 63W (GS-00497)	Retirement	\$420,000	1,486	No	N/A	Yes	\$681,639	\$0	\$8,498	\$673,141	\$36,000	\$0	\$0
2025	Overisel	Salem North Lobe Retirement (GS-00230)	Retirement	\$4,142,000	16,685	No	N/A	No	\$29,808	\$0	\$0	\$29,808	\$4,029,000	\$55,000	\$0
2025	Marion	Winterfield Lateral 56N (GS-00490)	Retirement	\$1,384,000	5,069	No	N/A	No	\$34,126	\$0	\$0	\$34,126	\$1,280,000	\$31,000	\$0
2025	Marion	Winterfield ML 22" (GS-00491)	Retirement	\$1,366,000	6,706	No	N/A	No	\$48,133	\$0	\$0	\$48,133	\$1,269,000	\$30,000	\$0
2026	Marion	Cranberry Lateral 64W (GS-00512)	Retirement	\$1,170,000	4,832	No	N/A	No	-	\$0	\$0	\$0	\$57,000	\$1,004,000	\$52,000
2026	Marion	Cranberry Lateral 66E (GS-00521)	Retirement	\$4,780,000	50,910	No	N/A	No	-	\$0	\$0	\$0	\$49,000	\$3,892,000	\$45,000
2026	Marion	Cranberry Laterals 67N/S (GS-00522)	Retirement	\$1,053,000	5,046	No	N/A	No	-	\$0	\$0	\$0	\$49,000	\$793,000	\$45,000

* Retirement projects are provided for information only; they are entirely COR expense and are not part of the request in this proceeding.

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Question:

377. Refer to ATT_1 to discovery response AG-CE-0521 on compression and storage projects. For each project where the current phase of the project has been designated as "Engineering Design", please provide the month when the phase started and when it will be completed.

Response:

Gas Compression Projects:

Project	Start	End
GC-00655: MRC-Plt-2 119,120,219 Vlv Repl	Jun-2024	Oct-2026
GC-00842: MRC-Plt2 H10 Rbld	Apr-2024	Dec-2027
GC-00463: MRC-SCP Inst	Mar-2024	Jul-2028
GC-00656: MRC-Plt-2 113, 115, Vlv Repl	Mar-2024	Oct-2026
GC-00670: MRC-P2 Dehy Inlet Vlv(s) Repl	Jun-2024	Oct-2026
GC-00813: MRC-Plt2 FG Heater Repl	Feb-2024	May-2028
GC-00124: OVC-Station Cntrls Upgrade	Apr-2023	Jul-2025
GC-00790: OVC-Plt1 NOX Red	Mar-2023	Apr-2026
GC-00837: OVC-Plt1 Lube Oil Ext Inst	Feb-2025	Dec-2026
GC-00803: OVC-Plt1 PG Field Reg Repl	May-2023	Jul-2027
GC-00886: OVC-Plt1 Salem Fld Htr Repl	Aug-2024	Jul-2027
GC-00775: NVL-U1&2 Eng Ctrl Repl	Jul-2023	Aug-2025
GC-00801: NVL-Plt1 JW Repl	Jun-2024	Jun-2026
GC-00784: NVL-Garrett RV Repl	May-2024	Jul-2026
GC-00788: NVL-Comp Air Sys Upgrd	Apr-2024	Jun-2028
GC-00833: NVL-Plt1 Process Gas Vlv Act Repl	Feb-2024	Sep-2026
GC-00774: RAY-Plt3 PG-Comp Vlv Repl	Jun-2024	May-2026
GC-00776: RAY-Plt1&2 Pipe Supt Repl	Nov-2022	Dec-2025
GC-00651: STC-1-1,1-2 Aftercooler Repl	Apr-2022	May-2025
GC-00785: STC-Plt134 Blow Down VS Repl	Jan-2024	Dec-2027
GC-00829: STC-Common 800 S Vlv Repl	Feb-2025	Jul-2026
GC-00839: STC-PLT4-TO Reboiler Bldg Upgrade	Aug-2024	Apr-2026
GC-00757: WPC-Solar Battery Inst	Apr-2022	Oct-2025
GC-00764: WPC-Plt2 Air Comp Repl	Jun-2024	May-2027
GC-00885: WPC-P2 Turbine Inst	Mar-2025	Dec-2028

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Gas Storage Projects:

Site	Title	Internal Approval	Has a Business Case	Projects of \$1 million or greater, provide the current phase of project development	Phase Start	Phase Projected End
St. Clair	GS-00352: STC Puttygut drill new well	Yes	Yes	Engineering Design	1/28/2025	2/27/2026
Marion	GS-00040: MAR Drill New Well R-511	Yes	Yes	Engineering Design	1/28/2025	2/27/2026
Marion	GS-00418: MAR-Drill New Well W-1007	Yes	Yes	Engineering Design	1/28/2025	2/27/2026
Jackson	GS-00034: STC Drill New Well FC-201	Yes	Yes	Engineering Design	1/28/2025	2/27/2026
Marion	GS-00371: STC-Drill New Well R-510	Yes	Yes	Engineering Design	1/28/2025	2/27/2026
Marion	GS-00027: Marion City Gate - Install Distribution	Yes	Yes	Engineering Design	3/14/2025	10/15/2025
Northville	GS-00016: Northville Reef Field Liquid Handling Upgrade	Yes	Yes	Engineering Design	3/1/2025	11/30/2026
Overisel	GS-00461: OVS Salem Scrub Sep Repl	Yes	Yes	Engineering Design	3/1/2025	11/1/2025
St. Clair	GS-00465: STC-4Corners Fac Upgrd	Yes	Yes	Engineering Design	3/1/2025	1/6/2026
Overisel	GS-00058: Overisel ML - 16" (Replacement)	Yes	Yes	Engineering Design	3/1/2025	1/6/2026
Overisel	GS-00505: OVS-Sal 8in ML 3 Repl	Yes	Yes	Engineering Design	3/1/2025	1/6/2026
Overisel	GS-00506: OVS-Sal 16in ML 2 Repl	Yes	Yes	Engineering Design	3/1/2025	1/6/2026
St Clair	GS-00526: JXN- WellSite Data Acquisition Program - Hessen	Yes	Yes	Engineering Design	2/17/2025	11/4/2025
Jackson	GS-00500: STC-Well SSV installs	Yes	Yes	*Engineering Design/Procurement/Construction	March	November

*Multi-year program, design for following year shown.

Witness: Timothy K. Joyce

Date: April 10, 2025

CECo WP-TKJ-5

MICHIGAN PUBLIC SERVICE COMMISSION Consumers Energy Company Compression Capital Detail (2024-2026) For Gas Rate Case - December 2024 (\$000)													
Title	Internal Approval	Has a Business Case	2024 7+5 Fcst	2025	2026	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	Projected Bridge Year	Projected Test Year	Projected			
								22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	10 Mos ending in 10/31/24	12 Mos. Ending 10/31/25	12 Mos Ending 10/31/2026	34 Mos ending 10/31/26
GC-00226: MRC-Clark HBA-9 EngCompr Rbld	Yes	No	56	0	0	56	0	56	0	56	0	0	56
GC-00597: MRC-Pit 2 Jet Installation	Yes	Yes	1	0	0	1	0	1	0	1	0	0	1
GC-00630: MRC-P2 Cooling Wtr System Inst	Yes	Yes	18,474	17,320	486	18,474	14,550	33,024	3,177	7,455	25,569	3,177	36,201
GC-00639: MRC-Plnt 2 Firegate Vlvs Repl	Yes	No	(22)	0	0	(22)	0	(22)	0	(22)	0	0	(22)
GC-00655: MRC-Pit-2 119,120,219 Vlv Repl	Yes	Yes	0	0	1,201	0	0	0	1,009	0	0	1,009	1,009
GC-00667: MRC-P2 TEG Charcoal Filt Inst	Yes	Yes	(2)	0	0	(2)	0	(2)	0	(2)	0	0	(2)
GC-00676: MRC-Pit 2 Air Comp Inst	Yes	Yes	2,527	0	0	2,527	0	2,527	0	2,496	31	0	2,527
GC-00808: MRC-Pit 2-GC 02 Det Inst	Yes	Yes	1	0	0	1	0	1	0	1	0	0	1
GC-00818: MRC-Pit 2 TLA Force Lube Sys Repl	Yes	Yes	5	0	0	5	0	5	0	5	0	0	5
GC-00842: MRC-Pit2 H10 Rbld	Yes	No	250	0	5,183	250	0	250	4,354	0	250	4,354	4,604
GC-00846: MRC-Pit2 Comp Bldg Heat Trace Upgrd	Yes	Yes	51	0	0	51	0	51	0	51	0	0	51
GC-00849: MRC-Solar Piping Stair & Pltfm Inst	Yes	Yes	43	0	0	43	0	43	0	30	13	0	43
GC-00463: MRC-SCP Inst	Yes	Yes	0	0	1,223	0	0	0	1,027	0	0	1,027	1,027
GC-00656: MRC-Pit-2 113, 115, Vlv Repl	Yes	Yes	0	0	1,283	0	0	0	1,078	0	0	1,078	1,078
GC-00670: MRC-P2 Dehy Inlet Vlv(s) Repl	Yes	Yes	0	0	1,263	0	0	0	1,061	0	0	1,061	1,061
GC-00772: MRC-Pit2 Pnl & Bkr Repl	Yes	Yes	0	0	454	0	0	0	382	0	0	382	382
GC-00802: MRC-Pit2 CD Heat Trace Inst	Yes	Yes	0	0	398	0	0	0	334	0	0	334	334
GC-00813: MRC-Pit2 FG Heater Repl	Yes	Yes	0	0	1,272	0	0	0	1,069	0	0	1,069	1,069
GC-00824: MRC-Solar Exh Catalyst Inst	Yes	Yes	50	0	113	50	0	50	95	0	50	95	145
GC-00830: MRC-Pit2 Therm Ox Stack Repl	Yes	Yes	0	0	332	0	0	0	279	0	0	279	279
GC-00852: MRC-Dehy Twr Gas Outlet DPT Repl	Yes	Yes	0	30	0	0	25	25	5	0	25	5	30
GC-00878: MRC-H12 Turbo Repl	Yes	Yes	0	0	304	0	0	0	256	0	0	256	256
TOTAL MUSKEGON RIVER			21,435	17,350	13,513	21,435	14,576	36,010	14,126	10,072	25,938	14,126	50,137
Title			2024 7+5 Fcst	2025	2026								
GC-00124: OVC-Station Cntrls Upgrade	Yes	Yes	1,797	4,327	48	1,797	3,635	5,432	732	735	4,697	732	6,164
GC-00484: OVC-Compression Capital Tools	Yes	No	2	0	0	2	0	2	0	2	0	0	2
GC-00634: OVC-Station Air,JW Cooler Repl	Yes	Yes	14	0	0	14	0	14	0	14	0	0	14
GC-00650: OVC-Valve 347 Repl	Yes	Yes	(13)	0	0	(13)	0	(13)	0	(13)	0	0	(13)
GC-00759: OVC-Unitized Cooling Inst	Yes	Yes	15,328	292	0	15,328	245	15,573	47	14,237	1,336	47	15,619
GC-00780: OVC-Pit1 FG401 Vlv Repl	Yes	Yes	30	330	0	30	277	307	53	0	307	53	360
GC-00790: OVC-Pit1 NOX Red	Yes	Yes	7,107	13,559	244	7,107	11,391	18,498	2,373	3,005	15,493	2,373	20,871
GC-00795: OVC-Pit1 U2 Ex Manifold Repl	Yes	Yes	123	377	0	123	316	440	60	62	378	60	500
GC-00796: OVC-Pit 1 Process Gas PSV 101 & 2101 Rep	Yes	Yes	375	0	315	375	0	375	264	286	89	264	639
GC-00837: OVC-Pit1 Lube Oil Ext Inst	Yes	Yes	50	750	7,348	50	630	680	6,293	0	680	6,293	6,973
GC-00902: OVC-Pit1 EM Gen Mon Press Reg Repl	Yes	Yes	20	0	0	20	0	20	0	20	0	0	20
GC-10375: JXN-Unit Monitoring Program	Yes	No	91	0	0	91	0	91	0	91	0	0	91
GC-00803: OVC-Pit1 PG Field Reg Repl	Yes	Yes	0	186	2,288	0	156	156	1,952	0	156	1,952	2,109
GC-00804: OVC-Pit1 PG Salem Slug Catch	Yes	Yes	0	0	870	0	0	0	731	0	0	731	731
GC-00809: OVC-Pit 1 GC 02 Det Inst	Yes	Yes	0	64	0	0	54	54	10	0	54	10	64
GC-00855: OVC-Pit1 Vlv 410 Repl	Yes	Yes	0	0	368	0	0	0	309	0	0	309	309
GC-00886: OVC-Pit1 Salem Fld Htr Repl	Yes	Yes	0	0	2,841	0	0	0	2,386	0	0	2,386	2,386
GC-00887: OVC-Pit1 Station Inlet MP Repl	Yes	Yes	0	284	0	0	238	238	45	0	238	45	284
GC-00889: OVC-L1100 PGSR Iso Vlv Repl	Yes	Yes	0	85	0	0	72	72	14	0	72	14	85
GC-00890: OVC-Pit1 Prim Fitr Sep RV 53 Repl	Yes	Yes	0	13	0	0	11	11	2	0	11	2	13
GC-00891: OVC-Pit1 Corr Iso Vlv LIB.L3B Repl	Yes	Yes	0	0	230	0	0	0	193	0	0	193	193
GC-00892: OVC-Pit1 Suct Scrub Iso Vlv Repl	Yes	Yes	0	0	114	0	0	0	96	0	0	96	96
TOTAL OVERISEL			24,925	20,266	14,665	24,925	17,025	41,950	15,561	18,439	23,512	15,561	57,511

CECo WP-TKJ-5

Title			2024 7+5 Fcst	2025	2026								
GC-00149: NVL-Elect Sys Upgrd	Yes	Yes	1,789	0	0	1,789	0	1,789	0	1,338	451	0	1,789
GC-00487: NVL-Compression Capital Tools	Yes	No	14	0	0	14	0	14	0	14	0	0	14
GC-00638: NVL-Fire Gate Valve Repl	Yes	No	23	0	0	23	0	23	0	23	0	0	23
GC-00775: NVL-U1&2 Eng Ctrl Repl	Yes	Yes	858	3,893	1,797	858	3,270	4,128	2,132	425	3,703	2,132	6,261
GC-00801: NVL-Pit1 JW Repl	Yes	Yes	83	453	3,466	83	380	463	2,984	8	455	2,984	3,447
GC-00835: NVL-Pwr Gas XMTR Inst	Yes	Yes	18	0	0	18	0	18	0	10	8	0	18
GC-00641: NVL-Int After Cooler Repl	Yes	No	0	0	580	0	0	0	488	0	0	0	488
GC-00784: NVL-Garrett RV Repl	Yes	Yes	0	285	2,381	0	239	239	2,046	0	239	2,046	2,285
GC-00788: NVL-Comp Air Sys Upgrd	Yes	Yes	0	0	2,195	0	0	0	1,844	0	0	1,844	1,844
GC-00833: NVL-Pit1 Process Gas Vlv Act Repl	Yes	Yes	0	0	1,046	0	0	0	879	0	0	879	879
GC-00893: NVL-Pit1 Mkt Gas Cooler Repl	Yes	Yes	0	0	406	0	0	0	341	0	0	341	341
GC-00894: NVL-Pit1 Stn Ctrls Repl	Yes	No	0	0	406	0	0	0	341	0	0	341	341
TOTAL NORTHVILLE			2,786	4,630	12,278	2,786	3,890	6,676	11,055	1,818	4,858	11,055	17,731

Title			2024 7+5 Fcst	2025	2026								
GC-00023: (13829) RAY - 3-2 Starter Repl	Yes	No	20	0	0	20	0	20	0	0	20	0	20
GC-00483: RAY-Compression Capital Tools	Yes	No	(0)	0	0	(0)	0	(0)	0	(0)	0	0	(0)
GC-00609: RAY - VLV 803 REPL	Yes	No	(1)	0	0	(1)	0	(1)	0	(1)	0	0	(1)
GC-00629: RAY-P2 FGV 607-608 Repl	Yes	No	18	0	0	18	0	18	0	18	0	0	18
GC-00657: RAY-Emergent Capital Expense (2019)	Yes	No	(2)	0	0	(2)	0	(2)	0	(2)	0	0	(2)
GC-00736: RAY-Stn Compressed Air Sys Upgrd	Yes	Yes	6,920	295	0	6,920	248	7,167	47	6,519	648	47	7,215
GC-00789: RAY-UPS Batt Repl	Yes	Yes	55	0	0	55	0	55	0	0	55	0	55
GC-00820: RAY-Unit 3-3 Starter Repl	Yes	Yes	0	0	0	0	0	0	0	0	0	0	0
GC-00321: RAY-Plant 1Vlv 354Repl	Yes	No	0	0	286	0	0	0	240	0	0	240	240
GC-00322: RAY-Plant 1Vlv 364 Repl	Yes	No	0	0	286	0	0	0	240	0	0	240	240
GC-00774: RAY-Pit3 PG-Comp Vlv Repl	Yes	Yes	0	3,637	0	0	3,055	3,055	582	0	3,055	582	3,637
GC-00776: RAY-Pit1&2 Pipe Supt Repl	Yes	No	0	0	1,334	0	0	0	1,121	0	0	1,121	1,121
GC-00863: RAY-Pit1.2 DeHy Slam Shut Vlv	Yes	No	0	283	0	0	238	238	45	0	238	45	283
GC-00864: RAY-Unit 3-4 Turbo Rbl	Yes	No	0	0	183	0	0	0	153	0	0	153	153
GC-00865: RAY-Unit 3-4 Starter Repl	Yes	No	0	26	0	0	22	22	4	0	22	4	26
GC-00866: RAY-Pit1.2 Blowdown Sys	Yes	No	0	0	870	0	0	0	731	0	0	731	731
GC-00867: RAY-Pit1.2 DeHy Pit Repl	Yes	No	0	0	580	0	0	0	488	0	0	488	488
GC-00868: RAY-P3 FCV Rbl	Yes	No	0	0	522	0	0	0	439	0	0	439	439
GC-00869: RAY-Pit2 Boiler Repl	Yes	No	0	0	345	0	0	0	290	0	0	290	290
GC-00870: RAY-Pit3 Hotstart Repl	Yes	No	0	0	115	0	0	0	97	0	0	97	97
RAY TOTAL			7,010	4,241	4,521	7,010	3,563	10,573	4,476	6,534	4,039	4,476	15,049

Title			2024 7+5 Fcst	2025	2026								
GC-00482: STC-Compression Capital Tools	Yes	No	(0)	0	0	(0)	0	(0)	0	(0)	0	0	(0)
GC-00651: STC-1-1,1-2 Aftercooler Repl	Yes	Yes	2,114	2,228	0	2,114	1,872	3,987	356	931	3,055	356	4,343
GC-00710: STC-H2O Transducer Inst	Yes	No	(4)	0	0	(4)	0	(4)	0	(4)	0	0	(4)
GC-00755: STC-Plnt 3 Unit ESM2 Inst	Yes	Yes	28	0	0	28	0	28	0	28	0	0	28
GC-00762: STC-Unit 1-1 Silencer Repl	Yes	Yes	779	0	0	779	0	779	0	779	0	0	779
GC-00770: STC-Pit1 FG Piping Fltr	Yes	Yes	244	558	0	244	469	714	89	87	626	89	803
GC-00782: STC-Pit3 Wtr Cool FanGbox Repl	Yes	Yes	50	0	0	50	0	50	0	(47)	97	0	50
GC-00807: STC-Pit3 Glycol Tnk Repl	Yes	Yes	221	0	0	221	0	221	0	216	6	0	221
GC-00819: STC-Pit 3 Lighting Upgrade	Yes	Yes	12	0	0	12	0	12	0	12	0	0	12
GC-00832: STC-Pit4 Flame Det Install	Yes	Yes	1	0	0	1	0	1	0	1	0	0	1
GC-00851: STC-UPS Batteries	Yes	Yes	165	0	0	165	0	165	0	110	55	0	165
GC-00785: STC-Pit134 Blow Down VS Repl	Yes	Yes	0	0	4,587	0	0	0	3,854	0	0	3,854	3,854
GC-00794: STC- D3 Relief Vlv Repl	Yes	Yes	0	140	284	0	118	118	261	0	118	261	379
GC-00829: STC-Common 800 S Vlv Repl	Yes	Yes	0	324	4,467	0	272	272	3,805	0	272	3,805	4,077
GC-00839: STC-PLT4-TO Reboiler Bldg Upgrade	Yes	Yes	0	1,062	5,653	0	892	892	4,919	0	892	4,919	5,811
GC-00876: STC-Common Scrubbers	Yes	Yes	0	0	870	0	0	0	731	0	0	731	731
GC-00877: STC-P1 Enclosure Upgrd	Yes	No	0	0	580	0	0	0	488	0	0	488	488
ST CLAIR TOTAL			3,610	4,313	16,442	3,610	3,623	7,234	14,502	2,112	5,122	14,502	21,736

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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CECo WP-TKJ-5

Title			2024 7+5 Fcst	2025	2026								
GC-00033: JXN - Small Valves and Instrumentation	Yes	No	60	0	0		60	0	60	0		0	60
GC-00051: GC-00913 WPC-Pit3 Tk Lvl Tm Repl	Yes	Yes	40	0	0		40	0	40	0		0	40
GC-00486: WPC-Compression Capital Tools	Yes	No	5	0	0		5	0	5	0		5	0
GC-00714: WPC-Aftercooler Walkway Modification	Yes	No	19	0	0		19	0	19	0		19	0
GC-00757: WPC-Solar Battery Inst	Yes	Yes	2,144	1,400	0		2,144	1,176	3,320	224		489	2,832
GC-00568: WPC-Cat 3616 3-3 Turbo Rebuild	Yes	No	0	298	0		0	250	250	48		0	250
GC-00764: WPC-Pit2 Air Comp Repl	Yes	Yes	0	0	1,612		0	0	0	1,354		0	0
GC-00766: WPC-Site Road Repl	Yes	Yes	0	0	671		0	0	0	563		0	0
GC-00880: WPC-P2 Pipe Support Repl	Yes	No	0	0	254		0	0	0	213		0	0
GC-00881: WPC-P3 U2.3.4 Chk Vlv Repl	Yes	Yes	0	0	341		0	0	0	286		0	0
GC-00882: WPC-P3 FGR ESD Vent Inst	Yes	No	0	0	580		0	0	0	488		0	0
GC-00883: WPC-P1 Aux Bldg Repl	Yes	No	0	0	339		0	0	0	285		0	0
GC-00884: WPC-P3 Aux Mech Rm Exh Fan	Yes	No	0	0	96		0	0	0	80		0	0
GC-00032: JXN - Operations Capital Tools	Yes	No	0	83	566		0	70	70	489		0	70
GC-00033: JXN - Small Valves and Instrumentation	Yes	No	0	0	119		0	0	0	100		0	0
GC-00045: JXN - Comp Engineer Analyzers	Yes	No	0	0	60		0	0	0	50		0	0
GC-00885: WPC-P2 Turbine Inst	Yes	Yes	0	0	2,552		0	0	0	2,144		0	0
WHITE PIGEON TOTAL			2,268	1,782	7,188		2,268	1,497	3,765	6,324		513	3,252
TOTAL FREEDOM UPGRADE			726	0	0		726	0	726	0		579	146
OTHER COMPRESSION PORTFOLIO - excludes Freedom upgrade			62,266	53,086	68,693		62,266	44,597	106,863	66,198		39,551	67,312
TOTAL COMPRESSION PORTFOLIO			62,992	53,086	68,693		62,992	44,597	107,589	66,198		40,130	67,459

CECo Response AG-CE-0517

U21806-AG-CE-0517

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Question:

179. Refer to Exhibit A-12, Schedule B-5.7, page 2. Please expand this schedule to include actual amounts for 2024 and provide it in Excel.

Response:

Please reference the attachment U21806-AG-CE-0517-Joyce_ATT_1.

Witness: Timothy K. Joyce

Date: March 17, 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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CECo Response AG-CE-0517

U21806-AG-CE-0517-Joyce_ATT_1							
MICHIGAN PUBLIC SERVICE COMMISSION					Case No.:	U-21806	
Consumers Energy Company					Exhibit No.:	A-12 (TKJ-5)	
Projected Capital Expenditures					Schedule:	B-5.7	
Gas Compression and Gas Storage					Page:	1 of 6	
Summary of Actual & Projected Gas Capital Expenditures (\$000)					Witness:	TKJoyce	
					Date:	December 2024	
(a)			(b)	(c)	(d)	(e)	
			Preliminary Actuals	Projected Bridge Period			Projected Test Year
Historical Year							
Line		12 Mos Ended	12 Mos Ended	12 Mos Ended	10 Mos Ending	22 Mos Ending	12 Mos Ending
No	Description	12/31/2023	12/31/2024	12/31/2024	10/31/2025	10/31/2025	10/31/2026
1	Freedom Upgrade Project	8,413	983	726	0	726	0
2	Compression	39,197	58,272	62,267	44,597	106,864	66,198
3	Storage	6,765	25,805	28,548	35,690	64,238	25,234
4	New Well	11,403	15,025	17,202	28,004	45,205	32,296
5	Well Rehabilitation	31,031	26,981	23,681	22,341	46,022	7,498
6	Storage Pipeline Replacement	3,550	13,835	14,836	24,398	39,233	20,930
7	Well Data Acquisition	239	62	203	3,671	3,875	4,568
8	Riverside Field Retirement	12,449	24,256	25,439	23,756	49,195	3,504
9	Safety Valve Installation	0	2,557	2,438	1,599	4,037	1,811
10	Total Capital Expenditures	113,046	167,776	175,339	184,056	359,395	162,039

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Question:

84. Refer to the Tracking and Traceability project on pages 76 of Mr. Warriner's direct testimony. Please provide the current phase of the project. State whether the Company has completed the full requirements phase of the project and when it was completed.

Response:

The Tracking and Traceability project is currently in the Origination phase. High-level requirements were developed on 6/7/2023, which allowed the Company to finalize the six scope of work items identified on page 77 lines 1 through 10 of my direct testimony. The detailed requirements are expected to be completed for each scope item in phases as follows:

- (1) changes in SAP Supply Chain processes to capture the required barcode information for all plastic components used in gas distribution and service lines – 8/1/2026;
- (2) changes in SAP Work Management processes to account for capturing barcode information as part of material components added to work orders, capturing fusion information from work order completion and capturing GPS coordinates from work order completion – 8/1/2026;
- (3) changes in GIS to capture GPS coordinates of plastic components and GPS coordinates of component fusions – 12/1/2025;
- (4) building of a repository for tracking and traceability reporting and analysis – 8/1/2026;
- (5) purchasing barcode reading equipment for storerooms and gas distribution trucks – 9/1/2025; and
- (6) purchasing of GPS locating equipment to capture coordinates – 9/1/2025.

Witness: Lincoln D. Warriner

Date: March 10, 2025

CECo Response AG-CE-0766

U21806-AG-CE-0766
Page 1 of 1

Question:

337. Refer to discovery response AG-CE-0370 on the Tracking and Traceability project. Please identify in which exhibit and line number the capital and O&M expenditures are shown or included.

Response:

The tables below provide the exhibit and line number where the ROM adjusted capital and Investments O&M expenses for the Tracking & Traceability project are included.

ROM Adjusted Capital		
Exhibit Reference	10 Mos Ending 10/31/2025	Projected Test Year 12 Mos. Ending 10/31/2026
A-12 (SHB-4), page 1, line 4	\$2,217,620	\$5,295,411

Investments O&M			
Exhibit Reference	2 Months Ending 12/31/2025	10 Months Ending 10/31/2026	Projected Test Year 12 Mos. Ending 10/31/2026
A-19 (SHB-3), page 1, line 3	\$85,065	\$423,542	\$508,607

Witness: Stacy H. Baker
Date: April 3, 2025

CECo Response AG-CE-0610

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Question:

228. Refer to page 46 of Ms. Baker's direct testimony on ROM projects. Please provide in Excel a list of ROM projects showing the ROM adjusted amount for each year 2023, 2024, 2025, 2026, 10 months ending October 2025, and the 12 months ending October 2026.

Response:

Refer to Attachment No. U21806-AG-CE-0610_ATT_1 and U21806-AG-CE-0610_ATT_2_CONF for the ROM projects showing the ROM adjusted capital amount for each year 2023, 2024, 2025, 2026, 10 months ending October 2025, and the 10 months ending October 2026.

Witness: Stacy H. Baker

Date: March 21, 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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Exhibit: AG-27

April 23, 2025

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CECo Response AG-CE-0610

MICHIGAN PUBLIC SERVICE COMMISSION				Attachment: U21806-AG-CE-0610			
Consumers Energy Company				Witness: SHBaker			
Summary of ROM Adjusted Capital Amounts				Date: March 2025			
For the Years 2023, 2024, 2025, 2026, 10 months ending October 2025, and the 10 months ending October 2026							
	(a)	(b)	(c)	(e)	(g)	(d)	(f)
		Actuals			Projected		
Line		12 Mos Ended	12 Mos Ended	12 Mos Ending	12 Mos Ending	10 Mos Ending	10 Mos Ending
N	Description	12/31/2023	12/31/2024	12/31/2025	12/31/2026	10/31/2025	10/31/2026
1	Application Currency-Corporate-Capital	\$ -	\$ -	\$ 14,410	\$ 48,994	\$ 12,008	\$ 40,828
2	Application Currency-Corporate-O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
3	Application Currency-Customer-O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
4	Application Currency-Electric & Gas Shared-Capital	\$ -	\$ -	\$ 30,952	\$ 98,842	\$ 25,794	\$ 82,368
5	Application Currency-Electric & Gas Shared-O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
6	Application Currency-Gas-Capital	\$ -	\$ -	\$ -	\$ 29,240	\$ -	\$ 24,367
7	Application Currency-Gas-O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
8	Application Currency-IT/Digital Foundation-Application Platforms-Capital	\$ -	\$ -	\$ 12,131	\$ 46,906	\$ 10,109	\$ 39,089
9	Application Currency-IT/Digital Foundation-Application Platforms-O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
10	Application Currency-IT/Digital Foundation-Infrastructure Platforms-O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
11	Application Currency-Operational Technology-Capital	\$ -	\$ -	\$ -	\$ 44,466	\$ -	\$ 37,055
12	Application Currency-Operational Technology-O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
13	Application Currency-Security-Capital	\$ -	\$ -	\$ 36,761	\$ 36,761	\$ 30,634	\$ 30,634
14	Application Currency-Security-O&M	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
15	Asset Accounting Tax Upgrade	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
16	Asset Accounting Upgrade 2025-2026	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
17	AxWay Secure Transport 2024 Upgrade	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
18	Business Continuity - Program Management Tool	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
19	Compression Air Permit And Compliance Digitalization	\$ -	\$ -	\$ -	\$ 369,804	\$ -	\$ 308,170
20	Customer Order Service Tracker	\$ -	\$ -	\$ 606,700	\$ 404,466	\$ 505,583	\$ 337,055
21	Data & Analytics Platform Rationalization	\$ -	\$ -	\$ 1,669,079	\$ 845,874	\$ 1,390,899	\$ 704,895
22	Enterprise Risk Management	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
23	Enterprise Service Bus Application 2024-2025 Upgrade	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
24	Expense Reporting Improvements	\$ -	\$ -	\$ -	\$ 148,199	\$ -	\$ 123,499
25	Forward Web Proxy Services	\$ -	\$ -	\$ -	\$ 1,126,836	\$ -	\$ 939,030
26	Gas Distribution Probabilistic Risk Model	\$ -	\$ -	\$ 1,945,136	\$ 831,712	\$ 1,620,947	\$ 693,093
27	Gas Leak Asset and Work Management	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
28	ISIS Papyrus 2026 Upgrade	\$ -	\$ -	\$ -	\$ 180,961	\$ -	\$ 150,801
29	Ittron Enterprise Edition 2025 Upgrade	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
30	Next Generation electronic Shift Operations Management System (eSOMS) Replacement	\$ -	\$ -	\$ -	\$ 150,895	\$ -	\$ 125,746
31	Operational Technology (OT) Datacenter Migration	\$ -	\$ -	\$ -	\$ 1,729,208	\$ -	\$ 1,441,007
32	Physical Access Management and Alarm Response	\$ -	\$ -	\$ -	\$ 813,070	\$ -	\$ 677,559
33	Replacement for Gas Automated Meter Reading (AMR) Technology	\$ -	\$ -	\$ -	\$ 822,080	\$ -	\$ 685,067
34	Security Threat Intelligence Tool	\$ -	\$ -	\$ -	\$ 183,143	\$ -	\$ 152,619
35	Security/OT Field Modernization	\$ -	\$ -	\$ 209,982	\$ 82,082	\$ 174,985	\$ 68,402
36	Self Service Vendor Portal	\$ -	\$ -	\$ -	\$ 33,898	\$ -	\$ 28,248
37	SiteCore Primary Upgrade 2025	\$ -	\$ -	\$ 29,276	\$ -	\$ 24,396	\$ -
38	Spatial Asset Management	\$ -	\$ 221,503	\$ 179,508	\$ -	\$ 149,590	\$ -
39	Standard Work Plan	\$ -	\$ -	\$ 231,938	\$ -	\$ 193,282	\$ -
40	Talent Management Enablement	\$ -	\$ -	\$ 138,569	\$ -	\$ 115,474	\$ -
41	Tracking & Traceability	\$ -	\$ -	\$ 2,661,144	\$ 5,822,264	\$ 2,217,620	\$ 4,851,887

Exhibit AG-28

CONFIDENTIAL

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Question:

242. Refer to page 108 of Ms. Baker's direct testimony on the SAP S/4HANA project support. Please:

- a. Confirm that the current SAP-ERP system functions well and the Company would not look to replace the system but for the expected end of system support from SAP. If not confirming provide evidence otherwise.
- b. Has the Company asked SAP to extend support for the current system through 2030 and potentially past 2030? If yes, provide details on the request and response with a copy of any written correspondence. If no explain, why not.
- c. Identify the number of times that the Company requested SAP to provide support for the ERP system and describe what that support entailed in the past five years.
- d. Does the Company have IT personnel who are knowledgeable of the SAP-ERP system and have resolved programming problems since implementation of the current system? If yes, identify the type of problems solved by Company personnel versus SAP personnel. If no, explain why not.
- e. Does the Company allow internet access to its ERP system? If yes, explain why and for what reasons or purpose.
- f. Does the Company have strong cyber-security shields in place for internet access to its computer systems? If no, explain why not.
- g. What additional cyber-security defenses would the new SAP system provide that the Company does not have in place currently?

Response:

- a. The current SAP-ERP system functions well. The Company must replace the current system due to the end of system support from SAP. The end of system support is critical for the SAP-ERP system, since it means we won't be able to engage SAP support team for operational incidents with the system software. Also, it means, we will not receive Security updates from SAP for the software version beyond 2030.
- b. The Company has not asked SAP to extend the current system through 2030 and potentially past 2030. Extending the current system through 2030 would require the Company to purchase extended support. Refer to my direct testimony on page 109, lines 3 through 10 for further explanation on why the Company must undertake this project at this time.
- c. The Company has raised 1,015 tickets with SAP over the past five years, 2020 – 2025. There were 450 system fixes and 565 support tickets. SAP support tickets serve as a primary way for customers to report issues or request assistance with SAP products and services.
- d. The Company does have resources that are knowledgeable of the SAP-ERP system. Standard SAP code is not modified by the Company's resources. SAP does not recommend standard code modifications, as it has the potential to create risk/failure with the system.
- e. The Company does not allow internet access to its SAP-ERP system.

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- f. The Company has strong cyber-security standards and protections in place for internet access to its computer systems.
- g. SAP S/4HANA offers enhanced security features beyond the standard SAP HANA security functions, including data masking, data anonymization, and data-at-rest encryption, along with authentication and authorization mechanisms, to strengthen data privacy and protection, support audit and regulatory requirements, and improve threat detection and response.

Witness: Stacy H. Baker

Date: March 21, 2025

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Page 1 of 1

Question:

243. Refer to page 109 of Ms. Baker's direct testimony on the SAP S/4HANA project cost. Please:

- a. Confirm that the Company issued requests for proposal to multiple vendors to replace the SAP-ERP. If confirming, provide the list of vendors solicited and the vendors that responded. Provide a copy of the bid analysis identifying the selection of SAP as the best and least costly option. If no, explain why not.
- b. Provide the total cost of the project by major component and by phase.
- c. If previous project cost estimates were prepared, provide those estimates and explain the reasons for project cost changes.

Response:

- a. The Company is currently preparing to issue a request for proposal (RFP) in May of 2025.
- b. Refer to Attachment No. U21806-AG-CE-0622_ATT 1_CONF for total cost of the project by year. Refer to Attachment No. U21806-SA-CE-241_ATT_1 for estimated timeline by release. Refer to my direct testimony pages 109-110 for how the cost estimate was developed.
- c. A previous cost estimate has not been prepared for the SAP S/4HANA Implementation project.

Witness: Stacy H. Baker
Date: March 24, 2025

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Question:

256. Refer to Page 1, 4, 6, 7, 8, 10, and 12 of Exhibit A-22 on the IT ARP programs. Please:

- a. Expand each page to include the same information for units and dollars for actual years 2022 and 2024, and projected costs for the 10 months ending October 2025. Provide the expanded schedules in Excel.
- b. For each page, provide also the number of units/devices in place at the end of each year 2022 through 2024 in Excel.

Response:

- a. Refer to attachment U21806-AG-CE-0638_ATT_1 for units and dollars for 2022 and 2023 actual, 2024 preliminary actual, projected 2025, 2026, and test year, and projected costs for the 10 months ending October 2025.
- b. Refer to attachment U21806-AG-CE-0638_ATT_1 for the number of units/devices put in place at the end of each year 2022, 2023 and preliminary 2024.

Witness: Stacy H. Baker

Date: March 24, 2025

CECo Response AG-CE-0638

MICHIGAN PUBLIC SERVICE COMMISSION Consumers Energy Company Asset Refresh Programs Projected Gas and Common Capital Expenditures For actual year 2022 and preliminary actual year 2024, and projected costs for the 10 months ending October 2025. For the number of units/devices in place at the end of each year 2022, 2023, and 2024							Attachment: U21806-AG-CE-0638_ATT_1	Witness: SHBaker	Page: 7 of 7 Date: March 2025
ARP-Workstation Asset Mgmt									
Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Units	Avg. Unit Cost	Total 2025 Units	Total 2026 Units	Total 2025 Dollars	Total 2026 Dollars	Total Test Year Dollars	Gas Allocation Dollars	10 months ending October 2025
	Replacements								
1	Desktops	\$1,378	35	95	\$48,230	\$130,910	\$117,130	\$36,814	\$40,192
2	HP Desktop Bundled	\$4,049	67	41	\$271,296	\$166,017	\$183,564	\$57,694	\$226,080
3	Laptop	\$1,908	2533	1787	\$4,832,964	\$3,409,596	\$3,646,824	\$1,146,197	\$4,027,470
4	Laptop 15"	\$3,037	654	273	\$1,986,133	\$829,074	\$1,021,917	\$321,188	\$1,655,111
5	RT Mount Device	\$8,480	20	15	\$169,600	\$127,200	\$134,267	\$42,200	\$141,333
6	Tablets	\$2,644	67	4	\$177,171	\$10,577	\$38,343	\$12,051	\$147,643
7	Accessories				\$51,443	\$97,133	\$89,518	\$28,135	\$42,869
	New Purchases								
8	24" Monitors	\$233	120	120	\$27,984	\$27,984	\$27,984	\$8,795	\$23,320
9	Apple Tablets	\$1,025	1	1	\$1,025	\$1,025	\$1,025	\$322	\$854
10	Desktop (MT)	\$1,378	14	14	\$19,292	\$19,292	\$19,292	\$6,063	\$16,077
11	SFF Desktop	\$1,246	8	8	\$9,964	\$9,964	\$9,964	\$3,132	\$8,303
12	HP Desktop	\$4,049	5	5	\$20,246	\$20,246	\$20,246	\$6,363	\$16,872
13	HP laptop (15"/16")	\$3,037	60	60	\$182,214	\$182,214	\$182,214	\$57,270	\$151,845
14	Laptop (14")	\$1,908	302	302	\$576,216	\$576,216	\$576,216	\$181,105	\$480,180
15	Antennas	\$1,942	3	3	\$5,827	\$5,827	\$5,827	\$1,831	\$4,856
16	Teams Monitors	\$323	280	280	\$90,524	\$90,524	\$90,524	\$28,452	\$75,437
17	Accessories				\$64,000	\$64,000	\$64,000	\$20,115	\$53,333
18	Shipping and Handling/other fees				\$2,708	\$2,708	\$2,708	\$851	\$2,256
19	Software, labor, contractor and overhead and other costs				\$445,632	\$299,771	\$324,081	\$101,859	\$371,360
20	Total Gas Allocation				\$8,982,469	\$6,070,278	\$6,555,643	\$2,060,439	\$7,485,391
	Units	Avg. Unit Cost	Total 2023 Units	Preliminary Actual 2024 Units	Total 2023 Dollars	Preliminary Actual 2024 Dollars	2023 Gas Allocation Dollars	Preliminary Actual 2024 Gas Allocation Dollars	
	Replacements								
21	Desktops	\$1,314	437	0	\$574,332	\$0	\$184,246	\$0	
22	Desktops	\$1,540	0	128	\$0	\$197,098	\$0	\$137,279	
23	SFF Desktop	\$1,251	10	0	\$12,508	\$0	\$4,013	\$0	
24	SFF Desktop	\$1,562	0	115	\$0	\$179,592	\$0	\$125,086	
25	HP Desktop Bundled	\$4,419	77	0	\$340,277	\$0	\$109,161	\$0	
26	HP Desktops OT	\$6,081	0	65	\$0	\$395,246	\$0	\$275,289	
27	Laptop	\$1,764	1253	0	\$2,209,853	\$0	\$708,921	\$0	
28	Laptop	\$2,740	189	0	\$517,828	\$0	\$166,119	\$0	
29	Laptop	\$1,843	0	912	\$0	\$1,681,236	\$0	\$1,170,981	
30	HP Laptop bundled	\$3,577	77	0	\$275,441	\$0	\$88,362	\$0	
31	HP Laptop bundled	\$3,131	0	512	\$0	\$1,603,308	\$0	\$1,116,704	
32	Rugged Devices	\$4,152	104	0	\$431,775	\$0	\$138,513	\$0	
33	RT Mount Device	\$8,480	0	51	\$0	\$432,480	\$0	\$301,222	
34	Surface Pro Laptops	\$3,342	0	17	\$0	\$56,806	\$0	\$39,565	
35	Tablets	\$1,825	6	0	\$10,952	\$0	\$3,513	\$0	
36	Tablets	\$2,187	0	39	\$0	\$85,290	\$0	\$59,405	
37	Accessories				\$267,836	\$148,563	\$85,922	\$103,474	
	New Purchases								
38	24" Monitors	\$233	79	0	\$18,423	\$0	\$5,910	\$0	
39	Apple Macbook	\$2,833	2	0	\$5,667	\$0	\$1,818	\$0	
40	Desktop	\$1,314	11	0	\$14,457	\$0	\$4,638	\$0	
41	Desktop	\$1,540	0	3	\$0	\$4,619	\$0	\$3,217	
42	HP Desktop	\$4,419	1	0	\$4,419	\$0	\$1,418	\$0	
43	HP Desktop	\$4,505	0	4	\$0	\$18,020	\$0	\$12,551	
44	HP laptop	\$3,131	0	100	\$0	\$313,146	\$0	\$218,106	
45	HP laptop	\$2,740	23	0	\$63,016	\$0	\$20,216	\$0	
46	Laptop	\$1,764	70	0	\$123,456	\$0	\$39,605	\$0	
47	Laptop	\$1,843	0	204	\$0	\$376,066	\$0	\$261,930	
48	Rugged Devices - Getac	\$4,718	45	0	\$212,313	\$0	\$68,110	\$0	
49	Rugged Devices - Panasonic CF33	\$4,152	113	0	\$469,140	\$0	\$150,500	\$0	
50	Semi-Rugged Devices - Panasonic FZ55	\$4,003	14	0	\$56,046	\$0	\$17,979	\$0	
51	SFF Desktop	\$1,251	3	0	\$3,752	\$0	\$1,204	\$0	
52	SFF Desktop	\$1,562	0	10	\$0	\$15,617	\$0	\$10,877	
53	Surface Pro Tablets	\$2,008	2	0	\$4,015	\$0	\$1,288	\$0	
54	Surface Pro Tablets	\$2,187	0	2	\$0	\$4,374	\$0	\$3,046	
55	Teams Monitors	\$324	92	0	\$29,841	\$0	\$9,573	\$0	
56	Teams Monitors	\$323	0	331	\$0	\$107,012	\$0	\$74,534	
57	Accessories				\$181,343	\$115,420	\$58,175	\$80,390	
58	Shipping and Handling/other fees				\$12,942	\$0	\$4,152	\$0	
59	Software, labor, contractor and overhead and other costs				\$312,824	\$259,099	\$100,354	\$180,462	
60	Total Gas Allocation				\$6,152,454	\$5,992,992	\$1,973,707	\$4,174,119	
	From (U-21490) A-22 (SHB-7)								
	Units	Avg. Unit Cost	Total 2022 Units	Total 2022 Dollars	2022 Gas Allocation Dollars				
	Replacements								
61	Curved Monitors	\$1,179	12	\$14,148	\$4,246				
62	Desktops	\$1,070	43	\$46,010	\$13,808				
63	HP Desktop Bundled	\$3,664	40	\$146,560	\$43,983				
64	HP Laptop bundled	\$4,226	22	\$92,972	\$27,901				
65	Laptop	\$1,767	1346	\$2,378,382	\$713,752				
66	Laptop 15"	\$2,577	95	\$244,815	\$73,469				
67	Monitors 24"	\$249	976	\$243,024	\$72,832				
68	Rugged Devices	\$4,424	13	\$57,512	\$17,259				
69	Semi Rugged Devices	\$3,312	17	\$56,304	\$16,897				
70	SFF Desktop	\$1,075	31	\$33,325	\$10,001				
71	Tablets	\$1,784	4	\$7,136	\$2,142				
72	Teams Monitors	\$324	69	\$22,381	\$6,716				
73	Accessories			\$486,961	\$146,137				
	New Purchases								
74	15"/16" HP laptop	\$2,577	14	\$36,078	\$10,827				
75	17" HP laptop	\$4,226	39	\$164,814	\$49,461				
76	24" Monitors	\$249	623	\$155,127	\$46,554				
77	Apple Macbook	\$2,330	7	\$16,310	\$4,895				
78	Apple Tablets	\$1,128	1	\$1,128	\$336				
79	Desktops MT /SFF	\$1,070	5	\$5,350	\$1,606				
80	Laptops 14"	\$1,767	405	\$715,635	\$214,762				
81	Rugged Devices	\$4,424	127	\$561,848	\$168,611				
82	Semi Rugged devices (Toughpads)	\$3,312	33	\$109,296	\$32,800				
83	Surface Pro Devices	\$1,784	1	\$1,784	\$535				
84	Teams Monitors	\$324	381	\$123,581	\$37,087				
85	PC Accessories			\$300,589	\$90,207				
86	Shipping and Handling, Asset tagging, other fees			\$1,434	\$430				
87	Software, labor, contractor and overhead and other costs			\$360,945	\$108,320				
88	Total Gas Allocation			\$6,383,449	\$1,915,673				

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Question:

234. Refer to lines 16-40 on page 62 and lines 1-5 on page 63 of Ms. Baker's direct testimony on the ARP-Physical Security. Please:

- a. Identify the problems experienced with security assets in the last three years and the number of problems experienced.
- b. Explain why the Company needs advanced door systems and how these systems differ from current door systems.
- c. Regarding security cameras, gate and lock systems, confirm that these devices and systems are already in place at the Company. If confirming, explain what is being proposed for the additional expenditures. If not confirming, explain why these devices and systems are not already being used.
- d. Regarding Alternatives 1 and 2, what are the specific risks that would exist?

Response:

- a. Incidents experienced with physical security assets include cameras no longer working, wiring issues, require cleaning, transmitter failures, hard drive failures, reader failures, door strike failures, and control board failures. Following is a table with the number of incidents for the last three years related to physical security assets.

Year	Number of Incidents
2022	758
2023	554
2024	568

- b. The Company requires advanced door systems, as the current badges can be easily cloned by off the shelf equipment leading to security vulnerabilities. This project would upgrade badge readers and control boards with encryption.
- c. Yes, the Company currently uses security cameras, motorized gates, and exterior pedestrian doors at occupied facilities controlled by badge readers for access. This project would upgrade badge readers and control boards with encryption to reduce security vulnerabilities.
- d. By not refreshing physical security assets or deferring a portion of the asset refreshes, the Company risks utilizing older, unsupported equipment, which results in continued security vulnerabilities and increased O&M costs to maintain older equipment.

Witness: Stacy H. Baker
Date: March 19, 2025

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Question:

399. Refer to discovery response AG-CE-0616 on ARP Physical Security. Please:

- a. Regarding subpart (a), provide the number of touch-points each year that relate to the number of incidents reported. Provide a few examples of the type of incidents that occurred in 2024.
- b. Regarding subpart (d), provide the increase in O&M costs and from what amount they would increase.

Response:

- a. Assuming that a touchpoint is referring to contact or interaction with a physical asset to resolve the incident, the number of touchpoints would be at least one per incident or more. An incident could impact more than one physical asset. Following are examples of the types of incidents that occurred in 2024:

Incident	Resolution
Labs Tech 1 Door latch is not working correctly, and the door will not secure.	Installed new Schlage EL RX Mortise lock on Lab Tech door.
Gate readers are offline as of 12:00am.	Repaired transformers at gate due to issue with step down transformer failure.
Door 14 not latching.	Removed the Latch plate, and grinded a bigger portion of the Doorstop / frame away, and then resecured the Latch plate lower than it was originally installed.
All badge readers are down. Power outage over the weekend.	Replaced strike at door 13. Replaced strike at door 15. Replaced strike at door 16. Replaced strike on door 5. Door 6 - the boot wash door had a lot of snow and ice built up at the bottom causing the door to hold pressure on the strike. Once you pull the door in the strike releases properly. Tested the rest of the exterior doors and they are working properly.

- b. In 2024, the Company incurred \$491,000 in O&M costs to maintain current equipment. The Company did not estimate the increased O&M costs to maintain older equipment.

Witness: Stacy H. Baker
Date: April 15, 2025

U21806-AG-CE-0621

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Question:

239. Refer to lines 30-40 on page 100 of Ms. Baker's direct testimony on the OT Datacenter Migration. Please:

- a. Provide the cost of this project by year from inception to completion for total company and, for the portion applicable to the gas business for both capital expenditures and O&M expense, separately. Provide this information in Excel.
- b. Identify what the dollars will be spent on for this project by year.
- c. Explain why this project needs to be completed at this time and whether it can be delayed to a later year.
- d. Provide the current phase of development of the project.

Response:

- a. Refer to Attachment No. U21806-AG-CE-0621_ATT 1 for the Total Company and gas allocation capital expenditures and O&M expense for the Operational Technology (OT) Datacenter Migration project in Excel.
- b. Refer to part a response for categorial spend by year.
- c. The OT Datacenter Migration project must be completed and cannot be delayed to a later year due to the state of the current datacenter and the associated risks. The current datacenter would require extensive work to modernize and would not address the risks discussed in my direct testimony starting on page 100, line 40 through page 101, line 6.
 - i. There is risk with the current datacenter due to the proximity of water pipes. If the main water piping bursts, the data center equipment would become wet, causing damage and failure. This could disrupt the monitoring of the critical OT systems, such as SCADA.
 - ii. The Company has had on-going issues with water infiltration into the basement from rain. The data center has a raised floor and has had standing water under the floor. Facilities have been repaired several times, and it is still an ongoing issue.
 - iii. Additionally, the climate conditioners in the current OT datacenter are aging and have had faults resulting in unplanned shutdowns. The failure of HVAC caused the temperature in the data center to rise causing the equipment to begin shutting down. This would cause the equipment to be damaged and fail causing potential disruption to the monitoring of the critical OT systems.

The Company utilizes this datacenter to operate critical control and monitoring of gas compression and natural gas pipeline. The datacenter migration would ensure these critical systems are highly available for safe and reliable natural gas and electric delivery.

- d. The project is in the Investment Planning phase.

Witness: Stacy H. Baker

Date: 3/21/2015

MICHIGAN PUBLIC SERVICE COMMISSION			Attachment:		U21806-AG-CE-0621_ATT 1		
Consumers Energy Company			Witness:		SHBaker		
Operational Technology (OT) Datacenter Migration			Date:		March 2025		
	Total Company		Gas Allocation				
Cost Category	Capital	O&M	Capital	O&M			
2026							
Software	500,000	-	157,150	-			
Material	5,010,000	-	1,574,643	-			
Labor	300,000	300,000	94,290	111,620			
Contractor Costs	500,000	545,000	157,150	202,777			
Non-Labor Overhead	56,000	59,150	17,601	22,008			
Non-Labor Other	511,220	1,406,621	160,676	523,363			
Total 2026	6,877,220	2,310,771	2,161,510	859,768			
2027							
Software	-	-	-	-			
Material	-	-	-	-			
Labor	200,000	350,000	62,860	129,199			
Contractor Costs	500,000	540,000	157,150	199,335			
Non-Labor Overhead	49,000	62,300	15,401	22,997			
Non-Labor Other	123,400	-	38,785	-			
Total 2027	872,400	952,300	274,195	351,531			
Total							
Software	500,000	-	157,150	-			
Material	5,010,000	-	1,574,643	-			
Labor	500,000	650,000	157,150	240,819			
Contractor Costs	1,000,000	1,085,000	314,300	402,112			
Non-Labor Overhead	105,000	121,450	33,002	45,005			
Non-Labor Other	634,620	1,406,621	199,461	523,363			
Total Project	7,749,620	3,263,071	2,435,706	1,211,299			

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Question:

248. Refer to pages 115 and 116 of Ms. Baker's direct testimony on the Forward Web Proxy Services project. Please:

- a. Provide the cost of this project for total company and the portion applicable to the gas business by year from inception to completion.
- b. Identify in which exhibit and line number these costs are included in this rate case, and for which amounts.
- c. How frequently did the problems occur with the current vendor platform in the past two years?
- d. Has the Company worked with the vendor to fix the problems and improve the system and its level of service? If yes, provide details. If no, explain why not.
- e. Provide the cost/benefit analysis that justifies undertaking this project.

Response:

- a. Refer to Attachment No U21806-AG-CE-0630_ATT_1 for the projected total Company and gas allocation from inception to completion for the Forward Web Proxy Services project.
- b. The projected gas allocation capital expenditures are included in Exhibit A-12 (SHB-4) Schedule B-5.1, line 6. The projected gas allocation O&M Investments expenses are included in Exhibit A-19 (SHB-3), page 1, line 4. Refer to part a response for the projected gas allocation capital expenditure and O&M expense amounts.
- c. The table below provides the number of Non-Critical Function and Company Operations (Ops) incidents with the duration of outages experienced from 4/1/2022 through 2024. The current solution was implemented 4/1/2022. Non-Critical Function incidents affect individual users or groups who cannot perform work but do not impact the entire company or critical business functions. Company Ops incidents affect the entire company or a critical business function, such as the ability for coworkers to perform a function to serve customers. The duration was calculated in days based on incident duration in ServiceNow from the identification of an incident until a majority of users have been resolved or a workaround has been identified. The year over year reduction in impacted days is a result of Security no longer using built in functionality of the current product due to the impact on business stability. This creates risk and additional controls to mitigate the risk.

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Year	Non-Critical Function Incidents	Non-Critical Function Impacted Days	Company Ops Incidents	Company Ops Impacted Days
2022	22	228.5	44	35.6
2023	18	133.8	15	61.5
2024	7	111.2	0	0

- d. The Company has worked with the vendor over the duration of the current implementation. This included escalated discussions with vendor. This has led to net improvements overall. However, the Company continues to have common issues with service, especially on standard maintenance tasks such as software upgrades. These standard upgrades often will lead to undiscovered defects.
- e. Refer to Exhibit A-21 (SHB-6), page 74, for the cost/benefit analysis for this project.

Witness: Stacy H. Baker
Date: March 24, 2025

[illegible]

U21806-AG-CE-0631
Page 1 of 1

Question:

249. Refer to page 117 of Ms. Baker's direct testimony on the Physical Access Management and Alarm Response project. Please:

- a. Please provide the cost of this project for total company and the portion applicable to the gas business by year from inception to completion.
- b. Identify in which exhibit and line number these costs are included in this rate case, and for which amounts.
- c. How frequently were the problems with the current system in the past two years?
- d. Has the Company worked to fix the problems and improve the system and level of service? If yes, provide details. If no, explain why not.
- e. Provide the cost/benefit analysis that justifies undertaking this project.

Response:

- a. Refer to Attachment No U21806-AG-CE-0631_ATT_1 for the projected total Company and gas allocation from inception to completion for the Physical Access Management and Alarm Response project.
- b. The projected gas allocation capital expenditures are included in Exhibit A-12 (SHB-4) Schedule B-5.1, line 6. The projected gas allocation O&M Investments expenses are included in Exhibit A-19 (SHB-3), page 1, line 4. Refer to part a response for the projected gas allocation capital expenditure and O&M expense amounts.
- c. Refer to attachment U21806-SA-CE-004_ATT 1 for a list of the operational issues for the past two years with the current physical access management system.
- d. The Company has worked with the vendor to address defects and issues. Additionally, the Company evaluated and completes upgrades as necessary. The most recent system upgrade was completed in 2024.
- e. Refer to Exhibit A-21 (SHB-6), page 98, for the cost/benefit analysis for this project.

Witness: Stacy H. Baker
Date: March 24, 2025

CECo Response AG-CE-0631

MICHIGAN PUBLIC SERVICE COMMISSION			Attachment:	U21806-AG-CE-0631_ATT 1	
Consumers Energy Company			Witness:	SHBaker	
Physical Access Management and Alarm Response			Date:	March 2025	

U21806-SA-CE-004

Requested By: Emma Zichi (EZ-1 - 4)

Respondent: Stacy H. Baker

Date of Response: 01/07/2025

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Question:

4. Regarding A-20 (SHB-5), 'Physical Access Management and Alarm Response' project:

- a. For the past two years please share the operational issues with the current physical access management system. Please specify the number of incidents, when they occurred, what was impacted and for how long.
- b. In alternatives considered the option to keep the current system is mentioned. What is the cost comparison between this option to the option chosen, a new system?
- c. Please detail the cost savings and waste reduction that will result from the new system.
- d. Has the Company chosen a specific vendor for the new system? If so, how were they selected?
- e. What is the timeline for this project and what phase of the project is the Company currently in?
- f. How will the Company implement and use mobile device badges?
- i. How is the use of mobile device badges a cost savings?
- ii. What security measures will be needed for mobile device badges? What is the cost associated with this?
- g. How was it determined that these specific security upgrades (stated in the "Scope" section of testimony, page 118 line 3) are the best solution?
- h. When did the current system become out of date?

Response:

- a. Refer to attachment U21806-SA-CE-004_ATT 1 for a list of the 14 operational issues for the past two years with the current physical access management system, detailing when they occurred. The operational issues impact productivity and create risk by causing delays when the system freezes and is unavailable, requiring rework and resubmission of requests, and reducing visibility to physical access at Company sites.
- b. The Company has not performed a cost comparison between continuing to use the current system and adopting a new system. The current system has operational issues and does not provide the Company the ability to adopt new physical access control methods that avoid costs and improve control and responsiveness.
- c. The Company will realize cost savings by reducing future purchases of badge printers and associated consumables, while still requiring identification badges. The Company will achieve waste reduction by improving system stability, increasing automation, and eliminating manual processing of alarms. The new solution will integrate with the Company's automation platforms to streamline automation of over 2,500 alarms per year, which are currently processed manually by security teams.
- d. The Company has not chosen a specific vendor for the new system. As a part of the project, the Company will conduct a Request for Proposal to select a vendor and solution.

U21806-SA-CE-004

Requested By: Emma Zichi (EZ-1 - 4)

Respondent: Stacy H. Baker

Date of Response: 01/07/2025

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- e. The Physical Access Management and Alarm Response project is currently in the Investment Planning phase and is planned to be initiated in January 2026 and complete in December 2029. The detailed timeline is provided in the Dates section on page 98 of Exhibit A-21 (SHB-6) REDACTED.
- f. The implementation and use of mobile device badges by the Company will vary depending on the selected vendor and solution. In general, the Company will provision and distribute mobile device badges to supported smart phones.
 - i. The use of mobile device badges reduces future purchases of badge printers and associated consumables.
 - ii. The security measures required will vary depending on the selected vendor and solution. Generally, the primary security measure needed is a controlled, encrypted method for device registration. Assignment of access levels, authentication, and authorization and revocation would be handled by Company controlled systems in a manner similar to what is in place today.
- g. The Company discussed and learned about best practices for physical access and alarm response by benchmarking with other companies and attending an industry conference.
- h. In 2024, the Company had to upgrade the software to address the operational issues and bring the software to a supportable version. The current solution does not provide the ability to enhance security options for entrance to facilities to include mobile device credential, which provides a higher level of security. Current identification badges can be easily cloned by readily available equipment.

MICHIGAN PUBLIC SERVICE COMMISSION			Attachment:	U21806-SA_CE_004_ATT 1
Consumers Energy Company			Witness:	SHBaker
			Date:	January 2025
Line No.	Number	Short description	Created	Duration
1	INC1014068	AIU Application Running on PACSTSP1 intermittent freeze	6/15/2023	1 min 31 sec
2	324722	Unplanned AIU outage	1/8/2024	13 min
3	INC1081786	Unable to close froze instance of AIU Production	2/6/2024	23 hrs 4 min 4 sec
4	341774	Unplanned AIU outage	3/13/2024	13 min
5	INC1092846	AIU outage	3/14/2024	1 hr 46 min 12 sec
6	347487	Unplanned AIU outage	3/29/2024	20 min
7	INC1136218	BP unable to access AIU.	8/9/2024	2 hrs 59 min 44 sec
8	INC1139275	Reopened: I can't log into my AIU.	8/19/2024	24 hrs 43 min 39 sec
9	INC1139276	Cannot access AIU. It worked perfectly on Thursday when I left, but when I returned on Sunday evening, it won't allow me to log on. Please revert any changes ma	8/19/2024	24 hrs 41 min 22 sec
10	INC1153269	BP is trying to login to remote desktop in AIU(Access Identity	10/2/2024	8 hrs 5 min 43 sec
11	INC1166533	AIU- Unable to sign out	11/10/2024	51 min 37 sec
12	INC1169129	Security AIU(physical access mgmt sys) is currently DOWN. Please contact the SCC at +18007603295,,,1 to provide status update.	11/19/2024	32 min 34 sec
13	INC1169488	AIU - error / frozen screen	11/20/2024	24 hrs 2 min 54 sec
14	399710	Unplanned AIU outage	12/13/2024	28 min

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Question:

255. Refer to page 1 of Exhibit A-12, Schedule B-5.1. Please expand this schedule to include actual amounts for 2022 and 2024 and provide it in Excel.

Response:

Refer to Attachment No. U21806-AG-CE-0637_ATT_1 for page 1 of Exhibit A-12, Schedule B-5.1 expanded to include 2022 actuals and 2024 preliminary actuals in Excel.

Witness: Stacy H. Baker

Date: March 19, 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21806
Exhibit: AG-32
April 23, 2025
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CECo Response AG-CE-0637

MICHIGAN PUBLIC SERVICE COMMISSION				Attachment No.:		U21806-AG-CE-0637_ATT_1			
Consumers Energy Company				Page:		1 of 1			
Projected Capital Expenditures				Witness:		SHBaker			
Information Technology				Date:		March 2025			
Summary of Actual & Projected Gas and Common Capital Expenditures (\$000)									
(a)				(b)		(c)			
				(d)		(e)			
				(f)		(g)			
				Capital Expenditures					
				Historical	Historical	Preliminary	Projected Bridge Year	Projected Test	
Line				12 Mos Ended	12 Mos Ended	12 Mos Ending	10 Mos Ending	22 Mos Ending	12 mos. Ending
No.	Description			12/31/2022	12/31/2023	12/31/2024	10/31/2025	10/31/2025	10/31/2026
1	Corporate			2,342	775	397	1,136	1,820	1,187
	Labor			228	101	72	688	1,124	695
	Software			907	98	111	0	111	0
	Materials			0	0	1	10	10	38
	Contractor			1,167	488	190	63	180	75
	Non-Labor Overhead			0	26	0	63	67	56
	Non-Labor Other			39	62	23	311	327	323
	Overhead & Others			0	0	0	0	0	0
	Contingency			0	0	0	0	0	0
2	Customer			2,054	1,096	649	2,550	3,235	2,371
	Labor			346	214	159	1,122	1,249	925
	Software			(120)	3	78	0	78	0
	Materials			7	9	0	0	0	0
	Contractor			1,482	714	361	736	1,172	872
	Non-Labor Overhead			0	55	0	88	103	79
	Non-Labor Other			0	101	52	603	633	496
	Overhead & Others			338	0	0	0	0	0
	Contingency			0	0	0	0	0	0
3	Electric & Gas Shared			1,564	2,020	1,608	591	2,534	586
	Labor			305	403	301	165	1,159	190
	Software			136	412	231	0	213	0
	Materials			97	22	66	20	119	32
	Contractor			813	902	855	222	753	168
	Non-Labor Overhead			0	74	0	30	43	40
	Non-Labor Other			0	206	154	154	247	155
	Overhead & Others			213	0	0	0	0	0
	Contingency			0	0	0	0	0	0
4	Gas			5,232	4,535	5,305	11,741	21,552	10,180
	Labor			397	330	813	2,651	4,150	2,930
	Software			125	1,592	1,062	2,937	4,135	1,123
	Materials			827	994	819	329	1,278	2,753
	Contractor			3,380	1,323	2,166	3,710	9,292	1,393
	Non-Labor Overhead			0	69	0	587	627	328
	Non-Labor Other			0	226	444	1,527	2,069	1,653
	Overhead & Others			504	0	0	0	0	0
	Contingency			0	0	0	0	0	0
5	IT/Digital Foundation			7,758	12,847	12,262	8,946	21,680	32,467
	Labor			641	926	1,239	931	2,758	4,111
	Software			302	3,784	442	68	602	7,448
	Materials			3,793	6,291	6,289	5,953	12,156	9,590
	Contractor			2,576	1,423	3,780	1,441	5,083	8,182
	Non-Labor Overhead			0	75	0	110	201	588
	Non-Labor Other			0	349	513	442	880	2,549
	Overhead & Others			445	0	0	0	0	0
	Contingency			0	0	0	0	0	0
6	Security			6,908	6,348	6,156	3,762	9,950	3,902
	Labor			1,036	1,196	550	692	1,401	392
	Software			833	203	913	73	576	1,335
	Materials			2,744	1,148	1,791	1,336	2,491	1,039
	Contractor			1,839	3,293	2,781	1,131	4,720	686
	Non-Labor Overhead			0	73	0	285	292	219
	Non-Labor Other			0	435	121	244	470	230
	Overhead & Others			456	0	0	0	0	0
	Contingency			0	0	0	0	0	0
7	Total Information Technology Capital			25,858	27,620	26,378	28,724	60,770	50,693
	Labor			2,954	3,170	3,134	6,248	11,841	9,242
	Software			2,184	6,093	2,837	3,078	5,715	9,906
	Materials			7,468	8,463	8,967	7,649	16,054	13,453
	Contractor			11,258	8,142	10,133	7,303	21,201	11,377
	Non-Labor Overhead			0	373	0	1,164	1,334	1,310
	Non-Labor Other			39	1,380	1,307	3,281	4,625	5,406
	Overhead & Others			1,955	0	0	0	0	0
	Contingency			0	0	0	0	0	0

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Question:

266. Refer to page 1 of Exhibit A-28 on vehicle unit purchases. Please:

- a. Expand this schedule to include actual dollars and units for each year 2022 to 2024 and forecasted for the full year 2026, and provide it Excel.
- b. Explain why there is a large increase to 44 in the number of ½ Ton Pickup trucks to be purchased for 2026 from considerably fewer units purchased or forecasted for prior years 2023 to 2025.
- c. Explain why there is a large increase to 21 in the number of Truck SVC 4WD to be purchased from considerably fewer units purchased or planned to be purchased in 2023 and 2024.
- d. Confirm that for column (j) the Electric Vehicle Investment line is missing the \$360,000. If not confirming, explain.
- e. Confirm that the Fleet Business Partner Funded summary line for 2023 should be \$160,000. If not confirming, explain.

Response:

- a. See excel attachment U21806-AG-CE-0648_Guinn_ATT_1.
- b. In previous years the market has been unable to produce the quantity of vehicles the Company needed in each category. Therefore, the Company of necessity substituted these replacements with other vehicle types. As supply chain constraints in the market ease and manufacturer capacity increases, the Company is now able to acquire vehicle types in the quantities it needs.
- c. See response to subpart (c).
- d. Yes, \$360,000 is missing from Exhibit A-28, Column J for Fleet Vehicle Electrification. The correction is shown in attachment U21806-AG-CE-0648_Guinn_ATT_1.
- e. Yes, the Fleet Business Partner Funded summary line for 2023 should be \$160,000. This correction is shown in attachment U21806-AG-CE-0648_Guinn_ATT_1.

Witness: Quentin A. Guinn
Date: March 21, 2025

CECo Response AG-CE-0648

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[illegible]

Exhibit AG-34

CONFIDENTIAL

Exhibit AG-35

CONFIDENTIAL

U21806-AG-CE-0498

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Question:

160. Refer to page 39 of Mr. Bleckman's testimony on the Cash component of Working Capital. For each year 2020 to 2024, please provide in Excel the 13-month average amounts for the periods ended December 31, March 31, June 30 and September 30.

Response:

See attached.

Witness: MARC R. BLECKMAN

Date: March 14, 2025

MICHIGAN PUBLIC SERVICE COMMISSION				Case No.:	U-21806
Consumers Energy Company		Discovery Request:			AG-CE-0498
Historical Average Cash Balances (Gas)				Witness:	MRBleckman
(in millions)		Date:			March 2025
		Page:			1 of 1
Line		13-Months Ended Average Cash Balance (Gas)			
No.	Year	March 31	June 30	September 30	December 31
1	2020	\$ 33.4	\$ 99.2	\$ 141.9	\$ 132.4
2	2021	\$ 116.6	\$ 87.2	\$ 34.6	\$ 22.4
3	2022	\$ 21.7	\$ 19.8	\$ 10.0	\$ 11.4
4	2023	\$ 8.8	\$ 9.3	\$ 9.7	\$ 8.7
5	2024	\$ 9.6	\$ 7.3	\$ 11.7	\$ 16.8

Exhibit AG-37

CONFIDENTIAL

U21806-AG-CE-0634
Page 1 of 1

Question:

252. Refer to page 1 of Exhibit A-18 on prepaid cloud computing expense. Please expand the schedule to provide the following information in Excel:

- a. Begin with the balance at 12/31/2022.
- b. Provide the monthly additions and amortizations from January 2023 to December 2026.
- c. Provide the same information in subpart (a) and (b) for total company in Excel.
- d. For the additions, identify what they pertain to.
- e. For new cloud computing contracts or arrangements, provide a copy of the analysis in Excel showing that the shift of the functions to cloud computing are financially beneficial in comparison to other alternatives currently or previously used by the Company.

Response:

- a. Refer to Attachment No. U21806-AG-CE-0634_ATT_1 for Exhibit A-18 (SHB-2), page 1, expanded to begin with the balance 12/31/2022.
- b. Refer to Attachment No. U21806-AG-CE-0634_ATT_1 for the monthly prepayments and expenses from January 2023 through the test year.
- c. Refer to Attachment No. U21806-AG-CE-0634_ATT_1.
- d. The prepaids pertain to renewal of cloud computing subscriptions and implementation costs.
- e. The primary increase in cloud computing costs in this case is related to the Digital-Hybrid Cloud and Data Center Migration project. The detailed cost savings were provided in Gas Rate Case No. U-21308 in my direct testimony on page 108, line 1 through page 109, line 7.

Witness: Stacy H. Baker
Date: March 24, 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21806
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CECo Response AG-CE-0634

MICHIGAN PUBLIC SERVICE COMMISSION														Attachment No.:	U21806-AT-CE-0634_ATT_1
Consumers Energy Company														Witness:	SHBaker
IT Cloud Computing														Date:	March 2025
For 12/31/2022 - 6/30/2024															
Total Company and Gas Allocation															
(a)															
Line		Bal. Ending	Bal. Ending	Bal. Ending	Bal. Ending	Bal. Ending	Bal. Ending	Bal. Ending	Bal. Ending	Bal. Ending	Bal. Ending	Bal. Ending	Bal. Ending		
No.	Description	11/30/2025	12/31/2025	1/31/2026	2/28/2026	3/31/2026	4/30/2026	5/31/2026	6/30/2026	7/31/2026	8/31/2026	9/30/2026	10/31/2026		
	Total Company														
1	Beginning Balance	\$ (16,957,590)	\$ (13,413,981)	\$ (11,463,172)	\$ (28,863,811)	\$ (26,740,727)	\$ (24,325,975)	\$ (23,614,875)	\$ (20,181,171)	\$ (19,278,539)	\$ (20,169,206)	\$ (17,142,993)	\$ (15,232,977)		
	Pre-payments	\$ (332,864)	\$ (1,802,720)	\$ (21,477,784)	\$ (1,838,497)	\$ (1,504,864)	\$ (3,353,113)	\$ (391,049)	\$ (2,954,538)	\$ (4,650,971)	\$ (757,059)	\$ (1,824,151)	\$ (1,007,807)		
	Expenses	\$ 3,876,474	\$ 3,753,529	\$ 4,077,145	\$ 3,961,580	\$ 3,919,617	\$ 4,064,214	\$ 3,824,752	\$ 3,857,170	\$ 3,760,304	\$ 3,783,272	\$ 3,734,168	\$ 3,782,279		
2	Ending Balance	\$ (13,413,981)	\$ (11,463,172)	\$ (28,863,811)	\$ (26,740,727)	\$ (24,325,975)	\$ (23,614,875)	\$ (20,181,171)	\$ (19,278,539)	\$ (20,169,206)	\$ (17,142,993)	\$ (15,232,977)	\$ (12,458,504)		
	Gas Allocation														
3	Beginning Balance	\$ (6,474,099)	\$ (5,148,789)	\$ (4,419,187)	\$ (10,927,025)	\$ (10,132,992)	\$ (9,229,875)	\$ (8,963,923)	\$ (7,679,718)	\$ (7,342,134)	\$ (7,675,243)	\$ (6,543,440)	\$ (5,829,093)		
	Pre-payments	\$ (124,491)	\$ (674,217)	\$ (8,032,691)	\$ (687,598)	\$ (562,819)	\$ (1,254,064)	\$ (146,252)	\$ (1,104,997)	\$ (1,739,463)	\$ (283,140)	\$ (682,233)	\$ (376,920)		
	Expenses	\$ 1,449,801	\$ 1,403,820	\$ 1,524,852	\$ 1,481,631	\$ 1,465,937	\$ 1,520,016	\$ 1,430,457	\$ 1,442,581	\$ 1,406,354	\$ 1,414,944	\$ 1,396,579	\$ 1,414,572	\$ 17,351,545	
4	Ending Balance	\$ (5,148,789)	\$ (4,419,187)	\$ (10,927,025)	\$ (10,132,992)	\$ (9,229,875)	\$ (8,963,923)	\$ (7,679,718)	\$ (7,342,134)	\$ (7,675,243)	\$ (6,543,440)	\$ (5,829,093)	\$ (4,791,441)		
	Average Balance												\$ (7,319,766)		

CECo Response WP-HLR-35

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
S/4 HANA Implementation Deferral Adjustment
For the Projected 12-Month Period Ending October 31, 2026

Case No.: U-21806
WP-HLR-35

(a)		(b)	(c)
Line No	Description	Source	Amount
1	Total deferred debits - June 2024 13-Month Average Balance	WP-HLR-23, Line 19, Col. (f.2)	\$ 288,992,286
2	S/4 HANA implementation deferral - June 2024 13-Month Average Balance	Conf. Exh. A-26 (SHB-11), page 1	-
3	S/4 HANA implementation deferral - October 2026 13-Month Average Balance	Conf. Exh. A-26 (SHB-11), page 2	2,781,267
4	Deferred debits - October 2026 13-Month Average Balance	Line 1 - Line 2 + Line 3	<u>291,773,553</u>
5	S/4 HANA implementation deferral adjustment	Line 4 - Line 1	<u><u>2,781,267</u></u>

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Question:

402. Refer to discovery response AG-CE-0634(d) on the cloud computing costs. Please

- a. Provide the specific items that make up the new pre-payment additions for each month from 2024 through 2026 in Excel.
- b. Regarding ATT_1, explain why the monthly balances and Pre-Payment additions are negative amounts when they are deferred debits.
- c. Explain why the monthly amortization within each year change each month. Explain how the monthly amortization amounts are determined and show the calculation in Excel for each month in 2024 through 2026.

Response:

- a. Refer to Attachment No. U21806-AG-CE-0852_ATT_1 for the actual and projected pre-payments from 2024 through 2026. Attachment No. U21806-AG-CE-0852_ATT_2 provides an updated Exhibit A-18 (SHB-2) excluding some non-cloud computing pre-payments and expenses that were included inadvertently. Attachment No. U21806-AG-CE-0852_ATT_3 updates Attachment No. U21806-AG-CE-0634_ATT_1 excluding the previously mentioned non-cloud computing pre-payments and expenses included inadvertently. It also updates the monthly balances, and pre-payment amounts to positive amounts, and expense amounts to negative amounts to represent how the entries would occur in the prepaid asset account.
- b. Refer to Attachment No. U21806-AG-CE-0852_ATT_3 and explanation in part a.
- c. The monthly amortization within each year changes each month as contracts are renewed during different months each year. The monthly expense amounts are determined based on the amount and term of each contractual agreement. For example, if a \$120,000 contract is a pre-payment for 12-month cloud subscriptions, the monthly expense of those cloud costs would be \$10,000 per month.

Witness: Stacy H. Baker
Date: April 16, 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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Exhibit: AG-38
April 23, 2025
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CECo Response AG-CE-0852

MICHIGAN PUBLIC SERVICE COMMISSION														Attachment No.:		U21806-AT-CE-0852_ATT_3	
Consumers Energy Company														Witness:		SHBaker	
IT Cloud Computing														Date:		April 2025	
For 12/31/2022 - 10/31/2026																	
Total Company and Gas Allocation																	

U21806-AG-CE-0500
Page 1 of 1

Question:

162. Refer to page 23 of witness Heather Rayl's direct testimony on the projected \$8.9 million loss from the sale of the Riverside storage field. Please explain how this loss was determined, the actual timing of it, how it impacts working capital, and identify in which exhibit, line number, and column it is shown or included.

Response:

Please refer to the response to U21806-AG-CE-0505. The Company reached a PSA with a buyer in October 2024. During the two-month due diligence period after the agreement, the buyer chose to terminate the agreement. The Company has moved forward with the next best evaluated bidder/buyer. Terms and proceeds of the sale have not been reached with the new buyer at this time.

Witness: Heidi J. Myers

Date: March 17, 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Riverside Storage Field Regulatory Asset Adjustment
For the Projected 12-Month Period Ending October 31, 2026

Case No.: U-21806
WP-HLR-34

(a)		(b)	(c)
Line No	Description	Source	Amount
1	Net book value of Riverside Storage Field - June 30, 2024	Property Accounting	\$ 9,195,888
2	Gas inventory balance - June 30, 2024	Property Accounting	3,608,904
3	Total book value of Riverside Storage Field	Line 1 + Line 2	<u>12,802,793</u>
4	Riverside Storage Field sale price, including estimated sales expenses	Property Accounting	3,925,000
5	Regulatory asset for the loss on sale of Riverside Storage Field - projected test year beginning balance	Line 3 - Line 4	<u>8,877,793</u>
6	Projected test year amortization of regulatory asset	Line 1 + 3 year amortization period	2,959,264
7	Regulatory asset for the loss on sale of Riverside Storage Field - projected test year ending balance	Line 1 - Line 2	<u>5,918,529</u>
8	Regulatory asset for the loss on sale of Riverside Storage Field - average balance	(Line 5 + Line 7) ÷ 2	<u><u>7,398,161</u></u>

U21806-AG-CE-0499

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Question:

161. Refer to Exhibit A-12 (HLR-34), Schedule B-4, for Accrued Taxes. Please provide the following information.

- a. A schedule in Excel with the monthly balances of Accrued Taxes for each month from January 2021 to December 2024.
- b. An explanation of how the Company determined the balance of \$12.4 million for Accrued Taxes for the projected test year, which is substantially lower than the historic test year. Identify the amount of rate relief from this rate case included in calculating the forecasted Accrued Taxes and the basis for that amount. If no rate relief amount was included, explain why not.

Response:

- a. Please see U21806-AG-CE-0499-Rayl_ATT_1.
- b. The calculation of projected accrued taxes on workpaper WP-HLR-30 is incorrect. Please see U21806-AG-CE-0499-Rayl_ATT_2 for the corrected calculation of projected accrued taxes.

The corrected projected accrued tax liability equates to an approximate \$9.8 million reduction in requested rate relief in this case:

Projected Accrued Taxes, As Filed	\$12,398,727
Projected Accrued Taxes, Revised	140,203,625
Decrease in Rate Base	127,804,898
Required Rate of Return [Exh. A-14 (MRB-1)]	6.22%
Estimated Income Requirement Impact	(7,948,832)
Estimated Income Tax Impact	(590,970)
Estimated Income Deficiency Impact	(7,357,862)
Revenue Conversion Factor	1.3381
Estimated Revenue Deficiency Impact	(9,845,401)

Witness: HEATHER L. RAYL
Date: March 17, 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21806
Exhibit AG-41
Date: April 23, 2025
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Recommended Capital Structure & Cost Rates for
Projected Year Ending October 2026 (Millions of Dollars)

Line	Description (a)	Note	Consumers Energy Capital Structure			Cost Rate* (e)	Total Cost (d) x (e) (f)	Conversion Factors** (g)	Pre-Tax Wtd. Cost (f) x (g) (h)
			Capital Balances (b)	% Permanent Capital (c)	% Total Capital (d)				
1	Long Term Debt	(A)	\$ 12,839	49.85%	41.82%	4.35%	1.82%	1.0000	1.82%
2	Preferred Stock		37	0.14%	0.12%	4.50%	0.01%	1.3381	0.01%
3	Common Equity	(A)	<u>12,877</u>	<u>50.00%</u>	<u>41.95%</u>	9.75%	<u>4.09%</u>	1.3381	<u>5.47%</u>
4	Total Permanent Capital	(B)	25,753	<u>100.00%</u>	83.89%		5.91%		7.30%
5	Short Term Debt	(B)	201		0.65%	4.52%	0.03%	1.0000	0.03%
6	Deferred Income Taxes	(B)	4,629		15.08%	0.00%	0.00%	1.0000	0.00%
7	JDITC								
8	Long Term Debt	(A)	57		0.19%	4.35%	0.01%	1.0000	0.01%
9	Preferred Stock		-		0.00%	4.50%	0.00%	1.3381	0.00%
10	Common Equity	(A)	<u>57</u>		0.19%	9.75%	0.02%	1.3381	<u>0.02%</u>
11	Total JDITC	(B)	<u>114.0</u>						
12	Total Capitalization & Cost Rates		<u>\$ 30,697</u>		<u>100.00%</u>		5.97%		7.36%

Notes

- * All Cost rates per Exhibit A-14 (MRB-1), Schedule D1 except for Common Equity which is set forth on Exhibit AG-42.
- ** See Company Exhibit A-14 (MRB-1), Schedule D1, column (h).
- (A) Reflects the permanent capital of CECO per Exhibit A-14 (MRB-1), Sched. D1, with common equity set at 50%.
- (B) Capital balances per Company Exhibit A-14 (MRB-1), Schedule D1.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21806
Exhibit AG-42
Date: April 23, 2025
Page 1 of 1

Summary of Cost of Common Equity Analysis

<u>Line</u>	<u>Description</u> (a)	<u>Relative Weighting</u> (b)	<u>Consumers Energy Proxy Rates</u> (c)	<u>Note</u> (d)
1	Discounted Cash Flow Approach (DCF)	50.00%	9.11%	1
2	Capital Asset Pricing Model Approach (CAPM)	25.00%	10.66%	2
3	Utility Equity Risk Premium Approach	25.00%	<u>9.20%</u>	3
4	Calc. Cost of Common Equity (Sum of Col. (b) x (c) for Lines 1, 2 and 3)		9.52%	
5	Adjustment for Other Factors		<u>0.23%</u>	4
6	Cost of Common Equity per AG Case (L4 + L5)		<u>9.75%</u>	

Note 1 See Exhibit AG-43

Note 2 See Exhibit AG-44

Note 3 See Exhibit AG-45

Note 4 Allowance for potential increases in interest rates and financial markets disruption.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21806
Exhibit AG-43
Date: April 23, 2025
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Discounted Cash Flow (DCF) Application
(See Equation Below)

Line	Company	Ticker	Average 30		Projected Avg.	Dividend	EPS Growth Rate***			DCF ROE	
			Day High	Low Price*			2025-26 Ann.	Yield	Value		Zacks
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)	(i)	
Proxy Group											
1	Atmos Energy	ATO	\$	147.59	\$	3.58	2.43%	4.84%	7.00%	5.92%	8.34%
2	Black Hills	BKH		59.90		2.75	4.59%	4.19%	N/A	4.19%	8.78%
3	Chesapeake Utilities	CPN		121.24		2.72	2.24%	6.13%	N/A	6.13%	8.37%
4	NiSource	NI		39.16		1.16	2.96%	7.82%	7.00%	7.41%	10.37%
5	Northwest Natural Holdings	NWN		40.94		1.97	4.81%	3.56%	N/A	3.56%	8.37%
6	One Gas	OGS		72.77		2.70	3.71%	6.40%	5.00%	5.70%	9.41%
7	Southwest Gas	SWX		75.43		2.48	3.29%	7.74%	6.00%	6.87%	10.16%
8	Spire	SR		74.43		3.20	4.30%	4.61%	5.00%	4.81%	9.11%
9	Average						3.54%	5.66%	6.00%	5.57%	9.11%
10	High										10.37%
11	Low										8.34%

* Average of High and Low prices per Yahoo from February 3 to March 17, 2025

** Value Line Projected Dividends for 2025 and 2026 (averaged) published February 21, 2025 and for Black Hills on January 17, 2025

*** Column (f) per workpapers. Column (g) from Bulkley Exhibit A-14 (AEB-1), Schedule D-5, page 3 of 29, Column 7. Value Line information based on EPS Growth over five years from 2024 except that Northwest Natural and Southwest Gas reflect a four year growth period from 2025 due to the residual affects of reorganizations in 2024.

N/A Information Not Available in Company witness Bulkley's sponsored exhibits.

Equation	$R = D/P + g$	Where	R = the required return on the equity security	D = the next dividend on the security
			P = the current price of the equity security	g = the expected growth rate of earnings

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21806
Exhibit AG-44
Date: April 23, 2025
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Capital Asset Pricing Model Application
(See Equation Below)

Line	Company & Ticker (a)	% Common Equity (b)	Current Beta (B) (c)	Risk Premium (R _p) (d)	Beta x Risk Premium Col. (c) x (d) (e)	Risk Free Rate (R _f) (f)	K _e or CAPM ROE for Each Co. Cols. (e) + (f) (g)
Proxy Group							
1	Atmos Energy ATO	60.5%	0.90	7.30%	6.57%	4.00%	10.57%
2	Black Hills BKH	43.0%	1.00	7.30%	7.30%	4.00%	11.30%
3	Chesapeake Utilities CPK	52.1%	0.85	7.30%	6.21%	4.00%	10.21%
4	NiSource NI	35.7%	0.95	7.30%	6.94%	4.00%	10.94%
5	Northwest Natural Holdings NWN	45.8%	0.90	7.30%	6.57%	4.00%	10.57%
6	One Gas OGS	55.8%	0.85	7.30%	6.21%	4.00%	10.21%
7	Southwest Gas SWX	41.9%	0.95	7.30%	6.94%	4.00%	10.94%
8	Spire SR	43.5%	0.90	7.30%	6.57%	4.00%	10.57%
9	Average	47.3%	0.91	7.30%	6.66%	4.00%	10.66%
10	High						11.30%
11	Low						10.21%

Sources

- Column (b) Per SEC Filings: Average for the four quarters ended December 2024
- Column (c) From the Value Line Investment Survey published February 21, 2025 and for Black Hills on January 17, 2025.
- Column (d) Reflects the average returns of Large Stocks (12.16%) vs Long Term Gov't Bond Income Returns (4.85%) for the period 1926 to 2023 per the Ibbotson Clasic Year Book (through 2022) and "slick charts" for 2023
- Column (f) The Blue Chip Financial Forecast of October 1, 2024 provided by the Company shows a 30 year bond at 4.0% for 2026.
See DR AG-CE-440, page 2.

Equation for CAPM

$$K_e = R_f + (B \times R_p)$$

Where K_e = the Cost of Common Equity; R_f = the Risk Free Rate of Return;
B = the Beta or covariance of the stocks price to overall market ; and
R_p = the Expected Risk Premium of the overall market

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21806
Exhibit AG-45
Date: April 23, 2025
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Utility Equity Risk Premium Approach

<u>Line</u>	<u>Description</u> (a)	<u>Rate Developed</u> (b)	<u>Note</u> (c)
1	Number of Companies in proxy group	8	
2	Average Rating	A/BBB	1
3	Projected Average of "A" and "BBB" Bonds New Issue Rate	5.40%	2
4	Historical Spread - Gas Util. Common Stocks vs. "A" Rated Utility Bonds	<u>3.80%</u>	3
5	Sub Total - Rate for "A" and "BBB" rated companies (lines 3 + 4)	<u>9.20%</u>	

1 Atmos, OneGas and Chesapeake Utilities are "A" rated. All other peer companies are "BBB" rated.

2 Based on analysis of 2024 new 30 Year issues (see workpapers)

"BBB" Rated Spread to 30 Yr, Treasuries 1.60%

"A" Rated Spread to 30 Yr. Treasuries 1.20%

Average Spread 1.40%

Assumed 30 Year US Treasury Bond Rate (from CAPM Analysis) 4.00%

Projected Average of "A" / "BBB" 30 Year bonds 5.40% To Line 3 above

3 Per AG Workpapers

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21806
Exhibit AG-46
Date: April 23, 2025
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Peer Group Non-Utility or Non Regulated Operations

Line	Company & Ticker (a)		Percent Common Equity*	Current Beta (B)	Utility Business	Non Utility & Non Reg. Business		Measure- ment Criteria	SEC Filing Information		
			(b)	(c)	(d)	(e)		(f)	SEC Form (g)	Period Ending (h)	Page (i)
	Proxy Group										
1	Atmos Energy	ATO	60.5%	0.90	64.4%	35.6%	A	Net Income	10-K	Sep. 24	27
2	Black Hills	BKH	43.0%	1.00	100.0%	0.0%	B	Op. Income	10-K	Dec. 24	39
3	Chesapeake	CPK	52.1%	0.85	86.0%	14.0%	C	Op. Income	10-K	Dec. 24	33
4	NiSource	NI	35.7%	0.95	100.0%	0.0%		Net Income	10-K	Dec. 24	7
5	Northwest Natural Gas	NWN	45.8%	0.90	90.6%	9.4%	D	Op. Income	10-K	Dec. 24	98
6	One Gas	OGS	55.8%	0.85	100.0%	0.0%		Revenues	10-K	Dec. 24	7
7	Southwest Gas	SWX	41.9%	0.95	100.0%	0.0%	**	Net Income	10-K	Dec. 24	33
8	Spire	SR	43.5%	0.90	91.6%	8.4%	E	Net Income	10-K	Sep. 24	74
9	Average		47.3%	0.91	91.6%	8.4%					

* Reflects Average Capitalization for the four quarters ended December 2024

** Certain residual investment in Centuri (Construction Sub) remains over the short-term

A Pipeline and Storage

B Utility equals 53% Gas and 47% Electric

C Non Utility is primarily Propane Distribution

D Renewables, Storage and Pipelines

E Gas Marketing, Storage and Pipelines

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

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Market to Book Equity Ratios

<u>Line</u>	<u>Company & Ticker</u> (a)		<u>Dec. 31, 2024 Mkt. Price p/ Sh.</u> (b)	<u>December 31, 2024</u>			<u>Market to Book Ratio</u> (f)
				<u>Book Value of Common Equity (\$Mil.)</u> (c)	<u>Shares Outstanding (Millions)</u> (d)	<u>Book Value Per Sh.</u> (e)	
	Proxy Group						
1	Atmos Energy	ATO	139.27	12,780.5	158.7	80.53	1.7
2	Black Hills	BKH	58.52	3,501.5	71.7	48.84	1.2
3	Chesapeake Utilities	CPK	121.35	1,390.2	22.9	60.71	2.0
4	NiSource	NI	36.76	8,684.2	469.8	18.48	2.0
5	Northwest Natural Gas	NWN	39.56	1,385.4	40.2	34.46	1.1
6	One Gas	OGS	69.25	3,104.5	59.9	51.83	1.3
7	Southwest Gas	SWX	70.71	3,504.2	71.3	49.15	1.4
8	Spire	SR	67.83	3,067.0	58.3	52.61	1.3
9	Average						1.5

Col. (b) Closing Price Per Yahoo
Col. (c) Per SEC Filings
Col. (d) Per SEC Filings
Col. (e) Equals Col. (c) divided by Col. (d)
Col. (f) Equals Col. (b) divided by Col. (e)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21806
Exhibit AG-48
Date: April 23, 2025
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Gas Regulatory Decisions - Authorized ROE's under 9.9% - 2023 and 2024

Line	Gas Company*	Order Date & Jurisdiction*			ROE Rate from Order*		Parent Company	Foreign,Prvt, Domestic	Long Term Debt Issued Since Rate Order**			
		(a)	(b)		2023	2024	(e)	(f)	(g)			
1	Texas Gas Service	Jan	19	TX	9.60%		One Gas	D	\$300M	5.10%	6 Yr	(Dec 2023)
2	Southwest Gas	Jan	23	AZ	9.30%		Southwest Gas Holdings	D	\$300M	5.45%	5 Yr	(Mar 2023)
3	Columbia Gas of Ohio	Jan	26	OH	9.60%		NiSource	D	\$300M	5.25%	5 Yr	(May 2023)
4	Northern States Power	Mar	23	MN	9.57%		Xcel Energy	D	\$800M	5.45%	10 Yr	(Jul 2023)
5	Pivotal Utility Holdings	Mar	28	FL	9.50%		Chesapeake Utilities	D	\$550M	Var. Rates	Var. Mat.	(Nov 2023)
6	Atmos Energy	May	4	CO	9.30%		Atmos	D	\$900M	5.9%/6.5%	10 & 30 Yr	(Oct 2022)
7	Intermountain Gas	Jun	30	ID	9.50%		MDU Resources	D	\$100M	5.39%	10 Yr	(Nov 2023)
8	Consolidated Edison of NY	Jul	20	NY	9.25%		Consolidated Edison	D				
9	Michigan Gas Utilities	Aug	30	MI	9.80%		WEC Energy	D	\$25 M	4.8%/5.2%	5 & 10 Yr.	(Oct 2024)
10	Avista	Aug	31	ID	9.40%		Avista	D				
11	Northern Utilities	Sep	20	ME	9.35%		Unitil	D				
12	Dominion Energy SC	Sep	20	SC	9.49%		Dominion	D	\$1.0 Bil	5/5.35%	10/30 Yr.	(Feb 2024)
13	Piedmont Natural Gas	Oct	5	SC	9.30%		Duke Energy	D	\$150M	4.85%	3/5 Yr	(Nov 2023)
14	Chattanooga Gas	Oct	6	TN	9.80%		Southern Co.	D	\$400M	5.70%	10 Yr	(Feb 2024)
15	New Youk State Elec. & Gas	Oct	12	NY	9.20%		Avangrid	D	\$680M	Var. Rates	Var. Mat.	(Dec 2023)
16	Rochester Gas & Electric	Oct	12	NY	9.20%		Avangrid	D	\$680M	Var. Rates	Var. Mat.	(Dec 2023)
17	Northwestern Energy	Oct	25	MT	9.55%		NorthWestern Energy	D				
18	Minnesota Energy Rescs	Oct	26	MN	9.65%		WEC Energy	D				
19	Avista	Oct	26	OR	9.50%		Avista	D				
20	Duke Energy Onio	Nov	1	OH	9.60%		Duke Energy	D	\$150M	4.85%	3/5 Yr	(Nov 2023)
21	Madison Gas & Electric	Nov	3	WI	9.70%		MGE Corp	D				
22	Questar Gas	Nov	7	WY	9.65%		Dominion Energy	D	\$1.0 Bil	5/5.35%	10/30 Yr.	(Feb 2024)
23	Northern States Power	Nov	9	FL	9.80%		Xcel Energy	D				
24	Wisconsin Power & Light	Nov	9	WI	9.80%		Alliant Energy	D				
25	Ameren Illinois	Nov	16	IL	9.44%		Ameren	D	\$700M	4.38%	5 Yr	(Dec 2023)
26	North Shore Gas	Nov	16	IL	9.38%		WEC Energy	D	\$20M	5.82%	5 Yr	(Dec 2023)
27	Northern Illinois Gas	Nov	16	IL	9.51%		Southern Co.	D	\$400M	5.70%	10 Yr	(Feb 2024)
28	Peoples Gas Light & Coke	Nov	16	IL	9.38%		WEC Energy	D				
29	Piedmont Natural Gas	Dec	4	TN	9.80%		Duke Energy	D	\$150M	4.85%	3/5 Yr	(Nov 2023)
30	Baltimore Gas & Electric	Dec	14	MD	9.45%		Exelon	D	\$1.7 B	5.2/5.4/5.6	5/10/20 Yrs	(Feb 2024)
31	Washington Gas Light	Dec	14	MD	9.50%		AltaGas BB Rated	F	900 M	7.20%	30 Yr.	(Sep 2024)
32	Washington Gas Light	Dec	15	MD	9.65%		AltaGas BB Rated	F	900 M	7.20%	30 Yr.	(Sep 2024)
33	Mountaineer Gas	Dec	21	WV	9.75%		UGI	D				
34	Average for 2023				9.52%							

* Per Regulatory Research Associates.

** Per various SEC Filings

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21806

Exhibit AG-48

Date: April 23, 2025

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Gas Regulatory Decisions - Authorized ROE's under 9.9% - 2023 and 2024

Line	Gas Company*	Order Date &			ROE Rate from Order*		Parent Company	Foreign,Prvt,		Long Term Debt Issued Since Rate Order**			
		Jurisdiction*			2023	2024		Domestic					
	(a)		(b)		(c)	(d)	(e)	(f)			(g)		
1	Black Hills Wyoming Gas	Jan	17	WY		9.85%	Black Hills	D	\$450 M	6.00%	10 Yr.	(May 2024)	
2	Texas Gas Service	Jan	31	TX		9.70%	One Gas	D	\$250 M	5.10%	5 Yr	(Aug 2024)	
3	Black Hills Colorado	Mar	24	CO		9.30%	Black Hills	D	\$450 M	6.00%	10 Yr.	(May 2024)	
4	Southwest Gas - North	Apr	8	NV		9.50%	Southwest Gas	D					
5	Southwest Gas - South	Apr	8	NV		9.50%	Southwest Gas	D					
6	Northeast Ohio Nat. Gas	Apr	17	OH		9.75%	First Energy	D	\$800 M	4.88%	15 Yr.	(Aug 2024)	
7	CenterPoint Energy	Jun	26	TX		9.80%	CenterPoint Energy	D	\$800 M	6.90%	31 Yr.	(Aug 2024)	
8	Fitchburg Gas & Elec.	Jun	28	MA		9.40%	Unitil	D					
9	Central Hudson Gas & Elec.	Jul	18	NY		9.50%	Fortis	F					
10	New Mexico Gas	Jul	25	NM		9.38%	Emera	F					
11	Northern Indiana Pub. Serv.	Jul	31	IN		9.75%	NiSource	D	\$500 M	6.37%	30 Yr.	(Sep 2024)	
12	KeySpan Gas East	Aug	15	NY		9.35%	National Grid P. C.	F					
13	Brooklyn Union Gas	Aug	15	NY		9.35%	National Grid P. C.	F					
14	Interstate Power & Light	Sep	17	IA		9.65%	Alliant Energy	D					
15	Sierra Pacific Power	Sep	18	NV		9.45%	Berkshire Hathaway	PVT					
16	Michigan Gas Utilities	Sep	26	MI		8.86%	WEC Energy	D	\$25 M	4.8%/5.2%	5 & 10 Yr.	(Oct 2024)	
17	Black Hills Arkansas	Oct	25	AR		9.85%	Black Hills	D					
18	Public Service Elec. & Gas	Oct	26	NJ		9.60%	Pub. Serv. Enterprises Group	D	\$1.0 B	4.9%/5.5%	5 & 10 Yr.	(Mar 2025)	
19	Northwest Natural Gas	Oct	26	OR		9.40%	Northwest Natural Holdings	D	\$325 M	7.00%	30 Yr.	(Mar 2025)	
20	Public Service of Colorado	Nov	1	CO		9.35%	Xcel Energy	D	\$1.1 B	4.8%/5.2%	5 & 10 Yr.	(Mar 2025)	
21	DTE Gas	Nov	7	MI		9.80%	DTE Energy	D	\$1.1 B	5.20%	5 Yr	(Feb 2025)	
22	Connecticut Nat. Gas	Nov	9	CT		9.15%	Avangrid	D					
23	Sthrn. Connecticut Nat. Gas	Nov	9	CT		9.15%	Avangrid	D					
24	Texas Gas Service	Nov	16	TX		9.70%	One Gas	D					
25	Elizabethtown Gas	Nov	16	NJ		9.60%	JP Morgan Infrast via S J Ind.	PVT					
26	New Jersey Natural Gas	Nov	16	NJ		9.60%	N J Resources	D					
27	Summitt Utilities	Nov	16	AR		9.85%	Kinder Morgan Ptns.	D					
28	National Fuel Gas	Dec	4	NY		9.70%	National Fuel Gas	D	\$1.0 B	5.5%/5.9%	5 & 10 Yr.	(Feb 2025)	
29	Wisconsin Gas	Dec	14	WI		9.80%	WEC Energy	D					
30	Wisconsin Public Svc.	Dec	14	WI		9.80%	WEC Energy	D	\$300 M	4.55%	5 Yr	(Dec 2024)	
31	Avista Washington	Dec	15	WA		9.80%	Avista	D					
32	Columbia Gas	Dec	21	KY		9.75%	NiSource	D					
33	Average for 2024					9.56%							

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy - Gas Rate Case

Gas Regulatory Decisions - Authorized ROE's Summary for all Cases - 2023 and 2024

Case No. U-21806

Exhibit AG-48

Date: April 23, 2025

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<u>Line</u>	<u>Caption</u> (a)	<u>Total Year 2023</u>		<u>Total Year 2024</u>		<u>Note</u>
		<u># of Orders</u> (b)	<u>Avg. ROE</u> (c)	<u># of Orders</u> (d)	<u>Avg. ROE</u> (e)	
1	Average Authorized ROE's page 1 and 2	<u>33</u>	<u>9.52%</u>	<u>32</u>	<u>9.56%</u>	
	<u>ROE Orders At 9.9% or Higher</u>					
2	Michigan Cases					
3	Consumers Energy Gas	1	9.90%	1	9.90%	
4	California Case					
5	Southern California Gas			1	10.08%	
6	Alaska Cases					
7	Enstar Natural Gas			1	11.88%	150,000 customers
8	Florida Cases					
9	Florida Public Utilities	1	10.25%	1	10.25%	83,000 customers
10	Peoples Gas System	1	10.15%	1	10.15%	400,000 customers (3 Fla. Locations)
11	Other Jurisdictions					
12	MDU Resources of N. Dakota			1	9.90%	1.1 million customers (9 States)
13	Northern States Power of N. Dakota			1	9.90%	96,000 customers
14	Liberty Utilities of Illinois			1	9.90%	See Note 1 Below
15	Ohio Valley Gas of Ohio			1	10.00%	See Note 2 Below
16	Total Number At 9.90% or Higher	<u>3</u>		<u>9</u>	<u>10.22%</u>	
17	Tota/Avg. of All Cases	<u>36</u>	<u>9.57%</u>	<u>41</u>	<u>9.71%</u>	

Notes:

- 1 Algonquin subsidiary serving 375,000 customers in New Brunswick, Canada and 7 States including Illinois
- 2 Serves 17 Counties in Indiana and Ohio

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company - Gas Rate Case

Case No. U-21806
Exhibit AG-49
Date: April 23, 2025
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2023 Rating Agency Cash Flow Ratios
(With ROE at 9.75% and a 50% Common Equity Ratio)

		2023 Adjusted Moody's Cash Flow Ratio (\$ Millions)			
Line	Caption	Cash From		Ratio	Note
		Operations			
		Pre-Wkg. Cap.	Debt	(e) / (f)	
	(a)	(b)	(c)	(d)	
1	2023 Actual Ratio Results	\$ 2,190	\$ 11,454	19.1%	1
2	Reduce Common Equity (to 50% vs 50.7%)	(12)	145		2
3	Increase ROE by 1.5% (to 9.75% vs 8,25%)	155			3
4	2023 Pro Forma w/50% Common Equity, 9.5% ROE	\$ 2,333	\$ 11,599	20.1%	L 1 + L 2 + L 3
5	Ratings Downgrade Risk			Below 18%	4

Notes

- From page 2 of Moody's May 31, 2024 report on Consumers Energy (see AG-CE-0444)
- As noted below under "Avg. 2023 Capitalization", the Company's Common Equity ratio was 50.7% in 2023. Adjusting to 50% shifts \$145 million from common equity to long-term debt (0.7% x \$20.6 billion = \$145 million).
Lower Common Equity of \$145 million x the Company's earned ROE of 8.25% = \$12 million in lower Net Income.
- Increasing the reported 2023 actual ROE of 8.25% to 9.75% (1.5% change) produces a \$155 million increase in total Company earnings (1.5% x \$10.3 billion = \$155 million).
Note: Consumers 2023 Net Income of \$865 million (p. 102, form 10-K) / \$10.5 billion common equity (below) = an 8.25% ROE.
- From page 3 of Moody's May 31, 2024 report on Consumers Energy (see AG-CE-0444)

<u>Average 2023 Capitalization (\$ Millions)</u> <u>(from Ex. A-14 (MRB-2) Sch. D1a, pg.1)</u>	<u>Actual 2023</u>		<u>Rebalancing</u> <u>Adjustmts.</u>	<u>2023 Rebalanced</u>	
	<u>Amount</u>	<u>% Capital</u>		<u>Amount</u>	<u>% Capital</u>
Long-Term Debt	\$ 10,135	49.1%	\$ 150	\$ 10,285	49.8%
Preferred Stock	37	0.2%		37	0.2%
Common Equity	<u>10,470</u>	<u>50.7%</u>	(150)	<u>10,320</u>	<u>50.0%</u>
Total	<u>\$ 20,642</u>	<u>100.0%</u>		<u>\$ 20,642</u>	<u>100.0%</u>

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company - Gas Rate Case

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2022 Rating Agency Cash Flow Ratios
Impact of Lower Gas in Storage

		<u>2022 Adjusted Moody's Cash Flow Ratio (\$ Millions)</u>			<u>Note</u>
<u>Line</u>	<u>Caption</u>	<u>Cash From Operations</u>	<u>Debt</u>	<u>Pro Forma Ratio</u>	
	(a)	<u>Pre-Wkg. Cap.</u>	<u>(c)</u>	<u>(e) / (f)</u>	
		(b)		(d)	
1	2022 Actual Ratio Results	\$ 2,096	\$ 10,472	20.0%	1
<u>Pro Forma Adjustment - Lower Gas in Storage</u>					
2	Lower Debt Financing - Gas in Storage		(378)		2
3	Lower Interest Expenbse	<u>11</u>	<u></u>		3
4	2022 Pro Forma results with lower Gas in Storage	<u>\$ 2,107</u>	<u>\$ 10,094</u>	20.9%	L 1 + L 2 + L 3
5	Improvement in Ratio Results			0.9%	L 4 less L 1

Notes

- From page 2 of Moody's May 31, 2024 report on Consumers Energy (see AG-CE-0444)
- Per CMS/Consumers Energy 2022 Form 10-K, Gas in Storage increased from \$462 million (Dec 2021) to \$840 million (Dec 2022) which is a \$378 million difference.
- Equals \$378 million capital difference x avg. debt rate from last gas case of 4.7% x after tax rate of 64%.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21806
Exhibit AG-50
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Most Recent Ordered ROEs of Peer Group

<u>Line</u>	<u>Company & Ticker</u> (a)		<u>Most Recent Authorized ROE*</u>	<u>State</u>	<u>Date</u>	<u>Corporate Unit</u>
	<i>Proxy Group</i>					
1	Atmos Energy	ATO	9.80%	LA	Jul-24	Atmos Energy**
2	Black Hills	BKH	9.85%	AR	Oct-24	Black Hills Arkansas
3	Chesapeake	CPK	9.50%	FL	Jun-23	Florida City Gas***
4	NiSource	NI	9.75%	KY	Oct-24	Columbia Gas of Kentucky
5	Northwest Natural Holdings	NWN	9.40%	OR	Oct-24	Northwest Natural Gas
6	One Gas	OGS	9.70%	TX	Nov-24	Texas Gas Service
7	Southwest Gas	SWX	9.50%	NV	Apr-24	Southwest Gas Nevada
8	Spire	SR	<u>9.37%</u>	MO	Oct-21	Spire Missouri
9	Average of eight companies		<u>9.61%</u>			

* Regulatory Research Associates

** 2024 Atmos Form 10-K page 7

*** Form 10-K for 2024, page 6

U21806-AG-CE-0444

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Question:

152. Provide a copy of all S&P and Moody's reports covering Consumers Energy and CMS Energy issued since the beginning of 2023 to date. The request for CMS Energy's rating agency reports is being made due to the reliance by the Company in receiving necessary capital injections from its parent company to fund capital investments and on-going operations.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request on the grounds that information regarding CMS Energy is irrelevant to this matter as CMS Energy is not a party to this case. Subject to the Company's objection, and without waiving that objection, Consumers Energy responds as follows:

Please find the requested rating agency credit opinions for Consumers Energy attached. Additional rating agency credit opinions may be available by subscription.

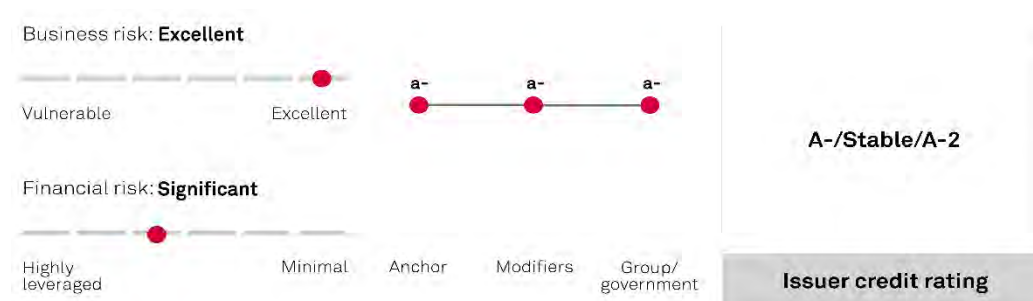
Witness: ANN E. BULKLEY

Date: March 19, 2025

Consumers Energy Co.

August 17, 2023

Ratings Score Snapshot



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Credit Highlights

Overview

Key strengths	Key risks
Monopolistic vertically integrated electric utility and gas distribution utility operations.	Lack of operating diversity makes the company largely depend on Michigan regulators to sustain its credit quality.
Favorable regulatory construct in Michigan.	Exposure to environmental risks due to its dependence on natural gas and coal-fired generation (about 70% of electricity generated or purchased in 2022), though this is partially mitigated by a plan to retire coal by 2025.
Large customer base of 1.9 million electric and 1.8 million gas customers.	Negative discretionary cash flow, reflecting robust capital spending, which indicates external funding needs.
The company is an insulated subsidiary of its parent, CMS Energy, allowing us to rate it one notch above the parent.	Susceptibility to adverse weather events, including winter storms.
	Exposure to cyclical commercial and industrial customers, which account for about 47% of electric revenues and 20% of gas revenues.

Consumers Energy Co.

We expect Consumers Energy Co. (CE) to continue to effectively manage its regulatory risk.

We view Michigan's regulatory construct as above average compared to peers because of the benefit of a streamlined 10-month rate case process and various constructive rate mechanisms, such as the use of forward test-years, power supply and natural gas cost rider adjustments, and partial decoupling for the gas business. These mechanisms help the company earn its allowed ROE and minimize regulatory lag.

CE is currently in the middle of both an electric rate case and a gas rate case. The company filed for a \$207.1 million electric rate increase based on a 10.25% return on equity (ROE) in May and reached a settlement with various intervenors for a \$95 million gas rate increase based on a 9.90% ROE in July. We expect final rate orders by the end of 2023 and continue to monitor related developments.

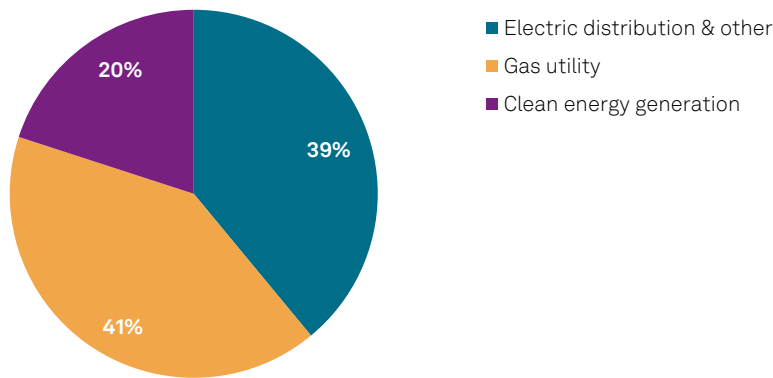
Consumers Energy Co. rate case details

	Present electric rate case: requested by company 5/1/2023	Previous electric rate case: authorized by Commission 1/19/2023	Present gas rate case: settlement filed 7/21/2023	Previous gas rate case: authorized by Commission 7/7/2022
Rate change amount (\$ mil.)	207.1	155.0	95.0	170.0
Rate base (\$ mil)	14,354.2	N/A	N/A	N/A
Rate base valuation method	Average	Average	Average	Average
Return on equity (%)	10.25	9.90	9.90	9.90
Common equity to total capital (%)	42.58	N/A	N/A	N/A
Rate of return (%)	6.11	N/A	N/A	N/A
Rate case test year end date	2/28/2025	12/31/2023	N/A	9/30/2023

Source: S&P CapitalIQ Pro. N/A—Not applicable.

The company's elevated capital spending plan prioritizes infrastructure upgrades, and its energy transition plans. Over the next five years, CE plans to spend about \$15.5 billion to maintain and upgrade its gas infrastructure and electric distribution systems and reduce its carbon emission. The capital plan includes investment of about \$6.3 billion in the gas segment and about \$9.2 billion in the electric segment. The company also intends to reduce its carbon exposure in line with its Integrated Resource Plan (IRP), which the MPSC approved in June 2022. The plan includes a goal to reach net-zero carbon emission by 2040 for CE's electric division and a goal to retire CE's owned coal-fired generation plants by 2025. Furthermore, the company's IRP targets a gradual reduction in its gas-fired generation dependence after 2025 as well as a target to meet 90% of its customer needs with clean energy sources by 2040. In addition, the company also announced a net-zero greenhouse gas emissions target for its gas distribution system by 2050.

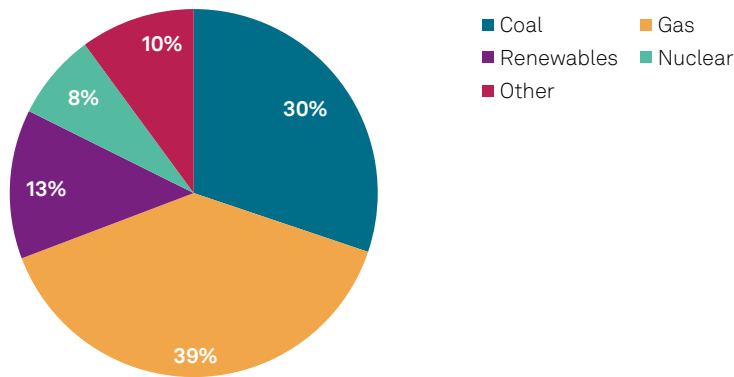
Consumers Energy Co.'s investment plan



Source: Company filings.

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Consumers Energy Co.'s electricity generated and purchased by source



Source: Company filings.

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The MPSC is currently investigating CE for malfunctioning meters and estimated billings. The company informed investors during its earnings call that meter vendors faced supply-chain issues since the start of the pandemic, which delayed the deployment of the company’s updated meters moving to 5G from 3G. Given these delays, there were some issues with meter reads as more wireless carriers moved to 5G. This said, the company expects more consistent meter reads by the end of August. We continue to monitor the developments surrounding this investigation.

We expect CE's credit measures to remain within the significant financial risk profile category. Throughout our base-case scenario, we expect CE’s funds from operations (FFO) to debt to be between 18%-20%.

Outlook

The stable rating outlook on CE reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk. We expect CE will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt of about 18%-20%.

Downside scenario

We could lower our rating on Consumers Energy if:

- The stand-alone financial measures weaken such that FFO to debt weakens to consistently below 15%; or
- We could also lower our rating on Consumers Energy if we lower our rating on parent CMS Energy Corp.

Upside scenario

Although less likely, we could raise our rating on Consumer's Energy if we raise our rating on CMS Energy and Consumers Energy's stand-alone financial measures improve, reflecting FFO to debt consistently above 20%.

Our Base-Case Scenario

Assumptions

- Consistent rate case filings and use of existing regulatory mechanisms;
- Elevated capital spending over the forecast period averaging about \$3 billion annually;
- Annual dividends averaging about \$960 million annually;
- All debt maturities are refinanced; and
- Continued negative discretionary cash flow will be financed in a balanced manner to support the regulated capital structure.

Key metrics

Consumers Energy Inc.—Forecast summary

Period ending (Mil. \$)	2021a	2022a	2023e	2024f	2025f	2026f	2027f
Revenue	6,987	8,117	7,932	8,376	8,896	9,428	9,985
EBITDA (reported)	2,252	2,321	2,653	2,902	3,143	3,392	3,655
Plus: Operating lease adjustment (OLA) rent	8	6	6	6	6	6	6
Plus/(less): Other	146	70	51	(47)	(58)	(58)	(65)
EBITDA	2,406	2,397	2,710	2,861	3,092	3,340	3,595
Less: Cash interest paid	(375)	(342)	(406)	(478)	(533)	(573)	(605)
Less: Cash taxes paid	10	2	--	(102)	(41)	(92)	(66)

Consumers Energy Co.

Consumers Energy Inc.—Forecast summary

Funds from operations (FFO)	2,041	2,058	2,303	2,281	2,518	2,675	2,925
Cash flow from operations (CFO)	2,014	985	2,717	2,221	2,471	2,585	2,798
Capital expenditure (capex)	2,136	2,275	3,707	2,823	3,117	2,765	2,737
Free operating cash flow (FOCF)	(123)	(1,290)	(990)	(602)	(647)	(180)	61
Dividends	724	771	788	913	968	1,044	1,099
Discretionary cash flow (DCF)	(847)	(2,061)	(1,778)	(1,515)	(1,615)	(1,224)	(1,038)
Debt (reported)	8,810	10,287	11,585	12,402	13,217	13,838	14,354
Plus: Lease liabilities debt	74	81	89	99	110	124	140
Plus: Pension and other postretirement debt	--	--	--	--	--	--	--
Less: Accessible cash and liquid Investments	(22)	(43)	(43)	(43)	(43)	(43)	(43)
Plus/(less): Other	535	680	27	98	180	267	355
Debt	9,397	11,005	11,658	12,556	13,465	14,186	14,807
Equity	9,279	10,155	10,885	11,687	12,603	13,369	14,096
Cash and short-term investments (reported)	22	43	43	43	43	43	43
Adjusted ratios							
Debt/EBITDA (x)	3.9	4.6	4.3	4.4	4.4	4.2	4.1
FFO/debt (%)	21.7	18.7	19.8	18.2	18.7	18.9	19.8
FFO cash interest coverage (x)	6.4	7.0	6.7	5.8	5.7	5.7	5.8
EBITDA interest coverage (x)	6.3	6.4	6.2	5.7	5.5	5.6	5.7
CFO/debt (%)	21.4	8.9	23.3	17.7	18.3	18.2	18.9
FOCF/debt (%)	(1.3)	(11.7)	(8.5)	(4.8)	(4.8)	(1.3)	0.4
DCF/debt (%)	(9.0)	(18.7)	(15.3)	(12.1)	(12.0)	(8.6)	(7.0)
Debt/debt and equity (%)	50.3	52.0	51.7	51.8	51.7	51.5	51.2

All figures adjusted by S&P Global Ratings. a—Actual. e—Estimate. f—Forecast.

Company Description

CE is a subsidiary of CMS Energy and operates as an electric and gas utility serving about 1.9 million electric and 1.8 million natural gas million customers in Michigan. CE's electric business operates as a vertically integrated utility that generates, distributes, and sells electricity. The electric utility sources about half of its generation from purchased power, rather than from its own plants. The company also sells, stores, and transports natural gas. It is based in Jackson, Mich. CE contributes to about 95% of CMS' EBITDA.

Peer Comparison

Consumers Energy Co.--Peer Comparisons

	Consumers Energy Co.	DTE Electric Co.	Wisconsin Power & Light Co.	Wisconsin Electric Power Co.	Consolidated Edison Co. of New York Inc.
Foreign currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A/Negative/A-1	A-/Stable/A-2	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A/Negative/A-1	A-/Stable/A-2	A-/Stable/A-2
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2022-12-31	2022-12-31	2022-12-31	2022-12-31	2022-12-31
Mil.	\$	\$	\$	\$	\$
Revenue	8,117	6,353	1,856	4,070	13,268
EBITDA	2,397	2,715	742	1,614	4,048
Funds from operations (FFO)	2,058	2,389	562	986	3,140
Interest	374	551	123	230	890
Cash interest paid	342	359	124	540	821
Operating cash flow (OCF)	985	1,654	286	726	3,264
Capital expenditure	2,275	2,617	1,007	1,018	3,563
Free operating cash flow (FOCF)	(1,290)	(964)	(721)	(293)	(299)
Discretionary cash flow (DCF)	(2,061)	(1,727)	(926)	(922)	(1,277)
Cash and short-term investments	43	15	5	6	1,056
Gross available cash	43	15	5	6	1,056
Debt	11,005	11,528	3,406	5,843	21,344
Equity	10,155	9,695	3,491	4,152	16,878
EBITDA margin (%)	29.5	42.7	40.0	39.7	30.5
Return on capital (%)	6.3	7.6	8.1	11.8	5.8
EBITDA interest coverage (x)	6.4	4.9	6.0	7.0	4.5
FFO cash interest coverage (x)	7.0	7.6	5.5	2.8	4.8
Debt/EBITDA (x)	4.6	4.2	4.6	3.6	5.3
FFO/debt (%)	18.7	20.7	16.5	16.9	14.7
OCF/debt (%)	8.9	14.3	8.4	12.4	15.3
FOCF/debt (%)	(11.7)	(8.4)	(21.2)	(5.0)	(1.4)
DCF/debt (%)	(18.7)	(15.0)	(27.2)	(15.8)	(6.0)

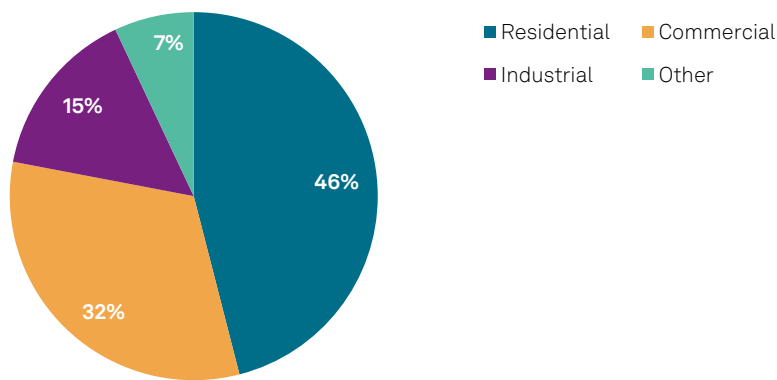
Business Risk

Our assessment of CE's business risk profile reflects the company's monopolistic electric and natural gas utility operations and effective management of regulatory risk. The Michigan Public Service Commission (MPSC) regulates CE and we view the regulatory environment in Michigan as above average compared to peers. This is demonstrated through the company's use of forward-looking test years and a streamlined 10-month rate case process. Furthermore, CE benefits from other constructive rate mechanisms, such as the Power Supply Cost Recovery and Gas Cost Recovery adjustment riders, as well as partial decoupling for the gas business, which annually reconciles actual weather-normalized nonfuel revenues with the revenues approved by the MPSC. These constructive rate mechanisms enable CE to generally earn its allowed ROE and minimize regulatory lag. The company also actively manages its gas supply for its gas system as it injects natural gas into storage during the summer months for use during the winter months. During 2022, 48 percent of the natural gas supplied to all customers during

Consumers Energy Co.

the winter months was supplied from storage. Furthermore, CE's business risk profile is bolstered by the company's large customer base of about 1.9 million electric customers and about 1.8 million natural gas customers throughout Michigan. This said, the company is exposed to cyclical commercial and industrial customers for its electric operations which contribute about 47% of the company's electric revenues.

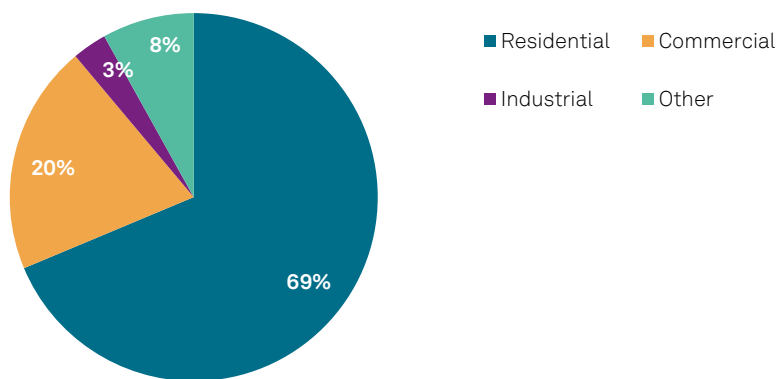
Consumers Energy Co.'s electrical revenue by customer class



Source: Company filings.

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Consumers Energy Co.'s gas revenue by customer class

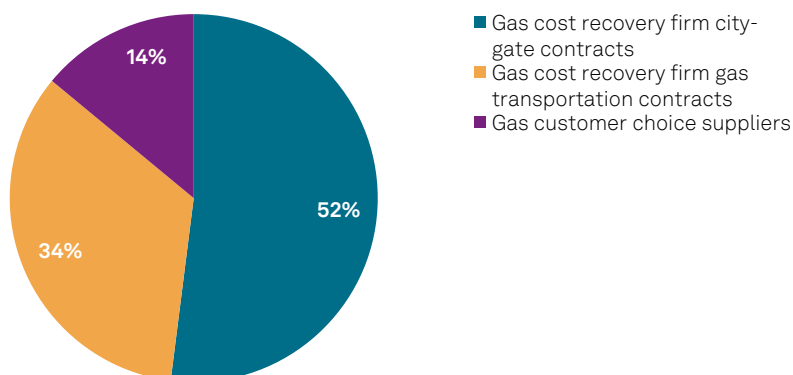


Source: Company filings.

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Consumers Energy Co.

Consumers Energy Co.'s gas supply sources



Source: Company filings.

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Financial Risk

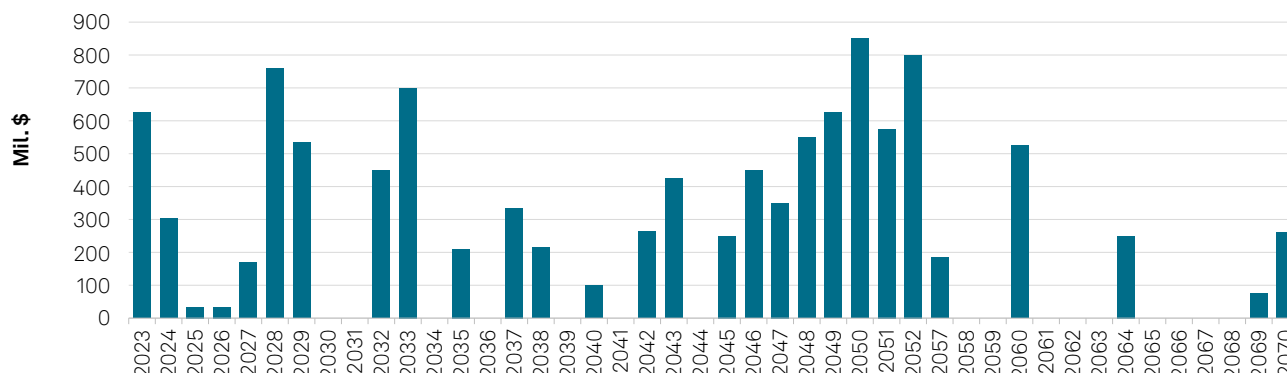
We assess CE's financial measures using our medial volatility table, reflecting the company's lower-risk regulated electric and gas utility operations and its effective management of regulatory risk. Under our base-case scenario, we expect elevated capital spending averaging around \$3 billion annually over the forecast period (inclusive of the company's acquisition of the Covert gas plant), dividends averaging about \$960 million annually, equity injections by the parent to maintain the company's capital structure, securitization issuance related to the retirement costs of the company's Karn coal plant units 1 and 2, continued use of existing regulatory mechanisms, negative discretionary cash flow, and refinancing of all debt maturities. As such, we anticipate financial measures to be consistent with the middle of the range for the significant financial risk category. Specifically, we forecast FFO to debt between 18%-20%.

Debt maturities

Consumers Energy Co.

Debt Maturities

As of June 2023



Source. Company filings

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Consumers Energy Co.--Financial Summary

Period ending	Dec-31-2017	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022
Reporting period	2017a	2018a	2019a	2020a	2021a	2022a
Display currency (mil.)	\$	\$	\$	\$	\$	\$
Revenues	6,187	6,430	6,341	6,155	6,987	8,117
EBITDA	2,267	2,152	2,252	2,392	2,406	2,397
Funds from operations (FFO)	1,954	1,665	1,823	1,968	2,041	2,058
Interest expense	347	355	335	393	380	374
Cash interest paid	314	331	296	373	375	342
Operating cash flow (OCF)	1,792	1,533	1,688	1,265	2,014	985
Capital expenditure	1,721	1,920	2,191	2,254	2,136	2,275
Free operating cash flow (FOCF)	71	(387)	(502)	(989)	(123)	(1,290)
Discretionary cash flow (DCF)	(453)	(918)	(1,094)	(1,628)	(847)	(2,061)
Cash and short-term investments	44	39	11	20	22	43
Gross available cash	44	39	11	20	22	43
Debt	7,037	7,774	8,238	9,113	9,397	11,005
Common equity	6,488	6,920	7,737	8,556	9,279	10,155
Adjusted ratios						
EBITDA margin (%)	36.6	33.5	35.5	38.9	34.4	29.5
Return on capital (%)	9.8	7.9	7.7	7.5	6.9	6.3
EBITDA interest coverage (x)	6.5	6.1	6.7	6.1	6.3	6.4
FFO cash interest coverage (x)	7.2	6.0	7.2	6.3	6.4	7.0
Debt/EBITDA (x)	3.1	3.6	3.7	3.8	3.9	4.6
FFO/debt (%)	27.8	21.4	22.1	21.6	21.7	18.7
OCF/debt (%)	25.5	19.7	20.5	13.9	21.4	8.9

Consumers Energy Co.--Financial Summary

FOCF/debt (%)	1.0	(5.0)	(6.1)	(10.9)	(1.3)	(11.7)
DCF/debt (%)	(6.4)	(11.8)	(13.3)	(17.9)	(9.0)	(18.7)

Reconciliation Of Consumers Energy Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. \$)

Financial year	Dec-31-2022	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Company reported amounts		10,287	10,155	8,151	2,321	1,233	335	2,397	994	771	2,239
Cash taxes paid		-	-	-	-	-	-	2	-	-	-
Cash interest paid		-	-	-	-	-	-	(331)	-	-	-
Lease liabilities		81	-	-	-	-	-	-	-	-	-
Operating leases		-	-	-	6	1	1	(1)	5	-	-
Accessible cash and liquid investments		(43)	-	-	-	-	-	-	-	-	-
Capitalized interest		-	-	-	-	-	2	(2)	(2)	-	(2)
Share-based compensation expense		-	-	-	25	-	-	-	-	-	-
Securitized stranded costs		(170)	-	(34)	(34)	(6)	(6)	6	(28)	-	-
Power purchase agreements		356	-	-	51	14	14	(14)	38	-	38
Asset-retirement obligations		589	-	-	28	28	28	-	-	-	-
Nonoperating income (expense)		-	-	-	-	(8)	-	-	-	-	-
Reclassification of interest and dividend cash flows		-	-	-	-	-	-	-	(22)	-	-
Debt: other		(95)	-	-	-	-	-	-	-	-	-
Total adjustments		718	-	(34)	76	29	39	(340)	(9)	-	36
S&P Global Ratings adjusted		Debt	Equity	Revenue	EBITDA	EBIT	Interest expense	Funds from Operations	Operating cash flow	Dividends	Capital expenditure
		11,005	10,155	8,117	2,397	1,262	374	2,058	985	771	2,275

Liquidity

We assess CE's liquidity as adequate, with sources covering uses by 1.1x over the coming 12 months, and that its sources cover uses even if forecasted consolidated EBITDA declines by 10%. We believe the supportive regulatory framework provides a manageable level of cash flow stability for the company even in times of economic stress, supporting our use of slightly lower thresholds to assess liquidity. In addition, CE has the ability to absorb high-impact, low-probability events, in our view, as the company maintains about \$1.1 billion in committed credit facilities through 2027, maintains another \$250 million in committed credit facilities through

November 2024, and can likely lower its capital spending (averaging about \$3 billion annually) during stressful periods, indicative of a limited need for refinancing under such conditions. CE can borrow \$500 million from the parent CMS Energy as per its renewed credit agreement in December 2022. Furthermore, our assessment reflects the company's prudent risk management and sound relationships with its banking group. Overall, we believe that the company should be able to withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations. The company has around \$300 million of long-term debt maturities coming up in 2024 and we expect the company to proactively address these maturities well in advance of their scheduled due dates.

Principal liquidity sources

- Cash FFO of about \$2.3 billion;
- Credit facilities of about \$1.3 billion;
- Working capital inflows of about \$150 million; and
- Available cash of about \$100 million.

Principal liquidity uses

- Debt maturities of about \$700 million over the next 12 months;
- Estimated maintenance capital spending of about \$1.9 billion; and
- Dividends of about \$850 million.

Environmental, Social, And Governance

Environmental factors are a moderately negative consideration in our credit rating analysis of CE. The company's use of above-average fossil fuel generation sources exposes it to heightened climate transition risk. The utility's generation capacity portfolio consists of 24% natural gas, 33% coal, 22% renewables, and 21% oil/gas as of Dec. 31, 2022. Slightly mitigating this risk is the utility's accelerated coal retirement plan, which includes a goal to be coal-free by 2025 and have 90% of its capacity portfolio sourced from clean energy resources by 2040.

Group Influence

Under our group rating methodology, we consider CMS Energy to be the parent of the group with a group credit profile (GCP) of 'bbb+'. We assess CE as a core subsidiary of CMS Energy because we view the utility as integral to the group's identity, highly unlikely to be sold and having a strong commitment from management, given the company's emphasis on maintaining the size of the regulated utility operations relative to the nonutility businesses.

Because CE is operationally separate and sufficient insulating measures are in place, we rate the utility one notch above the GCP. Some of the key insulating measures are:

- CE is a separate and stand-alone legal entity that functions independently (both financially and operationally), files its own rate cases, and is independently regulated by MPSC.
- CE has its own records and books, including stand-alone audited financial statements.
- The utility has its own funding arrangements, including issuing its own long-term debt, and it has a separate committed credit facility to cover its short-term funding needs.
- CE does not comingle funds, assets, or cash flow with parent CMS Energy or its other subsidiaries, and it does not participate in a money pool.

- We believe there is a strong economic basis for CMS Energy to preserve CE's credit strength, reflecting CE's low-risk, profitable, and regulated utility business model. CE is also a significant portion of CMS Energy, accounting for about 95% of the consolidated company.
- There are no cross-default provisions between parent CMS Energy and CE that could directly lead to a default at the utility.

Issue Ratings--Subordination Risk Analysis

Capital structure

CE's capital structure consists of about \$10.9 billion of long-term debt, including about \$10.8 billion in first-mortgage bonds (FMBs) and about \$110 million of tax-exempt revenue bonds.

Analytical conclusions

We rate the company's senior unsecured debt 'A-', in-line with the long-term issuer credit rating on CE as the rated issuances are senior unsecured debt issued by a qualifying investment grade utility as per our criteria.

We base our 'A-2' short-term rating on CE on our 'A-' issuer credit rating.

Issue Ratings--Recovery Analysis

Key analytical factors

- We assign recovery ratings to FMBs issued by U.S. utilities, which can result in issue ratings being notched above an issuer credit rating on a utility, depending on the rating category and the extent of the collateral coverage. The FMBs issued by U.S. utilities are a form of secured utility bonds that qualify for a recovery rating as defined in our criteria.
- CE's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

Rating Component Scores

Foreign currency issuer credit rating	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2
Business risk	Excellent
Country risk	Very Low
Industry risk	Very Low
Competitive position	Excellent
Financial risk	Significant
Cash flow/leverage	Significant
Anchor	a-
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)

Consumers Energy Co.

Rating Component Scores

Liquidity	Adequate (no impact)
Management and governance	Satisfactory (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	a-
Group credit profile	bbb+
Entity status within group	Insulated (no impact on SACP)

Related Criteria

- General Criteria: Hybrid Capital: Methodology And Assumptions, March 2, 2022
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of August 17, 2023)*

Consumers Energy Co.

Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2

Consumers Energy Co.

Ratings Detail (as of August 17, 2023)*

Senior Secured

A

Issuer Credit Ratings History

30-Oct-2019

A-/Stable/A-2

03-Dec-2014

BBB+/Stable/A-2

11-Sep-2014

BBB/Positive/A-2

Related Entities

CMS Energy Corp.

Issuer Credit Rating

BBB+/Stable/A-2

Junior Subordinated

BBB-

Preferred Stock

BBB-

Senior Unsecured

BBB

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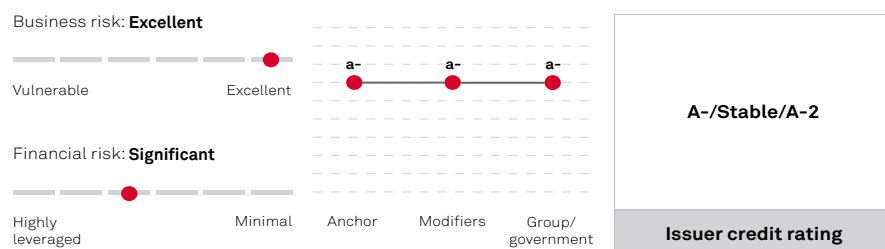
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Consumers Energy Co.

August 20, 2024

Ratings Score Snapshot



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Credit Highlights

Overview

Key strengths	Key risks
Monopolistic vertically integrated electric utility and gas distribution utility operations.	Lack of operating diversity that makes the company largely depend on Michigan regulators to sustain its credit quality.
Favorable regulatory construct in Michigan.	Energy transition risks due to its dependence on natural gas and coal-fired generation (about 75% of electricity generated or purchased in 2023), partially mitigated by a plan to retire coal in 2025.
Large customer base of 1.9 million electric and 1.8 million gas customers.	Negative discretionary cash flow, reflecting robust capital spending, which indicates external funding needs.
Insulated subsidiary of its parent, CMS Energy Corp., allowing us to rate it one notch above the parent.	Susceptibility to adverse weather events, including winter storms and convective storms.
	Exposure to cyclical commercial and industrial customers, which account for about 45%-50% of electric utility revenues and 20%-25% of gas utility revenues.

We expect Consumers Energy Co. (CE) to continue to effectively manage its regulatory risk.

We believe Michigan's regulatory construct is above average compared with peers because of the benefit of a streamlined 10-month rate case process. Other constructive rate mechanisms include the use of forward test-years, power supply cost rider adjustments, and natural gas

Consumers Energy Co.

cost rider adjustments. These mechanisms help the company earn its allowed return on equity (ROE) and minimize regulatory lag.

CE is in the middle of an electric rate case and just received a settlement approval in its recent gas rate case. The company filed for a \$325 million electric rate increase based on a 10.25% ROE in May and reached a settlement with various intervenors and received an order from the Michigan Public Service Commission (MPSC) for a \$35 million gas rate increase based on a 9.90% ROE. The gas rate increase granted was about only a quarter of the rate increase requested. However, this difference was partially because the commission authorized bill credits of \$27.5 million per year over four years related to the gain on the sale of CE's appliance service plan business, which happened after and was not a part of the company's case filing.

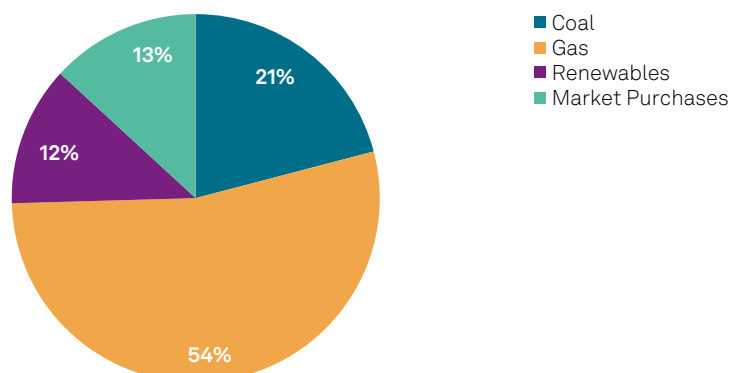
Consumers Energy Co. rate case details

	Electric rate case		Gas rate case	
	Present case: requested by company 5/31/2024	Previous case: authorized by MPSC 3/1/2024	Authorized by MPSC 7/23/2024	Requested by company 12/15/2023
Rate change amount (mil. \$)	325	92.0	35.0	136.0
Rate base (mil. \$)	15,571.5	13,669	10,850*	10,970
Rate base valuation method	Average	Average	Average	Average
Return on equity (%)	10.25	9.90	9.90	10.25
Common equity to total capital (%)	42.36	41.13	41.48*	42.73
Rate of return (%)	6.21	5.86	5.93*	6.20
Rate case test year end date	2/28/2026	2/28/2025	9/30/2025	9/30/2025

*Company assumption under settlement. Source: S&P CapitalIQ Pro. MPSC--Michigan Public Service Commission.

The company's elevated capital spending plan prioritizes infrastructure upgrades, and its energy transition plans. Over the next five years, CE plans to spend about \$17 billion to maintain and upgrade its gas infrastructure and electric distribution systems and reduce its carbon emissions. The capital plan includes investment of about \$6.3 billion in the gas segment and about \$10.7 billion in electric (of which, about two thirds are dedicated to distribution-related spending). The company also intends to reduce its carbon exposure in line with its Integrated Resource Plan (IRP), which the MPSC approved in June 2022. The plan includes a goal to reach net-zero carbon emission by 2040 and a goal to retire CE's owned coal-fired generation plants in 2025. Furthermore, the company's IRP targets a gradual reduction in its gas-fired generation dependence after 2025, as well as meeting 90% of its customer needs with clean energy sources by 2040. The company also announced a net-zero greenhouse gas emissions target by 2050 and a zero methane emissions target by 2030 for its gas distribution system.

CE's 2023 generated and purchased electricity supply by source



Source: Company filings.

The company's credit metrics were weak in 2023, largely because of weather-related issues.

Mild weather impaired sales for the company's gas operations, and the company saw heightened winter and convective storm activities. While the company has effectively recovered storm costs in past rate case proceedings, it has not been able to defer storm costs into regulatory assets, which introduced regulatory lag.

A portion of CE's service territory has a relatively high wildfire risk classification from the Federal Emergency Management Agency (FEMA). This area is contiguous and has a population of about 10,000-15,000 people, 7,000-9,000 housing units, of which about 40%-60% are occupied, and median home values of \$100,000-\$150,000 according to U.S. Census data. Part of the company's capital spending plan is focused on smart electric systems and anticipates pursuing further undergrounding pilots, with the potential to underground up to 400 miles of electric lines per year, starting in 2027, to address some of its climate-related risks. While CE has not been found culpable for any wildfires in its service territory and is not currently party to any such litigation, we will continue to monitor the company's ability to effectively manage its risks associated with adverse weather events.

We expect CE's credit measures to remain within the significant financial risk profile category. Throughout our base-case scenario, we expect funds from operations (FFO) to debt of 17%-19%.

Outlook

The stable rating outlook on CE reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk. We expect CE will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt of 17%-19%.

Downside scenario

We could lower our rating on CE if:

- The stand-alone financial measures weaken such that FFO to debt weakens to consistently below 15%; or

- We lower our rating on parent CMS Energy.

Upside scenario

Although less likely, we could raise our rating on CE if we raise our rating on CMS Energy and CE's stand-alone financial measures improve, reflecting FFO to debt consistently above 20%.

Our Base-Case Scenario

Assumptions

- Consistent rate case filings and use of existing regulatory mechanisms;
- Elevated capital spending over the forecast period averaging \$2.8 billion-\$3.0 billion annually;
- Annual dividends averaging about \$1 billion-\$1.1 billion annually;
- All debt maturities refinanced; and
- Continued negative discretionary cash flow financed in a balanced manner to support the regulated capital structure.

Key metrics

Consumers Energy Co.--Forecast summary

Period ending	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023	Dec-31-2024	Dec-31-2025	Dec-31-2026	Dec-31-2027
(Mil. \$)	2020a	2021a	2022a	2023a	2024e	2025f	2026f	2027f
Revenue	6,155	6,987	8,117	7,129	8,230	8,803	9,333	9,879
EBITDA (reported)	2,244	2,252	2,321	2,405	2,795	3,081	3,337	3,582
Plus: Operating lease adjustment (OLA) rent	9	8	6	6	6	6	6	6
Plus/(less): Other	139	146	70	74	(39)	(40)	(40)	(22)
EBITDA	2,392	2,406	2,397	2,485	2,762	3,047	3,303	3,566
Less: Cash interest paid	(373)	(376)	(343)	(454)	(480)	(559)	(620)	(684)
Less: Cash taxes paid	(51)	10	2	(31)	(112)	3	1	(9)
Plus/(less): Other	--	--	--	--	--	--	--	--
Funds from operations (FFO)	1,968	2,040	2,057	2,000	2,169	2,491	2,685	2,873
EBIT	1,268	1,246	1,262	1,349	1,625	1,826	1,993	2,172
Interest expense	393	381	375	496	512	591	652	716
Cash flow from operations (CFO)	1,265	2,013	984	2,415	2,316	2,529	2,662	2,802
Capital expenditure (capex)	2,254	2,136	2,275	2,279	2,892	3,318	2,897	2,890
Free operating cash flow (FOCF)	(989)	(124)	(1,291)	136	(576)	(789)	(235)	(88)
Dividends	639	723	770	696	865	951	1,047	1,129
Share repurchases (reported)	--	--	--	--	--	--	--	--
Discretionary cash flow (DCF)	(1,628)	(847)	(2,061)	(560)	(1,441)	(1,740)	(1,282)	(1,217)
Debt (reported)	8,429	8,810	10,287	11,285	12,331	13,437	14,319	15,172

Consumers Energy Co.

Consumers Energy Co.--Forecast summary

Plus: Lease liabilities debt	88	74	81	41	26	19	15	12
Plus: Pension and other postretirement debt	--	--	--	--	--	--	--	--
Less: Accessible cash and liquid Investments	(20)	(22)	(43)	(35)	(100)	(100)	(100)	(100)
Plus/(less): Other	616	553	699	80	167	282	404	532
Debt	9,113	9,415	11,024	11,371	12,423	13,637	14,638	15,616
Equity	8,556	9,261	10,137	10,782	11,564	12,735	13,667	14,580

Adjusted ratios

Debt/EBITDA (x)	3.8	3.9	4.6	4.6	4.5	4.5	4.4	4.4
FFO/debt (%)	21.6	21.7	18.7	17.6	17.5	18.3	18.3	18.4
FFO cash interest coverage (x)	6.3	6.4	7.0	5.4	5.5	5.5	5.3	5.2
EBITDA interest coverage (x)	6.1	6.3	6.4	5.0	5.4	5.2	5.1	5.0
CFO/debt (%)	13.9	21.4	8.9	21.2	18.6	18.5	18.2	17.9
FOCF/debt (%)	(10.9)	(1.3)	(11.7)	1.2	(4.6)	(5.8)	(1.6)	(0.6)
DCF/debt (%)	(17.9)	(9.0)	(18.7)	(4.9)	(11.6)	(12.8)	(8.8)	(7.8)
Annual revenue growth (%)	(2.9)	13.5	16.2	(12.2)	15.4	7.0	6.0	5.9
EBITDA margin (%)	38.9	34.4	29.5	34.9	33.6	34.6	35.4	36.1
Return on capital (%)	7.5	6.9	6.3	6.2	7.0	7.3	7.3	7.4
Debt/debt and equity (%)	51.6	50.4	52.1	51.3	51.8	51.7	51.7	51.7
Debt fixed-charge coverage (x)	6.1	6.3	6.4	5.0	5.4	5.2	5.1	5.0

All figures are adjusted by S&P Global Ratings, unless stated as reported. a--Actual. e--Estimate. f--Forecast. \$--U.S. dollar.

Company Description

CE is a subsidiary of CMS Energy and operates as an electric and gas utility serving about 1.9 million electric and 1.8 million natural gas million customers in Michigan. CE's electric business operates as a vertically integrated utility that generates, distributes, and sells electricity. The electric utility sources about 40%-50% of its generation from purchased power, rather than from its own plants. The company also sells, stores, and transports natural gas. It is based in Jackson, Mich. CE contributes to about 95% of CMS' EBITDA.

Peer Comparison

Consumers Energy Co.--Peer Comparisons

	Consumers Energy Co.	DTE Electric Co.	Wisconsin Power & Light Co.	Wisconsin Electric Power Co.	Consolidated Edison Co. of New York Inc.
Foreign currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A/Negative/A-1	A-/Stable/A-2	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A/Negative/A-1	A-/Stable/A-2	A-/Stable/A-2
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2023-12-31	2023-12-31	2023-12-31	2023-12-31	2023-12-31

Consumers Energy Co.

Consumers Energy Co.--Peer Comparisons

Mil.	\$	\$	\$	\$	\$
Revenue	7,129	5,729	1,827	4,045	13,476
EBITDA	2,485	2,715	760	1,716	4,232
Funds from operations (FFO)	2,000	2,282	544	1,056	3,276
Interest	496	623	152	383	1,032
Cash interest paid	454	418	166	561	983
Operating cash flow (OCF)	2,415	1,534	558	1,028	2,250
Capital expenditure	2,279	3,076	999	1,183	4,010
Free operating cash flow (FOCF)	136	(1,542)	(441)	(155)	(1,760)
Discretionary cash flow (DCF)	(560)	(2,544)	(625)	(524)	(2,816)
Cash and short-term investments	35	15	7	6	1,138
Gross available cash	35	15	7	6	1,138
Debt	11,371	12,009	3,748	5,657	22,824
Equity	10,782	10,224	3,897	5,068	19,146
EBITDA margin (%)	34.9	47.4	41.6	42.4	31.4
Return on capital (%)	6.2	6.8	7.6	12.2	5.6
EBITDA interest coverage (x)	5.0	4.4	5.0	4.5	4.1
FFO cash interest coverage (x)	5.4	6.5	4.3	2.9	4.3
Debt/EBITDA (x)	4.6	4.4	4.9	3.3	5.4
FFO/debt (%)	17.6	19.0	14.5	18.7	14.4
OCF/debt (%)	21.2	12.8	14.9	18.2	9.9
FOCF/debt (%)	1.2	(12.8)	(11.8)	(2.7)	(7.7)
DCF/debt (%)	(4.9)	(21.2)	(16.7)	(9.3)	(12.3)

Business Risk

Our assessment of CE's business risk profile reflects the company's monopolistic electric and natural gas utility operations and effective management of regulatory risk. The MPSC regulates CE, and we view the regulatory environment in Michigan as above average compared with peers. This is demonstrated through the company's use of forward-looking test years and a streamlined 10-month rate case process. Furthermore, CE benefits from other constructive rate mechanisms, such as the Power Supply Cost Recovery adjustment rider, and the Gas Cost Recovery adjustment rider.

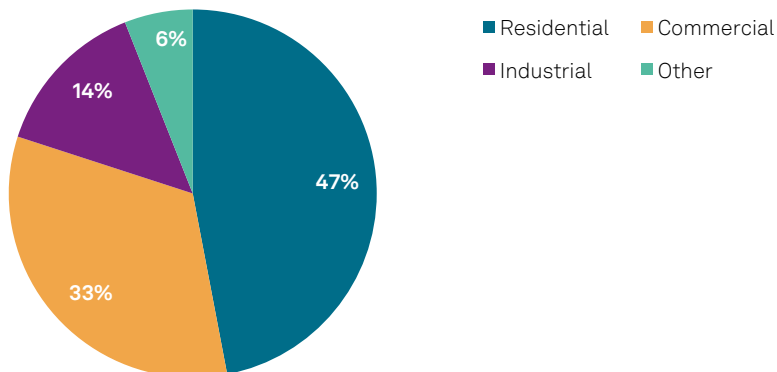
In 2023, the state also passed a law that allows electric utilities in the state to earn a return equal to their pre-tax weighted average cost of capital on payments made under new purchased-power agreements. These constructive rate mechanisms enable CE to generally earn its allowed ROE and minimize regulatory lag.

The company actively manages its gas supply to reduce the effects of price volatility and to support its gas system operations by injecting natural gas into storage during the summer months for use during the winter months. During 2023, 45% of the natural gas supplied to all customers during the winter months came from storage. Additionally, CE's large customer base

Consumers Energy Co.

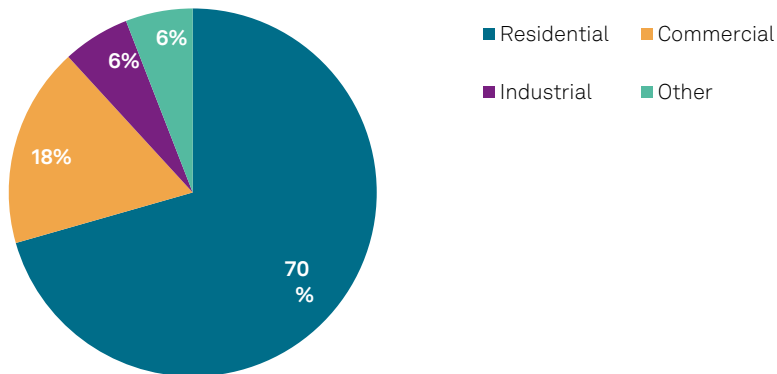
of about 1.9 million electric customers and about 1.8 million natural gas customers throughout Michigan bolsters the company's business risk profile. This said, the company is exposed to cyclical commercial and industrial customers for its electric operations, which contribute about 45%-50% of the company's electric revenues.

CE's 2023 electrical revenue by customer class



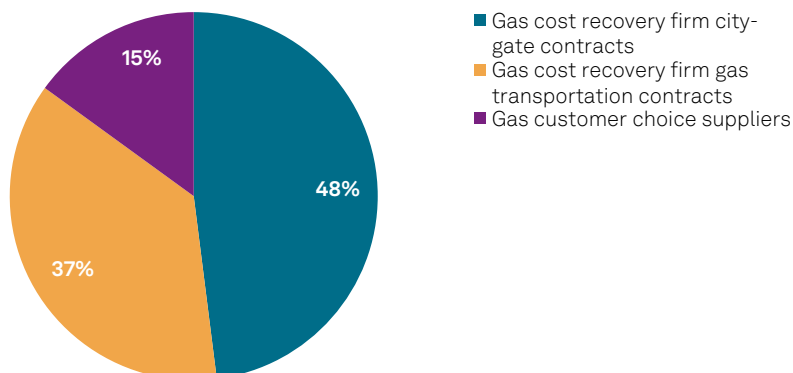
Source: Company filings.

CE's 2023 gas revenue by customer class



Source: Company filings

CE's 2023 gas supply sources



Source: Company filings

Financial Risk

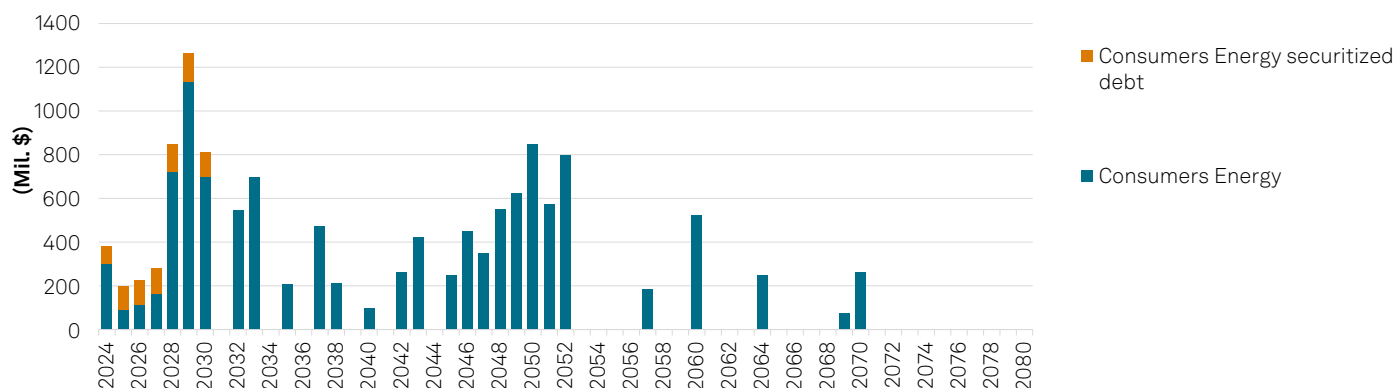
We assess CE's financial measures using our medial volatility table, reflecting the company's lower-risk regulated electric and gas utility operations and its effective management of regulatory risk. Under our base-case scenario, we expect:

- Elevated capital spending averaging \$2.8 billion-\$3.0 billion annually over the forecast period;
- Dividends averaging \$1 billion-\$1.1 billion annually;
- Equity injections by the parent to maintain the company's capital structure;
- Continued use of existing regulatory mechanisms;
- Negative discretionary cash flow; and
- The refinancing of all debt maturities.

As such, we anticipate financial measures to be consistent with the middle of the range for the significant financial risk category. Specifically, we forecast FFO to debt of 17%-19%.

Debt maturities

Consumers Energy debt maturities



Source: Company filings and S&P Global Ratings.

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Consumers Energy Co.--Financial Summary

Period ending	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023
Reporting period	2018a	2019a	2020a	2021a	2022a	2023a
Display currency (mil.)	\$	\$	\$	\$	\$	\$
Revenues	6,430	6,341	6,155	6,987	8,117	7,129
EBITDA	2,152	2,252	2,392	2,406	2,397	2,485
Funds from operations (FFO)	1,665	1,823	1,968	2,040	2,057	2,000
Interest expense	355	335	393	381	375	496
Cash interest paid	331	296	373	376	343	454
Operating cash flow (OCF)	1,533	1,688	1,265	2,013	984	2,415
Capital expenditure	1,920	2,191	2,254	2,136	2,275	2,279
Free operating cash flow (FOCF)	(387)	(502)	(989)	(124)	(1,291)	136
Discretionary cash flow (DCF)	(918)	(1,094)	(1,628)	(847)	(2,061)	(560)
Cash and short-term investments	39	11	20	22	43	35
Gross available cash	39	11	20	22	43	35
Debt	7,774	8,238	9,113	9,415	11,024	11,371
Common equity	6,920	7,737	8,556	9,261	10,137	10,782
Adjusted ratios						
EBITDA margin (%)	33.5	35.5	38.9	34.4	29.5	34.9
Return on capital (%)	7.9	7.7	7.5	6.9	6.3	6.2
EBITDA interest coverage (x)	6.1	6.7	6.1	6.3	6.4	5.0
FFO cash interest coverage (x)	6.0	7.2	6.3	6.4	7.0	5.4
Debt/EBITDA (x)	3.6	3.7	3.8	3.9	4.6	4.6
FFO/debt (%)	21.4	22.1	21.6	21.7	18.7	17.6
OCF/debt (%)	19.7	20.5	13.9	21.4	8.9	21.2

Consumers Energy Co.

Consumers Energy Co.--Financial Summary

FOCF/debt (%)	(5.0)	(6.1)	(10.9)	(1.3)	(11.7)	1.2
DCF/debt (%)	(11.8)	(13.3)	(17.9)	(9.0)	(18.7)	(4.9)

Reconciliation Of Consumers Energy Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. \$)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2023									
Company reported amounts	11,285	10,800	7,166	2,405	1,268	448	2,485	2,430	697	2,248
Cash taxes paid	-	-	-	-	-	-	(31)	-	-	-
Cash interest paid	-	-	-	-	-	-	(438)	-	-	-
Lease liabilities	41	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	6	1	1	(1)	5	-	-
Intermediate hybrids (equity)	19	(19)	-	-	-	1	(1)	(1)	(1)	-
Accessible cash and liquid investments	(35)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	3	(3)	(3)	-	(3)
Share-based compensation expense	-	-	-	26	-	-	-	-	-	-
Securitized stranded costs	(787)	-	(37)	(37)	(8)	(8)	8	(29)	-	-
Power purchase agreements	358	-	-	53	19	19	(19)	34	-	34
Asset-retirement obligations	584	-	-	32	32	32	-	-	-	-
Nonoperating income (expense)	-	-	-	-	37	-	-	-	-	-
Reclassification of interest and dividend cash flows	-	-	-	-	-	-	-	(21)	-	-
Debt: other	(93)	-	-	-	-	-	-	-	-	-
Total adjustments	86	(19)	(37)	80	81	48	(485)	(15)	(1)	31
S&P Global Ratings adjusted	Debt	Equity	Revenue	EBITDA	EBIT	Interest expense	Funds from Operations	Operating cash flow	Dividends	Capital expenditure
	11,371	10,782	7,129	2,485	1,349	496	2,000	2,415	696	2,279

Liquidity

We assess CE's liquidity as adequate, with sources covering uses by 1.1x over the coming 12 months, and that its sources cover uses even if forecast consolidated EBITDA declines 10%. We believe the supportive regulatory framework provides manageable cash flow stability for the company even in times of economic stress, supporting our use of slightly lower thresholds to assess liquidity.

In addition, CE can absorb high-impact, low-probability events, in our view, as the company maintains about \$1.1 billion in committed credit facilities through 2027, another \$250 million in committed credit facilities through November 2025, and can likely lower its capital spending (averaging \$2.8 billion-\$3.0 billion annually) during stressful periods, indicating a limited need for refinancing under such conditions. CE can borrow \$500 million from the parent CMS Energy as per its renewed credit agreement in December 2023.

Furthermore, our assessment reflects the company's prudent risk management and sound relationships with its banking group. Overall, we believe that the company can withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations. The company has around \$200 million of long-term debt maturities in 2025, and we expect the company to proactively address these maturities well in advance of their scheduled due dates.

Principal liquidity sources

- Cash FFO of about \$2.4 billion;
- Credit facilities of about \$1.3 billion;
- Working capital inflows of about \$70 million; and
- Available cash of about \$1.3 billion following the company's recent debt issuance.

Principal liquidity uses

- Debt maturities of about \$772 million over the next 12 months;
- Estimated maintenance capital spending of about \$2.7 billion; and
- Dividends of about \$900 million.

Covenant Analysis

Requirements

CE's credit agreements contain a covenant for CE to maintain debt to capitalization below 65%.

Compliance expectations

In our base-case scenario, we expect CE to remain compliant with this covenant and have sufficient headroom.

Environmental, Social, And Governance

Environmental factors are a negative consideration in our credit rating analysis of CE. The company's use of fossil fuel generation sources exposes it to heightened energy transition risks. Its generation portfolio's capacity comprises about 36% natural gas, 20% coal, 17%

hydroelectric, 17% oil and gas, and 9% wind and solar as of Dec. 31, 2023. The company's accelerated coal retirement plan for its utility slightly mitigates this risk. It includes a goal to be coal-free in 2025 and have 90% of its utility's capacity portfolio sourced from clean energy resources by 2040.

Furthermore, the company has experienced heightened winter and convective storm activities in recent years. While the company has effectively recovered storm costs in past rate case proceedings, it has not been able to defer storm costs into regulatory assets, which could introduce regulatory lag especially if costs are outsized.

While CMS has not been found culpable for any wildfires in its service territory and is not currently party to any litigation concerning these matters, a portion of its service territory has a relatively high wildfire risk classification from FEMA. This area is contiguous and has a population of about 10,000-15,000 inhabitants, 7,000-9,000 housing units, of which about 40%-60% are occupied, and median home values of \$100,000-\$150,000 according to U.S. Census data. Part of the company's capital spending plan is focused on smart electric systems and anticipates pursuing further undergrounding pilots, with the potential to underground up to 400 miles of electric lines per year starting in 2027. We will continue to monitor the company's ability to effectively manage its risks associated with adverse weather events.

Group Influence

Under our group rating methodology, we consider CMS Energy to be the parent of the group with a group credit profile (GCP) of 'bbb+'. We assess CE as a core subsidiary of CMS Energy largely because we view the utility as integral to the group's identity, highly unlikely to be sold and having a strong commitment from management, given the company's emphasis on maintaining the size of the regulated utility operations relative to the nonutility businesses.

Given CE's stand-alone credit profile, and because CE is operationally separate and maintains sufficient insulating measures, we rate the utility one notch above the GCP. Some of the key insulating measures are:

- CE is a separate and stand-alone legal entity that functions independently (both financially and operationally), files its own rate cases, and is independently regulated by MPSC;
- CE has its own records and books, including stand-alone audited financial statements;
- The utility has its own funding arrangements, including issuing its own long-term debt, and it has a separate committed credit facility to cover its short-term funding needs;
- CE does not comingle funds, assets, or cash flow with parent CMS Energy or its other subsidiaries, and it does not participate in a money pool;
- We believe there is a strong economic basis for CMS Energy to preserve CE's credit strength, reflecting CE's low-risk, profitable, and regulated utility business model. CE is also a significant portion of CMS Energy, accounting for about 95% of the consolidated company; and
- There are no cross-default provisions between parent CMS Energy and CE that could directly lead to a default at the utility.

Issue Ratings--Subordination Risk Analysis

Capital structure

CE's capital structure consists of about \$12.5 billion of long-term debt, including about \$11.7 billion in first-mortgage bonds (FMBs), \$787 million of securitized debt (all of which is deconsolidated from our credit metrics), and about \$110 million of tax-exempt revenue bonds.

Analytical conclusions

We rate the company's senior unsecured debt 'A-', in-line with the long-term issuer credit rating on CE as the rated issuances are senior unsecured debt issued by a qualifying investment grade utility as per our criteria.

We base our 'A-2' short-term rating on our 'A-' issuer credit rating.

Issue Ratings--Recovery Analysis

Key analytical factors

- We assign recovery ratings to FMBs issued by U.S. utilities, which can result in issue ratings being notched above an issuer credit rating on a utility, depending on the rating category and the extent of the collateral coverage. The FMBs issued by U.S. utilities are a form of secured utility bonds that qualify for a recovery rating as defined in our criteria.
- CE's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

Rating Component Scores

Foreign currency issuer credit rating	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2
Business risk	Excellent
Country risk	Very Low
Industry risk	Very Low
Competitive position	Excellent
Financial risk	Significant
Cash flow/leverage	Significant
Anchor	a-
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	a-
Group credit profile	bbb+
Entity status within group	Insulated (no impact on SACP)

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- General Criteria: Hybrid Capital: Methodology And Assumptions, March 2, 2022
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of August 20, 2024)*

Consumers Energy Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A
Issuer Credit Ratings History	
30-Oct-2019	A-/Stable/A-2
03-Dec-2014	BBB+/Stable/A-2
11-Sep-2014	BBB/Positive/A-2
Related Entities	
CMS Energy Corp.	
Issuer Credit Rating	BBB+/Stable/A-2
Junior Subordinated	BBB-
Preferred Stock	BBB-
Senior Unsecured	BBB

Consumers Energy Co.

Ratings Detail (as of August 20, 2024)*

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings credit ratings on the global scale are comparable across countries. S&P Global Ratings credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

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MOODY'S

INVESTORS SERVICE

CREDIT OPINION

31 May 2023

Update



Send Your Feedback

RATINGS

Consumers Energy Company

Domicile	Jackson, Michigan, United States
Long Term Rating	(P)A3
Type	Senior Unsec. Shelf - Dom Curr
Outlook	Stable

Please see the [ratings section](#) at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Asia Pacific 852-3551-3077

Japan 81-3-5408-4100

EMEA 44-20-7772-5454

Consumers Energy Company

Update to credit analysis

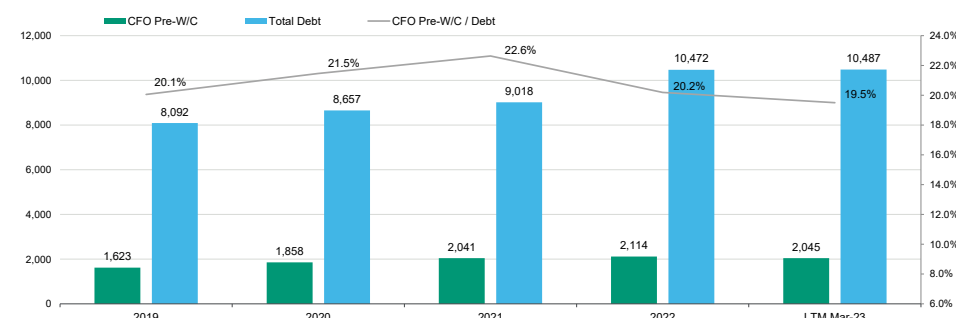
Summary

Consumers Energy Company's (Consumers Energy) credit profile reflects its business risk as a vertically integrated electric and gas utility operating in the credit supportive regulatory environment of Michigan. We expect the utility to maintain a stable financial profile with cash flow from operations before changes in working capital (CFO pre-WC) to debt averaging around 21%, including an adjustment to exclude securitization debt, over the next 2-3 years. At the end of the latest twelve month (LTM) period ending 31 March 2023, Consumers Energy's CFO pre-WC to debt ratio was 20.5%, including the adjustment to exclude securitization bonds. It will continue to execute its robust capital investment plan and will have an active regulatory calendar over this period. Based on the Michigan regulatory framework, we expect the utility to recover its investment costs on a timely basis and to earn an appropriate return on its investments.

Consumers Energy's stand-alone financial performance has historically been affected by the significant debt at its parent company CMS Energy Corporation (CMS, Baa2 stable). However, CMS has made notable progress in reducing the percentage of parent debt in its capital structure over the last 2-3 years. We now estimate that the percentage of parent debt will remain around mid-20% of total consolidated debt. All of Consumer Energy's outstanding debt obligations are secured.

Exhibit 1

Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt



When we adjust the total debt to exclude securitization debt, Consumers Energy's CFO pre-WC/debt would be 23.1%, 20.5% and 19.8% in 2021, 2022 and LTM ending 31 March 2023, respectively.

Source: Moody's Financial Metrics

Credit strengths

- » Credit supportive regulatory environment in Michigan
- » Transparent and timely cost recovery
- » Stable financial profile

Credit challenges

- » Robust capital investment plan
- » Maintaining regulatory support for these capital investments
- » Lack of geographic and regulatory diversity with single state service territory

Rating outlook

The stable outlook reflects our expectation that financial metrics will remain stable and that Consumers Energy will continue to benefit from a consistent and generally credit supportive regulatory environment. The stable outlook also incorporates our view that Consumers Energy will maintain prudent financial policies while managing through its robust investment cycle and that debt levels at the parent will not increase materially.

Factors that could lead to an upgrade

A rating upgrade could be considered if credit metrics improve such that CFO pre-WC to debt remains above 21% on a sustained basis. In addition, if the Michigan regulatory framework becomes even more formulaic, transparent or timely with its suite of cost recovery mechanisms for Consumers Energy, a rating upgrade could be possible.

Factors that could lead to a downgrade

A rating downgrade could be considered if there is a material deterioration in the credit supportiveness of the Michigan regulatory environment; or if the CFO pre-WC to debt ratio declines below 18% on a sustained basis.

Key indicators

Exhibit 2

Consumers Energy Company

	Dec-19	Dec-20	Dec-21	Dec-22	LTM Mar-23
CFO Pre-W/C + Interest / Interest	6.2x	6.6x	7.5x	7.2x	6.6x
CFO Pre-W/C / Debt	20.1%	21.5%	22.6%	20.2%	19.5%
CFO Pre-W/C – Dividends / Debt	12.7%	14.1%	14.6%	12.8%	12.0%
Debt / Capitalization	46.0%	44.9%	43.7%	45.1%	45.0%

All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.

Credit metrics included in the exhibit include securitization bonds. When we adjust total debt to exclude securitization debt, Consumers' CFO pre-WC/debt would be 23.1%, 20.5% and 19.8% in 2021, 2022 and LTM ending 31 March 2023, respectively.

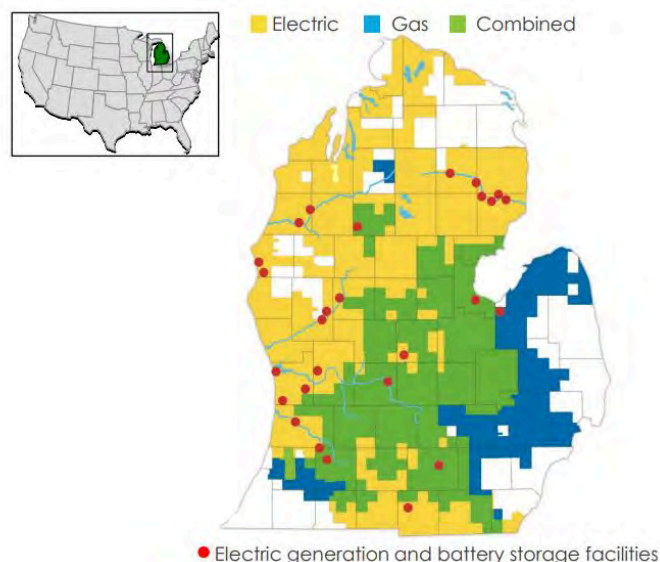
Source: Moody's Financial Metrics

Profile

Consumers Energy is a vertically integrated electric and gas utility serving approximately 1.9 million electric and 1.8 million gas customers in the state of Michigan with an average rate base of \$22.5 billion in 2022. Consumers Energy's electric operations account for approximately two thirds of its revenue, cash flow and asset base. The utility is a wholly-owned subsidiary of CMS and as the primary subsidiary of the parent company, it represents over 95% of CMS's consolidated earnings. In addition to Consumers Energy, CMS has a subsidiary called NorthStar Clean Energy, a non-utility domestic independent power producer and marketer.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the issuer/deal page on <https://ratings.moody.com> for the most updated credit rating action information and rating history.

Exhibit 3

Consumers Energy's Service Territory

Source: Company Presentations

Detailed credit considerations**Credit supportive regulatory environment**

Consumers Energy is regulated by the Michigan Public Service Commission (MPSC), which has a regulatory framework that we view to be more credit supportive than most other states. As a result of 2008 and 2016 energy legislation in Michigan, the regulatory framework has been streamlined, improving both the rate case process and the timeliness of cost recovery. The 2016 legislation provided additional assurance of utility investment recovery by expanding the certificate of necessity (CON) process, which had already included pre-construction approval for large generating resources, into an integrated resource planning (IRP) process. The IRP process considers a wide range of factors including fuel costs, demand forecasts, resource adequacy, competitive pricing, environmental mandates and transmission options before the construction of major projects. The legislation also lowered the threshold for major projects to \$100 million from \$500 million, allowing the project approval process to be more efficient.

On 20 April 2022, Consumers Energy and key stakeholders in Michigan reached a settlement related to the company's latest IRP. The settlement included the retirement of all of its remaining coal power plants (all three units at the Campbell power plant site) by 2025, in addition to two units at the Karn coal power plant already scheduled to close in 2023 as a result of the 2018 IRP. Consumers Energy will be able to record approximately \$1.2 billion of the remaining book value of these power plants as a regulatory asset and earn a 9% return on equity (ROE) through the remaining life. Instead of securitizing the remaining book value, the settlement will minimize the impact of the accelerated coal retirement on Consumers Energy's credit metrics. We view this settlement to be constructive and evidence of continued credit supportiveness in Michigan.

Timeliness of cost recovery based on a prescriptive suite of recovery mechanisms

Michigan utilities benefit from numerous formulaic rate adjustment mechanisms that provide a high degree of cash flow stability and assurance of recovery. For example, Consumers Energy has forward-looking Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) mechanisms that are intended to ensure that it can recover prudently incurred power and gas supply costs. The PSCR covers fuel and purchased power costs as well as transmission and emission allowance costs. Differences between actual and forecast costs are deferred for recovery or refunded in the following year. The PSCR is a surcharge mechanism and provides a degree of base rate and cash flow stability, a credit positive. The GCR mechanism may be adjusted monthly within a capped range to minimize over/under recoveries, although interim gas inventory buildup could substantially increase the company's working capital financing when gas prices increase sharply.

Gas utilities in the state also benefit from revenue decoupling mechanisms (RDM) and programs designed to assure recovery of needed infrastructure improvements. Consumers Energy's RDM compares and adjusts for differences between weather normalized actual and authorized revenues. The company's enhanced infrastructure replacement program (EIRP) is a MPSC authorized 25-year incremental investment program to upgrade natural gas infrastructure, including replacing approximately 293 miles of cast iron pipe and other high-risk components.

Active rate case filing cadence to be maintained

Consumers Energy maintains an active regulatory schedule with its electric and gas general rate cases typically filed annually in an alternating pattern. The utility currently has both electric and gas rate cases pending before the MPSC. Over the last three years, Consumers Energy experienced downward pressure on its allowed ROE in its electric and gas rate case outcomes with both electric and gas operations now at a 9.9% ROE. We expect Consumers Energy to maintain a stable financial profile because there are other offsetting mechanisms such as usage of forward test year to allow the utility to earn appropriate returns and to recover investment costs on a timely basis. However, further deterioration of the allowed ROE is likely to put negative pressure on the company's overall financial profile.

On 1 May 2023, Consumers Energy filed an electric rate case, requesting a \$216 million base rate increase. The proposed increase was based on a 10.25% ROE and a test year ending 28 February 2025. The pending rate case is expected to conclude in early 2024. In the last electric rate case, Consumers Energy reached an uncontested settlement with several parties and the MPSC issued an order in January 2023 approving the settlement effective 20 January 2023. Under the approved settlement, which resulted in an annual rate increase of \$161 million including the \$6 million distribution deferral surcharge, Consumers Energy applies a 9.9% ROE and 50.75% permanent capital structure on a regulatory basis with its rate base valued around \$13.38 billion.

On 15 December 2022, the utility filed a gas rate case, seeking a \$212 million increase based on a projected test year for the 12-month period ending 30 September 2024, requesting a 10.25% ROE, 51.5% equity capital structure and a rate base value estimated around \$10.34 billion. In April 2023, the MPSC Staff recommended an \$89 million increase based on a 9.7% ROE, 50.5% equity capital structure and a \$10.15 billion rate base value. A final decision is expected by 16 October 2023.

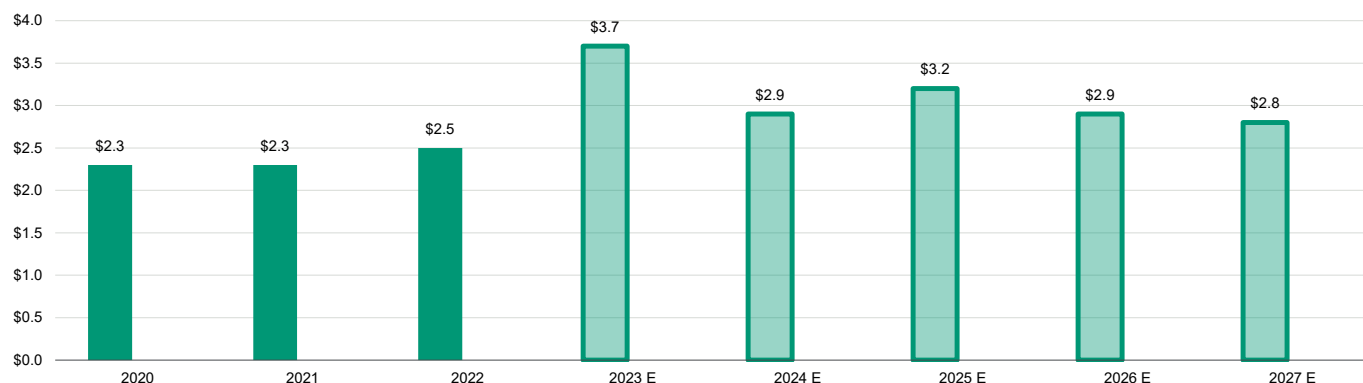
Stable credit metrics expected to be maintained through its high capital investment cycle

Consumers Energy's capital spending continues to be robust as it is currently in the midst of a large capital investment plan. The company increased its five-year capital expenditure plan through 2027 to \$15.5 billion, approximately \$1.2 billion higher than the previous plan. Over the next five years, Consumers Energy will invest approximately \$12.4 billion primarily to maintain and update its electric distribution system, Covert acquisition and other investment (\$6.1 billion) and gas infrastructure (\$6.3 billion). These investments should enhance the company's reliability and safety as well as help it execute its clean energy transition plan. In addition, Consumers will invest approximately \$3.1 billion in clean generation, which will include investments in wind, solar and hydro electric generation sources.

Exhibit 4

Consumers Energy's elevated capital program will extend through 2027

\$ billions



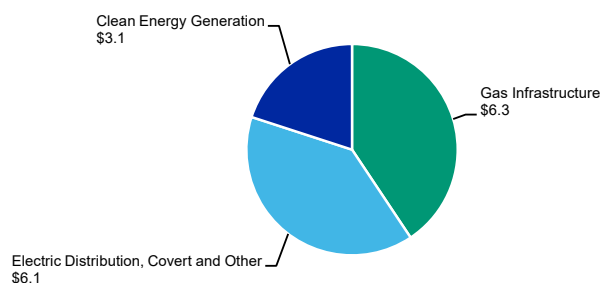
Source: Company Investor Presentation

Through this period, Consumers Energy plans to keep rate increases modest, which should help to maintain regulatory support for investment cost recovery. Funding for these investments will be provided by internally generated cash flow, the issuance of debt at Consumers Energy and equity contributions from CMS. We expect Consumers Energy to maintain its CFO pre-WC to debt at around 21% on average over the next 2-3 years. At the end of 2022 and for the LTM period ending 30 March 2023, Consumers Energy produced a CFO pre-W/C to debt ratio of 20.5% and 19.8%, respectively, excluding securitization debt. The company's ratio was negatively impacted by the under-recovery of PSCR when fuel prices for its electric generation increased significantly in 2022. Consumers is authorized to recover the 2022 under-recovery over three years starting in 2023. Our expectation of the company's financial profile incorporates the impact of this under-recovery and the subsequent recovery over three years.

Exhibit 5

Planned Capital Expenditures 2023 - 2027

\$ billions

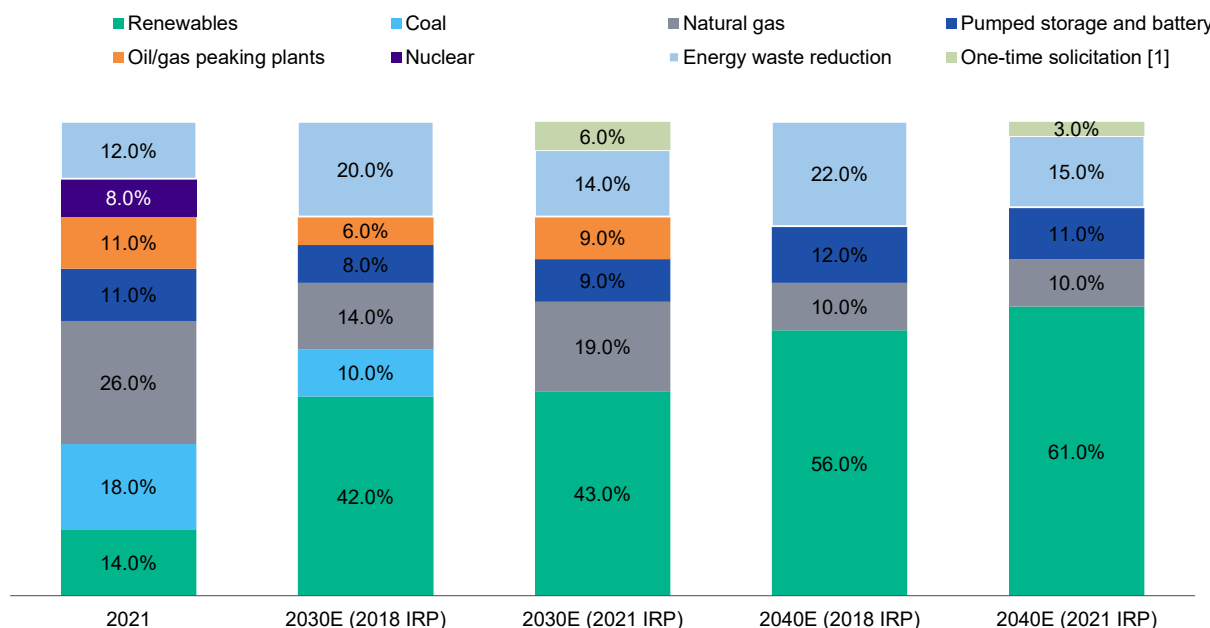


Source: Company 10K

Based on Consumers' latest IRP approved in 2022, the utility will add up to 8 GW of solar power, which is 2 GW more than what was approved in the company's 2018 IRP. As a result, by 2040, more than 60% of Consumer Energy's generation capacity will be from renewable sources. In order to replace the retiring coal capacity, the utility agreed to acquire the Covert natural gas-fired power plant for approximately \$815 million in 2023. It will also issue requests for proposals (RFP) in 2025 for two purchased power agreements (PPA) for 500 MW of dispatchable generation and 200 MW of clean energy sources.

Exhibit 6

Based on the latest IRP settlement, more than 60% of Consumers Energy's generation sources will be renewables by 2040



[1] One-time solicitation to acquire approximately 700 MW of capacity from sources in Michigan's Lower Peninsula beginning in 2025.

Source: Company's 10-K in 2022 and 2021, and latest investor presentation

ESG considerations

Consumers Energy's ESG Credit Impact Score is CIS-3 (Moderately Negative)

Exhibit 7

ESG Credit Impact Score

CIS-3

Moderately Negative



For an issuer scored CIS-3 (Moderately Negative), its ESG attributes are overall considered as having a limited impact on the current rating, with greater potential for future negative impact over time. The negative influence of the overall ESG attributes on the rating is more pronounced compared to an issuer scored CIS-2.

Source: Moody's Investors Service

Consumers Energy's ESG Credit Impact Score (**CIS-3**) reflects moderately negative environmental risk from some exposure to physical climate risk and moderating carbon transition risk. It also incorporates social risks stemming from inherent risk associated with regulated utilities and governance risk that is not a material driver.

Exhibit 8

ESG Issuer Profile Scores



Source: Moody's Investors Service

Environmental

Consumers Energy's ESG attributes reflect the company's moderating environmental risk (**E-3** issuer profile score). The company is better positioned for the carbon transition with strategies and plans in place that substantially mitigate its carbon transition exposure. The utility is currently in a transition to phase out its coal-fired generation and targets zero coal-fired generation output by 2025, accelerated from its prior target of 2039. The utility also established a goal of net zero methane emission for its gas delivery system by 2030 and net zero greenhouse gas emissions for its entire natural gas system, including customer and supplier emissions, by 2050. Michigan's regulatory framework supports the utility's transition plan by allowing certain investment cost recovery and renewable energy plan surcharges, for example.

Social

Social risk (**S-3** issuer profile score) for Consumers Energy is primarily related to its customer and regulatory relations as well as demographic and societal trends. The utility's regulatory environment, as well as its interaction with the MPSC, are important in considering the utility's social risk. Also, the safety and reliability of its operations are important social considerations.

Governance

As a subsidiary of CMS, corporate governance considerations include the financial policy and risk management of its parent company. Consumers Energy's governance does not pose a particular risk (**G-2** issuer profile score) and is not a material driver in the company's overall credit profile.

ESG Issuer Profile Scores and Credit Impact Scores for Consumers Energy are available on Moodys.com. In order to view the latest scores, please click [here](#) to go to the landing page for Consumers Energy on MDC and view the ESG Scores section.

Liquidity analysis

We expect Consumers Energy's liquidity profile to be adequate over the next 12-18 months.

Consumers Energy's external liquidity sources include a \$1.1 billion secured revolving credit facility expiring in December 2027 and, as of 31 December 2022, net availability was \$1.071 billion with \$29 million of letters of credit outstanding. Consumers Energy also maintains a \$250 million secured credit facility terminating in November 2024 and had \$223 million available at the end of 2022. Both facilities are secured by first mortgage bonds. These credit facilities provide support for working capital needs and act as a backstop to Consumer Energy's \$500 million commercial paper program. At 31 December 2022, the company had \$20 million of commercial paper notes outstanding under the program. The credit facilities do not include a material adverse change representation for new borrowings, and have only one financial covenant, setting the maximum debt to capital at 65%. At 31 December 2022, debt to capital was 50%.

These facilities includes a sustainability linked pricing metrics, which permits pricing adjustments for meeting targets related to sustainability. Targets include renewable generation and diverse supplier spend, highlighting its commitment to shifting its exposure to a greater renewable content and to supplier diversity.

The utility's continuing capital expenditure program and dividend policy will result in negative free cash flow for the foreseeable future. However, the company has a reasonable amount of external liquidity, demonstrated market access, and regularly receives capital contributions from its parent.

For the LTM period ended 31 March 2023, Consumers generated approximately \$1.3 billion of cash from operations, invested \$2.3 billion and distributed \$782 million of dividends to CMS, resulting in negative free cash flow of approximately \$1.8 billion.

Over the last twelve months, Consumers completed four first mortgage bond issuances with total proceeds of \$1.95 billion, including \$425 million notes due March 2028 and \$700 million notes due May 2033.

Appendix

Exhibit 9

Cash Flow and Credit Metrics

CF Metrics	Dec-19	Dec-20	Dec-21	Dec-22	LTM Mar-23
As Adjusted					
FFO	1,752	1,994	2,054	2,125	1,976
+/- Other	-129	-136	-13	-11	69
CFO Pre-WC	1,623	1,858	2,041	2,114	2,045
+/- ΔWC	-15	25	-53	-1,116	-722
CFO	1,608	1,883	1,988	998	1,323
- Div	593	638	723	770	782
- Capex	2,100	2,184	2,066	2,256	2,305
FCF	-1,085	-939	-801	-2,028	-1,764
(CFO Pre-WC) / Debt	20.1%	21.5%	22.6%	20.2%	19.5%
(CFO Pre-WC - Dividends) / Debt	12.7%	14.1%	14.6%	12.8%	12.0%
FFO / Debt	21.6%	23.0%	22.8%	20.3%	18.8%
RCF / Debt	14.3%	15.7%	14.8%	12.9%	11.4%
Revenue	6,376	6,189	7,021	8,151	8,078
Interest Expense	312	332	315	342	366
Net Income	725	798	838	883	728
Total Assets	23,699	25,399	27,140	29,916	29,772
Total Liabilities	16,053	16,862	17,880	19,780	19,616
Total Equity	7,647	8,538	9,261	10,137	10,157

All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months

Source: Moody's Financial Metrics

Exhibit 10

Peer Comparison Table

(In US millions)	Consumers Energy Company			DTE Electric Company			DTE Gas Company			Northern States Power Company (Minnesota)			Wisconsin Power and Light Company		
	(P)A3 (Stable)			A2 (Stable)			A3 (Stable)			A2 (Stable)			A3 (Negative)		
	FYE	FYE	LTM	FYE	FYE	LTM	FYE	FYE	LTM	FYE	FYE	LTM	FYE	FYE	LTM
	Dec-21	Dec-22	Mar-23	Dec-21	Dec-22	Mar-23	Dec-21	Dec-22	Mar-23	Dec-22	Dec-22	Mar-23	Dec-21	Dec-22	Mar-23
Revenue	7,021	8,151	8,078	5,809	6,397	6,286	1,532	1,894	1,894	5,756	6,684	6,652	1,523	1,856	1,866
CFO Pre-W/C	2,041	2,114	2,045	2,348	2,164	2,290	393	575	575	1,054	2,034	2,091	377	339	341
Total Debt	9,018	10,472	10,487	9,916	11,408	11,322	2,310	2,602	2,602	6,832	7,292	7,505	2,819	3,323	3,390
CFO Pre-W/C + Interest / Interest	7.5x	7.2x	6.6x	7.5x	6.5x	6.6x	5.8x	7.2x	7.2x	5.0x	8.2x	8.2x	4.9x	4.8x	4.7x
CFO Pre-W/C / Debt	22.6%	20.2%	19.5%	23.7%	19.0%	20.2%	17.0%	22.1%	22.1%	15.4%	27.9%	27.9%	13.4%	10.2%	10.1%
CFO Pre-W/C - Dividends / Debt	14.6%	12.8%	12.0%	17.8%	12.3%	14.3%	10.6%	15.8%	15.8%	9.1%	20.2%	20.7%	7.4%	4.9%	4.8%
Debt / Capitalization	43.7%	45.1%	45.0%	46.0%	47.4%	47.3%	43.5%	44.5%	44.5%	41.8%	43.4%	43.8%	44.1%	43.8%	43.0%

All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End.

Source: Moody's Financial Metrics

Rating methodology and scorecard factors

Exhibit 11

Methodology Scoring Factors

Consumers Energy Company

Regulated Electric and Gas Utilities Industry [1][2]			Current LTM 3/31/2023		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)			Measure	Score	Measure	Score
a) Legislative and Judicial Underpinnings of the Regulatory Framework			A	A	A	A
b) Consistency and Predictability of Regulation			Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)						
a) Timeliness of Recovery of Operating and Capital Costs			Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns			A	A	A	A
Factor 3 : Diversification (10%)						
a) Market Position			Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity			Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)						
a) CFO pre-WC + Interest / Interest (3 Year Avg)			7.1x	Aa	6x - 7x	Aa
b) CFO pre-WC / Debt (3 Year Avg)			22.4%	A	20% - 22%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)			14.4%	Baa	13% - 15%	Baa
d) Debt / Capitalization (3 Year Avg)			43.3%	A	43% - 47%	Baa
Rating:						
Scorecard-Indicated Outcome Before Notching Adjustment				A2		A2
HoldCo Structural Subordination Notching			0	0	0	0
a) Scorecard-Indicated Outcome				A2		A2
b) Actual Rating Assigned						(P)A3

* Senior Secured Rating.

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.

[2] As of 3/31/2023.

[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

Source: Moody's Financial Metrics

Ratings

Exhibit 12

Category	Moody's Rating
CONSUMERS ENERGY COMPANY	
Outlook	Stable
Sr Sec Bank Credit Facility	A1
First Mortgage Bonds	A1
Senior Secured Shelf	(P)A1
LT IRB/PC	A3
Pref. Stock	Baa1
Commercial Paper	P-2
PARENT: CMS ENERGY CORPORATION	
Outlook	Stable
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Pref. Stock	Ba1

Source: Moody's Investors Service

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EMEA	44-20-7772-5454

CREDIT OPINION

31 May 2024

Update



Send Your Feedback

RATINGS

Consumers Energy Company

Domicile	Jackson, Michigan, United States
Long Term Rating	(P)A3
Type	Senior Unsec. Shelf - Dom Curr
Outlook	Stable

Please see the [ratings section](#) at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Consumers Energy Company

Update to credit analysis

Summary

Consumers Energy Company's (Consumers Energy) credit profile reflects its business risk as a vertically integrated electric and gas utility operating in the credit supportive regulatory environment of Michigan. We expect the utility to maintain a stable financial profile with cash flow from operations before changes in working capital (CFO pre-WC) to debt averaging around 20-21%, including an adjustment to exclude securitization debt, over the next 2-3 years. At the end of the latest twelve month (LTM) period ending 31 March 2024, Consumers Energy's CFO pre-WC to debt ratio was 20%, including the adjustment to exclude securitization bonds. The company will continue to execute its robust capital investment plan and have an active regulatory calendar over this period. Based on the Michigan regulatory framework, we expect the utility to recover its investment costs on a timely basis and to earn an appropriate return on its investments.

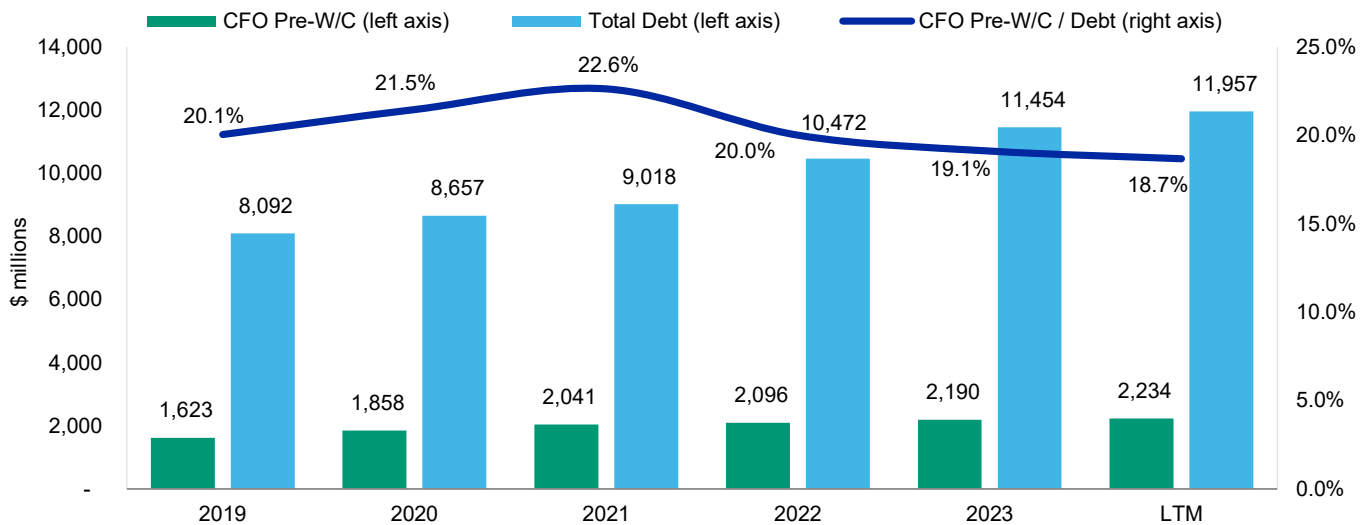
Consumers Energy's stand-alone financial performance has historically been affected by the significant debt at its parent company CMS Energy Corporation (CMS, Baa2 stable). However, CMS has made notable progress in reducing the percentage of parent debt in its capital structure in recent years. We now estimate that the percentage of parent debt will remain below 25% of total consolidated debt. All of Consumer Energy's outstanding debt obligations are secured.

Recent development

In November 2023, Michigan enacted a new energy law (2023 Energy Law), which raised the state's renewable energy standard while providing additional authority to the Michigan Public Service Commission (MPSC). Consumer Energy's operations are under the purview of MPSC. In general, we view this development to be constructive because the utilities in the state will now outline a renewable energy plan with greater transparency, and the MPSC will have an expanded scope of consideration for various factors influencing Consumers Energy's plan to decarbonize.

Exhibit 1

Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt



When we adjust the total debt to exclude securitization debt, Consumers Energy's CFO pre-WC/debt would be 20.3%, 20.4% and 20.0% in 2022, 2023 and LTM ending 31 March 2024, respectively.

Source: Moody's Financial Metrics

Credit strengths

- » Credit supportive regulatory environment in Michigan
- » Transparent and timely cost recovery
- » Stable financial profile

Credit challenges

- » Robust capital investment plan
- » Maintaining regulatory support for these capital investments
- » Lack of geographic and regulatory diversity with single state service territory

Rating outlook

The stable outlook reflects our expectation that financial metrics will remain stable and that Consumers Energy will continue to benefit from a consistent and generally credit supportive regulatory environment. The stable outlook also incorporates our view that Consumers Energy will maintain prudent financial policies while managing through its robust investment cycle and that debt levels at the parent will not increase materially.

Factors that could lead to an upgrade

A rating upgrade could be considered if credit metrics improve such that CFO pre-WC to debt is above 21% on a sustained basis. In addition, if the Michigan regulatory framework becomes even more formulaic, transparent or timely with its suite of cost recovery mechanisms for Consumers Energy, a rating upgrade could be possible.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the issuer/deal page on <https://ratings.moody's.com> for the most updated credit rating action information and rating history.

Factors that could lead to a downgrade

A rating downgrade could be considered if there is a material deterioration in the credit supportiveness of the Michigan regulatory environment; or if the CFO pre-WC to debt ratio declines below 18% on a sustained basis.

Key indicators

Exhibit 2

Consumers Energy Company

	2019	2020	2021	2022	2023	LTM
CFO Pre-W/C + Interest / Interest	6.2x	6.6x	7.5x	7.1x	5.8x	5.6x
CFO Pre-W/C / Debt	20.1%	21.5%	22.6%	20.0%	19.1%	18.7%
CFO Pre-W/C – Dividends / Debt	12.7%	14.1%	14.6%	12.7%	13.0%	13.0%
Debt / Capitalization	46.0%	44.9%	43.7%	45.1%	45.8%	46.7%

All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.

Credit metrics included in the exhibit include securitization bonds. When we adjust the total debt to exclude securitization debt, Consumers Energy's CFO pre-WC/debt would be 20.3%, 20.5% and 20.0% in 2022, 2023 and LTM ending 31 March 2024, respectively.

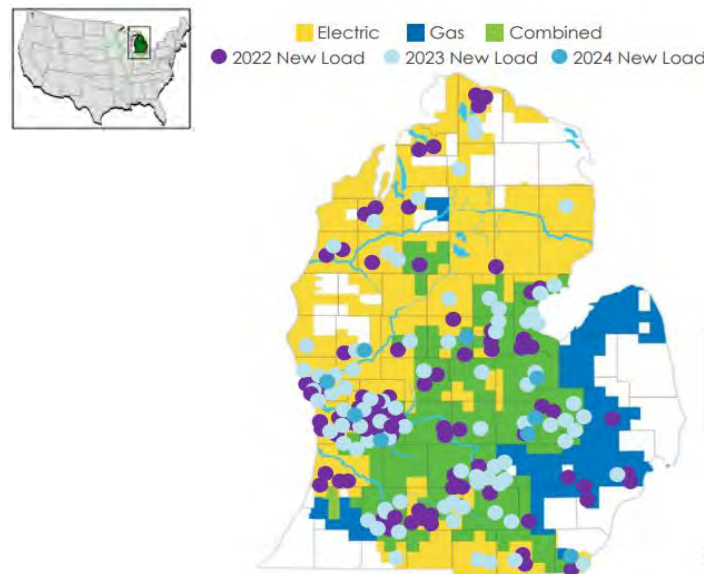
Source: Moody's Financial Metrics

Profile

Consumers Energy is a vertically integrated electric and gas utility serving approximately 1.9 million electric and 1.8 million gas customers in the state of Michigan with an average rate base of \$25 billion in 2023. Consumers Energy's electric operations account for approximately two thirds of its revenue, cash flow and asset base. The utility is a wholly-owned subsidiary of CMS and, as the primary subsidiary of the parent company, it represents over 95% of CMS's consolidated earnings. In addition to Consumers Energy, CMS has a subsidiary called NorthStar Clean Energy, a non-utility domestic independent power producer and marketer.

Exhibit 3

Consumers Energy's Service Territory



Source: Company Presentations

Detailed credit considerations

Credit supportive regulatory environment

Consumers Energy is regulated by the MPSC, which has a regulatory framework that we view to be more credit supportive than most other states. As a result of 2008 and 2016 energy legislation in Michigan, the regulatory framework has been streamlined, improving both the rate case process and the timeliness of cost recovery. The 2016 legislation provided additional assurance of utility investment recovery by expanding the certificate of necessity (CON) process, which had already included pre-construction approval for large

generating resources, into an integrated resource planning (IRP) process. The IRP process considers a wide range of factors including fuel costs, demand forecasts, resource adequacy, competitive pricing, environmental mandates and transmission options before the construction of major projects.

In November 2023, new energy legislation (2023 Energy Law) was enacted. Under the new law, the state's renewable energy standards were raised to 50% by 2030 and 60% by 2035 from the previous 15% by 2021 requirement. It also set a clean energy standard of 80% by 2035 and 100% by 2040. Under the law, zero to low-carbon emitting sources, such as nuclear generation and natural gas generation with carbon capture, are considered clean energy sources. Along with these new standards, the new legislation expanded the authority of the MPSC to oversee their implementation. CMS's utility subsidiary Consumers Energy will file updates to its renewable energy plans in 2024 and its Clean Energy Plan in or before 2027. Given the existing regulatory framework in Michigan, we expect the company's collaborative dialogue with both stakeholders and regulator to continue under the new legislation.

In June 2022, Consumers Energy and key stakeholders in Michigan reached a settlement related to the company's latest IRP. The settlement included the retirement of all of its remaining coal power plants (all three units at the Campbell power plant site) in 2025 as a result of the 2021 IRP. Consumers Energy will be able to record approximately \$1.3 billion of the remaining book value of these power plants as a regulatory asset and earn a 9% return on equity (ROE) through the remaining life. Instead of securitizing the remaining book value, the settlement will minimize the impact of the accelerated coal retirements on Consumers Energy's credit metrics. We view this settlement to be constructive and evidence of continued credit supportiveness in Michigan.

Timeliness of cost recovery based on a prescriptive suite of recovery mechanisms

Michigan utilities benefit from numerous formulaic rate adjustment mechanisms that provide a high degree of cash flow stability and assurance of recovery. For example, Consumers Energy has forward-looking Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) mechanisms that are intended to ensure that it can recover prudently incurred power and gas supply costs. The PSCR covers fuel and purchased power costs as well as transmission and emission allowance costs. Differences between actual and forecast costs are deferred for recovery or refunded in the following year. The PSCR is a surcharge mechanism and provides a degree of base rate and cash flow stability, a credit positive. The GCR mechanism may be adjusted monthly within a capped range to minimize over/under recoveries, although interim gas inventory buildup could substantially increase the company's working capital financing when gas prices increase sharply.

Gas utilities in the state also benefit from programs designed to assure recovery of needed infrastructure improvements. Consumers Energy's RDM compares and adjusts for differences between weather normalized actual and authorized revenues. The company's enhanced infrastructure replacement program (EIRP) is a MPSC authorized 25-year incremental investment program to upgrade natural gas infrastructure, including replacing less than 250 miles of cast iron pipe and other high-risk components.

Active rate case filing cadence

Consumers Energy maintains an active regulatory schedule with its electric and gas general rate cases typically filed annually in an alternating pattern. The utility currently has its gas rate case pending before the MPSC, and filed its request for an electric rate increase on 31 May 2024. Over the last three years, Consumers Energy experienced downward pressure on its allowed ROE in its rate cases although the company was able to maintain a 9.9% allowed ROE. We expect Consumers Energy to maintain a stable financial profile because there are other offsetting mechanisms such as usage of forward test year to allow the utility to earn appropriate returns and to recover investment costs on a timely basis. However, further deterioration of the allowed ROE is likely to put negative pressure on the company's overall financial profile.

On 1 March 2024, the commission authorized a \$92 million increase based on a 9.9% ROE, 50.02% equity capital structure and a \$13.67 billion rate base value. Also, the final order approved an Investment Recovery Mechanism (IRM) rider for distribution reliability projects totaling \$99 million over two years.

On 15 December 2023, the utility filed a gas rate case, seeking a \$136 million increase based on a projected test year for the 12-month period ending 30 September 2025, requesting a 10.25% ROE, 51.5% equity capital structure and a rate base value estimated around \$10.97 billion. In April 2024, the MPSC Staff recommended an \$70.77 million increase based on a 9.85% ROE, 49.92% equity capital structure and a \$10.88 billion rate base value. A final decision is expected by 15 October 2024.

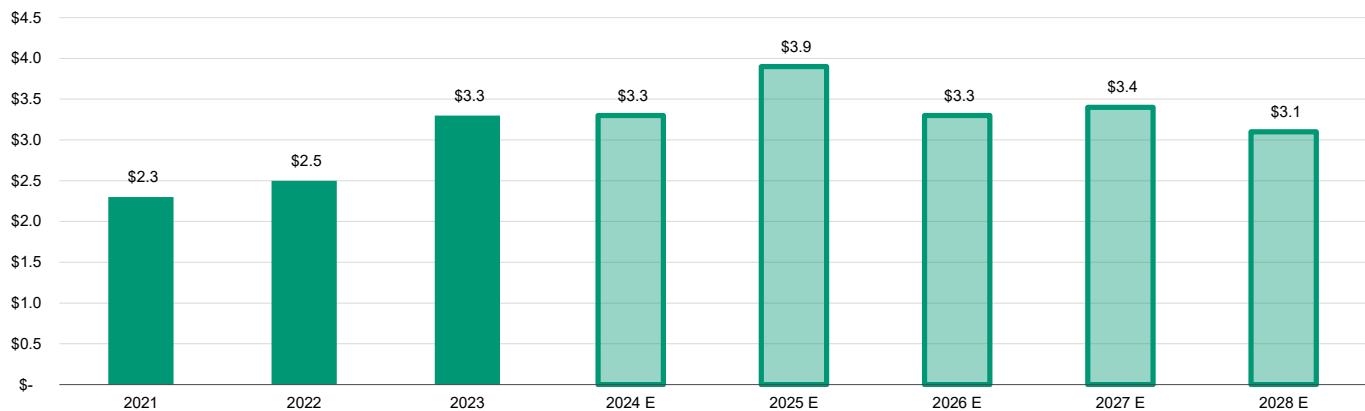
Stable credit metrics expected to be maintained through its high capital investment cycle

Consumers Energy's capital spending continues to be robust as it is currently in the midst of a large capital investment plan. The company increased its five-year capital expenditure plan through 2028 to \$17 billion, approximately \$1.5 billion higher than the previous plan. Consumers Energy will invest approximately \$6.3 billion primarily to maintain and upgrade its gas utility infrastructure; \$7.3 billion related to its electric distribution and other infrastructure; and \$3.4 billion related to clean energy generation. These investments should enhance the company's reliability and safety as well as help it execute its decarbonization plan.

Exhibit 4

Consumers Energy's elevated capital program will extend at least through 2028

\$ billions



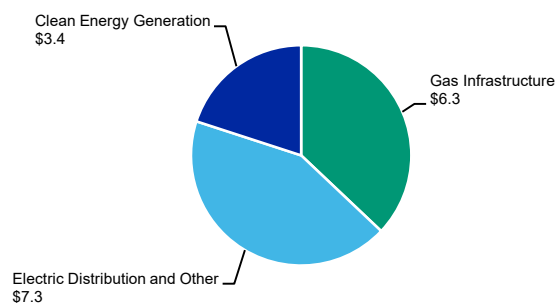
Source: Company 10K

Through this period, Consumers Energy plans to keep rate increases modest, which should help to maintain regulatory support for investment cost recovery. Funding for these investments will be provided by internally generated cash flow, the issuance of debt at Consumers Energy and equity contributions from CMS. We expect Consumers Energy to maintain its CFO pre-WC to debt at around 20%-21% on average over the next 2-3 years. At the end of 2023 and for the LTM period ending 31 March 2024, Consumers Energy produced a CFO pre-WC to debt ratio of 20.5% and 20%, respectively, excluding securitization debt.

Exhibit 5

Planned Capital Expenditures 2024 - 2028

\$ billions



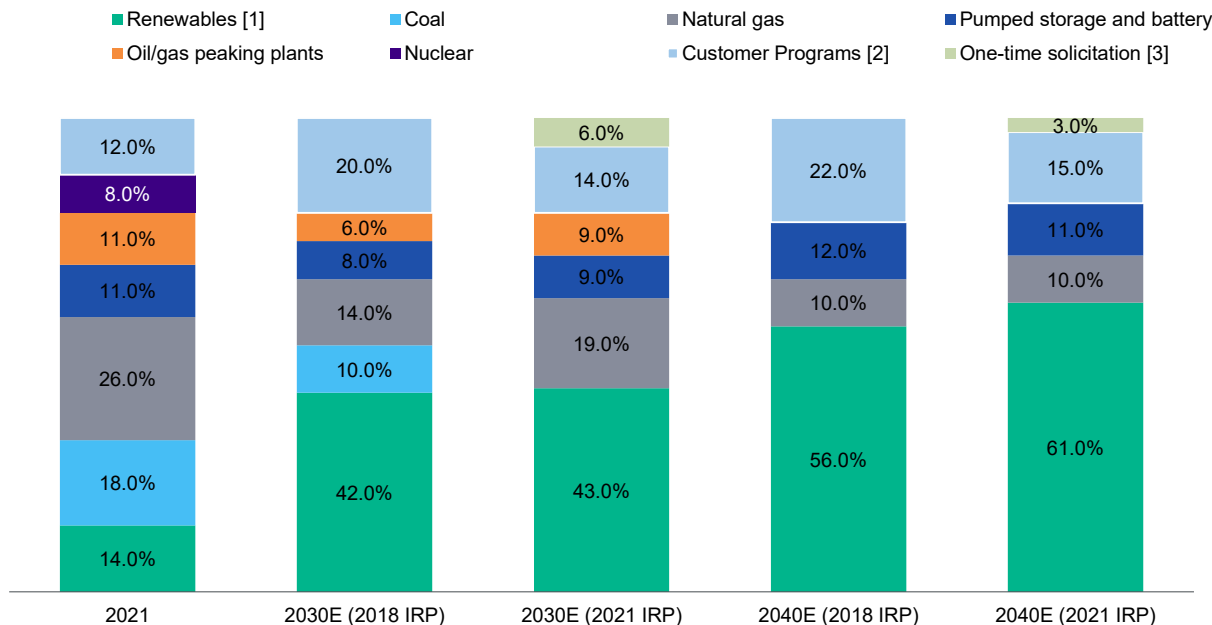
Source: Company 10K

Based on Consumers' latest IRP approved in 2022, the utility will add up to 8 GW of solar power, which is 2 GW more than what was approved in the company's 2018 IRP. As a result, by 2040, more than 60% of Consumers Energy's generation capacity will be from renewable sources. In order to replace the retiring coal capacity, the utility acquired the Covert natural gas-fired power plant for

approximately \$815 million in 2023. It issued requests for proposals (RFP) for two purchased power agreements (PPA) for 500 MW of dispatchable generation and 200 MW of clean energy sources.

Exhibit 6

Based on the latest IRP settlement, more than 60% of Consumers Energy's generation sources will be renewables by 2040



[1] Does not include renewable RECs.

[2] Includes energy waste reduction, demand response, and conservation voltage reduction program.

[3] One-time solicitation to acquire approximately 700 MW of capacity from sources in Michigan's Lower Peninsula beginning in 2025.

Source: Company's 10-K in 2022 and 2021, and latest investor presentation

ESG considerations

Consumers Energy Company's ESG credit impact score is CIS-3

Exhibit 7

ESG credit impact score

CIS-3



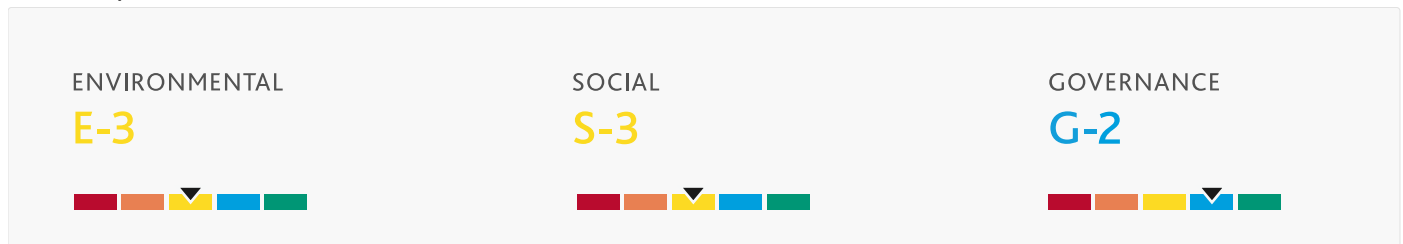
ESG considerations have a limited impact on the current rating, with potential for greater negative impact over time.

Source: Moody's Ratings

Consumers Energy's **CIS-3** indicates that ESG considerations have limited impact on the current credit rating with greater potential for negative impact over time. It reflects some exposure to physical climate risk and moderating carbon transition risk. It also incorporates social risks stemming from inherent risk associated with regulated utilities and governance risk that is not a material driver.

Exhibit 8

ESG issuer profile scores



Source: Moody's Ratings

Environmental

Consumers Energy's **E-3** issuer profile score reflects its moderate position for the carbon transition with tangible strategies and plans in place that substantially mitigate its carbon transition exposure. The utility is currently in a transition to phase out its coal-fired generation and targets zero coal-fired generation output in 2025, accelerated from its prior target of 2039. The utility also established a goal of net zero methane emission for its gas delivery system by 2030; net zero carbon emissions for its electric business by 2040, including MISO market purchases and PPAs; and net zero greenhouse gas emissions for its entire business, including customer and supplier emissions, by 2050. Michigan's regulatory framework supports the utility's transition plan by allowing certain investment cost recovery and renewable energy plan surcharges, for example.

Social

S-3 issuer profile score for Consumers Energy is primarily related to its customer and regulatory relations as well as demographic and societal trends. The utility's regulatory environment, as well as its interaction with the Michigan Public Service Commission, are important in considering the utility's social risk. Also, the safety and reliability of its operations are important social considerations.

Governance

Consumers Energy's **G-2** issuer profile score reflects our view that its governance does not pose a particular risk and is not a material driver in the company's overall credit profile. It also incorporates its position as a subsidiary of CMS whose corporate governance considerations including financial policy and risk management influence Consumers Energy.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click [here](#) to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Liquidity analysis

We expect Consumers Energy's liquidity profile to be adequate over the next 12-18 months.

Consumers Energy's external liquidity sources include a \$1.1 billion secured revolving credit facility expiring in December 2027 and, as of 31 March 2024, net availability was \$1.073 billion with \$27 million of letters of credit outstanding. Consumers Energy also maintains a \$250 million secured credit facility terminating in November 2025 and had \$197 million available as of 31 March 2024. Both facilities are secured by first mortgage bonds. These credit facilities provide support for working capital needs and act as a backstop to Consumer Energy's \$500 million commercial paper program. At 31 March 2024, the company had no commercial paper notes outstanding under the program. The credit facilities do not include a material adverse change representation for new borrowings, and have only one financial covenant, setting the maximum debt to capital at 65%. At 31 March 2024, debt to capital was 50%.

These facilities includes sustainability linked pricing metrics, which permits pricing adjustments for meeting targets related to sustainability. Targets include renewable generation and diverse supplier spend, highlighting its commitment to shifting its exposure to a greater renewable content and to supplier diversity.

The utility's continuing capital expenditure program and dividend policy will result in negative free cash flow for the foreseeable future. However, the company has a reasonable amount of external liquidity, demonstrated market access, and regularly receives capital contributions from its parent.

For the LTM period ended 31 March 2024, Consumers generated approximately \$2.3 billion of cash from operations, invested \$3.2 billion and distributed \$673 million of dividends to CMS, resulting in negative free cash flow of approximately \$1.6 billion. Given its robust investment plan, we expect Consumers Energy to maintain its negative free cash flow position over the 12-18 months.

In January 2024, Consumers Energy issued \$600 million first mortgage bonds with 4.6% rate maturing in May 2029.

Rating methodology and scorecard factors

Exhibit 9

Methodology Scoring Factors

Consumers Energy Company

Regulated Electric and Gas Utilities Industry [1][2]			Current LTM 3/31/2024		Moody's 12-18 Month Forward View As of 5/19/2024 [3]	
Factor 1 : Regulatory Framework (25%)			Measure	Score	Measure	Score
a) Legislative and Judicial Underpinnings of the Regulatory Framework			A	A	A	A
b) Consistency and Predictability of Regulation			Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)						
a) Timeliness of Recovery of Operating and Capital Costs			Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns			A	A	A	A
Factor 3 : Diversification (10%)						
a) Market Position			Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity			Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)						
a) CFO pre-WC + Interest / Interest (3 Year Avg)			6.5x	Aa	5x - 6x	A
b) CFO pre-WC / Debt (3 Year Avg)			20.4%	Baa	20% - 21%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)			13.4%	Baa	13% - 14%	Baa
d) Debt / Capitalization (3 Year Avg)			44.5%	A	45% - 46%	Baa
Rating:						
Scorecard-Indicated Outcome Before Notching Adjustment				A2		A3
HoldCo Structural Subordination Notching			0	0	0	0
a) Scorecard-Indicated Outcome				A2		A3
b) Actual Rating Assigned						A3

* Senior Secured Rating.

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.

[2] As of 3/31/2024.

[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

Source: Moody's Financial Metrics

Appendix

Exhibit 10

Cash Flow and Credit Metrics

CF Metrics (in \$ millions)	2019	2020	2021	2022	2023	LTM
FFO	1,752	1,994	2,054	2,125	2,065	2,136
+/- Other	(129)	(136)	(13)	(29)	125	98
CFO Pre-WC	1,623	1,858	2,041	2,096	2,190	2,234
+/- ΔWC	(15)	25	(53)	(1,098)	243	108
CFO	1,608	1,883	1,988	998	2,433	2,342
- Div	593	638	723	770	696	674
- Capex	2,100	2,184	2,066	2,256	2,260	2,289
FCF	(1,085)	(939)	(801)	(2,028)	(523)	(621)
(CFO Pre-W/C) / Debt	20.1%	21.5%	22.6%	20.0%	19.1%	18.7%
(CFO Pre-W/C - Dividends) / Debt	12.7%	14.1%	14.6%	12.7%	13.0%	13.0%
FFO / Debt	21.6%	23.0%	22.8%	20.3%	18.0%	17.9%
RCF / Debt	14.3%	15.7%	14.8%	12.9%	12.0%	12.2%
Revenue	6,376	6,189	7,021	8,151	7,166	7,053
Interest Expense	312	332	315	342	455	482
Net Income	725	798	838	883	802	842
Total Assets	23,699	25,399	27,140	29,916	31,852	32,209
Total Liabilities	16,053	16,862	17,880	19,780	21,071	21,418
Total Equity	7,647	8,538	9,261	10,137	10,782	10,792

All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months

Source: Moody's Financial Metrics

Exhibit 11

Peer Comparison Table

(In \$ millions)	Consumers Energy Company (P)A3 Stable			DTE Electric Company (P)A2 Stable			DTE Gas Company A3 Stable			Northern States Power Company (Minnesota) A2 Stable			Wisconsin Power and Light Company Baa1 Stable		
	FY	FY	LTM	FY	FY	LTM	FY	FY	LTM	FY	FY	LTM	FY	FY	LTM
	Dec-22	Dec-23	Mar-24	Dec-22	Dec-23	Mar-24	Dec-22	Dec-23	Mar-24	Dec-22	Dec-23	Mar-24	Dec-22	Dec-23	Mar-24
Revenue	8,151	7,166	7,053	6,397	5,804	5,895	1,894	1,726	1,736	6,684	6,043	5,913	1,856	1,827	1,817
CFO Pre-W/C	2,096	2,190	2,234	2,164	2,565	2,726	575	638	580	2,034	2,259	2,306	317	602	595
Total Debt	10,472	11,454	11,957	11,408	12,523	12,612	2,602	2,642	2,565	7,292	7,692	8,212	3,323	3,700	3,679
CFO Pre-W/C + Interest / Interest	7.1x	5.8x	5.6x	6.5x	6.7x	6.8x	7.2x	7.2x	6.4x	8.2x	7.8x	7.7x	4.5x	7.4x	6.6x
CFO Pre-W/C / Debt	20.0%	19.1%	18.7%	19.0%	20.5%	21.6%	22.1%	24.1%	22.6%	27.9%	29.4%	28.1%	9.5%	16.3%	16.2%
CFO Pre-W/C - Dividends / Debt	12.7%	13.0%	13.0%	12.3%	12.5%	13.6%	15.8%	16.9%	14.9%	20.2%	21.0%	20.2%	4.2%	11.3%	11.1%
Debt / Capitalization	45.1%	45.8%	46.7%	47.4%	48.4%	48.6%	44.5%	42.3%	39.4%	43.4%	43.0%	43.2%	43.8%	44.0%	43.5%

All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End; LTM = Last Twelve Months.

Source: Moody's Financial Metrics

Ratings

Exhibit 12

Category	Moody's Rating
CONSUMERS ENERGY COMPANY	
Outlook	Stable
Sr Sec Bank Credit Facility	A1
First Mortgage Bonds	A1
Senior Secured Shelf	(P)A1
LT IRB/PC	A3
Pref. Stock	Baa1
Commercial Paper	P-2
PARENT: CMS ENERGY CORPORATION	
Outlook	Stable
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Pref. Stock	Ba1

Source: Moody's Ratings

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EMEA	44-20-7772-5454

Consumers Energy Company

Consumers Energy Company's ratings reflect stability of its predominantly low-risk state-regulated electric and natural gas utility operations, constructive regulatory environment in Michigan and solid financial profile.

Key Rating Drivers

Constructive Regulatory Environment: Fitch Ratings believes the Michigan regulatory environment remains constructive from a credit perspective, as demonstrated by credit-supportive general rate case (GRC) outcomes in recent years. The Michigan Public Service Commission (MPSC) approved an authorized ROE of 9.9% in Consumer Energy's last GRC, which compares favorably with the industry average.

Supportive state legislation and MPSC policies mitigate regulatory lag through the use of a forward test year, a 10-month review period for GRCs, and power supply and gas cost recovery mechanisms. Consumers Energy's natural gas utility business also benefits from partial revenue decoupling, which annually reconciles Consumers Energy's actual weather-normalized, nonfuel revenues with revenues approved by the MPSC. Fitch does not expect a material negative outcome in the pending audit ordered by MPSC in October 2022 to assess CMS Energy Corporation's compliance with storm outages and safety regulations. Unexpected deterioration in Michigan rate regulation could result in future adverse rating actions.

Gas Base Rate Case: In December 2022, Consumers Energy filed a gas rate case requesting an annual rate increase of \$212 million, based on a 10.25% authorized ROE and projected test year ending September 2024. The filing requests authority to recover costs of upgrading transmission infrastructure, transforming compression and storage operations and replacing aging distribution pipes. Fitch expects a final MPSC decision around October 2023.

Electric Base Rate Case: In April 2022, Consumers Energy filed its electric rate case requesting an annual rate increase of \$272 million, based on a 10.25% authorized ROE for a projected test year ending December 2023. The filing requests authority to recover investments associated with distribution system, reliability, solar generation, environmental compliance, enhanced technology and approval of an unrecovered surcharge of \$6 million of distribution investments.

Consumers Energy submitted a settlement agreement to the MPSC in December 2022. The settlement, approved in January 2023, increases annual rates by approximately \$155 million based on a 9.9% authorized ROE. The common equity ratio is 50.75%

Solid Financial Profile: Fitch believes Consumers Energy's current and projected credit metrics are consistent with the rating. Fitch projects FFO leverage will remain within its sensitivities in 2023–2025, averaging 4.3x. Fitch estimates higher FFO leverage of 4.5x in 2022, reflecting moderate pressure from high capital spending and elevated commodity costs. Debt maturities are manageable, and Fitch expects the company to have continued access to capital markets.

Significant Capex Driven by Decarbonization Plans: Consumers Energy's capital program is elevated at \$14.3 billion for 2022–2026, with 45% allocated for gas infrastructure, 36% for electric distribution and supply, and 19% for clean generation. Concerns regarding the large capex plan are mitigated by the MPSC's constructive ratemaking policies and alignment of planned capex with state energy policy. Consumers Energy plans to eliminate coal from its generation mix in 2025, replacing it with low-emitting gas and non-emitting renewable generation facilities.

Ratings

Rating Type	Rating	Outlook	Last Rating Action
Long-Term IDR	A-	Stable	Affirmed Jan. 19, 2023
Short-Term IDR	F2		Affirmed Jan. 19, 2023
Senior Secured Debt	A+		Affirmed Jan. 19, 2023
Senior Unsecured Debt	A		Affirmed Jan. 19, 2023
Preferred Stock	BBB+		Affirmed Jan. 19, 2023
CP	F2		Affirmed Jan. 19, 2023

[Click here for full list of ratings](#)

Applicable Criteria

[Corporate Rating Criteria \(October 2022\)](#)

[Sector Navigators: Addendum to the Corporate Rating Criteria \(October 2022\)](#)

[Parent and Subsidiary Linkage Rating Criteria \(December 2021\)](#)

[Corporates Recovery Ratings and Instrument Ratings Criteria \(April 2021\)](#)

[Corporate Hybrids Treatment and Notching Criteria \(November 2020\)](#)

Related Research

[North American Utilities, Power & Gas Dashboard: Fourth-Quarter 2022 \(January 2023\)](#)

[North American Utilities, Power & Gas Outlook 2023 \(December 2022\)](#)

[U.S. Utilities: Mostly Strong Quarterly Earnings; Bill Affordability in Focus \(3Q22 Earnings Wrap-Up\) \(November 2022\)](#)

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Parent-Subsidiary Linkage: There is parent-subsidiary rating linkage between CMS Energy and Consumers Energy. Fitch determines CMS Energy's standalone credit profile (SCP) based upon consolidated metrics. Fitch considers Consumers Energy's SCP to be stronger than CMS Energy's. Emphasis is placed on Consumers Energy's status as a regulated entity. Legal ring-fencing is considered porous given the general protections afforded by economic regulation. Access and control are also evaluated as porous.

CMS Energy centrally manages the treasury function for all of its entities. However, both the parent and Consumers Energy issue their own long-term debt. Due to the aforementioned linkage considerations, Fitch will limit the difference between the Long-Term Issuer Default Ratings (IDRs) of CMS Energy and Consumers Energy to two notches.

Financial Summary

(\$ Mil., as of Dec. 31)	2018	2019	2020	2021
Gross Revenue	6,430	6,342	6,155	6,987
EBITDA	1,952	2,047	2,187	2,195
Cash Flow from Operations	1,424	1,569	1,186	1,948
Capital Intensity (Capex/Revenue) (%)	28.3	32.9	35.3	29.4
Debt	6,791	7,198	8,318	8,727
FFO Interest Coverage (x)	6.3	7.2	5.1	7.8
FFO Leverage (x)	3.8	3.6	5.4	3.9
EBITDA Leverage (x)	3.5	3.5	3.8	4.0

Source: Fitch Ratings, Fitch Solutions

Rating Derivation Relative to Peers

The credit profile of Consumers Energy is comparable to peers, such as DTE Electric Company (A-/Stable), Northern States Power Company-Minnesota (A-/Stable), Northern States Power Company-Wisconsin (A-/Stable), and Public Service Company of Colorado (A-/Stable). All four are regulated utilities with single-state operations, albeit in constructive environments.

FFO leverage at the electric peers is marginally stronger in the 3.8x-4.1x range. However, it is marginally weaker at DTE Gas Company (BBB+/Stable) at approximately 4.8x. Fitch forecasts FFO leverage to average around 4.3x through 2025 at Consumers Energy.

Rating Sensitivities

Factors that Could, Individually or Collectively, Lead to Positive Rating Action/Upgrade

- FFO leverage expected to be less than 3.5x on a sustained basis;
- A positive rating action on Consumers Energy would also require an equally positive rating action on parent CMS Energy. Fitch's parent-subsidiary linkage results in a maximum two-notch difference between the Long-Term IDRs of CMS Energy and Consumers Energy.

Factors that Could, Individually or Collectively, Lead to Negative Rating Action/Downgrade

- FFO leverage expected to exceed 4.5x on a sustained basis;
- A material deterioration of the Michigan regulatory environment that results in less-timely cost recovery or significantly weaker financial metrics;
- A downgrade to CMS Energy's Long-Term IDR.

Liquidity and Debt Structure

Adequate Liquidity: Fitch considers liquidity for CMS Energy and Consumers Energy to be adequate. CMS Energy has a \$550 million unsecured revolving credit facility (RCF) that will mature on Dec. 14, 2027. As of September 2022, CMS Energy had \$14 million of LOCs outstanding and no borrowings outstanding, leaving \$536 million of availability under its RCF. It also has a fully utilized LOC of \$50 million as of Sept. 30, 2022, which terminates in September 2024.

Consumers Energy primarily meets its short-term liquidity needs through the issuance of CP under its \$500 million CP program supported by its \$1.1 billion RCF, which increased from \$850 million in December 2022. Consumers Energy's RCF will mature on Dec. 14, 2027 and is secured by the utility's first mortgage bonds (FMBs). Consumers Energy had no CP borrowings and \$29 million of LOCs outstanding as of Sept. 30, 2022, leaving \$821 million of unused availability under its RCF.

Consumers Energy has a separate \$250 million RCF that will mature on Nov. 19, 2024. This RCF had no borrowings and \$62 million of LOCs outstanding at Sept. 30, 2022, leaving \$188 million of availability. The facility is also secured by the utility's FMBs.

ESG Considerations

Unless otherwise disclosed in this section, the highest level of ESG credit relevance is a score of '3'. This means ESG issues are credit-neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity. For more information on Fitch's ESG Relevance Scores, visit www.fitchratings.com/esg.

Liquidity and Debt Maturities

Liquidity Analysis

(\$ Mil.)	YE 2021	3Q22
Total Cash and Cash Equivalents	44	110
Short-Term Investments	—	—
Less: Not Readily Available Cash and Cash Equivalents	22	27
Fitch-Defined Readily Available Cash and Cash Equivalents	22	83
Availability Under Committed Lines of Credit	1,080	1,080
Total Liquidity	1,102	1,163
LTM EBITDA After Associates and Minorities	2,195	2,365
LTM FCF	-828	-1,715

Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

Scheduled Debt Maturities

(\$ Mil.)	2021
2022	0
2023	625
2024	852
2025	0
2026	0
Thereafter	7,268
Total	8,745

Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

Key Assumptions

Fitch's Key Assumptions Within Our Rating Case for the Issuer Include

- Periodic rate case filings to recover Consumers Energy's investment in rate base and associated costs;
- Operating cost reductions averaging 2% per year;
- Flat annual electric and natural gas sales growth;
- Total utility capex in line with management's assumptions;
- Dividend growth of 6%–8% per year;
- Normal weather;
- No material equity issuances till 2025 at the parent level, apart from the equity issuances planned during 2023 for the acquisition of the Covert power generation unit by Consumers Energy.

Financial Data

(\$ Mil., as of Dec. 31)	Historical			
	2018	2019	2020	2021
Summary Income Statement				
Gross Revenue	6,430	6,342	6,155	6,987
Revenue Growth (%)	3.9	-1.4	-2.9	13.5
EBITDA (Before Income from Associates)	1,952	2,047	2,187	2,195
EBITDA Margin (%)	30.4	32.3	35.5	31.4
EBITDAR	1,963	2,080	2,187	2,195
EBITDAR Margin (%)	30.5	32.8	35.5	31.4
EBIT	1,056	1,104	1,197	1,152
EBIT Margin (%)	16.4	17.4	19.4	16.5
Gross Interest Expense	-283	-275	-296	-291
Pretax Income (Including Associate Income/Loss)	847	928	989	1,024
Summary Balance Sheet				
Readily Available Cash and Equivalents	39	11	20	22
Debt	6,791	7,198	8,318	8,727
Lease-Adjusted Debt	6,879	7,462	8,318	8,727
Net Debt	6,752	7,187	8,298	8,705
Summary Cash Flow Statement				
EBITDA	1,952	2,047	2,187	2,195
Cash Interest Paid	-284	-275	-296	-287
Cash Tax	-156	-132	-51	10
Dividends Received Less Dividends Paid to Minorities (Inflow/[Out]flow)	0	0	0	0
Other Items Before FFO	-11	70	-610	50
Funds Flow from Operations	1,512	1,720	1,239	1,974
FFO Margin (%)	23.5	27.1	20.1	28.3
Change in Working Capital	-88	-151	-53	-26
Cash Flow from Operations (Fitch Defined)	1,424	1,569	1,186	1,948
Total Non-Operating/Nonrecurring Cash Flow	0	0	0	0
Capex	-1,822	-2,085	-2,170	-2,052
Capital Intensity (Capex/Revenue) (%)	28.3	32.9	35.3	29.4
Common Dividends	-533	-594	-639	-724
FCF	-931	-1,110	-1,623	-828
Net Acquisitions and Divestitures	0	77	58	0
Other Investing and Financing Cash Flow Items	-140	-115	-161	-138
Net Debt Proceeds	816	445	1,085	393
Net Equity Proceeds	250	675	650	575
Total Change in Cash	-5	-28	9	2
Leverage Ratios (x)				
EBITDA Net Leverage	3.5	3.5	3.8	4.0
EBITDAR Leverage	3.5	3.6	3.8	4.0
EBITDAR Net Leverage	3.5	3.6	3.8	4.0
EBITDA Leverage	3.5	3.5	3.8	4.0
FFO-Adjusted Leverage	3.8	3.7	5.4	3.9
FFO-Adjusted Net Leverage	3.8	3.7	5.4	3.9
FFO Leverage	3.8	3.6	5.4	3.9
FFO Net Leverage	3.8	3.6	5.4	3.9
Calculations for Forecast Publication				
Capex, Dividends, Acquisitions and Other Items Before FCF	-2,355	-2,602	-2,751	-2,776
FCF After Acquisitions and Divestitures	-931	-1,033	-1,565	-828



	Historical			
(\$ Mil., as of Dec. 31)	2018	2019	2020	2021
FCF Margin (After Net Acquisitions) (%)	-14.5	-16.3	-25.4	-11.9
Coverage Ratios (x)				
FFO Interest Coverage	6.3	7.2	5.1	7.8
FFO Fixed-Charge Coverage	6.1	6.5	5.1	7.8
EBITDAR Fixed-Charge Coverage	6.7	6.8	7.4	7.6
EBITDA Interest Coverage	6.9	7.5	7.4	7.6
Additional Metrics (%)				
CFO – Capex/Debt	-5.9	-7.2	-11.8	-1.2
CFO – Capex/Net Debt	-5.9	-7.2	-11.9	-1.2
CFO – Cash flow from operations.				
Source: Fitch Ratings, Fitch Solutions				



Ratings Navigator



Consumers Energy Company

ESG Relevance:



Corporates Ratings Navigator

North American Utilities

Factor Levels	Sector Risk Profile	Operating Environment	Management and Corporate Governance	Regulatory Environment	Business Profile Market Position	Asset Base and Operations	Commodity Exposure	Profitability	Financial Profile Financial Structure	Financial Flexibility	Issuer Default Rating
aaa											AAA
aa+											AA+
aa											AA
aa-											AA-
a+											A+
a											A
a-											A-
bbb+											BBB+
bbb											BBB
bbb-											BBB-
bb+											BB+
bb											BB
bb-											BB-
b+											B+
b											B
b-											B-
ccc+											CCC+
ccc											CCC
ccc-											CCC-
cc											CC
c											C
d or rd											D or RD

Bar Chart Legend

Vertical Bars = Range of Rating Factor		Bar Arrows = Rating Factor Outlook	
Bar Colors = Relative Importance			
■	Higher Importance	↑	Positive
■	Average Importance	↓	Negative
■	Lower Importance	↕	Evolving
■		□	Stable

Operating Environment

aa+	Economic Environment	aa	Very strong combination of countries where economic value is created and where assets are located.
aa	Financial Access	aa	Very strong combination of issuer specific funding characteristics and of the strength of the relevant local financial market.
	Systemic Governance	aa	Systemic governance (eg rule of law, corruption; government effectiveness) of the issuer's country of incorporation consistent with 'aa'.
b-			
ccc+			

Regulatory Environment

a+	Degree of Transparency and Predictability	a	Track record of transparent and predictable regulation.
a	Timeliness of Cost Recovery	a	Minimal lag to recover capital and operating costs.
a-	Trend in Authorized ROEs	a	Above-average authorized ROE.
bbb+	Mechanisms Available to Stabilize Cash Flows	bbb	Revenues partially insulated from variability in consumption.
bbb	Mechanisms Supportive of Creditworthiness	bbb	Effective regulatory ring-fencing or minimum creditworthiness requirements.

Asset Base and Operations

a	Diversity of Assets	bbb	Good quality and/or reasonable scale diversified assets.
a-	Operations Reliability and Cost Competitiveness	a	Track record of reliable, low-cost operations.
bbb+	Exposure to Environmental Regulations	bbb	Limited or manageable exposure to environmental regulations.
bbb	Capital and Technological Intensity of Capex	bbb	Moderate reinvestments requirements in established technologies.
bbb-			

Profitability

a+	Free Cash Flow	bbb	Structurally neutral to negative FCF across the investment cycle.
a	Volatility of Profitability	a	Higher stability and predictability of profits relative to utility peers.
a-			
bbb+			
bbb			

Financial Flexibility

a+	Financial Discipline	a	Clear commitment to maintain a conservative policy with only modest deviations allowed.
a	Liquidity	bbb	One-year liquidity ratio above 1.25x. Well-spread maturity schedule of debt but funding may be less diversified.
a-	FFO Interest Coverage	a	5.5x
bbb+			
bbb			

How to Read This Page: The left column shows the three-notch band assessment for the overall Factor, illustrated by a bar. The right column breaks down the Factor into Sub-Factors, with a description appropriate for each Sub-Factor and its corresponding category.

Management and Corporate Governance

aa-	Management Strategy	aa	Coherent strategy and very strong track record in implementation.
a+	Governance Structure	a	Experienced board exercising effective check and balances. Ownership can be concentrated among several shareholders.
a	Group Structure	a	Group structure shows some complexity but mitigated by transparent reporting.
a-	Financial Transparency	a	High quality and timely financial reporting.
bbb+			

Market Position

a+	Market Structure	a	Well-established market structure with complete transparency in price-setting mechanisms.
a	Consumption Growth Trend	bbb	Customer and usage growth in line with industry averages.
a-	Customer Mix	a	Favorable customer mix.
bbb+	Geographic Location	bbb	Beneficial location or reasonable locational diversity.
bbb	Supply Demand Dynamics	bbb	Moderately favorable outlook for prices/rates.

Commodity Exposure

a	Ability to Pass Through Changes in Fuel	bbb	Limited exposure to changes in commodity costs.
a-	Underlying Supply Mix	bbb	Low variable costs and moderate flexibility of supply.
bbb+	Hedging Strategy	a	Highly captive supply and customer base.
bbb			
bbb-			

Financial Structure

a+	EBITDA Leverage	a	3.25x
a	FFO Leverage	a	3.5x
a-			
bbb+			
bbb			

Credit-Relevant ESG Derivation

				Overall ESG	
Consumers Energy Company has 12 ESG potential rating drivers				key driver	0 issues
➡	Emissions from operations			5	
➡	Fuel use to generate energy and serve load	driver	0 issues	4	
➡	Impact of waste from operations				
➡	Plants' and networks' exposure to extreme weather	potential driver	12 issues	3	
➡	Product affordability and access				
➡	Quality and safety of products and services; data security	not a rating driver	2 issues	2	
			0 issues	1	

Showing top 6 issues

For further details on Credit-Relevant ESG scoring, see page 3.

Credit-Relevant ESG Derivation

Consumers Energy Company has 12 ESG potential rating drivers

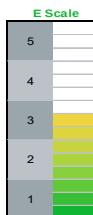
- Consumers Energy Company has exposure to emissions regulatory risk but this has very low impact on the rating.
- Consumers Energy Company has exposure to energy productivity risk but this has very low impact on the rating.
- Consumers Energy Company has exposure to waste & impact management risk but this has very low impact on the rating.
- Consumers Energy Company has exposure to extreme weather events but this has very low impact on the rating.
- Consumers Energy Company has exposure to access/affordability risk but this has very low impact on the rating.
- Consumers Energy Company has exposure to customer accountability risk but this has very low impact on the rating.

Showing top 6 issues

Overall ESG Scale			
key driver	0	issues	5
driver	0	issues	4
potential driver	12	issues	3
not a rating driver	2	issues	2
	0	issues	1

Environmental (E)

General Issues	E Score	Sector-Specific Issues	Reference
GHG Emissions & Air Quality	3	Emissions from operations	Asset Base and Operations; Commodity Exposure; Regulation; Profitability
Energy Management	3	Fuel use to generate energy and serve load	Asset Base and Operations; Commodity Exposure; Profitability
Water & Wastewater Management	2	Water used by hydro plants or by other generation plants, also effluent management	Asset Base and Operations; Regulation; Profitability
Waste & Hazardous Materials Management; Ecological Impacts	3	Impact of waste from operations	Asset Base and Operations; Regulation; Profitability
Exposure to Environmental Impacts	3	Plants' and networks' exposure to extreme weather	Asset Base and Operations; Regulation; Profitability



How to Read This Page

ESG scores range from 1 to 5 based on a 15-level color gradation. Red (5) is most relevant and green (1) is least relevant.

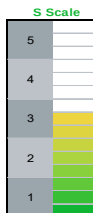
The **Environmental (E)**, **Social (S)** and **Governance (G)** tables break out the individual components of the scale. The right-hand box shows the aggregate E, S, or G score. General Issues are relevant across all markets with Sector-Specific Issues unique to a particular industry group. Scores are assigned to each sector-specific issue. These scores signify the credit-relevance of the sector-specific issues to the issuing entity's overall credit rating. The Reference box highlights the factor(s) within which the corresponding ESG issues are captured in Fitch's credit analysis.

The **Credit-Relevant ESG Derivation** table shows the overall ESG score. This score signifies the credit relevance of combined E, S and G issues to the entity's credit rating. The three columns to the left of the overall ESG score summarize the issuing entity's sub-component ESG scores. The box on the far left identifies the some of the main ESG issues that are drivers or potential drivers of the issuing entity's credit rating (corresponding with scores of 3, 4 or 5) and provides a brief explanation for the score.

Classification of ESG issues has been developed from Fitch's sector ratings criteria. The General Issues and Sector-Specific Issues draw on the classification standards published by the United Nations Principles for Responsible Investing (PRI) and the Sustainability Accounting Standards Board (SASB).

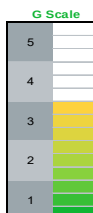
Social (S)

General Issues	S Score	Sector-Specific Issues	Reference
Human Rights, Community Relations, Access & Affordability	3	Product affordability and access	Asset Base and Operations; Regulation; Profitability; Financial Structure
Customer Welfare - Fair Messaging, Privacy & Data Security	3	Quality and safety of products and services; data security	Regulation; Profitability
Labor Relations & Practices	3	Impact of labor negotiations and employee (dis)satisfaction	Asset Base and Operations; Profitability
Employee Wellbeing	2	Worker safety and accident prevention	Profitability; Asset Base and Operations
Exposure to Social Impacts	3	Social resistance to major projects that leads to delays and cost increases	Asset Base and Operations; Profitability



Governance (G)

General Issues	G Score	Sector-Specific Issues	Reference
Management Strategy	3	Strategy development and implementation	Management and Corporate Governance
Governance Structure	3	Board independence and effectiveness; ownership concentration	Management and Corporate Governance
Group Structure	3	Complexity, transparency and related-party transactions	Management and Corporate Governance
Financial Transparency	3	Quality and timing of financial disclosure	Management and Corporate Governance

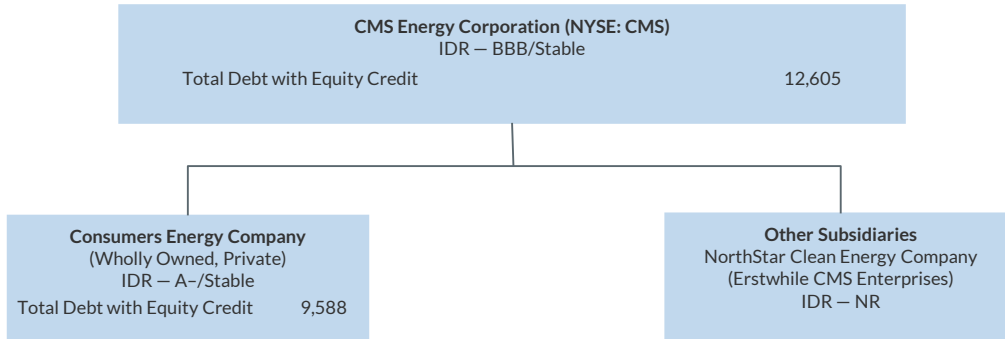


CREDIT-RELEVANT ESG SCALE

How relevant are E, S and G issues to the overall credit rating?	
5	Highly relevant, a key rating driver that has a significant impact on the rating on an individual basis. Equivalent to "higher" relative importance within Navigator.
4	Relevant to rating, not a key rating driver but has an impact on the rating in combination with other factors. Equivalent to "moderate" relative importance within Navigator.
3	Minimally relevant to rating, either very low impact or actively managed in a way that results in no impact on the entity rating. Equivalent to "lower" relative importance within Navigator.
2	Irrelevant to the entity rating but relevant to the sector.
1	Irrelevant to the entity rating and irrelevant to the sector.

Simplified Group Structure Diagram

Organizational and Debt Structure – Consumers Energy Company (\$ Mil., as of Sept. 30, 2022)



IDR – Issuer Default Rating. NR – Not rated.
Source: Fitch Ratings, Fitch Solutions, Consumer Energy Company

Peer Financial Summary

Company	Issuer Default Rating	Financial Statement Date	Gross Revenue (\$ Mil.)	Funds Flow from Operations (\$ Mil.)	FFO Interest Coverage (x)	FFO Leverage (x)	EBITDA Leverage (x)
Consumers Energy Company	A-						
	A-	2021	6,987	1,974	7.8	3.9	4.0
	A-	2020	6,155	1,239	5.1	5.4	3.8
	A-	2019	6,342	1,720	7.2	3.6	3.5
DTE Gas Company	BBB+						
	BBB+	2021	1,532	317	4.9	5.8	4.5
	BBB+	2020	1,396	337	5.3	5.1	4.4
	BBB+	2019	1,462	385	5.8	4.2	4.2
DTE Electric Company	A-						
	A-	2021	5,809	1,842	6.5	4.2	3.8
	A-	2020	5,506	1,849	6.7	3.9	3.6
	A-	2019	5,224	1,532	6.0	4.2	3.6
Northern States Power Company-Minnesota	A-						
	A-	2021	5,756	1,519	6.9	3.9	3.7
	A-	2020	5,101	1,415	6.9	3.7	3.5
	A-	2019	5,112	1,330	7.0	3.6	3.3
Northern States Power Company-Wisconsin	A-						
	A-	2021	1,105	254	7.4	3.7	3.4
	A-	2020	974	221	6.8	3.5	3.1
	A-	2019	981	220	6.9	3.4	3.3
Public Service Company of Colorado	A-						
	A-	2021	4,815	1,354	6.3	4.2	4.1
	A-	2020	4,183	1,169	6.6	4.4	4.1
	A-	2019	4,237	1,289	7.4	3.7	3.8
Wisconsin Electric Power Company	A						
	A	2020	3,657	818	2.8	2.5	2.4
	A	2019	3,367	783	2.7	2.5	2.4
	A	2018	3,497	779	2.6	2.3	2.5

Source: Fitch Ratings, Fitch Solutions

Fitch Adjusted Financials

(\$ Mil., as of Dec. 31, 2021)	Notes and Formulas	Reported Values	Sum of Adjustments	CORP- Lease Treatment	Other Adjustments	Adjusted Values
Income Statement Summary						
Revenue		7,021	-34		-34	6,987
EBITDAR		2,252	-57	-23	-34	2,195
EBITDAR After Associates and Minorities	(a)	2,252	-57	-23	-34	2,195
Lease Expense	(b)	0				0
EBITDA	(c)	2,252	-57	-23	-34	2,195
EBITDA After Associates and Minorities	(d) = (a-b)	2,252	-57	-23	-34	2,195
EBIT	(e)	1,175	-23	-16	-7	1,152
Debt and Cash Summary						
Other Off-Balance-Sheet Debt	(f)	0				0
Debt	(g)	8,971	-244	-46	-198	8,727
Lease-Equivalent Debt	(h)	0				0
Lease-Adjusted Debt	(i) = (g+h)	8,971	-244	-46	-198	8,727
Readily Available Cash and Equivalents	(j)	22				22
Not Readily Available Cash and Equivalents		22				22
Cash Flow Summary						
EBITDA After Associates and Minorities	(d) = (a-b)	2,252	-57	-23	-34	2,195
Preferred Dividends (Paid)	(k)	-2				-2
Interest Received	(l)	7				7
Interest (Paid)	(m)	-298	11	16	-5	-287
Cash Tax (Paid)		10				10
Other Items Before FFO		37	13		13	50
Funds from Operations (FFO)	(n)	2,008	-34	-7	-27	1,974
Change in Working Capital (Fitch-Defined)		-26				-26
Cash Flow from Operations (CFO)	(o)	1,982	-34	-7	-27	1,948
Non-Operating/Nonrecurring Cash Flow		0				0
Capital (Expenditures)	(p)	-2,052				-2,052
Common Dividends (Paid)		-724				-724
Free Cash Flow (FCF)		-794	-34	-7	-27	-828
Gross Leverage (x)						
EBITDAR Leverage ^a	(i/a)	4				4
FFO Adjusted Leverage	(i)/(n-m-l-k+b))	4				4
FFO Leverage	(i-h)/(n-m-l-k)	4				4
EBITDA Leverage ^a	(i-h)/d	4				4
(CFO-Capex)/Debt (%)	(o+p)/(i-h)	-0.8				-1.2
Net Leverage (x)						
EBITDAR Leverage ^a	(i-j)/a	4.0				4.0
FFO Adjusted Net Leverage	(i-j)/(n-m-l-k+b)	3.9				3.9
FFO Net Leverage	(i-h-j)/(n-m-l-k)	3.9				3.9
EBITDA Net Leverage ^a	(i-h-j)/d	4.0				4.0
(CFO-Capex)/Debt (%)	(o+p)/(i-h-j)	-0.8				-1.2
Coverage (x)						
EBITDAR Fixed Charge Coverage ^a	a/(-m+b)	7.6				7.6
EBITDA Interest Coverage ^a	d/(-m)	7.6				7.6
FFO Fixed-Charge Coverage	(n-l-m-k+b)/(-m-k+b)	7.7				7.8
FFO Interest Coverage	(n-l-m-k)/(-m-k)	7.7				7.8

^aEBITDA/R after dividends to associates and minorities. Note: Includes other off-balance-sheet debt.

Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

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Consumers Energy Company

Consumers Energy Company's ratings continue to derive support from its regulated utility operations in a constructive regulatory environment in Michigan. Sharpened focus on decarbonization and reliability is fueling the company's sizeable capex plans. Nevertheless, Fitch Ratings projects that Consumers Energy's funds from operations (FFO) leverage will average 4.1x through 2028, aided by increasing base rates and monetization of tax credits.

Key Rating Drivers

Constructive Regulatory Environment: Fitch believes the regulatory environment in Michigan under the Michigan Public Service Commission (MPSC) remains mostly constructive from a credit perspective. The regulatory framework allows for full pass-through of fuel costs and purchased power, forward-looking test years and a timely 10-month review period for general rate case resolution. Furthermore, Consumers Energy's authorized ROE of 9.9% compares favorably with industry averages.

Increasing storm activity in Michigan and resultant power outages have attracted regulatory focus on reliability. In March 2023, the MPSC tightened performance standards for utilities by way of enhanced outage credits, and updated reliability standards. An MPSC-led straw proposal for additional potential financial incentives and disincentives has also been underway since August 2023.

In Fitch's view, the risk of performance-based penalties is manageable within Consumers Energy's current credit profile. Fitch also does not expect a material negative outcome in the pending audit ordered by MPSC in October 2022 to assess the compliance of Consumers Energy with storm outages and safety regulations during the 2021 storms in Michigan. The final audit report is expected in summer 2024.

Electric Base Rate Case: In March 2024, the MPSC approved a largely constructive settlement authorizing an increase in Consumers Energy's annual rates by approximately \$92 million based on a 9.9% authorized ROE and 50.02% equity thickness. The originally requested rate increase was \$216 million, based on a 10.25% authorized ROE and 51.5% equity thickness, which was later reduced to \$168.9 million by Consumers Energy.

In addition, the MPSC partially approved an infrastructure recovery mechanism for two years as well as an undergrounding pilot program. Fitch expects Consumers Energy's next electric rate case to be filed in 2Q24.

Gas Base Rate Case: In August 2023, the MPSC approved a largely constructive settlement authorizing an increase in Consumers Energy's annual rates by approximately \$95 million, based on a 9.9% authorized ROE and 50.75% equity thickness, compared with a requested rate increase of \$212 million, based on a 10.25% authorized ROE and 51.5% equity thickness. The rates allow for the recovery of new gas infrastructure investment and related costs.

In December 2023, Consumers Energy filed a gas rate case requesting an annual rate increase of \$136 million, based on a 10.25% authorized ROE, 51.5% equity thickness and projected test year-ending September 2025. Fitch expects a decision in line with other recent decisions at MPSC by October 2024.

Ratings

Long-Term IDR	A-
Short-Term IDR	F2
Senior Unsecured Debt - Long-Term Rating	A
Senior Secured Debt - Long-Term Rating	A+
Senior Unsecured Debt - Short-Term Rating	F2

Outlook

Long-Term Foreign-Currency IDR	Stable

[Click here for the full list of ratings](#)

2035 Climate Vulnerability Signal: 44

Applicable Criteria

[Corporate Hybrids Treatment and Notching Criteria \(November 2020\)](#)

[Corporates Recovery Ratings and Instrument Ratings Criteria \(October 2023\)](#)

[Parent and Subsidiary Linkage Rating Criteria \(June 2023\)](#)

[Sector Navigators: Addendum to the Corporate Rating Criteria \(November 2023\)](#)

[Corporate Rating Criteria \(November 2023\)](#)

Related Research

[Global Corporates Macro and Sector Forecasts \(March 2024\)](#)

[North American Utilities, Power & Gas Dashboard: Fourth-Quarter 2023 \(January 2024\)](#)

[North American Utilities, Power & Gas Outlook 2024 \(December 2023\)](#)

[4Q23 North American Utilities Earnings Wrap Up Report \(March 2024\)](#)

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Decarbonization and Reliability Driven Capex: Consumers Energy's current capital program is high at \$17 billion for 2024-2028, increasing from \$15.5 billion for 2023-2027. The increased capex is predominantly focused on system reliability and decarbonization initiatives, with 37% allocated for gas infrastructure, 43% for electric distribution and others and 20% for clean generation.

Consumers Energy is also on track to eliminate coal from its generation mix in 2025, replacing it with low-emitting gas and non-emitting renewable generation facilities. Consumers Energy was authorized to securitize previous coal retirements costs and has received proceeds of \$646 million in 2023. Fitch expects continued regulatory support for Consumers Energy's future decarbonization efforts as well.

Fitch believes that an upward revision in capex is possible, given the increasing focus on reliability and the string of legislation passed in Michigan in 2023 that targets 100% clean generation by 2040 in Midcontinent Independent System Operator (MISO). Consumers Energy is expected to file its new renewable energy plan in 2H24. However, any concerns regarding the large capex plan are mitigated by the MPSC's constructive ratemaking policies and alignment of planned capex with state policy. Furthermore, the new energy legislation provides expanded incentives for energy efficiency, and could also lend improved economics for PPAs, which are beneficial in Fitch's view.

Supportive Financial Profile: Fitch believes Consumers Energy's FFO leverage will remain well within its sensitivities, averaging 4.1x through 2028. Any pressure from capex plans is largely offset by incremental earnings from rate-base growth, continued operation and maintenance savings and the ability to monetize tax credits on renewable projects using the tax credit transfer ability provisions of the Inflation Reduction Act.

Fitch forecasts Consumers Energy will sell about \$400 million of tax credits over the forecast period using the tax credit transferability provisions of the Inflation Reduction Act. Fitch also assumes that any changes in the ability to monetize tax credits at the projected levels would result in adjustments to Consumers Energy's financial plan, supporting the current credit metrics.

Parent/Subsidiary Linkage: There is parent-subsidiary rating linkage between CMS and Consumers Energy. Fitch determines CMS's Standalone Credit Profile (SCP) based upon consolidated metrics. Fitch believes Consumers Energy's SCP to be stronger than CMS's SCP. Emphasis is placed on Consumers Energy's status as a regulated entity. Legal ring-fencing is considered porous, given the general protections afforded by economic regulation. Access and control are also evaluated as porous.

CMS centrally manages the treasury function for all of its entities; however, both the parent and Consumers Energy issue their own long-term debt. Due to the aforementioned linkage considerations, Fitch will limit the difference between the Long-Term Issuer Default Ratings (IDR) of CMS and Consumers Energy to two notches.

Financial Summary

(USD Mil.)	2020	2021	2022	2023
Gross revenue	6,155	6,987	8,116	7,127
EBITDA	2,187	2,195	2,260	2,345
CFO (Fitch-defined)	1,186	1,948	954	2,387
FFO	1,239	1,974	2,052	2,144
Debt	8,318	8,727	10,230	10,613
FFO leverage (x)	5.5	3.9	4.4	4.2
FFO interest coverage (x)	5.3	8.0	8.1	6.2
EBITDA leverage (x)	3.8	4.0	4.5	4.5

Source: Fitch Ratings, Fitch Solutions

Rating Derivation Relative to Peers

The credit profile of Consumers Energy is comparable to peers like DTE Electric Company (A-/Stable), Northern States Power Company-Minnesota (A-/Stable) and Northern States Power Company-Wisconsin (A-/Stable), and Public Service Company of Colorado (A-/Stable). All four are regulated utilities with single-state operations, albeit in generally constructive environments.

Fitch forecasts FFO leverage to average around 4.1x through 2028 at Consumers Energy. Financial metrics at its peers are marginally stronger, with leverage forecast to average 3.8x through 2026 at DTE and range 3.8x-4.0x for NSP-Wisconsin and 3.4x-3.8x for NSP-Minnesota through 2028.

Rating Sensitivities

Factors that Could, Individually or Collectively, Lead to A Positive Rating Action/Upgrade

- A positive rating action on Consumers Energy would also require an equally positive rating action on its parent, CMS, under Fitch's *Parent and Subsidiary Linkage Criteria*;
- FFO leverage expected to be less than 3.5x on a sustained basis.

Factors that Could, Individually or Collectively, Lead to A Negative Rating Action/Downgrade

- FFO leverage expected to exceed 4.5x on a sustained basis;
- A material deterioration of the Michigan regulatory environment;
- A downgrade to CMS's Long-Term IDR.

Liquidity and Debt Structure

Adequate Liquidity: Consumers Energy primarily meets its short-term liquidity needs through the issuance of CP under its \$500 million CP program, which is supported by its \$1.1 billion revolving credit facility (RCF) as of year-end 2023. Consumers Energy's RCF will mature on Dec. 14, 2027 and is secured by the utility's first mortgage bonds (FMBs). Although the amount of outstanding CP does not reduce the RCF's available capacity, Consumers Energy states it would not issue CP in an amount exceeding the available RCF capacity.

Consumers Energy had \$93 million of CP borrowings and \$27 million of Letters of Credits outstanding as of year-end 2023, leaving \$1 billion of unused availability under its RCF. Consumers Energy has a separate \$250 million RCF that will mature on Nov. 18, 2025. This RCF had no borrowings, and \$48 million of LCs outstanding at year-end 2023, leaving \$202 million available. The facility is secured by the utility's FMBs.

CMS has a \$550 million unsecured revolving credit facility (RCF) that will mature on Dec. 14, 2027. As of year-end 2023, CMS had \$24 million of Letters of Credit outstanding and no borrowings outstanding, leaving \$526 million of availability under its RCF. It also has a fully utilized LOC of \$50 million as of Dec 31, 2023, which terminates in September 2024. CMS Energy's operations require modest cash on hand. The company had \$237 million of unrestricted cash and cash equivalents at Dec. 31, 2023, \$35 million of which was at Consumers Energy.

At the parent level, CMS has \$250 million of bonds expiring in 2025 followed by \$300 million in 2026, \$625 million in 2027 and \$800 million in 2028. Consumers Energy has bond maturities of \$302 million in 2024 and subsequently lower maturities of \$116 million in 2025, \$237 million in 2026, \$263 million in 2027 and \$843 million in 2028. In Fitch's view, the aforementioned debt maturities remain manageable given the company's history of successful refinancing. Fitch expects CMS and Consumers Energy to have continued access to the capital markets.

CMS and Consumers Energy were compliant with consolidated debt/capitalization of 70% and 65%, respectively, as defined under the credit agreement, as of Dec. 31, 2023.

ESG Considerations

The highest level of ESG credit relevance is a score of '3', unless otherwise disclosed in this section. A score of '3' means ESG issues are credit neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity. Fitch's ESG Relevance Scores are not inputs in the rating process; they are an observation on the relevance and materiality of ESG factors in the rating decision. For more information on Fitch's ESG Relevance Scores, visit <https://www.fitchratings.com/topics/esg/products#esg-relevance-scores>.

Climate Vulnerability Considerations

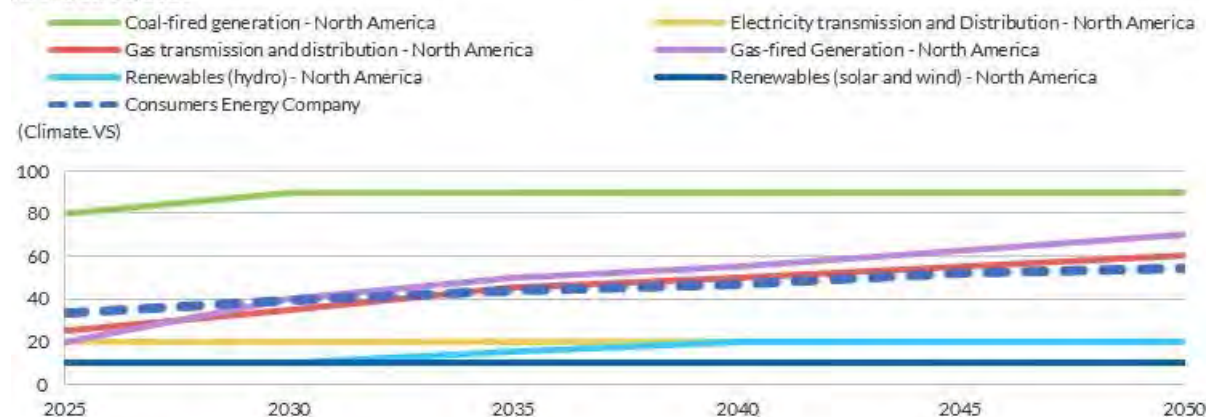
Fitch uses Climate Vulnerability Signals (Climate.VS) as a screening tool to identify sectors and Fitch-rated issuers that are potentially most exposed to credit-relevant climate transition risks and, therefore, require additional consideration of these risks in rating reviews. Climate.VS range from 0 (lowest risk) to 100 (highest risk). For more information on Climate.VS, see Fitch's [Corporate Rating Criteria](#).

The 2023 asset-weighted Climate.VS for Consumers Energy is 44 for 2035 out of 100. The utility's Climate.VS is a function of ownership of around 1.4 gigawatts (GW) of coal-fired generating capacity and 2.5GW of gas-fired capacity. The score also reflects growing opposition to methane and other greenhouse gas (GHG) emissions in recent years, driven by growing concern about the impact of global climate change and evolving state and federal policies to reduce GHG emissions.

Consumers Energy plans to phase out coal generation in 2025. By 2040, Consumers Energy expects to move towards a portfolio supported by around 61% renewable energy generation as it adds solar, wind and storage. For further information on how Fitch perceives climate-related risks in the utilities sector, see [Utilities-Long-Term Climate Vulnerability Signals Update](#).

Climate.VSEvolution

As of Dec. 31, 2023



Source: Fitch Ratings

Liquidity and Debt Maturities

Cash and maturities report		
(USD Mil.)	Dec. 31, 2022	Dec. 31, 2023
Total cash and cash equivalents	60	56
Short-term investments		
Less not readily available cash and cash equivalents	17	21
Fitch-defined readily available cash and cash equivalents	43	35
Availability under committed lines of credit	1,274	1,182
Total liquidity	1,317	1,217
LTM EBITDA after associates and minorities	2,260	2,345
LTM FCF	-2,056	-1,368

Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

Scheduled debt maturities	
(USD Mil.)	December 31, 2023
2024	395
2025	116
2026	237
2027	263
2028	843
Thereafter	8,777
Total	10,631

Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

Key Assumptions

Fitch's Key Assumptions Within Its Rating Case for the Issuer Include:

- Constructive regulatory environment in Michigan with authorized ROE of 9.9% for both electric and gas utility operations;
- Gas rate case decision in 4Q24;
- Annual rate case filings;
- Largely flat annual electric and natural gas sales;
- Total utility capex in line with management's assumptions;
- Dividend growth of 6%-8% a year;
- Normal weather;
- No material equity issuances in 2024 (other than the conversion of equity forwards and CMS's running Dividend Reinvestment Plan and subsequently up to \$350 million annually through 2028).

Financial Data

(USD Mil.)	2020	2021	2022	2023
Summary income statement				
Gross revenue	6,155	6,987	8,116	7,127
Revenue growth (%)	-2.9	13.5	16.2	-12.2
EBITDA before income from associates	2,187	2,195	2,260	2,345
EBITDA margin (%)	35.5	31.4	27.9	32.9
EBITDA after associates and minorities	2,187	2,195	2,260	2,345
EBITDAR	2,187	2,195	2,260	2,345
EBITDAR margin (%)	35.5	31.4	27.9	32.9
EBIT	1,197	1,152	1,212	1,249
EBIT margin (%)	19.4	16.5	14.9	17.5
Gross interest expense	-298	-291	-316	-416
Pretax income including associate income/loss	989	1,024	1,085	1,028
Summary balance sheet				
Readily available cash and equivalents	20	22	43	35
Debt	8,318	8,727	10,230	10,613
Lease-adjusted debt	8,318	8,727	10,230	10,613
Net debt	8,298	8,705	10,187	10,578
Summary cash flow statement				
EBITDA	2,187	2,195	2,260	2,345
Cash interest paid	-283	-277	-290	-401
Cash tax	-51	10	2	-31
Dividends received less dividends paid to minorities (inflow/outflow)	—	—	—	—
Other items before FFO	-622	40	73	203
FFO	1,239	1,974	2,052	2,144
FFO margin (%)	20.1	28.3	25.3	30.1
Change in working capital	-53	-26	-1,098	243
CFO (Fitch-defined)	1,186	1,948	954	2,387
Total non-operating/nonrecurring cash flow	—	—	—	—
Capex	-2,170	-2,052	-2,239	-3,060
Capital intensity (capex/revenue) (%)	35.3	29.4	27.6	42.9
Common dividends	-639	-724	-771	-695
FCF	-1,623	-828	-2,056	-1,368
FCF margin (%)	-26.4	-11.9	-25.3	-19.2
Net acquisitions and divestitures	58	—	—	—
Other investing and financing cash flow items	-163	-131	-87	-121
Net debt proceeds	1,085	393	1,474	1,010
Net equity proceeds	650	575	685	475
Total change in cash	7	9	16	-4
Leverage ratios (x)				
EBITDA leverage	3.8	4.0	4.5	4.5
EBITDA net leverage	3.8	4.0	4.5	4.5
EBITDAR leverage	3.8	4.0	4.5	4.5
EBITDAR net leverage	3.8	4.0	4.5	4.5
FFO adjusted leverage	5.5	3.9	4.4	4.2
FFO adjusted net leverage	5.5	3.9	4.4	4.2
FFO leverage	5.5	3.9	4.4	4.2
FFO net leverage	5.5	3.9	4.4	4.2

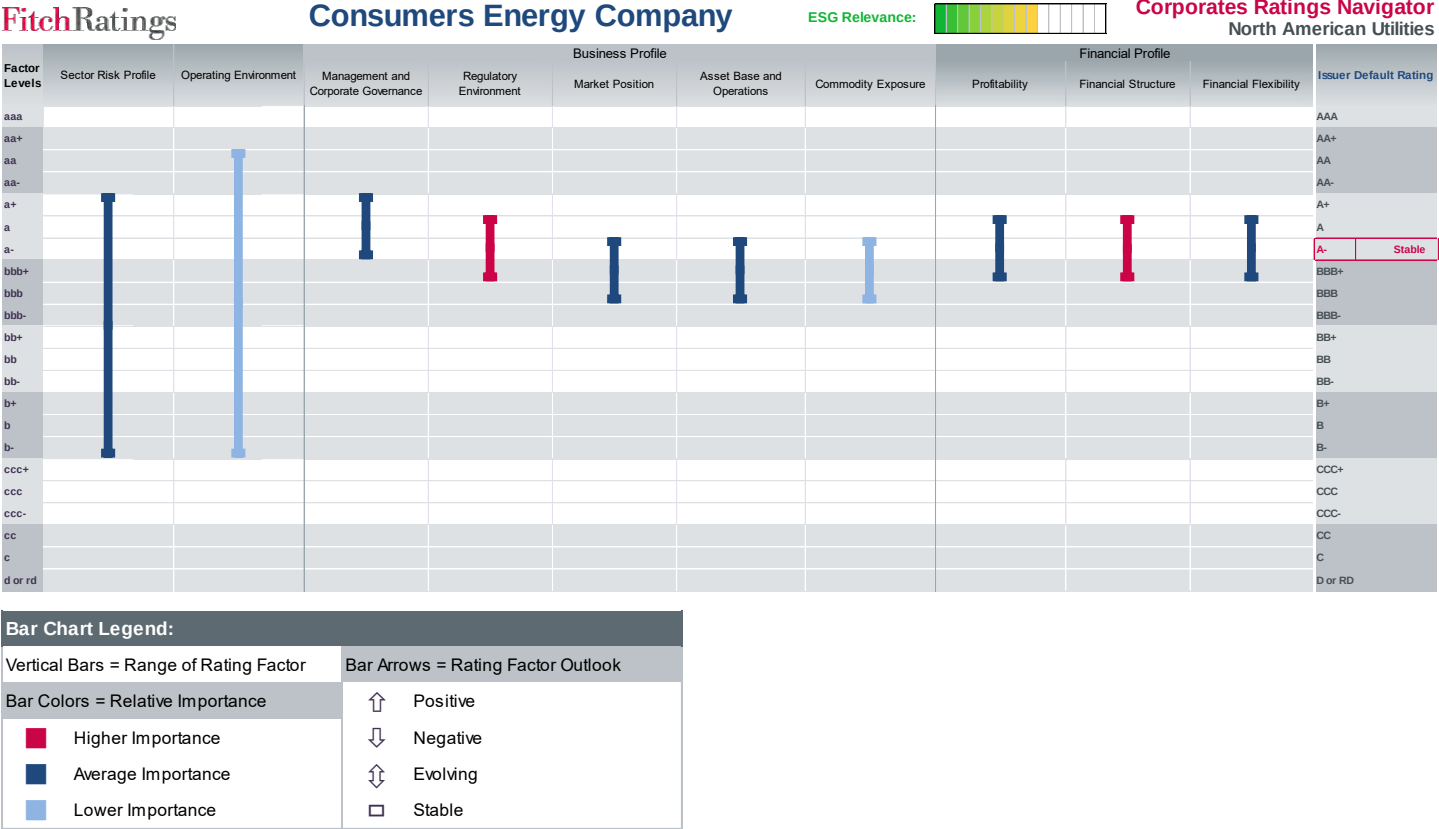
(USD Mil.)	2020	2021	2022	2023
Calculations for forecast publication				
Capex, dividends, acquisitions and other items before FCF	-2,751	-2,776	-3,010	-3,755
FCF after acquisitions and divestitures	-1,565	-828	-2,056	-1,368
FCF margin after net acquisitions (%)	-25.4	-11.9	-25.3	-19.2
Coverage ratios (x)				
FFO interest coverage	5.3	8.0	8.1	6.2
FFO fixed-charge coverage	5.3	8.0	8.1	6.2
EBITDAR fixed-charge coverage	7.7	7.9	7.8	5.8
EBITDAR net fixed-charge coverage	7.9	8.1	8.0	6.3
EBITDA interest coverage	7.7	7.9	7.8	5.8
Additional metrics (%)				
CFO-capex/debt	-11.8	-1.2	-12.6	-6.3
CFO-capex/net debt	-11.9	-1.2	-12.6	-6.4
CFO/capex	54.6	94.9	42.6	78.0
REIT fixed-charge coverage (x)	7.7	7.9	7.7	5.8
REIT leverage (x)	3.8	4.0	4.5	4.5
CFO – Cash flow from operations				
Source: Fitch Ratings, Fitch Solutions				

How to Interpret the Forecast Presented

The forecast presented above is based on Fitch Ratings' internally produced, conservative rating case forecast. It does not represent the forecast of the rated issuer. The forecast set out above is only one component used by Fitch Ratings to assign a rating or determine a rating outlook, and the information in the forecast reflects material but not exhaustive elements of Fitch Ratings' rating assumptions for the issuer's financial performance. As such, it cannot be used to establish a rating, and it should not be relied on for that purpose. Fitch Ratings' forecasts are constructed using a proprietary internal forecasting tool, which employs Fitch Ratings' own assumptions on operating and financial performance that may not reflect the assumptions that you would make. Fitch Ratings' own definitions of financial terms such as EBITDA, debt or free cash flow may differ from your own such definitions. Fitch Ratings may be granted access, from time to time, to confidential information on certain elements of the issuer's forward planning. Certain elements of such information may be omitted from this forecast, even where they are included in Fitch Ratings' own internal deliberations, where Fitch Ratings, at its sole discretion, considers the data may be potentially sensitive in a commercial, legal or regulatory context. The forecast (as with the entirety of this report) is produced strictly subject to the disclaimers set out at the end of this report. Fitch Ratings may update the forecast in future reports but assumes no responsibility to do so. Original financial statement data for historical periods is processed by Fitch Solutions on behalf of Fitch Ratings. Key financial adjustments and all financial forecasts credited to Fitch Ratings are generated by rating agency staff.



Ratings Navigator



Operating Environment

aa+	Economic Environment	aa	Very strong combination of countries where economic value is created and where assets are located.
aa	Financial Access	aa	Very strong combination of issuer specific funding characteristics and of the strength of the relevant local financial market.
	Systemic Governance	aa	Systemic governance (eg rule of law, corruption, government effectiveness) of the issuer's country of incorporation consistent with 'aa'.
b-			
ccc+			

Management and Corporate Governance

aa-	Management Strategy	a	Coherent strategy and good track record in implementation.
a+	Governance Structure	aa	No record of governance failing. Experienced board exercising effective check and balance to management. No ownership concentration.
a	Group Structure	a	Group structure shows some complexity but mitigated by transparent reporting.
a-	Financial Transparency	a	High quality and timely financial reporting.
bbb+			

Regulatory Environment

a+	Degree of Transparency and Predictability	a	Track record of transparent and predictable regulation.
a	Timeliness of Cost Recovery	a	Minimal lag to recover capital and operating costs.
a-	Trend in Authorized ROEs	a	Above-average authorized ROE.
bbb+	Mechanisms Available to Stabilize Cash Flows	bbb	Revenues partially insulated from variability in consumption.
bbb	Mechanisms Supportive of Creditworthiness	bbb	Effective regulatory ring-fencing or minimum creditworthiness requirements.

Market Position

a	Market Structure	a	Well-established market structure with complete transparency in price-setting mechanisms.
a-	Consumption Growth Trend	bbb	Customer and usage growth in line with industry averages.
bbb+	Customer Mx	a	Favorable customer mix.
bbb	Geographic Location	bbb	Beneficial location or reasonable locational diversity.
bbb-	Supply Demand Dynamics	bbb	Moderately favorable outlook for prices/rates.

Asset Base and Operations

a	Diversity of Assets	bbb	Good quality and/or reasonable scale diversified assets.
a-	Operations Reliability and Cost Competitiveness	a	Track record of reliable, low-cost operations.
bbb+	Exposure to Environmental Regulations	bbb	Limited or manageable exposure to environmental regulations.
bbb	Capital and Technological Intensity of Capex	bbb	Moderate reinvestments requirements in established technologies.
bbb-			

Commodity Exposure

a	Ability to Pass Through Changes in Fuel	bbb	Limited exposure to changes in commodity costs.
	Underlying Supply Mx	bbb	Low variable costs and moderate flexibility of supply.
bbb+	Hedging Strategy	a	Highly captive supply and customer base.
bbb			
bbb-			

Profitability

a+	Free Cash Flow	bbb	Structurally neutral to negative FCF across the investment cycle.
a	Volatility of Profitability	a	Higher stability and predictability of profits relative to utility peers.
a-			
bbb+			
bbb			

Financial Structure

a+	EBITDA Leverage	a	3.25x
a	FFO Leverage	a	3.5x
a-			
bbb+			
bbb			

Financial Flexibility

a+	Financial Discipline	a	Clear commitment to maintain a conservative policy with only modest deviations allowed.
a	Liquidity	bbb	One-year liquidity ratio above 1.25x. Well-spread maturity schedule of debt but funding may be less diversified.
a-	FFO Interest Coverage	bbb	4.5x
bbb+			
bbb			

How to Read This Page: The left column shows the three-notch band assessment for the overall Factor, illustrated by a bar. The right column breaks down the Factor into Sub-Factors, with a description appropriate for each Sub-Factor and its corresponding category.

Credit-Relevant ESG Derivation

				Overall ESG	
Consumers Energy Company has 12 ESG potential rating drivers				key driver	0 issues
▶	Emissions from operations	0	issues	5	
▶	Fuel use to generate energy and serve load	0	issues	4	
▶	Impact of waste from operations	12	issues	3	
▶	Plants' and networks' exposure to extreme weather	2	issues	2	
▶	Product affordability and access	2	issues	2	
▶	Quality and safety of products and services; data security	0	issues	1	

Showing top 6 issues

For further details on Credit-Relevant ESG scoring, see page 3.

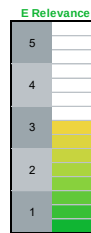
Credit-Relevant ESG Derivation

				ESG Relevance to Credit Rating	
Consumers Energy Company has 12 ESG potential rating drivers					
➔	Consumers Energy Company has exposure to emissions regulatory risk but this has very low impact on the rating.	key driver	0	issues	5
➔	Consumers Energy Company has exposure to energy productivity risk but this has very low impact on the rating.	driver	0	issues	4
➔	Consumers Energy Company has exposure to waste & impact management risk but this has very low impact on the rating.	potential driver	12	issues	3
➔	Consumers Energy Company has exposure to extreme weather events but this has very low impact on the rating.				
➔	Consumers Energy Company has exposure to access/affordability risk but this has very low impact on the rating.	not a rating driver	2	issues	2
➔	Consumers Energy Company has exposure to customer accountability risk but this has very low impact on the rating.		0	issues	1

Showing top 6 issues

Environmental (E) Relevance Scores

General Issues	E Score	Sector-Specific Issues	Reference
GHG Emissions & Air Quality	3	Emissions from operations	Asset Base and Operations; Commodity Exposure; Regulation; Profitability
Energy Management	3	Fuel use to generate energy and serve load	Asset Base and Operations; Commodity Exposure; Profitability
Water & Wastewater Management	2	Water used by hydro plants or by other generation plants, also effluent management	Asset Base and Operations; Regulation; Profitability
Waste & Hazardous Materials Management; Ecological Impacts	3	Impact of waste from operations	Asset Base and Operations; Regulation; Profitability
Exposure to Environmental Impacts	3	Plants' and networks' exposure to extreme weather	Asset Base and Operations; Regulation; Profitability



How to Read This Page

ESG relevance scores range from 1 to 5 based on a 15-level color gradation. Red (5) is most relevant to the credit rating and green (1) is least relevant.

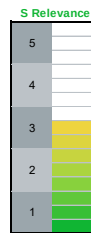
The **Environmental (E)**, **Social (S)** and **Governance (G)** tables break out the ESG general issues and the sector-specific issues that are most relevant to each industry group. Relevance scores are assigned to each sector-specific issue, signaling the credit-relevance of the sector-specific issues to the issuer's overall credit rating. The Criteria Reference column highlights the factor(s) within which the corresponding ESG issues are captured in Fitch's credit analysis. The vertical color bars are visualizations of the frequency of occurrence of the highest constituent relevance scores. They do not represent an aggregate of the relevance scores or aggregate ESG credit relevance.

The **Credit-Relevant ESG Derivation** table's far right column is a visualization of the frequency of occurrence of the highest ESG relevance scores across the combined E, S and G categories. The three columns to the left of ESG Relevance to Credit Rating summarize rating relevance and impact to credit from ESG issues. The box on the far left identifies any ESG Relevance Sub-factor issues that are drivers or potential drivers of the issuer's credit rating (corresponding with scores of 3, 4 or 5) and provides a brief explanation for the relevance score. All scores of '4' and '5' are assumed to reflect a negative impact unless indicated with a '+' sign for positive impact.

Classification of ESG issues has been developed from Fitch's sector ratings criteria. The General Issues and Sector-Specific Issues draw on the classification standards published by the United Nations Principles for Responsible Investing (PRI), the Sustainability Accounting Standards Board (SASB), and the World Bank.

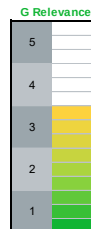
Social (S) Relevance Scores

General Issues	S Score	Sector-Specific Issues	Reference
Human Rights, Community Relations, Access & Affordability	3	Product affordability and access	Asset Base and Operations; Regulation; Profitability; Financial Structure
Customer Welfare - Fair Messaging, Privacy & Data Security	3	Quality and safety of products and services; data security	Regulation; Profitability
Labor Relations & Practices	3	Impact of labor negotiations and employee (dis)satisfaction	Asset Base and Operations; Profitability
Employee Wellbeing	2	Worker safety and accident prevention	Profitability, Asset Base and Operations
Exposure to Social Impacts	3	Social resistance to major projects that leads to delays and cost increases	Asset Base and Operations; Profitability



Governance (G) Relevance Scores

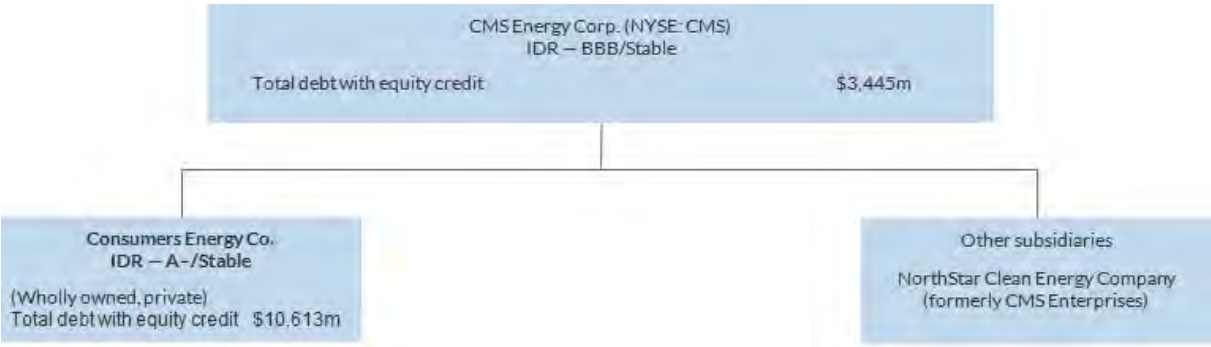
General Issues	G Score	Sector-Specific Issues	Reference
Management Strategy	3	Strategy development and implementation	Management and Corporate Governance
Governance Structure	3	Board independence and effectiveness; ownership concentration	Management and Corporate Governance
Group Structure	3	Complexity, transparency and related-party transactions	Management and Corporate Governance
Financial Transparency	3	Quality and timing of financial disclosure	Management and Corporate Governance



CREDIT-RELEVANT ESG SCALE

How relevant are E, S and G issues to the overall credit rating?	
5	Highly relevant, a key rating driver that has a significant impact on the rating on an individual basis. Equivalent to "higher" relative importance within Navigator.
4	Relevant to rating, not a key rating driver but has an impact on the rating in combination with other factors. Equivalent to "moderate" relative importance within Navigator.
3	Minimally relevant to rating, either very low impact or actively managed in a way that results in no impact on the entity rating. Equivalent to "lower" relative importance within Navigator.
2	Irrelevant to the entity rating but relevant to the sector.
1	Irrelevant to the entity rating and irrelevant to the sector.

Simplified Group Structure Diagram



Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company, as of April 2024

Peer Financial Summary

Company	Issuer Default Rating	Financial statement date	Gross revenue (USD Mil.)	FFO (USD Mil.)	FFO leverage (x)	FFO interest coverage (x)	EBITDA leverage (x)
Consumers Energy Company							
	A-	2023	7,127	2,144	4.2	6.2	4.5
	A-	2022	8,116	2,052	4.4	8.1	4.5
	A-	2021	6,987	1,974	3.9	8.0	4.0
DTE Electric Company							
	A-	2023	5,804	1,968	4.5	5.6	4.1
	A-	2022	6,397	2,463	3.6	7.8	4.0
	A-	2021	5,809	1,842	4.2	6.5	3.8
Northern States Power Company-Minnesota							
	A-	2023	6,043	1,985	3.3	7.3	3.9
	A-	2022	6,684	1,587	3.9	6.7	3.7
	A-	2021	5,756	1,519	3.9	6.9	3.7
Northern States Power Company-Wisconsin							
	A-	2023	1,177	295	3.7	6.8	3.3
	A-	2022	1,201	270	3.7	7.4	3.2
	A-	2021	1,105	254	3.7	7.4	3.4

Source: Fitch Ratings, Fitch Solutions

Fitch Adjusted Financials

(USD Mil. as of Dec. 31, 2023)	Notes and formulas	Standardised values	Other adjustments	Lease treatment	Other adjustments	Adjusted values
Income statement summary						
Revenue		7,166	—	—	-39	7,127
EBITDA	(a)	2,405	—	-21	-39	2,345
Depreciation and amortization		-1,137	—	8	33	-1,096
EBIT		1,268	—	-13	-6	1,249
Balance sheet summary						
Debt	(b)	11,299	—	—	-787	10,613
Of which other off-balance-sheet debt		—	—	—	—	—
Lease-equivalent debt		—	—	—	—	—
Lease-adjusted debt		11,299	—	—	-787	10,613
Readily available cash and equivalents	(c)	35	—	—	—	35
Not readily available cash and equivalents		21	—	—	—	21
Cash flow summary						
EBITDA	(a)	2,405	—	-21	-39	2,345
Dividends received from associates less dividends paid to minorities	(d)	—	—	—	—	—
Interest paid	(e)	-417	—	13	-9	-413
Interest received	(f)	30	—	—	—	30
Preferred dividends paid	(g)	-2	—	—	—	-2
Cash tax paid		-31	—	—	—	-31
Other items before FFO		200	—	—	15	215
FFO	(h)	2,185	—	-8	-33	2,144
Change in working capital		243	—	—	—	243
CFO	(i)	2,428	—	-8	-33	2,387
Non-operating/nonrecurring cash flow		—	—	—	—	—
Capex	(j)	-3,060	—	—	—	-3,060
Common dividends paid		-695	—	—	—	-695
FCF		-1,327	—	-8	-33	-1,368
Gross leverage (x)						
EBITDA leverage	b / (a+d)	4.7	—	—	—	4.5
FFO leverage	b / (h-e-f-g)	4.4	—	—	—	4.2
(CFO-capex)/debt (%)	(i+j) / b	-5.5	—	—	—	-6.3
Net leverage (x)						
EBITDA net leverage	(b-c) / (a+d)	4.7	—	—	—	4.5
FFO net leverage	(b-c) / (h-e-f-g)	4.4	—	—	—	4.2
(CFO-capex)/net debt (%)	(i+j) / (b-c)	-5.6	—	—	—	-6.4
Coverage (x)						
EBITDA interest coverage	(a+d) / (-e)	5.8	—	—	—	5.7
FFO interest coverage	(h-e-f-g) / (-e-g)	6.1	—	—	—	6.1

CFO – Cash flow from operations

Note: The standardised items presented above are based on Fitch's taxonomy for the given sector and region. Reported items may not match the Fitch taxonomy, but they are captured into corresponding lines accordingly.

Debt includes other off-balance-sheet debt.

Debt in the standardised values column excludes lease liabilities of \$44 million.

Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

Parent Subsidiary Linkage Analysis

Parent	CMS Energy Corporation
Parent LT IDR	BBB/Stable
Subsidiary	Consumers Energy Company
Subsidiary LT IDR	A-/Stable
Path	Stronger Subsidiary
Legal ring-fencing	Porous
Access and control	Porous
Notching matrix outcome	Consolidated Plus 2
Override applied	No
Notching approach	Consolidated Plus 2

LT IDR – Long-Term Issuer Default Rating
Source: Fitch Ratings

Access and control	Open	Porous	Insulated
With open ring-fencing	Consolidated	Consolidated+1	Consolidated+2 ^b
With porous ring-fencing	Consolidated+1	Consolidated+2 ^b	Consolidated+2 ^b
With insulated ring-fencing	^a	Standalone	Standalone

^aIt is unlikely that considerations for "insulated" legal ring-fencing would coexist with the conditions outlined under "open" for access and control. It is more likely that other factors relevant to legal ring-fencing or access and control, but not within this table, would move either one, or both, of the individual Linkage Factor Assessments (LFAs) to a "porous" level that would lead to a consolidated+1, consolidated+2 or standalone outcome.

^bNotching is capped at the subsidiary's Standalone Credit Profile.

Source: Fitch Ratings

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VLFAAlert



ValueLinefunds

4th Quarter 2018

Volume VII, Issue IV

00207257



Mitchell Appel
President
Value Line Funds

Dear Fellow Shareholder,

Thank you for choosing Value Line Funds as a part of your diversified investment portfolio. For over half a century, Value Line Funds has championed sound investment principles and helped thousands of investors accomplish their financial goals with our actively managed family of mutual funds.

We hope you enjoy this edition of the VLFAAlert and thank you for your continued support.

Volatility is Not Risk:

Why the Difference is Critical to Long-Term Results

2017 lulled many equity investors into a comfort zone based on historically low volatility. 2018 has been more volatile—with tighter monetary policy and geopolitical and trade policy uncertainty among the drivers of the increase. But volatility levels in 2018 are actually historically normal—even with the bouts of volatility anticipated ahead of the November mid-term elections. But volatility is not risk. And recognizing the difference can be critical to your long-term investment returns.

Defining Our Terms

Volatility is simply the measure of the up and down movements of the market. For example, since 1950, when the Value Line Funds were first established, the average maximum drawdown in the broad U.S. equity market during midterm election years has been -17%, with weakness tending to be concentrated in the pre-election days. However, the good news is that there has been a consistent tendency historically for post-drawdown rallies, averaging +32% in the subsequent year.¹ Volatility? Yes! Uncertainty? Yes! But volatility is only risk if you act during down times—that is, only if you sell. To which the often-invoked quip may well be the most prudent answer: "Don't just do something, sit there."

Risk, on the other hand, is the probability of a permanent loss. You might think of risk as the possibility of having to lower your quality of life in the future.

"Volatility is not synonymous of risk but—for those who truly understand it—of wealth."

- Francois Rochon*

Recognizing the Difference

Volatility is independent of risk. Too many investors let an investment's short-term price movements, or perceptions of short-term price movements, drive their buying and selling decisions. Too often volatility is regarded as something to be

avoided. But since short-term price moves are unknowable and independent of underlying fundamentals and value, such volatility should not be a determinant.

And ALL investments have risk of some kind, including cash and CDs. One just needs to pick the risks that are best to take based on your individual tolerance level, time horizon and financial needs and goals.

As famed investor and Berkshire Hathaway CEO Warren Buffet wrote:

"Stock prices will always be far more *volatile* than cash-equivalent holdings. *Over the long term*, however, currency-denominated instruments are *riskier* investments — far riskier investments — than widely-diversified stock portfolios that are bought over time and that are owned in a manner invoking only token fees and commissions. **That lesson has not customarily been taught in business schools, where volatility is almost universally used as a proxy for risk. Though this pedagogic assumption makes for easy teaching, it is dead wrong: Volatility is far from synonymous with risk.** Popular formulas that equate the two terms lead students, investors and CEOs astray."²

**"Volatility is our friend.
Volatility has nothing to do with risk."**

- Mohnish Pabrai*

(continued on back)

Value Line Article on Volatility vs. Risk

It's a Matter of Time, Not Timing

Most experienced investors do not fear volatility, only unrecoverable loss. But most losses, as measured by a day, a week, a quarter or a year, are recoverable over time. Declines in principal value have historically been temporary. Of course, there are true risks. A company could go totally out of business. An innovation could transform an industry so profoundly to make a once "blue chip" company a relic. A geopolitical event could happen to negate all assumptions. But these occurrences are rare. For the vast majority of investors, maintaining a long-term perspective is the real key to attaining gains over their investing lifetime. Historically, since World War II, the longer you hold stocks, the narrower the range of returns.³ In other words, even if volatility is a concern, it decreases the longer you hold stocks. It's the old adage: what matters is time in the market, not market timing.

"You can't overlook the volatility, but you don't let it push you around in the market."

*- Boone Pickens**

solutions designed to meet a broad array of investment goals. Whether you are looking for income or long-term capital appreciation, whether you choose to invest in equities, taxable or tax-exempt fixed income or a hybrid fund of multiple asset classes, you can rely on the solid fundamentals of Value Line Funds.

Value Line Funds Include:
Equity Funds
Premier Growth Fund
Larger Companies Focused Fund
Mid Cap Focused Fund
Small Cap Opportunities Fund
Hybrid Funds
Asset Allocation Fund
Capital Appreciation Fund
Fixed Income Funds
Tax Exempt Fund
Core Bond Fund

Comparison of Gas Sales Volumes - 2019-2024 Actuals to October 2026 Test Year Forecast

Line	Description (a)	Actual						2025F	2026F	Test Year 12 Months Ended Oct. 2026F ⁴	2021-2024 3-YR CAGR	2019-2024 5-YR CAGR
		2019	2020	2021	2022	2023	2024			(j)	(k)	(k)
1	Average Gas Use Per Customer (Mcf):¹											
2	Residential Sales	96.63	97.42	93.61	95.23	93.51	92.12	92.79	92.21	92.32		
3	Percent Change from Prior Yr		0.8%	-3.9%	1.7%	-1.8%	-1.5%	0.7%	-0.6%	0.2%	-0.5%	-1.0%
4	Commercial Sales	446.69	433.79	426.51	443.57	433.02	432.31	443.81	442.47	442.75		
5	Percent Change from Prior Yr		-2.9%	-1.7%	4.0%	-2.4%	-0.2%	2.7%	-0.3%	2.4%	0.5%	-0.7%
6	Industrial Sales	1,887.47	1,888.06	1,955.11	2,078.10	2,112.12	2,110.46	2,258.75	2,235.76	2,239.86		
7	Percent Change from Prior Yr		0.0%	3.6%	6.3%	1.6%	-0.1%	7.0%	-1.0%	6.1%	2.6%	2.3%
8	Residential Transport	6,552.77	6,434.64	5,582.34	5,661.38	5,711.09	4,888.33	6,475.78	6,452.07	6,459.72		
9	Percent Change from Prior Yr		-1.8%	-13.2%	1.4%	0.9%	-14.4%	32.5%	-0.4%	32.1%	-4.3%	-5.7%
10	Commercial Transport	9,695.18	9,475.39	9,743.18	9,770.37	9,936.75	9,593.01	9,065.00	9,012.75	9,027.66		
11	Percent Change from Prior Yr		-2.3%	2.8%	0.3%	1.7%	-3.5%	-5.5%	-0.6%	-5.9%	-0.5%	-0.2%
12	Industrial Transport²	97,813.63	93,615.25	97,090.22	108,917.99	110,393.90	104,800.32	107,372.53	106,977.40	106,835.38		
13	Percent Change from Prior Yr		-4.3%	3.7%	12.2%	1.4%	-5.1%	2.5%	-0.4%	1.9%	2.6%	1.4%
14	Gas Deliveries - Weather-Normalized:^{2,3}											
15	(MMCF)											
16	Residential Sales	159,366	162,020	156,515	159,918	157,474	155,705	157,928	157,762	157,809		
17	Commercial Sales	55,723	54,840	54,241	56,930	55,836	56,198	57,682	57,667	57,677		
18	Industrial Sales	8,492	8,237	8,136	8,178	7,876	7,502	8,155	8,072	8,087		
19	Residential Transport	1,159	1,120	1,132	1,130	1,184	1,025	1,366	1,361	1,363		
20	Commercial Transport	26,853	26,015	26,536	26,735	27,075	26,209	25,090	25,027	25,048		
21	Industrial Transport ²	51,972	49,421	51,854	58,298	59,042	56,190	57,337	57,126	57,157		
	Total	303,565	301,653	298,414	311,190	308,487	302,829	307,558	307,014	307,141		
22	Average Number of Customers:^{2,3}											
23	Residential	1,649,303	1,663,158	1,672,062	1,679,345	1,683,983	1,690,262	1,702,076	1,710,885	1,709,433		
24	Commercial	124,748	126,419	127,173	128,345	128,943	129,993	129,971	130,330	130,270		
25	Industrial Sales	4,499	4,363	4,161	3,935	3,729	3,555	3,610	3,610	3,611		
26	Residential Transport	177	174	203	200	207	210	211	211	211		
27	Commercial Transport	2,770	2,746	2,724	2,736	2,725	2,732	2,768	2,777	2,775		
28	Industrial Transport	531	528	534	535	535	536	534	534	535		

Source:

- (1) Calculated by dividing weather-normalized deliveries by number of customers.
- (2) Part III Attachment 015 and 016 Revised for forecasted 2025 and 2026 gas deliveries and number of customers. DR AG-CE-0310 & 311 for W/N historical data.
- (3) Exhibit A-15 (MA-6) Schedule E-2 and (MA-10) Schedule E-6 for test year October 2026 gas deliveries and customers. Excludes Inter-Departmental sales.
- (4) Percent increase from 2024.

Incremental Revenue from Higher Commerical Transportation Volume for Forecasted Test Year

Line #	(a)				(b)				(c)	
1	Average Transport Volumes per Customer - Actual 2024 ¹								9,593.01	Mcf
2										
3	3-Year average rate of change in Usage per Customer ¹				-0.50%					
4										
5	Average Transport Volumes per Customer -October 2025 ²								9,553.03	Mcf
6										
7	Average Transport Volumes per Customer - October 2026 ³								9,505.27	Mcf
8										
9	Forecasted Test Year average number of customers ⁴								<u>2,775</u>	
10										
11	AG Forecasted Volumes for the Projected Test year (Line 7 x Line 9)								26,373,162	Mcf
12										
13	CECo Forecasted Transport Volumes ⁴								<u>25,048,000</u>	Mcf
14										
15	Increase in Sales Volumes (Line 13 - Line 11)								1,325,162	Mcf 5.3%
16										
17	<u>GS-1</u>	<u>GS-2</u>	<u>GS-3</u>	<u>ST</u>	<u>LT</u>	<u>XLT</u>	<u>XXLT</u>	<u>Total</u>		
18	0.76%	7.52%	0.55%	37.28%	25.98%	9.04%	18.87%	100%	Note (5)	
19										
20	10,058	99,714	7,260	493,977	344,272	119,763	250,119	1,325,162	Mcf	
21										
22	\$ 4.9147	\$ 3.5306	\$ 3.3012	\$ 1.4273	\$ 1.3009	\$ 0.9564	\$ 0.5177		Current Rate Comm per Mcf ⁶	
23										
24	\$ 49,430	\$ 352,050	\$ 23,966	\$ 705,053	\$ 447,863	\$ 114,541	\$ 129,487	<u><u>\$ 1,822,391</u></u>	Incremental Revenue	

Source: (1) Exhibit AG-53.
(2) Line 1 x 10/12 of Line 3 (Represents the rate change in usage from January 2025 to October 2025).
(3) Line 5 x Line 3 (Represents a full year of rate change in usage).
(4) Exhibit A-15 (MA-10), Schedule E-6, line 39, column (d).
(5) Allocation to each rate schedule based on DR AG-CE-0309 Attachment 1.
(6) Exhibit A-16, Schedule F3, Distribution rate for each rate schedule.

U21806-AG-CE-0313

Page 1 of 1

Question:

27. Refer to Exhibit A-13, Schedule E-10. Please explain what makes up the reduction in Transportation deliveries of 1,764 MMcf. Identify any additions and reductions in load by rate schedule and what specifically drove those changes.

Response:

The “change in determinants” column is a formula calculating the difference between weather adjusted history and the forecasted test year and the description of how the forecast was done can be found in the testimony. The primary drivers for Transportation forecast are economic indicators and usage patterns in recent history.

Witness: Mustafa A. Sherwani

Date: March 7, 2025

U21806-AG-CE-0746

Page 1 of 1

Question:

317. Refer to discovery response AG-CE-0313 on the reduction in transportation deliveries. Please confirm that the Company cannot identify any specific reasons for the transportation load reduction from 2023 to the end of the projected test year. If not confirming, provide evidence otherwise.

Response:

As noted in my response AG-CE-0313: The primary drivers for the load reduction for Transportation forecast are economic indicators and usage patterns in recent history.

Witness: Mustafa A. Sherwani

Date: April 2, 2025

Exhibit AG-56

CONFIDENTIAL

U21806-AG-CE-0373

Page 1 of 1

Question:

86. Refer to lines 10-11 on page 7 of Ms. Pascarello's direct testimony. Please explain what you mean by stating that 63 co-workers were impacted. Does it mean that 31 employees were reassigned and 32 were released from employment with the Company? If not, what does it mean?

Response:

The remaining 32 workers were assigned to the Electric Quality Lean Team. The projected O&M expenses, as described in my direct testimony and exhibits, only include the employees assigned to the Gas Quality Lean team.

Witness: Kristine A. Pascarello

Date: March 10, 2025

U21806-AG-CE-0374

Page 1 of 1

Question:

87. Refer to page 7 of Ms. Pascarello's direct testimony. Please:

- a. For the reorganization and shifting of employees and costs within and outside of the Gas Supply and Engineering operation, please provide a pro-forma comparison of O&M expenses for each year 2021-2024 as if the reorganization had taken place beginning in 2021 in order to present comparable data for evaluation of cost trends for each of the 15 departments listed in Exhibit A-81. Provide this information in Excel.
- b. Provide a comparison of the pro-forma 2023 expense for each of the 15 departments to the forecasted 2024, 2025, and projected test year, and explain any year over year variance of 5% or greater in Excel. Assign an amount to each reason for the cost variance.
- c. Provide the same pro-forma comparison requested in subpart (a) for the number of employees in each of the 15 departments at year end and explain the reasons for any year over-year variance of 2 or more employees.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request because it requests an analysis that the Company has not performed and is not proportional to the needs of the case. Without waiving this objection, Consumers Energy responds as follows:

- a. The Company has not performed this analysis, it would involve a level of detail and complexity that has not previously been undertaken, and would be extremely burdensome and difficult to attempt to perform due to the extensive data collection and evaluation required.
- b. See response to a.
- c. See response to a.

Witness: Kristine A. Pascarello

Date: March 13, 2025

CECo Response AG-CE-0378

U21806-AG-CE-0378

Page 1 of 1

Question:

91. Refer to line 14 on page 11 of Ms. Pascarello's direct testimony on the Quality Lean Office. Please:

- a. Provide the number of employees working in the Quality Lean Office, at the end of each year 2021 to 2024 and forecasted for 2025 and 2026. Provide also the number of contract employees and consultants during each year.
- b. Provide the O&M cost of the Quality Lean Office for each year 2021 to 2024 and forecasted for 2025, 2026, and the projected test year. Provide the labor expense separately from other expenses, identifying any consultant fees paid each year.
- c. Provide the list of major accomplishments achieved by the Quality Lean Office for each year 2021-2024 and the related cost savings or financial benefits that accrued to customers each year.

Response:

a.

	2021	2022	2023	2024	2025	2026	Test Year
Employees - Gas Only	9	7	6	22	24	24	24
Contract/Consultants	1	1	0	3	6	6	6

b.

Gas Only (\$000)	2021	2022	2023	2024	2025	2026	Test Year
Labor	\$ 652	\$ 673	\$ 548	\$ 449	\$ 725	\$ 749	\$ 745
Contractor	\$ 26	\$ 32	\$ -	\$ 29	\$ 321	\$ 302	\$ 305
Other Non Labor	\$ 79	\$ 37	\$ 20	\$ 128	\$ 191	\$ 213	\$ 209
Total	\$ 756	\$ 742	\$ 568	\$ 605	\$ 1,237	\$ 1,263	\$ 1,259

- c. The Quality Lean Department, which is inclusive of the ECAP organization as of 2024, does not itself achieve improvements but provides support to other Company personnel. This department provides learning and development on lean methodologies and tools and facilitates problem solving, value stream assessments, etc. to identify opportunities to improve process efficiency and effectiveness. These process improvements can help to control and at times lower overall costs. With the integration of ECAP into the Lean Quality Department, the team absorbed responsibility for the enterprise-wide issue management and compliance program, also known as the Corrective and Preventative Action (CAPA) system, to support safe and excellent operations.

Witness: Kristine A. Pascarello

Date: March 12, 2025

U21806-AG-CE-0381
Page 1 of 1

Question:

94. Refer to lines 2-7 on page 19 of Ms. Pascarello's direct testimony on O&M expense for System Integrity. Please:

- a. Provide in complete detail what led to the departmental reassessment for additional inspections and remediations.
- b. Provide the number of inspections and remediations performed in each year 2021 to 2024 and forecasted for 2024, 2025, and the projected test year with the related dollars in Excel.
- c. Identify what the additional \$1.5 million or more for O&M expense forecasted for the projected test year over 2023 will be spent on.

Response:

- a. The Company annually reviews historical costs to consider what portion of inspection and remediation work leads to capital replacements or to O&M repairs. This review informs the Company's expectation regarding the percentage of costs that will be funded through O&M or through capital. As discussed on page 19 of my direct testimony, an increase in O&M expenses is attributed to the Company's expectation that additional remediation activities will be funded through O&M.
- b. Please see U21806-AG-CE-0381_Pascarello_Attachment_1. As described on page 18, lines 16 through 18 of my direct testimony, I am sponsoring the O&M expenses for staffing of the System Integrity department and the SIMP program. The O&M expenses related to pipeline inspection and remediation activities in this attachment are sponsored by Company witness Michael P. Griffin.
- c. The additional \$1.5 million does not represent an increase in workload. Instead, it reflects a reclassification of existing salaries and expenses as operational and maintenance (O&M) costs based on activities expected to be performed.

Witness: Kristine A. Pascarello

Date: March 13, 2025

CECo Response AG-CE-0422

U21806-AG-CE-0422-Pascarello_Attachment_1								
Advanced Methane Detection								
Table 11: AMD Actual and Projected Costs								
	2021 Actual	2022 Actual	2023 Actual	2024 Projected	2024 Preliminary Actual	2025 Projected	2026 Projected	Total
O&M	\$122,874	\$102,706	\$188,561	\$452,204	\$409,360	\$572,508	\$572,508	\$1,968,517
Capital	\$2,400,000	\$4,635,000	\$ -	\$4,650,000	\$4,635,000	\$ -	\$3,181,000	\$14,851,000

CECo Response AG-CE-0422

U21806-AG-CE-0422-Pascarello_Attachment_2						
O&M	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Projected	2026 Projected
Software licensing	\$ 120,000	\$ 50,800	\$ 120,000	\$ 120,000	\$ 120,000	\$ 120,000
Contracted AMD Surveying	\$ 2,874	\$ 51,906	\$ 68,561	\$ 289,360	\$ 452,508	\$ 452,508
Total O&M	\$ 122,874	\$ 102,706	\$ 188,561	\$ 409,360	\$ 572,508	\$ 572,508
Capital						
Unit purchases incl vehicles	\$ 2,400,000	\$ 4,635,000	\$ -	\$ 4,635,000		\$ 3,181,000
Total Capital	\$ 2,400,000	\$ 4,635,000	\$ -	\$ 4,635,000	\$ -	\$ 3,181,000

U21806-AG-CE-0561-Revised
Page 1 of 1

Question:

223. Refer to Table 62 on page 86 of Mr. Pnacek's direct testimony on EIRP O&M expense. Please:

- a. Expand the table to include the actual expense for each item for years 2022 through 2024. Provide the expanded table in Excel.
- b. Explain the reasons for the increase in OM&C Non-Labor expense of \$250,000 between 2023 and the test year.
- c. Explain the increase in Labor OM&C Training of \$1.6 million between 2023 and the test year.
- d. Explain why training expense is included both here and in Table 54.

Response:

- a) See attachment U21806-AG-CE-0561_Pnacek_ATT_1_Revised.xlsx.
- b) ~~This increase reflects the food, lodging and travel expenses associated with the increased training discussed in part c. This increase to non-OM&C labor also includes cost associated with the use of third-party instructors.~~
It has been determined that the food, lodging, and travel expenses were incorrectly mapped to the EIRP OM&C Expenses (Non-Labor) Work Type at the time of the filing. These expenses should have been included in EIRP Supervision & Admin Sal/Exp. This led to an invalid data comparison in the previous response. There is no change to the total program cost and a revised Table 62 is included in attachment U21806-AG-CE-0561_Pnacek_ATT_1_Revised.xlsx showing the corrected Work Type allocation for the Test year.
- c) See page 86 line 11 to line 3 on page 87 of my direct testimony for the explanation. The EIRP workforce continues to experience employees transferring to other operating departments within the Company. Along with this employee movement, hiring and training are planned to allow for appropriate staffing as the Company implements the NGDP. Based on projections, this will result in increased spending compared to 2023. This increase is due to additional training needed for the complexity of the EIRP work plan, and for training new hires to maintain the workforce.
- d) The training in this program is the technical training required to ensure the field employees are fully skilled and qualified to complete the EIRP work. This includes initial training for newly hired employees, as well as more advanced training for higher skilled employees.

Witness: James P. Pnacek
Date: April 9, 2025

Table 62 p86 REVISED				
EIRP O&M				
Projection Breakdown by Activity Type				
<u>Work Type</u>	<u>2022 Actual</u>	<u>2023 Actual</u>	<u>2024 Preliminary Actual</u>	<u>2025-2026 Test Year</u>
EIRP Supervision & Admin Sal/Exp	\$874,904	\$869,933	\$974,098	~~685,299~~ \$945,439
EIRP Tools	\$126,553	\$84,056	\$34,238	\$41,757
EIRP OM&C Expenses (Non-Labor)	\$19,592	\$10,059	\$5,256	~~260,140~~ \$0
EIRP Facilities	\$253,348	\$251,148	\$182,023	\$271,422
EIRP Labor OM&C Training	\$3,096,001	\$2,132,942	\$1,846,780	\$3,789,331
Total Program	\$4,370,398	\$3,348,137	\$3,042,395	\$5,047,949

U21806-AG-CE-0338
Page 1 of 1

Question:

52. Refer to Exhibit A-58, page 2, on Transmission and Distribution O&M expenses. For the other adjustments in column (i) on lines 1 through 3, please explain what the amounts pertain to and provide detailed support for the amount on each line.

Response:

The amounts pertain to the difference between the program level test year projections and what these projections would have been had they been projected utilizing inflation factors. As described in my direct testimony on page 30, lines 2 to 7, the expenses in these programs were not projected utilizing inflation.

For line 1, MAOP Transmission, see the response to U21806-AG-CE-320.

For line 2, Corrosion Control Transmission, the increase is due to the change in PHMSA regulations, (Safety of Gas Transmission Pipelines, including Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments) referred to as RIN 2 and the projected increase in work that would need to be done to comply with the new regulation. As can be seen in the table below, work in Atmospheric Corrosion projects, Re-coat remediation and Internal corrosion monitoring are all projected to increase in work due to increased monitoring and mitigation needs as a result of regulatory requirements.

Work Type	Units	2023	2024	2025	12 ME 10/31/2026
Close Interval Surveys	miles	\$ 187,333	\$ 162,527	\$ 200,000	\$ 200,000
Atmospheric Corrosion Projects	projects	\$ 364,425	\$ 389,785	\$ 600,000	\$ 800,000
Test station installations/repairs	projects	\$ 74,244	\$ 39,956	\$ 90,000	\$ 100,000
Recoat remediation	projects	\$ 314,938	\$ 563,154	\$ 1,000,000	\$ 1,000,000
Casing remediation	projects	\$ 7,181	\$ 340	\$ 10,000	\$ 10,000
Internal Corrosion monitoring	yearly	\$ 804	\$ 6,985	\$ 55,000	\$ 100,000

For line 3, Pipeline Integrity TOD, see the response to U21806-AG-CE-315.

Witness: MICHAEL P. GRIFFIN
Date: March 10, 2025

U21806-AG-CE-0380 (Partial)
Page 1 of 1

Question:

93. Refer to lines 13-14 on page 16 of Ms. Pascarello's direct testimony on O&M expense for MAOP work. Please:

- a. Provide the number of employees and contractors at the end of each year 2021-2024 and forecasted for 2025 and the projected test year working at determining whether the Company's records for Distribution, Transmission, and Storage pipeline and facilities meet the PHMSA requirements of being traceable, verifiable, and complete (TVC) to confirm the MAOP and pipeline material properties.
- b. Provide the O&M expense pertaining to the work being done as described in subpart (a) for each year 2021 to 2024 and forecasted for 2025 and the projected test year.

Response:

- a. See below.

2021	2022	2023	2024	2025	2026
12	16	18	14	10	12

- b. See below. The expenses are explained in my direct testimony beginning on page 29, line 1 through page 30, line 1.

					Test Year 12
2021	2022	2023	2024	2025	ME 10/31/2026
Actual	Actual	Actual	Actual	Projection	Projection
720,526	712,697	-	1,866,354	1,122,384	1,122,384

Witness: MICHAEL P. GRIFFIN
Date: March 12, 2025

U21806-AG-CE-0380 (Partial)
Page 1 of 1

Question:

93. Refer to lines 13-14 on page 16 of Ms. Pascarello's direct testimony on O&M expense for MAOP work. Please:

- a. Provide the number of employees and contractors at the end of each year 2021-2024 and forecasted for 2025 and the projected test year working at determining whether the Company's records for Distribution, Transmission, and Storage pipeline and facilities meet the PHMSA requirements of being traceable, verifiable, and complete (TVC) to confirm the MAOP and pipeline material properties.
- b. Provide the O&M expense pertaining to the work being done as described in subpart (a) for each year 2021 to 2024 and forecasted for 2025 and the projected test year.

Response:

- a. The referenced section of my direct testimony does not include employees and contractors verifying the Company's records for Distribution, Transmission, and Storage pipelines and facilities against PHMSA's TVC requirements for MAOP and pipeline material properties. As described in my direct testimony, the projected O&M expenses for the Gas Engineering – Transmission section covers the labor and expense costs for staff performing the engineering and design of transmission and storage facilities. The O&M expenses requested in this interrogatory are sponsored by Company witness Michael P. Griffin.
- b. Please see the response provided by Company witness Michael P. Griffin.

Witness: Kristine A. Pascarello
Date: March 12, 2025

U21806-AG-CE-0760
Page 1 of 1

Question:

331. Refer to discovery response AG-CE-0338 on transmission O&M expense. For Atmospheric Corrosion and Recoat Remediation projects, please explain what work is being done in these two areas. Explain and justify the increase in expense from 2023 to the projected test year.

Response:

For Atmospheric Corrosion projects, the coating (typically paint) at above grade facilities has deteriorated and needs to be repaired. As explained in the testimony on page 23, starting at line 15, these projects are at sites that have not been fully painted in several years but rather have had numerous small touch-ups done. This will reduce repeat visits to repaint small sections in the near future.

Recoat remediation is similar, but for pipe coating that is underground. The Safety of Gas Transmission Pipelines, including Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments ("RIN2") regulations now require performing additional close interval surveys when systemic issues are identified during annual surveys. This additional survey is projected to indicate the need for additional coating repairs (recoat). The increase in expenditures will allow the Company to address these repairs in the time required by the RIN 2 regulations.

Witness: MICHAEL P. GRIFFIN
Date: April 1, 2025

U21806-AG-CE-0778

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Question:

341. Refer to discovery response AG-CE-0380 on MAOP O&M expense. Please confirm that the \$1,122,384 expense for the projected test year includes the expense for all Company facilities in Distribution, Transmission, and Storage. If not confirming, provide the total expense for the periods shown in the response to DR AG-CE-0380b.

Response:

The \$1,122,384, is for employees and contractors working at determining whether the Company's records for Distribution, Transmission, and Storage pipeline and facilities meet the PHMSA requirements of being traceable, verifiable, and complete (TVC) to confirm the MAOP and pipeline material properties. This effort is described in my direct testimony beginning on page 25, line 23 through page 27, line 3. The expenses are explained in my direct testimony beginning on page 29, line 1 through page 30, line 1, and are shown in Table 2 on page 29 of my direct testimony. These dollars are separate and in no way duplicative of the dollars for the Gas Engineering Transmission section represented by Company witness Kristine A. Pascarello as described in the response to U21806-AG-CE-380 (Partial). To be clear, in this context facilities would include city gate stations and other non-pipeline assets, and not office buildings nor service centers.

Witness: MICHAEL P. GRIFFIN

Date: March 30, 2025

U21806-AG-CE-0659

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Question:

277. Refer to Exhibit A-37, pages 1-3. Please:

- a. Expand the schedules to included actual amounts for 2022 and 2024 and provide them in Excel.
- b. For each year 2022 to 2024 actual and forecasted for 2025 and 2026, provide the number of units, work activities, and other metrics that support the expenses in each function. Provide this information in Excel.
- c. For each year 2022 to 2024 actual and forecasted for 2025 and 2026, provide the number of employees at year end in each function. Provide this information in Excel.
- d. For each year 2022 to 2024 actual and forecasted for 2025 and 2026, provide the number of contractor employees at year end in each function. Provide this information in Excel.
- e. Regarding Analytics & Outreach and Digital Customer Operations, please identify specifically what tasks and outcomes were accomplished in 2023 and 2024 and what have been planned for 2025 and 2026.

Response:

a.-d.: Please see attachment U21806-AG-CE0659_ATT_1.xlsx

e. The Digital Customer Operations Team manages the Company's website, with more than 45 million visits annually. In 2023 and 2024, the Digital Customer Operations team supported the ongoing maintenance of the website, supporting customers paying their bills, checking the status of power interruptions, managing their energy usage, etc. Utilizing the customer feedback gained from the customer satisfaction surveys, the DCO team manages a monthly development cycle process to make updates to the website either for new features requested by customers or defects identified. Some notable examples of updates made in 2023 and 2024 include updating all customer program webpages to be more informative to ease enrollments, transitioning customers to an updated login platform to conform with vendor changes, implementing changes to the payment flow to conform with credit card processing fees, etc. The website also added new webpages for different areas of the business to add additional information to the website to help better inform customers. In 2025 and 2026, the DCO team will continue to perform these customer satisfaction surveys and will plan their work based on new business needs or based on customer feedback through the surveys.

The Analytics and Outreach team supports the overall customer analytics, experience design for utility products, and research activities used to improve the overall customer experience. This team supports the overall enterprise and partners with teams across the Company to include the voice of customers in business decisions and processes. This team helps to identify new technological needs for the company to better serve customers, supports building business cases for new work, and builds data visualizations and automated processes. This team works with other parts of the Company to improve customer outcomes within the billing & payment, outage, move in/move out, and field experiences. This team will continue to partner with organizations across the Company in 2025 and 2026 to deliver analytics based on customer feedback and will build business cases for new technological enhancements for inclusion in regulatory filings.

Witness: Jessica R. Byrom

Date: March 25, 2025

CECo Response AG-CE-0659

MICHIGAN PUBLIC SERVICE COMMISSION		Case No.:	U-21806	
Consumers Energy Company		Witness:	Jessica Byrom	
Summary of Actual & Projected O&M Expenses				
Add Description				
(\$000)		U21806-AG-CE-0659_ATT_1		
Line		Actual	Actual	Actual
No.	Description	12-Mos Ending	12-Mos Ending	Projected
		12/31/2022	12/31/2023	12-Mos Ending
				10/31/2026
1	Analytics & Outreach	3,132	2,656	1,737
	Labor	2,626	2,065	1,485
	Material	15	4	2
	Contractor	461	520	381
	Non-Labor Overhead	-	-	-
	Non-Labor Other	31	67	(131)
2	Business Customer Care	2,019	1,826	1,517
	Labor	1,820	1,557	1,364
	Material	2	1	1
	Contractor	146	235	108
	Non-Labor Overhead	-	-	-
	Non-Labor Other	52	34	44
3	Credit & Assistance	2,544	2,270	2,132
	Labor	1,689	1,544	1,535
	Material	1	10	48
	Contractor	664	534	476
	Non-Labor Overhead	-	-	-
	Non-Labor Other	190	183	73
4	Customer Contact Center	13,718	12,998	13,192
	Labor	10,690	10,029	9,251
	Material	9	21	14
	Contractor	2,490	2,255	2,998
	Non-Labor Overhead	-	-	-
	Non-Labor Other	530	693	929
5	Digital Customer Operations	3,738	1,884	872
	Labor	1,256	555	560
	Material	3	0	0
	Contractor	2,315	1,292	251
	Non-Labor Overhead	-	-	-
	Non-Labor Other	164	36	61
6	Total Customer Interactions O&M Expenses	25,152	21,634	19,451
	Labor	18,081	15,749	14,195
	Material	29	36	65
	Contractor	6,076	4,835	4,214
	Non-Labor Overhead	-	-	-
	Non-Labor Other	967	1,013	976

CECo Response AG-CE-0659

	U21806-AG-CE-0659_ATT_1								
b.	Number of work units (work items):								
		12 Mos Ended 12/31/2022	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	Projected 12 Mos Ending 12/31/2025	Projected 12 Mos Ending 12/31/2026			
	Row Labels								
	Billing & Payment								
	Customer Billing	5	5	5	5	5			
	Customer Payment Programs	3	3	4	4	4			
	Grand Total	8	8	9	9	9			
		12 Mos Ended 12/31/2022	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	Projected 12 Mos Ending 12/31/2025	Projected 12 Mos Ending 12/31/2026			
	Row Labels								
	Customer Interactions								
	Analytics & Outreach	17	17	7	7	7			
	Business Customer Care	8	8	5	5	5			
	Credit & Assistance	6	6	6	6	6			
	Customer Contact Center	13	13	13	13	13			
	Digital Customer Operations	4	4	3	3	3			
	Grand Total	48	48	34	34	34			
c. & d.	CE Employee & Contractor Headcount								
		12 Mos Ended 12/31/2022	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	Projected 12 Mos Ending 12/31/2025	Projected 12 Mos Ending 12/31/2026			
	Row Labels								
		Headcount	Headcount	Headcount	Headcount	Headcount			
	Billing & Payment								
	Customer Billing								
	CE Labor	57	53	51	53	53			
	Contractor	2	3	3	3	3			
	Customer Payment Programs								
	Labor	16	15	14	14	14			
	Contractor	7	5	7	7	7			
	Grand Total								
	Total CE EX & NEX Headcount	73	68	65	67	67			
	Total Contractor Headcount	9	8	10	10	10			
		12 Mos Ended 12/31/2022	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	Projected 12 Mos Ending 12/31/2025	Projected 12 Mos Ending 12/31/2026			
	Row Labels								
		Headcount	Headcount	Headcount	Headcount	Headcount			
	Customer Interactions								
	Analytics & Outreach								
	CE Labor	103	98	58	60	60			
	Contractor	6	14	14	14	14			
	Business Customer Care								
	CE Labor	41	42	35	38	38			
	Contractor	0	0	0	0	0			
	Credit & Assistance								
	CE Labor	48	48	43	43	43			
	Contractor	0	0	0	0	0			
	Customer Contact Center								
	CE Labor	335	336.5	293	300	300			
	Contractor	3	3	3	3	3			
	Digital Customer Operations								
	CE Labor	28	31	23	24	24			
	Contractor	5	5	5	5	5			
	Grand Total								
	Total CE EX & NEX Headcount	555	555.5	452	465	465			
	Total Contractor Headcount	14	22	22	22	22			

U21806-AG-CE-0372
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Question:

85. With regard to the 2023 and 2024 corporate reorganizations and cost reduction initiatives across all areas of the Company through employee and other cost reductions, please:

- a. Describe what the reorganizations and cost initiatives entailed, when they took place, the number of employee reductions, and describe other cost efficiency initiatives.
- b. Provide the cost savings expected to be achieved in 2024, 2025, and the projected test year from the 2023 O&M expense level.
- c. Provide the calculations of the cost savings in Excel with formulas intact.
- d. Identify the cost savings in Excel by department matching to the departments or functions as reported in the various O&M expense exhibits sponsored by each witness in this rate case. Specify what cost savings are reflected in the filed exhibits and specifically on which line number and column. Provide evidence through workpapers and other means showing what cost savings were included in the projected test year versus the 2023 expense level.

Response:

- a. In April 2023, a voluntary separation program was announced for non-union employees. A total of 404 employees were approved for and accepted early separation of which 161 were gas utility. Also refer to the response to U21806-AG-CE-0291.
- b. See attachment U-21806-AG-CE-0372-Myers_ATT_1
- c. See attachment U-21806-AG-CE-0372-Myers_ATT_1
- d. See attachment U-21806-AG-CE-0372-Myers_ATT_1

Witness: Heidi J. Myers
Date: March 12, 2025

CECo Response AG-CE-0372

Page 2 of 2

[illegible]

U21806-AG-CE-0686

Page 1 of 2

Question:

294. Refer to pages 29 and 30 of Ms. Grob's direct testimony on the health care plan changes implemented during 2022-2024. Please:

- a. Identify the total cumulative amount and percentage of cost savings realized during the three-year period from those changes.
- b. Provide the expected plan changes and cost savings for 2025 and 2026.

Response:

a. 2022

- Salaried Active Employee Community Blue PPO & Delta Dental premiums increased.
- Implemented SaveOn Pharmacy Benefit with a savings of \$1.4M.

2023

- Medical Plan Design Changes – Increase deductible and out-of-pocket limits for Community Blue PPO and Express Scripts Prescription Drug Plans – total savings of \$508,000.
- Removal of Aetna Dental – only have coverage through Delta Dental. Projected savings of \$85K admin fee and \$1.4M in network discount savings. Actual negotiated savings on administrative fees were \$70K.
- SaveOn Pharmacy Benefit program projected annual savings of \$1.7M.

2024

- SaveOn Pharmacy Benefit program projected annual savings of \$1.7M.
- Delta Dental admin fees & Network discount projected savings of \$85k admin fee and \$1.4M in network discount savings.
- Union PPO contributions set to 18% of full plan cost with no cap with estimated savings of \$1.45M.
- Negotiated savings on Medical ASO Negotiated Fees resulted in \$29K savings.
- Rx / ESI Renewal Savings resulted in \$1.9M savings.
- Life Insurance move to MetLife with a projected savings of \$510,000 (\$390,000 active basic life and \$120,000 retiree life).

Additional detail on chart below for years 2023-2026.

- b. Through plan design action and renewal negotiations across Medical, Pharmacy, Dental and Life Insurance benefits, Consumers is expected to save \$5.4M in 2024 and upwards of \$6.4M in 2025 and 2026. Please see chart below.

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Page 2 of 2

Total Annual Plan Savings				
	2023	2024	2025	2026
PPO Plan Changes	\$508,000	\$0	\$123,000	TBD
Medical ASO Negotiated Fees	\$70,000	\$29,000	\$60,000	TBD
Pre-65 move to Pre-Medicare market	n/a	\$650,000	\$650,000	TBD
RxC / ESI Renewal Savings	n/a	\$1,969,000	\$2,683,000	\$2,683,000
SaveOn Savings	\$1,700,000	\$1,700,000	\$1,700,000	\$1,700,000
Dental Admin Savings	\$85,000	\$85,000	\$85,000	\$85,000
Dental Network Savings	\$1,400,000	\$1,400,000	\$1,400,000	\$1,400,000
Life Insurance Savings	n/a	\$510,000	\$510,000	\$510,000
Total Annual Savings	\$3,763,000	\$6,343,000	\$7,211,000	\$6,378,000

Witness: Kendra K. Grob

Date: March 26, 2025

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Page 1 of 1

Question:

280. Refer to Ms. Conrad's direct testimony on the EICP incentive compensation plan. For each year 2020 to 2024, please provide the target performance for each of the operating measures compared to the actual results for those years. Identify what percentage of the target performance was achieved.

Response:

For years 2020 to 2023, see part III 086 and for 2024 see attachment 1 for the target performance for of the operating measures compared to the actual results for those years as well as the performance achieved.

Witness: Amy M. Conrad

Date: March 24, 2025

2022 Non-Officer Incentive Compensation Plan Results

Operational Measures	Weighting	50% Threshold	75%	100% Target	125%	150%	175% Max	ACTUAL	Payout %
Employee Safety (Recordable Incidents Rate, High-Risk Injuries ¹ & No fatalities ²)	2.50%	a.1.74	a.1.31	a.1.20	a.1.15	a.1.10	a.1.03	a.1.17	145%
	2.50%	b. 34	b.32	b.30	b.28	b.26	b.24	b.22	
Culture Index (Empowerment, Employee Engagement & DEI)	8.3%	1 index at Target ³	2 index at Target ³	All 3 indexes at Target ³	2 indexes at Target & 1 Index above Target	1 index at Target & 2 Indexes above Target	3 Indexes above Target	0	0%
Customer Experience (Survey Measuring CXi)	8.3%	69	71	73	75	77	79	73	100%
Electric Reliability (SAIDI)	8.3%	190	185	180	175	165	152	182	90%
Waste Elimination (Affordability) ⁴ (O&M Savings through Waste Elimination)	8.3%	\$31M	\$35M	\$39M	\$43M	\$47M	\$55M	\$58M	175%
Methane Emission (Reduction through replacement of mains and services)	8%	357MT	378MT	399MT	420MT	457MT	483MT	448MT	144%
	50%							TOTAL	109%

Financial	Weighting	25% Threshold	100% Target	200% Maximum	Actual Achieved	Award Payout%
Earnings Per Share	50%	\$2.71	\$2.85	\$2.99	\$2.89	160%

TOTAL EICP Award Payout Level = 135%									
1	High-Risk = Recordable or non-recordable injury caused by a release of high energy								
2	A fatality = zero payout for employee safety								
3	Target = +2 from 2021 actual. Baseline will be reaffirmed in 2022 with move to new survey platform.								
4	The Company is not seeking recovery of this measure as it is financial in nature.								

2023 Non-Officer Incentive Compensation Plan Results

Operational Measures		Weighting	50% Threshold	75%	100% Target	125%	150%	175% Max	ACTUAL	Payout %
Employee Safety (Recordable Incidents Rate, High-Risk Injuries ¹ & No fatalities ²)	2.50%	a.1.65	a.1.28	a.1.07	a.0.97	a.0.87	a.0.77	a.1.48	141%	
	2.50%	b. 32	b.30	b.27	b.25	b.23	b.20	b.10		
Culture Index (Empowerment, Employee Engagement & DEI)	8.3%	1 of 3 indexes at target	2 of 3 indexes at target	All 3 indexes at target	2 indexes at target & 1 index above target	1 index at target & 2 indexes above target	3 indexes above target	0	0%	
Customer Experience (Survey Measuring CXi)	8.3%	66	68	73	74	75	80	64	0%	
Electric Reliability (SAIDI)	8.3%	185	180	170	160	155	150	176	85%	
Waste Elimination (Affordability) ³ (O&M Savings through Waste Elimination)	8.3%	\$30M	\$35M	\$45M	\$50M	\$55M	\$65M	\$79M	175%	
Methane Emission (Reduction through replacement of mains and services)	8%	414MT	436MT	459MT	485MT	510MT	551MT	533MT	164%	
	50%								TOTAL	94%

Financial	Weighting	25% Threshold	100% Target	200% Maximum	Actual Achieved	Award Payout%			
Earnings Per Share	50%	\$2.95	\$3.06	\$3.25	\$3.11	140%			

TOTAL EICP Award Payout Level = 117%									
1	High-Risk = Recordable or non-recordable injury caused by a release of high energy								
2	A fatality=zero payout for employee safety								
3	The Company is not seeking recovery of this measure as it is financial in nature.								

Computation of Revenue Deficiency for Projected Test Year Ending October 2026

(\$000)

Line	Description	Company Filed Amount	AG Recommended Adjustments	Revised Amount
	(a)	(b)	(c)	(d)
1	Rate Base ⁽¹⁾	\$ 11,750,740	\$ (514,702)	\$ 11,236,038
2	Rate of Return	6.22%	-0.25%	5.97%
3	Income Required	\$ 730,838	\$ (60,047)	\$ 670,791
4	Adjusted Net Operating Income ⁽²⁾	545,492	53,854	599,346
5	Income Deficiency (Sufficiency)	\$ 185,346	\$ (113,901)	\$ 71,445
6	Revenue Multiplier	1.3381	1.3381	1.3381
7	Revenue Deficiency (Sufficiency)	\$ 248,008	\$ (152,408)	\$ 95,600

⁽¹⁾ Rate Base Adjustments Revised Exhibit AG-34.

⁽²⁾ AG adjustments to Operating Income

		Source
Revenue	\$ 1,822	Exhibit AG-54
Lower Forecast of O&M Expenses	56,422	Revised Exhibit AG-56
Property Taxes	3,731	Revised Exhibit AG-34
Depreciation Expense	13,250	Revised Exhibit AG-34
Total	\$ 75,225	
Effective Tax Rate (1-1/1.3381)	25.27%	
Taxes	19,006	
Interest Synchronization for cap. Ex. adjustments	(2,364)	AG-67 WP1
Adjusted Net Operating Income	\$ 53,854	

Question:

423. Refer to pages 20-21 of Ms. Baker's rebuttal testimony on the Tracking and Traceability project. Please:

- a. Confirm that Mr. Coppola's statements that the project was in the Origination or Investment Planning Phase is correct. If not confirming, explain whether the Company is retracting a similar statement made in response to DR AG-CE-0370 (Exhibit AG-27).
- b. If the Company believes that the project is necessary and must meet a regulatory requirement, why did it not advance its development further past the investment planning stage and proceed with development instead of waiting for the capital expenditures to be included in rate base in this rate case?
- c. Confirm that the PHMSA-2014-0098 does not require that pipeline operators implement the specific system proposed by the Company in this case but imply a method to track and trace assets. If not confirming, provide evidence otherwise.

Response:

- a. The Company confirms that the Tracking and Traceability project is in the Origination or Investment Planning phase.
- b. In response to Discovery Request U21806-AG-CE-0370 (Exhibit AG-27), the Company provided its plans to advance the project to the Planning phase in 2025 to perform detailed requirements for each scope item in phases.
- c. Refer to Company witness Warriner's response.

Witness: Stacy H. Baker

Date: May 24, 2025

Question:

423. Refer to pages 20-21 of Ms. Baker's rebuttal testimony on the Tracking and Traceability project. Please:

- a. Confirm that Mr. Coppola's statements that the project was in the Origination or Investment Planning Phase is correct. If not confirming, explain whether the Company is retracting a similar statement made in response to DR AG-CE-0370 (Exhibit AG-27).
- b. If the Company believes that the project is necessary and must meet a regulatory requirement, why did it not advance its development further past the investment planning stage and proceed with development instead of waiting for the capital expenditures to be included in rate base in this rate case?
- c. Confirm that the PHMSA-2014-0098 does not require that pipeline operators implement the specific system proposed by the Company in this case but imply a method to track and trace assets. If not confirming, provide evidence otherwise.

Response:

Partial response to part c.

Docket No. PHMSA-2014-0098 does not specify a particular system as a requirement for compliance. PHMSA does require pipeline operators to implement a process to maintain records for tracking and traceability information for the life of the pipeline. The Company has identified that the most prudent way to meet the proposed requirements of Docket No. PHMSA-2014-0098 is to modify existing applications used in operating the pipeline system. Changes are required in the Company's Supply Chain, Enterprise Asset Management, Field Work Management, and Geographic Information System applications to capture the traceability information (ASTM F2897) and tracking information (location of pipe and components) in the work orders used in field operations. The Company participated in an industry benchmarking exercise and identified other utilities with similar approaches.

Witness: Lincoln D. Warriner

Date: May 22, 2025

Question:

424. Refer to pages 22-25 of Ms. Baker's rebuttal testimony on the SAP/ERP S/4HANA project. Please:

- a. Confirm that Mr. Coppola's statements that the project was in the Investment Planning Phase and no vendor has yet been selected are correct. If not confirming, explain whether the Company is retracting similar statements made in response to DR AG-CE-0622d (Exhibit AG-28 CONF) and DR AG-CE-0625 (Exhibit AG-29).
- b. Confirm that the Company has not requested SAP to provide extended support for the existing ERP system past 2030. If not confirming, provide evidence otherwise.
- c. If the Company believes that the project is necessary and must be completed by 2030, why did it not advance its development further past the investment planning stage and proceed with development instead of waiting for the capital expenditures to be included in rate base in this rate case?
- d. Explain whether the Company allows non-Company internet user to access the current SAP/ERP system. If yes, explain for what purpose.
- e. Confirm that the Company has a robust cyber security system outside of the ERP system that any cyber-attacks would need to penetrate before reaching the SAP/ERP. If not confirming, explain why the Company does not have such a robust system in place.

Response:

- a. The Company confirms that the SAP S/4 HANA Implementation project is in the Investment Planning phase and the Company has not yet selected a system integrator.
- b. The Company has not requested SAP to provide extended support for the existing ERP system past 2030.
- c. The Company is proceeding with the project in 2025, by conducting a Request for Proposal to select a system integrator and procure software licenses.
- d. The Company does not allow non-Company internet users to access the current ERP system.
- e. The Company has a robust cyber security system outside of the ERP system that any cyber-attacks would need to penetrate before reaching the ERP system.

Witness: Stacy H. Baker

Date: May 24, 2025

Question:

425. Refer to lines 11-23 on page 25 and lines 1-4 on page 26 of Ms. Baker's rebuttal testimony on the amortization of the cloud computing fees. Please:

- a. If the inadvertent inclusion of non-cloud computing pre-payments and expenses are not errors in the calculation of the amortization expense, what are they?
- b. Confirm that the amounts provided by the Company in ATT 3 to DR AG-CE-0852 and included on page 5 of Exhibit AG-38 are correct and the monthly balances for the 13 months ending October 2026 match to the monthly balances in Exhibit A-158. If not confirming, explain why they are not correct.
- c. Confirm that in DR AG-CE-0634b, the Attorneys General asked the Company to provide the monthly additions and amortization expense for cloud computing from January 2023 to December 2026. If not confirming, explain.
- d. Confirm that in response to DR AG-CE-0634, the Company provided ATT 1, which shows monthly cloud computing amortization expenses from November 2025 to October 2026 accumulating to \$17,351,546, as shown on page 2 of Exhibit AG-38. If not confirming, provide evidence otherwise.
- e. Provide the amount of cloud computing amortization expense included in the projected test year and show in Excel how that amount was derived and from what source.
- f. Explain why the amortization expense provided in subpart (e) to this discovery question does not match the amortization expense provided in ATT 1 to DR AG-CE-0634.

Response:

- a. The inadvertent inclusion of non-cloud computing pre-payments and expenses did result in errors in the calculation of the gas allocation IT Cloud Computing monthly ending balances in Exhibit A-18 (SHB-2), which is used to calculate a working capital adjustment for cloud computing costs. The Company corrected Exhibit A-18 (SHB-2) in Exhibit A-158 (SHB-17) (response to Discovery request No. U21806-AG-CE-0852, Attachment 2) and Exhibit A-150 (HLR-56).
- b. The Company confirms that the amounts provided in response to Discovery request No. U21806-AG-CE-0852, Attachment 3 (Exhibit AG-38, page 5) are correct and for the monthly gas allocation IT Cloud Computing Prepaid balances match the monthly balances in Exhibit A-158 (SHB-17).
- c. The Company confirms that in Discovery request No. U21806-AG-CE-0634, part b, the Attorney General requested the Company to provide the monthly additions and amortization expense for cloud computing from January 2023 to December 2026.
- d. The Company confirms that in response to Discovery request No. U21806-AG-CE-0634, part b, the Company provided U21806-AG-CE-0634, Attachment 1, which provides the monthly gas allocation cloud computing amortization expenses from November 2025 to October 2026 accumulating to \$17,351,545, as shown in Exhibit AG-38, page 2.

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- e. Refer to response to Discovery request No. U21806-AG-CE-0852, Attachment 3 (Exhibit AG-38, page 5), for the cloud computing amortization expense of \$11,874,017, included in the projected test year and shown in Excel. The \$11,874,017 is a correction to U21806-AG-CE-0634, Attachment 1 (Exhibit A-38, page 2) of \$17,351,545.
- f. The amortization expense provided in response to part e of this discovery request of \$11,874,017 does not match the amortization expense provided in response to Discovery request No. U21806-AG-CE-0634, Attachment 1 (Exhibit AG-38, page 2) of \$17,361,545 due to some non-cloud computing expenses inadvertently being included in response to Discovery request No. U21806-AG-CE-0634, Attachment 1.

Witness: Stacy H. Baker

Date: May 24, 2025

Question:

427. Refer to lines 17-21 on page 28 of Ms. Baker's rebuttal testimony on the Forward Web Proxy Services project. Please confirm with the that the current system the vendor provides the filtering out of unwanted or harmful content from the internet. If not confirming, explain why the current system does not provide those protections.

Response:

The Company confirms that the current system filters out unwanted or harmful content from the internet.

Witness: Stacy H. Baker

Date: May 24, 2025

U21806-AG-CE-0932

Page 1 of 1

Question:

428. Refer to page 30 of Ms. Baker's rebuttal testimony on the OT Datacenter Migration project. Please:

- a. Provide the distance from the railway system to the building housing the datacenter and identify the risks posed by the railway system.
- b. Provide the number of years that the data center has been located in this building and why it was located in the building if the railway and water pipe risks have existed since the beginning.
- c. If the Company believes that the project is necessary and must be completed soon, why did it not advance its development further past the investment planning stage and proceed with development instead of waiting for the capital expenditures to be included in rate base in this rate case?

Response:

- a. The distance from the railway to the building, where the data center is currently located, is approximately 170 meters. The Telecommunications Infrastructure Standard for Data Centers TIA-924-A-2012 recommends that a data center be no closer to a railway than .8 KM (1/4) mile. The risk posed by the data center located approximately 170 meters from the railway are incidents such as derailment or hazardous materials spills. These incidents could lead to physical damage and power outages, resulting in disruptions to operations.
- b. The Operational Technology (OT) Datacenter was installed at its current location in 2008. At the time, the decision was to locate the OT Datacenter next to the Corporate Datacenter to be able to share heating and cooling, backup systems, and telecommunication with the Corporate Datacenter. The Corporate Datacenter was removed from this location in 2020.
- c. The OT Datacenter Migration project is still in the Investment Planning phase as the project is not planned to start until June 2026, as indicated in Exhibit A-21 (SHB-6), page 96, when funding is planned to be available.

Witness: Stacy H. Baker

Date: May 24, 2025

Question:

429. Refer to pages 31 and 32 of Ms. Baker's rebuttal testimony on the Physical Access Management and Alarm Response project. Please:

- a. Identify the growing risk of system failure that would result in unauthorized physical access and when this risk first came about.
- b. If the Company believes that the project is necessary and must be completed soon, why did it not advance its development further past the investment planning stage and proceed with development instead of waiting for the capital expenditures to be included in rate base in this rate case?

Response:

- a. The growing risk of system failure that would result in unauthorized physical access comes from some of the Company's current card access readers and boards being over 20 years old. While the card access readers and boards are still functional, there is a greater risk of failure due to the age of the assets. The technology in new card access readers and boards is more secure and less likely to fail than in the older equipment.
- b. The Physical Access Management and Alarm Response project is still in the Investment Planning phase as the project is not planned to start until January 2026, as indicated in Exhibit A-21 (SHB-6), page 98, when funding is planned to be available.

Witness: Stacy H. Baker

Date: May 24, 2025

Question:

430. Refer to page 3 of Mr. Pnacek's rebuttal testimony on leak repair backlog. Please:

- a. Provide in Excel the number of leak repairs in backlog at the end of each year 2021 to 2024 and forecasted for 2025 and 2026 along with the number repairs added and completed each year. Explain whether the backlog increased at the end of 2023 or 2024 and why.
- b. Explain why the Company requires an additional \$1.3 million in expense to reduce the backlog. Explain to what level the Company wants to reduce the backlog for the projected test year and why.
- c. Explain why the backlog was not reduced in 2023 and 2024 and why the company is waiting until the projected test year to reduce the backlog.
- d. Provide the amount of O&M expense and capital expenditures spent for leak repairs for each year 2021 to 2024 and forecasted for 2025, 2026 and the projected test year.

Response:

- a. For the capital expenditures for leak renewals:

	Historical Year 12 Mos Ended 12/31/2021	Historical Year 12 Mos Ended 12/31/2022	Historical Year 12 Mos Ended 12/31/2023	Preliminary Actual 12 Mons Ending 12/31/2024	Projected 12 Mons Ending 12/31/2025	Projected 12 Mons Ending 12/31/2026	Projected Test Year 12 Mos Ending 10/31/2026
(\$000)							
Leak Renew Main	\$ 4,522	\$ 3,065	\$ 7,157	\$ 2,387	\$ 4,328	\$ 4,328	\$ 4,328
Leak Renew Service	\$ 21,537	\$ 16,040	\$ 13,866	\$ 17,642	\$ 13,889	\$ 13,889	\$ 13,889
Leak Renew Mtr/Stand	\$ 740	\$ 1,027	\$ 1,745	\$ 1,628	\$ 1,195	\$ 1,195	\$ 1,195

Witness: Kristine A. Pascarello

Date: 5/24/2025

Question:

430. Refer to page 3 of Mr. Pnacek's rebuttal testimony on leak repair backlog. Please:

- a. Provide in Excel the number of leak repairs in backlog at the end of each year 2021 to 2024 and forecasted for 2025 and 2026 along with the number repairs added and completed each year. Explain whether the backlog increased at the end of 2023 or 2024 and why.
- b. Explain why the Company requires an additional \$1.3 million in expense to reduce the backlog. Explain to what level the Company wants to reduce the backlog for the projected test year and why.
- c. Explain why the backlog was not reduced in 2023 and 2024 and why the company is waiting until the projected test year to reduce the backlog.
- d. Provide the amount of O&M expense and capital expenditures spent for leak repairs for each year 2021 to 2024 and forecasted for 2025, 2026 and the projected test year.

Response:

- a. See attachment U21808-AG-CE-0934_ATT_1.xlsx, tab "Part a", for the leak backlog, found leak, and repaired leak actuals for 2021-2024 and forecasted backlog for 2025 and 2026. This data includes both potential Capital and O&M funded leaks since the backlog includes leaks that could be repaired with Capital or O&M funds.
- b. The leak backlog increased from 2022 to 2023 and decreased from 2023 to 2024. The Company did not have sufficient funding to address all of the prior year leak backlog and all newly discovered leaks in order to reduce or eliminate the leak backlog. The funding requested in this case will allow the Company to accelerate the reduction of leaks on the leak backlog for customer safety, risk reduction, and emissions reduction to serve all of the Company's customers and increase public trust.
- c. Beginning in 2025, the Company is accelerating the reduction of leaks on the leak backlog for customer safety, risk reduction, and emissions reduction to serve all of the Company's customers and increase public trust. The Company plans to end 2026 with a leak backlog of zero (0) known system leaks.
- d. The Company did not have sufficient funding to address all of the prior year leak backlog and all newly discovered leaks in order to reduce or eliminate the leak backlog. The funding requested in this case will allow the Company to accelerate the reduction of leaks on the leak backlog for customer safety, risk reduction, and emissions reduction to serve all of the Company's customers and increase public trust. The Company is not waiting until the test year to begin reducing the leak backlog. For 2025, the Company plans to reduce the leak backlog from 5,480 to 2,750 known system leaks at year end. The Company plans to end 2026 with a leak backlog of zero (0) known system leaks.
- e. See attachment U21808-AG-CE-0934_ATT_1.xlsx, tab "Part d", for O&M Expenses. See Company Witness Pascarello's response regarding the Capital expenses.

Witness: James P. Pnacek

Date: May 23, 2025

	All Grade - Leaks Found	All Grade - Leaks Repaired	Year end open leaks (Backlog)
2021 Actual	26,363	26,909	3,028
2022 Actual	16,378	17,842	1,564
2023 Actual	21,963	17,909	5,618
2024 Actual	30,695	30,833	5,480
2025 Projected	20,039	22,769	2,750
2026 Projected	19,555	22,305	-

<u>Work Type</u>	<u>2021 Actual</u>	<u>2022 Actual</u>	<u>2023 Actual</u>	<u>2024 Preliminary Actual</u>	<u>2025 Projected</u>	<u>2025-2026 Test Year</u>	<u>2026 Projected</u>
Leak Repairs – Meter Stands and Regs	\$3,968,720	\$5,026,589	\$3,286,805	\$5,235,841	\$ 3,705,641	\$4,510,960	\$ 4,510,960
Leak Repairs – Services	\$5,111,308	\$2,376,288	\$1,553,816	\$3,478,992	\$ 1,751,818	\$2,132,528	\$ 2,132,528
Leak Repair – Mains	\$3,444,353	\$3,967,922	\$2,594,560	\$2,415,682	\$ 2,925,183	\$3,531,910	\$ 3,531,910
Total	\$12,524,381	\$11,370,799	\$7,435,181	\$11,130,514	\$8,382,642	\$10,175,398	\$10,175,398

Question:

431. Refer to page 6 of Mr. Pnacek's rebuttal testimony on the staking and locating dedicated model. Please:

- a. Confirm that the Company has not performed a comparative cost analysis between the Consumers Energy's dedicated staking and locating model and the dedicated models of DTE Gas, SEMCO and MGU. If not confirming, provide a copy of the comparative cost analysis.
- b. Confirm that to the best of the Company's knowledge, the Commission Staff did not perform a comparative cost analysis and a staking and locating performance analysis between Consumers Energy's shared model and the dedicated models of DTE Gas, SEMCO and MGU. If not confirming, provide a copy of the comparative cost analysis.
- c. Confirm that to the best of the Company's knowledge, the Commission Staff has not perform a comparative cost analysis and a staking and locating performance analysis between Consumers Energy's dedicated model and the dedicated models of DTE Gas, SEMCO and MGU. If not confirming, provide a copy of the comparative cost analysis.
- d. Confirm that the Company did not evaluate the alternative and cost of having its own employees perform the staking and locating work. If not confirming, provide evidence otherwise.

Response:

- a. The Company has not performed a comparative cost analysis between the Company's dedicated staking and locating models and the dedicated models of DTE Gas, SEMCO and MGU.
- b. The Company has no knowledge of the Commissions Staff's actions.
- c. The Company has no knowledge of the Commissions Staff's actions.
- d. Not confirmed. The Company conducted an informal evaluation considering an alternative to have Company employees perform the staking and locating work, that was identified in the RFP, which resulted in a cost estimated of around twice the cost of the dedicated contractor.

Witness: James P. Pnacek

Date: May 23, 2025

Question:

432. Refer to lines 8-22 page 8 of Mr. Pnacek's rebuttal testimony on the staking and locating dedicated model. Please confirm that the Company did not seek another more competent shared resource contractor before moving to the dedicated resources model for the Oakland and Kent counties. If not confirming, provide evidence otherwise.

Response:

Given the lower level of performance that the Company observed as the result of its prior use of the Shared Resource Model, in 2023 the Company began transitioning to the dedicated model in two-thirds of Oakland County as an initiative to improve public safety by meeting timeliness obligations within Public Act 174 of 2013, improve staking accuracy, and improve excavator communication while pursuing the lowest cost approach that yields the intended benefits of the staking and locating program. After successful results for the dedicated model for two-thirds of Oakland County, the company transitioned to the dedicated model for Kent County in 2024.

Witness: James P. Pnacek

Date: May 23, 2025

Question:

433. Refer to lines 10-13 on page 9 of Mr. Pnacek's rebuttal testimony on the staking and locating dedicated model. Please confirm that the Company did not attempt improve public safety, reduce damages, mitigate communication risks with excavators, improve quality, and comply with timeliness requirements by seeking another shared contractor who could achieved these objectives before moving to the dedicated resource model in Oakland and Kent counties. If not confirming, provide evidence otherwise.

Response:

Given the lower level of performance that the Company observed as the result of its prior use of the Shared Resource Model, in 2023 the Company began transitioning to the dedicated model in two-thirds of Oakland County as an initiative to improve public safety by meeting timeliness obligations within Public Act 174 of 2013, improve staking accuracy, and improve excavator communication while pursuing the lowest cost approach that yields the intended benefits of the staking and locating program. After successful results for the dedicated model for two-thirds of Oakland County, the company transitioned to the dedicated model for Kent County in 2024.

Witness: James P. Pnacek

Date: May 23 2025

Question:

434. Refer to page 11 of Mr. Pnacek's rebuttal testimony on the staking and locating dedicated model. Please:

- a. Confirm that prior to 2021, the Company used a shared resource model for staking and locating because it was effective and a lower cost option versus the dedicated model. If not confirming, explain why the Company used the shared model.
- b. Confirm that for at least the ten years prior to 2023, the Company's use of the shared model resulted in a lower costs than the dedicated model. If not confirming, provide evidence otherwise.

Response:

- a. The Company did not begin transitioning to the dedicated model until 2023 therefore no cost comparison between the models is available prior to 2021. In addition, prior to 2021 the shared model was not effective. Performance under the Shared resource model resulted in a Show Cause Order on July 7, 2019, under MPSC Case No U-20569. Additionally, the company continued to receive 62 violations for staking related violations since 2019. Please reference Page 51, line 5 to 25 of my direct testimony which describes the level of improvement the company has seen with the Dedicated model.
- b. The Company did not begin transitioning to the dedicated model until 2023 therefore no cost comparison is available between the models prior to 2023.

Witness: James P. Pnacek

Date: May 23, 2025

Question:

435. Refer to page 12 of Mr. Pnacek's rebuttal testimony on the staking and locating dedicated model. Please confirm that the Company disclosing its preference to move to a dedicated resource model gave contractors a clear indication that a shared model was not desirable, and dedicated model was preferable to the Company. If not confirming, explain why a dedicated model is not also more preferable to the contractor given the potential for higher revenues.

Objection by Counsel: Consumers Energy objects to this discovery question on the grounds that it assumes facts that have not been established to be true. Subject to the Company's objection, and without waiving its objection, the Company responds as follows:

Response:

Contrary to the assumption in the question, the Company did not generally disclose a preference to move to a dedicated resource model across its entire service territory in the most recent RFP. The Company indicated in the RFP that it would likely move to the Dedicated Resource Model in 2025 at least for Kalamazoo and Ingham Counties. The Company indicated that the final determination about which counties would transition to a Dedicated Resource Model in this contract would be made after the bid review. At the time of the RFP, the Company was not planning to transition all the counties in its service territory from the Shared Resource Model to the Dedicated Resource Model. All bidders were given the opportunity to submit a proposal for: (i) only the Dedicated Resource Model, (ii) only the Shared Resource Model, and/or (iii) both models for all territories excluding Oakland and Kent counties.

Witness: James P. Pnacek

Date: May 23, 2025

Question:

436. Refer to pages 14 and 15 of Mr. Pnacek's rebuttal testimony on the necessity for deferred accounting for staking and locating costs. Please confirm that the Company does not install fiber optic cable within the gas business and only handles staking and locating requests for gas facilities. If not confirming, provide evidence otherwise.

Response:

The Company does not install fiber optic cables within the gas business. The Company only handles staking and locating requests for gas and electric facilities, which includes staking and locating its gas and electric facilities in the vicinity of any third-party's installation of fiber optic cables in the vicinity of the Company's infrastructure.

Witness: James P. Pnacek

Date: May 23, 2025

Question:

437. Refer to lines 13-23 on page 16 and lines 1-8 on page 17 of Mr. Pnacek's rebuttal testimony on the number of employees requiring training for the EIRP. Please:

- a. Confirm that Exhibit A-145 shows only 23 new employees were hired for the program in 2023, 38 new employees were hired in 2024, and 45 new employee hires were planned for 2025. If not confirming, provide evidence otherwise.
- b. Confirm that the Company shows 100 new employee hires forecasted for 2026 and has provided support for why the number would more than double from 2024 and 2025. If not confirming, show where in direct testimony the Company has justified this large employee increase.
- c. Confirm that Exhibit A-145 shows only 35 employee losses in 2024 and no forecast of losses for 2025 and 2026. If not confirming, explain where they are shown.

Response:

- a. I confirm this is the new hired data provided in Exhibit A-145 for 2023 to 2025.
- b. Exhibit A-145 shows 100 new employees are forecasted to be hired for 2026. As shown in Exhibit A-145 (JPP-7), the Gas Construction EIRP Program had a headcount of 495 Operating, Maintenance, and Construction ("OM&C") employees at the end of 2020. From the end of 2020 to the end of 2024, the program lost 116 employees due to headcount reductions but also needed to hire 216 new OM&C employees to replace some of the 379 OM&C employees that remained after the headcount reductions. This means a total of 332 employees left Gas Construction during this time period. As Exhibit A-145 (JPP-7) shows, this is a turnover rate of 76%. The Company plans to hire a total of 145 OM&C employees for 2025 and 2026. The hiring is necessary to support the increase in the EIRP work plan miles from 118.1 miles of plastic in 2025 to 136.2 miles of plastic in 2026 as shown in the Exhibit A-138 (KAP-8).
- c. There was an overall headcount loss of 35 employees from 2023 to 2024. The Company did not include a total headcount forecast for 2025 and 2026 as part of the exhibit.

Witness: James P. Pnacek

Date: May 27, 2025

Question:

438. Refer to lines 6-22 on page 17 of Mr. Pnacek's rebuttal testimony regarding the number of employees requiring training for the EIRP. Please:

- a. Confirm that the EIRP Labor OM&C Training expense decreased in 2024 to \$1.8 million from \$2.1 million in 2023, although the number of hired employees increased to 38 in 2024 from 23 in 2023, which is a 65% increase.
- b. Confirm that the 136.2 miles of EIRP work proposed by the Company for 2026 is only a 15% increase from the 118.1 miles forecasted for 2025. If not confirming, provide the correct percentage increase.

Response:

- a. The EIRP Labor OM&C Training expense for 2023 was \$2.1 million with 23 new hires. The EIRP Labor OM&C Training expense for 2024 was \$1.8 million with 38 new hires. However this EIRP Labor OM&C Training expense program is not for just new hire training. It includes labor grade and non-labor grade specific training. The actual number of employees trained in each of the specific training classes was provided in discovery response AG-CE-0843_Pnacek_ATT_1.xlsx for 2021 to 2024. This data explains the cost variation by showing the increased number of employees trained in these classes in 2023 compared to 2024.
- b. The math is confirmed.

Witness: James P. Pnacek

Date: May 23, 2025

Question:

439. Refer to lines 3-5 on page 22 of Ms. Byrom's rebuttal testimony on the Analytics and Outreach group within the Customer Service department. By stating that the group serves a vital function, confirm that the Company is not implying that this function is a matter of life or death that could affect customers. If not confirming, provide evidence otherwise.

Response:

Confirmed. The Company is not implying that this function is a matter of life or death that could affect customers.

The word vital is defined by Merriam-Webster meaning "of the utmost importance," in this case in relation to the Customer organization.

Witness: Jessica R. Byrom

Date: May 19, 2025

Question:

440. Refer to lines 13-22 on page 23 of Ms. Byrom's rebuttal testimony on the DCO group within the Customer Service department managing channels with millions of customer interactions and transactions and keeping systems running. Please:

- a. Confirm that systems processing the millions of customer interactions and transactions were already in place as of 2024. If not confirming, explain why not.
- b. Confirm that the website and mobile apps are automated functions and the DCO is not running or operating these systems manually. If not confirming, provide evidence otherwise.

Response:

- A. Confirmed. The systems were already in place as of 2024.
- B. Some parts of the website and mobile app are based on automated functions. For other parts of those systems the DCO team is responsible for the maintenance, content management, and continuous improvement of the website and mobile app to ensure that it functions optimally to serve customer needs.

Witness: Jessica R. Byrom

Date: May 23, 2025

Question:

441. Refer to lines 1-7 on page 3 of Ms. Conrad's rebuttal testimony on the awarding of incentive compensation even if only a single metric is achieved. Please:

- a. Explain what you mean by "employees, as a whole," must re-earn the incentive/at risk portion of the compensation...
- b. Confirm that if only one performance metric is achieved that an incentive payout would still occur for the year. If not confirming, provide evidence otherwise.

Response:

- a. The phrase "employees, as whole" means that eligible employees must meet the achievement requirements of the EICP goals each year before any payout occurs. The incentive is not a fixed amount that is guaranteed. It is "at risk" based on the outcome of the individual goal achievement.
- b. Confirming that if at least threshold level of performance is met for one operational measure as illustrated in Exhibit A-39 (AMC-1) page 2, then a 50% of target payout would occur.

Witness: Amy M. Conrad

Date: May 23, 2025

Question:

442. Refer to lines 1-8 on page 3 of Ms. Conrad's rebuttal testimony on the awarding of annual merit increases of 3.5%. Please explain why the Company is denying this fact given that historically the Company has made those pay increases, as shown in response to DR AG-CE-0677 ATT1 REVISED, and reflected in the 2023 base salaries?

Response:

What my testimony is stating on lines 1-8 on page 3 is that for purposes of escalating labor costs for revenue requirements in this rate case, an inflation factor is used. This is the same factor used for non-labor expenses. The actual merit budget or historical merit averages is not used. The amounts referred to in DR AG-CE-0677 ATT1 REVISED reflect actual labor increases not the requested pay increases. For details regarding the annual inflation rates see witness Rayl.

	12-Mo Ending 2024	12-Mo Ending 2025	10-Mo Ending 2026
Annual inflation rates per Company witness Rayl	3.2%	2.4%	2.5%

Witness: Amy M. Conrad

Date: May 23, 2025

Consumers Energy Company
Average Pay Increases
For The Years 2021 Through 2026
U21806-AG-CE-0677_ATT_1_REVISED
(\$000)

	(a)	(b)	(c)	(d)
Line No.	Description	Officer {a}	Non-Union {b}	Union {c}
1	2021	3.66%	3.47%	3.98%
2	2022	4.86%	2.87%	6.36%
3	2023	4.07%	2.82%	5.03%
4	2024	3.86%	3.24%	4.24%
5	2025	4.77%	3.10%	4.90%
6	2026	4.30%	3.10%	4.90%

Notes

{a} Average pay increases for officers are based on an annual pay increases and market adjustment effective in January each year.

{b} Average is based on annual merit increases.

{c} Average is based on cost of living adjustment and general wage increases. The 2025 and 2026 forecasts are currently in progress; the percentage increase is based on an average of 2021 - 2024.

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Question:

443. Refer to lines 1-4 and the table on page 6 of Ms. Conrad's rebuttal testimony on the average payout percentage over the past five years. Please:

a. Confirm that the annual, as well as the five-year, overall average payout percentage shown in the table includes achieving certain performance measures significantly above 100%, which obscure not achieving other important performance measures at target. If not confirming, provide evidence otherwise.

b. Confirm that based on the information provided by the Company and included in Exhibit AG-66, the Company has only achieved 66% of its operating performance measures at target performance level or better during the five-year period. If not confirming, provide evidence otherwise.

Response:

a. Lines 1-4 and the table on page 6 of my testimony, illustrates the EICP payout which is determined based on the overall payout requirements for the particular performance year.

Overall payout includes the results of each EICP metric whether it is below target performance, at target performance or above target performance results. The payout is an accumulation of all goal results.

The payout formula does not make achievement of any one goal less important. As stated in witness Meschke's testimony on page 9 lines 15-18, "There is a direct tie between the design of the EICP operational goals and desirable benefits for customers. The operational goals focus on delivering customer value through safe, reliable, affordable, and clean energy services—all desirable benefits for customers."

b. Beginning with 2022 payout, requirements moved to a banded approach (threshold, target and maximum) vs. a number of goals achieved. The company is not seeking recovery of above target level of payout.

Performance Year	Operational Goal Payout %	Performance Year	Operational Goal Payout at or above Target					
2020	125%	2020	7 of 9	78%	Target was 6 of 9 goals achieved			
2021	75%	2021	5 of 9	56%	Target was 6 of 9 goals achieved			
2022	109%	2022	4 of 6	67%	Moved to Banding. Not # of goals achieved			
2023	94%	2023	3 of 6	50%	Moved to Banding. Not # of goals achieved			
2024	124%	2024	4 of 6	67%	Moved to Banding. Not # of goals achieved			
5 Year AVG	105%	5 Year AVG		63%				

Witness: Amy M. Conrad

Date: May 23, 2025

Question:

444. Refer to lines 10-14 on page 2 of Mr. Dreisig's rebuttal testimony on the company's forecasted capital expenditures. Please confirm that page 6 of Exhibit AG-1, shows projected Utility Investments of \$20 billion. Confirm also that Mr. Coppola stated in the referenced section of testimony that a large portion of the \$20 billion investment was coming from the gas utility. If not confirming, explain why this information is not correct.

Response:

Page 6 of Exhibit AG-1 shows \$20B, correct. This reference is associated with the entire utility investment across gas and electric businesses. It is incorrect that a "large" portion of this \$20 billion is attributable to the natural gas utility. As described in my rebuttal testimony, Exhibit A-42 (Natural Gas Delivery Plan) shows approximately \$5.5 billion of the \$20 billion. This represents a rather small portion of the total investment plan.

Witness: NEAL P. DREISIG

Date: May 23, 2025

Question:

445. Refer to lines 15-22 on page 2 and lines 1-11 on page 3 of Mr. Dreisig's rebuttal testimony on the potential growth in gas bills. Please:

- a. Provide the percentage decline or growth in the average residential gas bill for the gas cost portion and the non-gas portion, separately, for the past 10 years ending December 2024. Provide the underlying calculations in Excel.
- b. Confirm that while gas costs have declined non-gas costs have increased at a rate above the inflation rate over the past 10 years. If not confirming, provide evidence otherwise.

Response:

- a. Attachment U21806-AG-CE-0949_ATT1 shows fuel and delivery components broken out and the associated growth or decline rates.
- b. It is confirmed that gas costs have declined while non-gas costs have increased. However, it is not confirmed that non-gas costs have risen higher than inflation, rather, delivery costs are near exactly in line with inflation at 2.9%.

Witness: NEAL P. DREISIG

Date: May 23, 2025

U21806-AG-CE-0950

Page 1 of 1

Question:

446. Refer to page 4 of Ms. Grob's rebuttal testimony on Health Care, Life Insurance and LTD expenses. Please:

a. Confirm that the annual plan savings provided in DR AG-CE-0686 and shown on page 2 of Exhibit AG-65 are incremental savings each year over the prior year savings. If not confirming or if the amounts represent cumulative savings, explain why in certain years the amount of savings decrease or disappear.

b. Provide the calculation showing how the \$483,000 was determined in Excel with formulas intact.

Response:

- a. The top two lines of AG-CE-0686 were incremental; the other lines were not incremental, but the savings carried over for that change item. I have updated the chart below to show the savings by year and to also show the incremental change by year. Also, please note, as shown below, that the Salaried Pre-65 Market Exchange is included in the Retiree healthcare, known as the OPEB plan, which was included in the Aon projections.

Total Annual Plan Savings				
	2023	2024	2025	2026
Plan Design Changes	\$508,000	\$508,000	\$631,000	\$631,000
Medical ASO Negotiated Fees	\$70,000	\$101,000	\$134,000	\$134,000
Salaried Pre-65 Marketplace Exchange	0	\$650,000	\$650,000	\$650,000
RxC / ESI Renewal Savings	0	\$1,969,000	\$2,683,000	\$2,683,000
SaveOn Savings	\$1,700,000	\$1,700,000	\$1,700,000	\$1,700,000
Dental Admin Savings	\$85,000	\$85,000	\$85,000	\$85,000
Dental Network Savings	\$1,400,000	\$1,400,000	\$1,400,000	\$1,400,000
Life Insurance Savings	0	\$510,000	\$510,000	\$510,000
Total Annual Savings	\$3,763,000	\$6,923,000	\$7,793,000	\$7,793,000
Salaried Pre-65 Marketplace Exchange	0	\$650,000	\$650,000	\$650,000
Total Annual Savings Active Healthcare/LTD/Life line	\$3,763,000	\$6,273,000	\$7,143,000	\$7,143,000
Incremental Change year over year	0	\$2,510,000	\$870,000	\$0

- b. Please see attached to show how the \$483,000 amount was determined. The amount of \$2,754,000 listed in AG testimony Coppola page 185, line 5, is a gross amount prior to electric/gas business split and capitalization.

Witness: Kendra K. Grob

Date: May 27, 2025

U-21806-AG-CE-0950 part b

	Healthcare/Life	
AG testimony amount	2,754,000.00	AG testimony Coppola page 185 line 5 gross amount
elec	1,514,700.00	
gas	1,239,300.00	
elec O&M	711,909.00	
gas O&M	483,327.00	
Total O&M	1,195,236.00	
splits		
elec	0.55	
gas	0.45	
capital		
elec	0.53	
gas	0.61	
O&M		
elec	0.47	
gas	0.39	

Question:

447. Refer to page 4 of Ms. Grob's rebuttal testimony on Health Care, Life Insurance, and LTD expenses. Please confirm that in forecasting these expenses for the projected test year, the Company applied the inflation factors for 2024, 2025 and 10 months in 2026 to the 2023 expense level and did not show any cost savings offsetting those inflation factors. If not confirming, provide evidence otherwise.

Response:

In Case No. U-21806, as filed, the Company did use the general inflation rates for active healthcare, Life Insurance and LTD expenses after reviewing the numbers. As you can see from the attached file, the first tab is the projections using the general inflation rates as filed. The Company also looked at what the cost would be if all the pieces were broken out, as healthcare trend rates are above what the general inflation rates are in this case. The second tab shows Healthcare projected out using the expected healthcare trend rates offset by the known plan changes and expected changes in reduced employee counts. The amount filed for this case was \$19,765 for Active Healthcare/Life/LTD, and looking at all the pieces broken out, the Company would have been a slightly higher amount of \$20,017. The Company chose for this specific rate case to file with only the general inflation as it was only a small difference.

Witness: Kendra K. Grob

Date: May 27, 2025

U-21806-AG-CE-0951

(\$000's)

Electric captial split 1.1 to 6.30
Gas captial split 1.1 to 6.30
Electric capital split 7.1 to 12.31
Gas capital split 7.1 to 12.31
OPEB electric split 1.1 to 12.31
OPEB gas split 1.1 to 12.31
Active healtcare percentage increase
Inflation

Active Health & Life

Employee Health Care
Exec Physicals

Life Insurance
Total Life Insurance/LTD
Fidelity Fees

Electric
Electric Cap
Exec Phys
Exec Phys Cap
Life Insurance
Life Insurance Cap
Fidelity Fees

Electric O&M

Elec Exc Phys & LTD

Gas
Gas Capital
Exec Phys
Exec Phys Cap
Life Insurance
Life Insurance Cap
Fidelity Fees

Gas O&M

Gas Exc Phys & LTD

Total Consumers O&M

5/28/2025

(\$000's)

Electric captial split 1.1 to 6.30

Gas captial split 1.1 to 6.30

Electric capital split 7.1 to 12.31

Gas capital split 7.1 to 12.31

OPEB electric split 1.1 to 12.31

OPEB gas split 1.1 to 12.31

Active healtcare percentage increase

Inflation

Active health plan changes over previous ye

Life plan changes over previous year

High level assumption lower employees ave

Active Health & Life

Employee Health Care

Exec Physicals

Life Insurance

Total Life Insurance/LTD

Fidelity Fees

Electric

Electric Cap

Exec Phys

Exec Phys Cap

Life Insurance

Life Insurance Cap

Fidelity Fees

Electric O&M

Elec Exc Phys & LTD

Gas

Gas Capital

Exec Phys

Exec Phys Cap

Life Insurance

Life Insurance Cap

Fidelity Fees

Gas O&M

Gas Exc Phys & LTD

Total Consumers O&M

5/28/2025

Question:

448. Refer to lines 1-15 on page 3 of Mr. Quinn's rebuttal testimony on forecasted capital expenditures for vehicle replacements. Please:

- a. Confirm that no specific vehicle price increases from manufacturers were presented in direct testimony by the Company in this rate case. If not confirming, provide evidence otherwise.
- b. Confirm that capital expenditures for the projected test year at \$13.283 million are forecasted to increase by 45% from the 2023 capital expenditures of \$9.164 million. If not confirming, provide evidence otherwise.
- c. Confirm that for the projected test year, the Company forecasted the purchase of 105 vehicles versus 138 vehicles in 2023.

Response:

- a. Most specifications represented in Exhibit A-28 (CEB-3) are provided by multiple different manufacturers. The unit cost of a specification varies by manufacturer. The forecasted capital expenditures represented in Line 1, Line 2, and Line 3 of Exhibit A-28 (CEB-3) are based on current manufacturer pricing plus an inflation factor of 3 percent.
- b. As represented in Exhibit A-12 (CEB-1), Schedule B-5.2, the Company forecasts total Fleet Services Capital Expenditures of \$13.532 million for the projected test year and \$9.405 million for the 12 month period ending 12/31/23. Historically, the pace of deliveries is much higher and therefore the rate of spend is much higher during the fourth quarter (calendar period October through December) as compared to the first 3 quarters of each year (calendar period January through September). In order to avoid receiving such a large portion of Fleet Vehicle Capital Replacement deliveries at year end, however, the Company has begun shifting these purchases to an earlier time period each calendar year (i.e. the period between January and September). Despite this shift, the rate of increase of total Fleet Vehicle Capital Replacement forecasted spend on a calendar year to calendar year basis remains within historical plus inflation. November 2026 and December 2026 are not included in the test year of this case. However, the Company can report that it forecasts total Fleet Vehicle Capital Replacement expenditures of \$558,000 during the period November 2026 through December 2026.
- c. As outlined in discovery response U21806-AG-CE-0648, the Company forecasts purchasing 105 vehicles in the test year and purchased 138 vehicles during the 12 month period ending 12/31/23.

Witness: Quentin A. Guinn

Date: May 27, 2025

Question:

453. Refer to page 5 of Mr. Griffin's rebuttal testimony on the capital expenditures risk assessment of HCA and non-HCA pipelines. Please:

- a. Confirm that the Company did not provide any evidence that the number of risk assessment miles need to triple in 2026 to 105 miles from 34 miles in 2025, and increase nearly six-fold from 18 miles in 2024. If not confirming, provide evidence otherwise.
- b. Confirm that non-HCA and HCA pipelines generally consist of the same material type. If not confirming, explain.
- c. Confirm that in his testimony, Mr. Coppola does not propose that risk mitigation assessments should not be performed, but instead he proposes that the number of miles in 2026 be doubled from 2025. If not confirming, provided evidence otherwise.

Response:

Consumers Energy objects to this request on the grounds that the request is unreasonable and argumentative. Subject to this objection, and without waiving it, Consumers Energy answers as follows:

- a. The reason for the increase in mileage is discussed in my rebuttal testimony on page 5, lines 11 through 15.
- b. HCA and non-HCA pipelines both consist of steel pipe.
- c. My rebuttal testimony appropriately addresses the Company's rejection of Mr. Coppola's proposal for this program's expenditure reduction and does not state that Mr. Coppola proposes that risk assessments should not be performed.

Witness: MICHAEL P. GRIFFIN

Date: May 23, 2025

Question:

454. Refer to line 12 on page 6 through page 8 of Mr. Griffin's rebuttal testimony on the MAOP projects. Please confirm that Mr. Coppola has not recommended full disallowance of the referenced projects, but instead that the Company be responsible for 50% of the cost. If not confirming, provide evidence otherwise.

Response:

My rebuttal testimony appropriately addresses the Company's rejection of Mr. Coppola's proposal for this program's expenditure reduction. There is no evidence that I stated in my rebuttal that Mr. Coppola has made the recommendation of full disallowance.

Witness: MICHAEL P. GRIFFIN

Date: May 23, 2025

Question:

455. Refer to page 9 of Mr. Griffin's rebuttal testimony on the Transmission Asset Relocation projects. Please confirm that design work on the projects identified in Mr. Coppola's testimony had not been completed as of March 2025. If not confirming, provide evidence otherwise and explain why the information provided in response to AG-CE-0326 was erroneous.

Response:

The Asset Relocation projects were in the phase as stated Exhibit AG-17, which is the normal stage for these types of projects at that time. Each of these projects are progressing and have undertaken activities commensurate with projects that will be constructed in 2026. Company engineers primarily manage projects being constructed in the current year up until late spring when these projects start to be released for construction. They then begin to work on projects for the next year which would include pre-engineering work such as SAP order creation, design commencement, environmental reviews, and long lead-time material ordering. Then they meet with gas control on when the projects can be done based on all other project work and system demands which determines the final scheduling of construction. Thus, Company engineering sources utilize a prudent cadence prior to construction. Further, the timing of and cost of these projects is shown in Exhibit AG-17 (workpaper WP-MPG-1). The Company continues its normal cadence with these projects which also accounts for overall program risk and which ensures continued safety of the system.

Witness: MICHAEL P. GRIFFIN

Date: May 23, 2025

Question:

456. Refer to lines 1-14 on page 10 of Mr. Griffin's rebuttal testimony on the Base Field Measurement projects. Please:

- a. Identify when the metering problems started and why it is an MPSC technical standard compliance issue now.
- b. Explain why the Company believes that gas losses are occurring and when they began.

Response:

- a. The Laingsburg Meter Installation Project is part of the Company's continuing effort to invest in metering to diagnose line losses on line 400. The addition of metering at Laingsburg is an investment in measurement equipment that conforms to the MPSC technical standard to develop additional internal LAUF reports that identify losses more rapidly. As described in my direct testimony, this project is part of the Company's efforts to conform to the MPSC technical standard requirements concerning natural gas quality, measurement accuracy, and Lost and Unaccounted For ("LAUF") gas. There is no compliance issue at this very moment. This project is to ensure continued compliance.
- b. Most "unaccounted for" losses are likely due to leaking flanged or threaded connections and unidentified leaks in the system. The system could show additional losses outside of that due to "measurement uncertainty." For instance, the Gas Technical Code has allowances for 1% error in repeatable results (R 460.2351 (a)). Newer metering technology can achieve tighter tolerances than 1% upon initial installation and stay within those tolerances with routine maintenance and in some instances recalibration. The Company believes continued investments in "Lost and Unaccounted for" metering will allow it to diagnose and pinpoint losses closer to real time.

Witness: MICHAEL P. GRIFFIN

Date: May 23, 2025

Question:

457. Refer to line 15 on page 10 through line 2 of page 14 of Mr. Griffin's rebuttal testimony on the Williamston Meter Proving Station project. The information provided appears to be inconsistent with typical building construction projects and typical cost savings. It is also incomplete and confusing. Please provide the following information in Excel:

a. The O&M costs incurred in each year 2021 to 2024 for the Company to pay a third party to perform the meter proving functions with detailed cost breakdown of expenses. Explain what specific functions the third party performs.

b. The O&M costs incurred each year 2021 to 2024 for Company employees including management employees to assist, validate, supervise, and otherwise manage the work performed by the third party. Explain what tasks or work Company employees currently perform, including supervisory and management employees.

c. Provide the capital expenditures by year to bring the meter proving function in-house, including buying any required equipment, from start of the project and over 20 years. Provide a breakdown of what the capital expenditures will be spent on by year.

d. Provide the O&M costs that the Company will incur annually from start of the project and over a 20-year period by bringing the meter proving functions in-house. Provide a breakdown of these costs by year.

e. Provide the amount of costs that will no longer be paid to the third party annually from start of operation of the new meter proving station and over the 20-year period defined above. Provide a breakdown of these costs by year.

f. Identify and provide any other cost savings by year over the 20-year period. Explain why these are cost savings and show how you determined them.

g. Confirm that the Company has not performed a present value cost/benefit analysis that includes items (a) through (f) above to justify bringing the meter proving functions in-house. If not confirming, provide the cost/benefit analysis in Excel with formulas intact and assumptions clearly explained.

h. Identify how many buildings the Company plans to build, the cost of each building, the function of each building, and why multiple buildings are necessary.

i. Show in Excel with formulas intact how you determined the \$750,000 cost savings.

j. Confirm that the Company is currently compliant with API-1164 and API-1164 which does not require that the Company build its own meter proving facility. If not confirming, provide evidence otherwise.

k. Confirm that Exhibit AG-18 does not show over \$1,000,000 in annual project efficiencies, but only amounts that Mr. Griffin claims are cost efficiencies.

Response:

Since the filing of rebuttal testimony, the Company is reviewing other alternative options for the Williamston Transmission Meter Proving Station Facility (GM-01089) and is no longer seeking recovery of the expenditures for this project in this docket at this time.

Witness: MICHAEL P. GRIFFIN

Date: May 27, 2025

Question:

458. Refer to lines 2 -3 of page 16 of Mr. Griffin's rebuttal testimony on project BGL-00274 for the emergent inoperable valve. Provide the phase of development that this project was in as of March 2025.

Response:

As provided in U21806-AG-CE-0333, in March of 2025, project BGL-00274 had not kicked off engineering or design work yet. Construction is planned for 2026 with engineering and design kicking off in summer of 2025. The project is thus in the normal stage for a project to be constructed in 2026.

Witness: MICHAEL P. GRIFFIN

Date: May 23, 2025

Question:

460. Refer to lines 9-23 of page 16 of Mr. Griffin's rebuttal testimony on the Deliverability Base Pipeline projects. Please confirm that the 11 projects are not the only projects that support the Company's operations in accordance with the Michigan Gas Safety Standards and the Company is not currently in violation of those standards. If not confirming, provide evidence otherwise.

Response:

Yes, the 11 projects are not the only projects that support the Company's operations in accordance with the Michigan Gas Safety Standards.

Witness: MICHAEL P. GRIFFIN

Date: May 23, 2025

Question:

461. Refer to lines 5-23 of page 17 of Mr. Griffin's rebuttal testimony on the T&S City Gate projects. Please confirm that averages include both high and low-cost projects for all years of capital expenditures presented by the Company and discussed in Mr. Coppola's testimony. If not confirming, explain why not.

Response: ...

The average cost utilized by Mr. Coppola included all projects. As described in my rebuttal testimony on page 17, lines 14 through 20, some of these projects were very small in scope and should not be included in the overall average cost when that cost is used to project costs of major rebuilds.

Witness: MICHAEL P. GRIFFIN

Date: May 23, 2025

Question:

462. Refer to line 18 on page 18 through line 21 of page 19 of Mr. Griffin's rebuttal testimony on the T&S City Gate projects. Please provide a list of the top 6 highcost projects in each year 2021 to 2024 in Excel.

Response:

See attachment U21806-AG-CE-0966_Griffin_ATT_1 for the requested information. Note that the response to U21806-AG-CE-0324-Revised (summarized below) demonstrates how many major modernization projects that were completed in each year. Thus, in 2 of the years there were not 6 modernization projects. The city gate program contains expenditures and activities outside of modernization projects as shown on the attachment.

Modernization projects from 2021 to 2026 funded from the city gate program:

- 2021: 3 projects completed
- 2022: 8 projects completed
- 2023: 3 projects completed
- 2024: 8 projects completed
- 2025: 7 projects projected
- 2026: 7 projects projected

Witness: MICHAEL P. GRIFFIN

Date: May 23, 2025

U21806-AG-CE-0966-Griffin_ATT_1

		Costs: Actual Version:604
Project Definition		2021
GM-95011	JXN-RTU-Electical Upgrade (Transmission)	8,819,603
GM-00822	FDM-Lansing CG-Turner Rd Rbld	7,107,170
GM-00789	SAG-Mt Pleasant CG Rbld	4,920,139
GM-00803	KZO-Marshall-Lansing CG Rbld	4,845,378
GM-00514	STC-Greenfield CG Rbld	2,236,224
GM-00793	STC-Mt Clemons CG Htr Repl	1,701,874
		2022
GM-00867	FDM-Lansing CG-Airport Rd Rbld	8,082,082
GM-00901	STC-Rochester CG Rbld	7,499,386
GM-00514	STC-Greenfield CG Rbld	6,340,439
GM-00900	JXN-Napoleon-Brooklyn CG Rbld	6,275,876
GM-00902	KZO-Kzo CG-Nazareth Rd Rbld	5,784,883
GM-95014	JXN-RTU-Electical Upgrade (2022)	4,919,042
		2023
GM-00794	KZO-M Ave CG Rbld	12,710,911
GM-00899	SAG-Akron CG Rbld	7,544,837
GM-95021	JXN-RTU CG Upgrade Program 2023	2,080,436
GM-00942	KZO- Galesburg CG Rbld	1,791,768
GM-00976	ALM-St. Louis VS RTU, Bldg Rep	1,249,972
GM-00951	JXN-PEPL-Blissfield CG Rbld	1,216,665
		2024
GM-00943	STC-Orion CG Rbld	12,637,190
GM-00994	STC-Leonard-Lakeville City Gate Rbld	7,525,000
GM-00951	JXN-PEPL-Blissfield CG Rbld	7,171,118
GM-00942	KZO- Galesburg CG Rbld	4,470,219
GL-03398	MAR-Bear Lk-Excelsior PL Inst	4,282,320
GM-00941	OVS-Dorr CG Rbld	2,496,970

Question:

463. Refer to lines 1-9 on page 20 of Mr. Griffin's rebuttal testimony on the T&S City Gate projects. Please confirm that despite the fact that design work on the 7 projects had not yet been completed, Mr. Coppola did not recommend disallowance of the project costs and instead recommended that the project capital expenditures for the 10 months ending October 2025 and the projected test year be set based on the historical three-year average cost per project adjusted for 2025 and 2026 inflation. If not confirming, provide evidence otherwise.

Response:

My rebuttal testimony appropriately addresses the Company's rejection of Mr. Coppola's proposal for this program's expenditure reduction. There is no evidence that I stated in my rebuttal that Mr. Coppola has made the recommendation of full disallowance.

Witness: MICHAEL P. GRIFFIN

Date: May 23, 2025

U21806-AG-CE-0969

Page 1 of 1

Question:

465. Refer to line 15 on page 22 through line 16 on page 23 of Mr. Griffin's rebuttal testimony on O&M expense for Transmission Corrosion Control. Please:

- a. Confirm that in DR AG-CE-0338 (Exhibit AG-59) the Attorney General requested that the Company provide detail support for the amounts of each line comprising the total corrosion control expense and that detail support would have included number of units or activities. If not confirming, explain what detail support would otherwise refer to, which the Company provided.
- b. Confirm that the two largest increases in expense from Transmission corrosion control from 2023 to 2026 shown in DR CUB-CE-0248 are for Atmospheric (Eternal) Painting and Pipeline Recoating. If not confirming, explain.
- c. Confirm that in DR CUB-CE-0248 the number of units for Atmospheric Painting increases by one unit between 2023 and 2026 but the cost increases from \$392,825 to \$910,000, or 132%. If not confirming, provide evidence otherwise.
- d. Confirm that in DR CUB-CE-0248 the expense for Pipeline Recoating increases by \$715,000 from 2023 to 2026 and the number of units increase from 300 units (feet) in 2023 to 2,500 units in 2026, which is a 733% increase in 2026 with no explanation for this large increase in the number of units. If not confirming, provide evidence otherwise.

Response:

- a. Confirming that the AG asked for detailed support and did not request units or activities. It is my conclusion that the Company provided detailed support of the activities in the program. Absent clear questions it is difficult to speculate what is being sought by participants in the filing.
- b. Confirmed.
- c. Confirmed. The difficulty with projecting work based on units in this program is the variability in the work. For atmospheric corrosion projects, a project can be one item at a compressor station, or an entire city gate. The amount of work and resulting cost can be significantly different.
- d. It is unclear what the Attorney General is asking to be confirmed in this interrogatory. As such, I am not confirming. The difficulty with projecting work based on units in this program is the variability in the work. For recoating projects, the diameter of the pipe as well as length of the project are both variables that are difficult to anticipate and significantly affect the cost. Further, I can confirm that Exhibit AG-59, page 4 of 5 shows that the Company stated that The Safety of Gas Transmission Pipelines, including Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments ("RIN2") regulations now require performing additional close interval surveys when systemic issues are identified during annual surveys. This additional survey is projected to indicate the need for additional coating repairs (recoat). The increase in expenditures will allow the Company to address these repairs in the time required by the RIN 2 regulations.

Witness: MICHAEL P. GRIFFIN

Date: May 23, 2025

Question:

466. Refer to pages 2 and lines 1-7 on page 3 of Mr. Joyce's rebuttal testimony on the LAUF gas adjustment for the Company's methane reduction goal. Please:

- a. Confirm that natural gas consists of 70% to 90% methane gas. If not confirming, provide the composition of the Company's natural gas delivered to customers.
- b. Confirm that none of the other components of LAUF gas can be forecasted with 100% accuracy and be guaranteed. If not confirming, provide evidence otherwise.
- c. Confirm that by filing a projected test year, the Company has included forecasted expenses in this rate case that may not be 100% accurate or guaranteed. If not confirming, explain why not.
- d. Confirm that the Company is still committed to achieving its net-zero methane goal and those reductions are quantifiable. If not confirming, explain why not.
- e. Provide the actual reductions in methane volume that the Company has achieved by year or cumulative since it set its net-zero goals and identity the timeframe.

Response:

Objection of Counsel: Consumers Energy Company objects to part b. of this discovery request on the ground that it is vague and ambiguous. The Company does not know what "other components of LAUF" the question refers to.

- a. Confirmed.
- b. See objection.
- c. The Company has forecasted expenses for the bridge period and test year for this case.
- d. Confirmed, as outlined on page 78-79 of the Natural Gas Delivery Plan, Exhibit A-42 (NPD-1).
- e. 2013-2023 methane emission levels are shown in Figure 39 on page 79 of the Natural Gas Delivery Plan, Exhibit A-42 (NPD-1).

Witness: Timothy K. Joyce

Date: May 26, 2025

Question:

467. Refer to line 12 on page 5 through line 6 on page 6 of Mr. Joyce's rebuttal testimony on new well drilling. Please confirm that the Company did not disclose any information on well depths, pipelines lengths, and site preparation cost differences for each of the wells planned to be drilled in 2025 and 2026 in comparison to wells drilled in prior years. If not confirming, provide evidence otherwise.

Response:

Confirmed.

Witness: Timothy K. Joyce

Date: May 26, 2025

Question:

468. Refer to lines 3-18 on page 7 of Mr. Joyce's rebuttal testimony on the Lyon 29/34 Northville Storage Dehydration project. Please:

- a. Confirm that the cost of the Lyon 29/34 Dehydration project is \$37.4 million, excluding the other two projects under Northville Storage in WPTJK-6. If not confirming, provide the correct amount.
- b. Confirm that Mr. Joyce did not disclose the \$37.4 million cost of the project in his direct testimony or any other similar cost for that matter. If not confirming, provide evidence otherwise.

Response:

- a. Confirmed.
- b. Confirmed. The Company only presented the portion of the project costs for this project that impact the time period (historical test year, bridge period, and projected test year) relevant to this case.

Witness: Timothy K. Joyce

Date: May 26, 2025

Question:

469. Refer to line 19 on page 7 through line 4 on page 8 of Mr. Joyce's rebuttal testimony on evaluating all methods to meet the 7 lbs/MMcf requirement for delivery of gas to the customer meters from the Lyon 29/34 Northville storage fields. Please confirm that the Company did not fully evaluate the gas blending alternative and instead dismissed its use. If not confirming, provide a copy of that evaluation.

Response:

Not confirmed. While no formal analysis has been performed, my direct testimony on pages 34, lines 11-16 and response to U21806-AG-CE-0507 outlines why the engineering teams have determined that gas blending is not a competent means for ensuring gas quality. Installing the gas conditioning equipment will allow for effective utilization, dispatch, and cycling of the fields. Gas measurement accuracy is also impacted with moisture content above the 7lb/mmcf limit, including gas storage inventory and reservoir integrity verification.

Witness: Timothy K. Joyce

Date: May 26, 2025

Question:

470. Refer to lines 5-16 on page 8 and lines 10-11 on page 10 of Mr. Joyce's rebuttal testimony on the Lyon 29/34 Northville Storage Dehydration project and the limited use of the Northville storage fields. Please confirm that in testimony filed by the Company in Gas Cost Recovery (GCR) cases since 2022, there has been no mention of withdrawal limitation from the Northville fields due to high moisture content for the gas in storage. If not confirming, provide evidence where this limitation has been disclosed in the GCR cases.

Response:

Confirmed. Though not specifically noted in the GCR cases, the Company has limited its planned utilization of the Northville to extreme design cold weather conditions and minimal well flow testing, making it a "last on, first off" resource due to the high moisture content of gas extracted from the Northville fields during 2019-2022 time period described in my direct testimony and response to discovery question U21806-AG-CE-0506. There have been no instances in the past five years where the Company reached this extreme weather operating condition. The Company *would have* planned to utilize the field more frequently had the dehydration equipment been in place during those years.

Additionally, it should be noted that the significant value peaking storage facilities offer to the Company's customers is not just their utilization in design cold weather conditions, regardless of the frequency, but the significant role they play in allowing the Company to minimize monthly purchases and maximize utilization of all the Company's storage assets per the Company's filed GCR Plans.

As stated above, the Company has only chosen to use the field at potentially higher moisture content levels when the Company was in jeopardy of losing service to customers during extreme conditions, and it is the first field to be shut down when the condition improves. During these operational periods and afterwards, additional O&M expenses are needed to address potential impacts of high moisture content, including the real time monitoring of equipment performance, scrubber filter replacements at city gates, and maintenance pigging/cleaning.

Witness: Timothy K. Joyce

Date: May 26, 2025

Question:

471. Refer to lines 17 on page 8 through line 13 of Mr. Joyce's rebuttal testimony on the Lyon 29/34 Northville Storage Dehydration project and the potential risk to Company assets and delivering gas to customers above the 7 lbs/MMcf moisture content. Please confirm that with proper blending of gas withdrawn from the Northville storage fields with other gas flowing through the Company's transmission lines, the risk to Company assets and of exceeding the 7 lbs/MMcf moisture limit to customer meters is nearly zero given the relatively small volume of gas withdrawn from the fields versus the total gas flow on the transmission lines. If not confirming, provide evidence otherwise.

Response:

Not confirmed. My direct testimony on pages 34, lines 11-16 and responses to U21806-AG-CE-0507 and U21806-AG-CE-975 outline why our engineering teams have determined that gas blending is not a competent means for ensuring gas quality.

Witness: Timothy K. Joyce

Date: May 26, 2025

Question:

472. Refer to lines 14-22 on page 9 of Mr. Joyce's rebuttal testimony on the Lyon 29/34 Northville Storage Dehydration project and gas blending. Please:

- a. Confirm that although the Company dislikes gas blending, it does not mean it is not a workable solution. If not confirming provide evidence otherwise.
- b. Confirm that the Company has not made any effort to contact DTE Gas Company to determine how they use gas blending as a potential solution that would avoid the Company spending \$37.4 million on a dehydration project with limited use. If not confirming, provide evidence otherwise.

Response:

Objection by Counsel: Consumers Energy objects to part a. of this discovery request on the grounds that it assumes facts that have not been established as true. There is no evidence in this case to support the assumption that Consumers Energy "dislikes gas blending." Subject to the Company's objection, and without waiving its objection, Consumers Energy responds as follows:

- a. Not confirmed. Consumers Energy does not "dislike" gas blending. My direct testimony on pages 34, lines 11-16 and responses to U21806-AG-CE-0507 and U21806-AG-CE-975 outline why our engineering teams have determined that gas blending is not a competent means for ensuring gas quality.
- b. Confirmed. The Company has not contacted DTE Gas to "determine how they use gas blending as a potential solution." Consumers Energy has qualified and skilled engineers who understand how gas blending works (and when it will not). DTE Gas and Consumers Energy have different gas transmission and distribution systems. Even if DTE Gas is able to use gas blending to address moisture content on some parts of its system – which has not been established by anyone with engineering knowledge in this case – that does not mean that Consumers Energy would be able to use gas blending to address moisture associated with the Northville storage fields. Consumers Energy does not consider blending a competent means for ensuring gas quality for the reasons stated in my direct and rebuttal testimony.

Witness: Timothy K. Joyce

Date: May 27, 2025

Question:

169. Refer to lines 11-16 on page 34 of Mr. Joyce's direct testimony on the Lyon 29/34 project. Please:

- a. Identify on which occasions in the most recent five years the Company has tried gas blending. Describe those situations and the results thereof.
- b. Explain why the integrated nature of the Company's gas system, its variable operating conditions, and system design are unsurmountable obstacles to gas blending.
- c. Explain whether the Company discussed the gas blending practices employed by DTE Gas with that utility to learn and potentially adopt the same practices in lieu of undertaking the Lyon 29/34 capital project. If yes, provide details and lessons learned. If no, explain why not.

Response:

- a. The Company has not tried gas blending in the most recent five years for the reasons outlined in parts b. and c. of this question.
- b. The Company does not recognize blending as a competent means for ensuring gas quality. Various conditions can affect how and whether gases are mixed in a pipe. The gas that enters the CE transmission system from the Lyon 29 and Lyon 34 storage fields is processed through gas separator vessels to remove free liquids down to a range 5-10 microns in size and often resulting in gas moisture content in the range of 20 lbs/MMSCF at the outlet of the separators. The tariff limit is for gas moisture is 7lbs/MMSCF which gas separation equipment alone, existing or new, can reliably obtain. Obtaining the tariff limit for gas moisture through mixing is complex and unreliable due the varying factors such as flow rate from both streams, pressure, temperature, and the varying moisture content in both streams. Installing the gas conditioning (dehydration) equipment downstream of gas separation equipment is the only reliable way to ensure effective utilization, dispatch, and cycling of the fields.
- c. No. The Company has not contacted DTE Gas to understand how they use gas blending. Consumers Energy has qualified and skilled engineers who understand how gas blending works (and when it will not). DTE Gas and Consumers Energy have different gas transmission and distribution systems. Even if DTE Gas is able to use gas blending to address moisture content on some parts of its system – which has not been established by anyone with engineering knowledge in this case – that does not mean that Consumers Energy would be able to use gas blending to address moisture associated with the Northville storage fields.

Witness: Timothy K. Joyce

Date: March 18, 2025

Question:

473. Refer to page 13 of Mr. Joyce's rebuttal testimony on the length of time that some Company projects remain in engineering design. Please:

- a. Confirm that the time required for procurement of materials is separate from the time required for engineering design and sufficient engineering design needs to be completed to identify what materials need to be procured. If not confirming, provide evidence otherwise.
- b. Confirm that construction of a project cannot start or progress significantly until engineering design of the project is sufficiently developed or completed and it is not the length of construction that typically drives the completion of engineering design for small to moderate size projects. If not confirming, provide evidence otherwise.

Response:

- a. Not confirmed. Engineering design and equipment procurement activities are performed in parallel. Engineering teams are involved before and during the procurement process. There are also deliverables from equipment or material procurement vendors that are needed to complete engineering.
- b. Confirmed. Engineering designs are typically completed prior to the start of construction regardless the project size. The length of construction does not typically drive the engineering schedule.

Witness: Timothy K. Joyce

Date: May 26, 2025

Question:

474. Refer to lines 3-16 on page 14 of Mr. Joyce's rebuttal testimony on the Company incurring costs for material and equipment during the engineering design phase of the 13 projects. Please confirm that the Company did not identify any material or equipment costs that would be incurred for the 13 projects, and the composition of the costs forecasted for 2025 and 2026 is unknown. If not confirming, provide evidence otherwise.

Response:

Not confirmed. There are estimated material and equipment expenses incorporated into the projected expenses for 2025 and 2026 presented in WP-TKJ-5.

Witness: Timothy K. Joyce

Date: May 26, 2025

Question:

475. Refer to lines 9-16 on page 2 of Ms. Meschke's rebuttal testimony on the Company's employee safety performance record back to 2007 and 2008. Please confirm that the incentive compensation plan is an annual plan based on forward targets of performance and what occurred back in 2007 and 2008 is no longer relevant to current performance goals and incentive compensation payments. If not confirming, explain why 2007 and 2008 safety information is relevant to projected test year incentive compensation and safety benefits.

Response:

The incentive compensation plan is an annual plan based on forward targets of performance and what occurred back in 2007 and 2008 is no longer relevant to current performance goals and incentive compensation payments. However, it is relevant when analyzing performance trends and understanding the impact of having metrics such as Employee Safety included in the EICP program to incentivize performance improvement. Therefore, it is also directly relevant to (and refutes) the Attorney General's incorrect claim that the Company's safety initiative, supported by its EICP goals, reflects a negative performance trend.

Witness: Ashley E. Meschke

Date: May 27, 2025

Question:

477. Refer to line 16 on page 4 through line 3 on page 5 of Ms. Meschke's rebuttal testimony stating that the Company's calculated cost savings are not actually achieved historical cost savings. Please confirm that if the calculated cost savings have not been actually achieved then they are aspirational cost savings and not real cost savings. If not confirming, explain why not.

Response:

The calculated cost savings identified in my direct testimony are not merely aspirational. They are the savings that the Company expects to realize when performance targets are achieved within the test year based on historical cost experience.

Witness: Ashley E. Meschke

Date: May 27, 2025

Question:

479. Refer to page 6 and lines 1-2 on page 7, including the graph on page 7, of Ms. Meschke's rebuttal testimony on the SAIDI historical performance. Please confirm that based on the information provided by the Company and included in Exhibit AG-66, the Company did not meet its SAIDI target performance from 2019 through 2023. If not confirming, provide evidence otherwise.

Response:

That is correct. In 2019 through 2023 the Company did not achieve the EICP operational performance measure targets for SAIDI. However, the Company's SAIDI performance has been improving as outlined in my rebuttal testimony on page 7. This further demonstrates that the Company's EICP operational performance measure is working and providing customer benefits even though the Company did not achieve the target performance level in those years.

Witness: Ashley E. Meschke

Date: May 27, 2025

Question:

480. Refer to page 14 of Ms. Myers' rebuttal testimony on the costs savings from the Voluntary Separation Program (VSP). Please:

- a. Confirm that in providing the purported actual cost savings the Company did not identify and report the actual positions vacated and the related salary and labor costs for those positions. If not confirming, provide evidence otherwise.
- b. Confirm that despite the fact that the Company witnesses sponsoring each of the O&M exhibits provided the expense build up by year from 2023 to the projected test year, they did not identify the VSP cost savings supposedly included in each of the exhibits and no footnote reference was made to the amount of savings included in the cost build-up to allow validation that each department included the cost savings in the O&M expense for the 12 months ending October 2026. If not confirming, provide evidence otherwise.

Response:

- A. Confirmed.
- B. Confirmed.

Witness: Heidi J. Myers

Date: 5/20/2025

Question:

481. Refer to page 9 of Ms. Pascarello's rebuttal testimony on select EIRP projects. Please:

- a. Confirm that as of March 2025 the projects listed in the table either did not have any design work completed or less than 30% of the design had been completed. If not confirming, provide evidence otherwise.
- b. Confirm that the Company did not provide any specific evidence that the projects not yet fully designed will have a detrimental impact on any other projects if the costs are disallowed in this rate case and recovered in the next rate case after being fully designed and completed by the Company. If not confirming, provide evidence otherwise.

Response:

- a. As provided in discovery response U21806-AG-CE-0802, "Design in Progress" means that the survey is completed, and the design has started but has not reached the 30% complete milestone. As stated on page 8 of my rebuttal testimony, these projects are progressing through the design process during 2025 and have activities aligned with projects scheduled for construction in 2026.
- b. Page 9 of my rebuttal testimony states that the listed projects are individual phases of larger EIRP projects and outlines potential risks and impacts, such as detrimental effects on project cohesion, construction sequencing, and resource wastage to the larger EIRP project.

Witness: Kristine A. Pascarello

Date: 5/24/2025

Question:

482. Refer to lines 4-15 on page 10 of Ms. Pascarello's rebuttal testimony on establishing a firm capital expenditures budget for the EIRP. Please:

- a. Confirm that the program cuts alleged by Ms. Pascarello are actually avoided program increases over the 2023 capital spending level, which allowed the Company to complete sufficient program activities at a cost of \$181 million. If not confirming, explain why not.
- b. Confirm that any layoffs or production cuts would be avoided if the Company works within the established budget and plans its resources and projects for the coming year based on that level of activity as it did in 2023. If not confirming, explain why not.

Response:

- a. As stated in my rebuttal testimony, spending caps would lead to actual programmatic cuts, not just avoided increases, and would hinder the Company's ability to manage projects effectively. The Company has reduced unit costs, and the additional spending being requested is due to increased miles planned because of productivity improvements, not higher unit costs. The proposed capital expenditure cuts would necessitate reductions in both the program and workforce, limit flexibility to respond to evolving needs, and could result in unintended consequences like disincentivizing process improvements.
- b. Spending caps would adversely affect project selection, potentially leading to layoffs or production cuts by excluding essential phases and disrupting overall project cohesion and sequencing. EIRP projects vary significantly in scope, schedule, cost, size (grid, segment, HP), mix of plastic and steel pipe to be installed, pipe size, etc. Spending caps would impact project selection and could shift the focus from enhancing processes and productivity to merely staying within budget constraints, ultimately undermining the program's effectiveness and efficiency. As shown in Exhibit A-138 (KAP-8), the Company has already ramped up engineering, operations and expenditures above 2023 levels. The 2024 capital expenditures and miles completed in EIRP were higher than 2023. Additionally, the EIRP operates on a 3-year planning cycle, meaning that projects for 2025 are already designed and the 2026 projects are currently being designed. Consequently, reverting spending to 2023 levels would necessitate substantial reductions including potentially shelving these pre-designed projects, which would result in wasted resources and future engineering rework. Unfortunately, this could include measures such as potential layoffs to achieve the 2023 spending level.

Witness: Kristine A. Pascarello

Date: May 27, 2025

Question:

483. Refer to lines 13-14 on page 12 of Ms. Pascarello's rebuttal testimony on wrought iron projects not being prioritized under the EIRP. If the projects meet the threshold risk level, why would they not be prioritized for replacement within the EIRP?

Response:

As stated in my rebuttal testimony, these smaller segments may not be prioritized in the EIRP risk modeling and could result in a leak requiring an emergent project. The Company's distribution risk model contains over 500,000 segments and includes multiple scoring criteria. Additionally, as stated in my rebuttal testimony on page 12, line 10, the risk model does not account for whether the main is weldable. Wrought iron projects are also completed in the EIRP as detailed in response U21806-AG-CE-0397.

Witness: Kristine A. Pascarello

Date: May 25, 2025

Question:

484. Refer to lines 6-23 on page 14 of Ms. Pascarello's rebuttal testimony on the Obsolete Meters project. Please:

- a. Confirm that the only information provided on page 51 of your testimony and the discovery response on page 4 of Exhibit AG-19 is the number of 5,500 meters and the \$3.7 million of capital expenditures for 2026 and there is no explanation of what this project entails and why 5,500 meters were targeted at a cost of \$3.7 million. If not confirming, provide evidence otherwise.
- b. Provide a specific reference to a page and line numbers in the Material Conditions Renewable program section of your testimony where the Obsolete Meters project is discussed in detail.

Response:

- a. In addition to providing the number of meters and capital expenditures, line 23 on page 51 of my direct testimony states "Additional details on leaks and obsolete meters are included below in the Material Condition Renewals program." Also, my rebuttal testimony on page 14, lines 16 – 19, provides the page numbers of the information on obsolete meters in my direct testimony.
- b. As included in my rebuttal testimony, the information on obsolete meters is on page 63, line 1 though page 64 line 8 of my direct testimony, which also references the Customer Metering section of the Company's NGDP, Exhibit A-42 (NPD-1). The Customer Metering section begins on page 58 of the NGDP.

Please note that the referenced Page 4 of Exhibit AG-19 is not related to my direct or rebuttal testimony regarding obsolete meters. The referenced exhibit is about the Deliverability Base Pipeline Program sponsored by Company witness Michael Griffin.

Witness: Kristine A. Pascarello

Date: May 25, 2025

Question:

485. Refer to lines 1-10 on page 17 of Ms. Pascarello's rebuttal testimony on capital expenditures for leak repairs. Confirm that this section of your testimony addresses the capital expenditures side of the O&M expense on leak repairs discussed by Mr. Pnacek in his rebuttal testimony. If confirming, supplement the discovery information requested by the Attorney General in the 13th request (Question 430) for the capital side of the program. If not confirming, provide the following information:

- a. Provide in Excel the number of leak repairs in backlog at the end of each year 2021 to 2024 and forecasted for 2025 and 2026 along with the number of repairs added and completed each year. Explain whether the backlog increased at the end of 2023 or 2024 and why.
- b. Explain why the Company requires an additional \$1.3 million in expense to reduce the backlog. Explain to what level the Company wants to reduce the backlog for the projected test year and why.
- c. Explain why the backlog was not reduced in 2023 and 2024 and why the Company is waiting until the projected test year to reduce the backlog.
- d. Provide the amount of capital expenditures spent for leak repairs for each year 2021 to 2024 and forecasted for 2025, 2026 and the projected test year.

Response:

- a. Please see response U21806-AG-CE-0934.
- b. Leak remediation is completed by either leak repairs or leak renewals. Please see response U21806-AG-CE-0934 for the response on the additional \$1.3 million in O&M expenses for leak repairs. The Company is requesting an additional \$1.51 million in capital expenditure for leak renewals to eliminate the leak backlog. As stated in my rebuttal testimony, page 17, the Company plans to eliminate the leak backlog regardless of when the LDAR rule is published. The elimination of the leak backlog is prudent to reduce system risks and ensure public safety. The \$1.51 million is to address Grade 2 leak renewals across mains, services, and meter stands. The breakdown of the additional \$1.51 million is provided in response U21806-SA-CE-318.
- c. Please see response U21806-AG-CE-0934.
- d. Please see response U21806-AG-CE-0934-Pascarello.

Witness: Kristine A. Pascarello

Date: May 25, 2025

Question:

487. Refer to lines 13-23 on page 20 of Ms. Pascarello's rebuttal testimony on the ECAP capital spending. Please confirm that other than generalities, the Company has not provided any detailed or concrete benefits achieved or that will be achieved by ECAP.

Response:

As described in my direct testimony beginning on page 80 and my rebuttal testimony on page 20 lines 13-23 and page 21 lines 1-4, the Enterprise Corrective Action Program (ECAP) has been designed to support safe and excellent operations through a structured approach that includes transparency in reporting issues, identifying trends, and closing compliance and safety gaps with corrective actions and controls based on risk thresholds. Since its inception in 2020, ECAP has achieved several specific accomplishments, including a standard approach for a closed-loop corrective and preventative action (CAPA) process, a phased roll-out of a software platform to facilitate the process, support to ensure adoption, establishment of performance metrics, and training for operations and engineering to self-identify concerns. In 2025, Phase 4 expands the ECAP program to Corporate Safety & Health to expand these accomplishments. These accomplishments demonstrate ECAP's concrete benefits in improving safety, reliability, and service through the resolution of non-conforming conditions on the gas system, ultimately benefiting customers by reducing concerns and preventing recurrence of issues.

Witness: Kristine A. Pascarello

Date: May 25, 2025

Question:

488. Refer to lines 8-10 on page 22 of Ms. Pascarello's rebuttal testimony on the benefits of the Utility Network system. If the system increases productivity, streamline workflows, and provides various new functionality, why did the Company not quantify those benefits and cost savings and provide a cost/benefit analysis to support the project?

Response:

While it is true that the system increases productivity, streamline workflows, and provides various new functionalities, as stated in my rebuttal testimony, the primary drivers for the Utility Network project are addressing technology obsolescence and mitigating the associated risks. The current system is outdated and poses significant risks to our operations, including potential system failures and core regulatory required processes as listed beginning on page 22 of my rebuttal testimony. Upgrading to the Utility Network system is essential to address technology obsolescence and ensure continued operational excellence. Additionally, the new system is necessary to meet the growing business requirements for advanced analytics, which are critical for making informed decisions and improving overall efficiency. Given these primary drivers, the focus of the project has been on mitigating risks and ensuring long-term operational stability rather than on quantifying immediate cost savings. While the benefits of increased productivity and streamlined workflows are important, they are secondary to the urgent need to replace the obsolete technology and address the associated risks. Therefore, the decision to proceed with the Utility Network project was based on the necessity to maintain a secure and reliable system that can support future business needs, rather than a traditional cost/benefit analysis.

Witness: Kristine A. Pascarello

Date: May 27, 2025

Question:

490. Refer to page 25 of Ms. Pascarello's rebuttal testimony on the Lean Office accomplishments. Please:

- a. Confirm that the items disclosed on lines 18-23 were not previously disclosed in response to DR AG-CE-0378c (Exhibit AG-57, page 3), requesting this type of information.
- b. Explain in detail what the Lean Office specifically did to achieve the \$3.6 million of benefits tied to incentive compensation.
- c. Explain specifically what the Lean Office did to reduce the EIRP cost per mile by \$216,500.

Response:

- a. This is correct. DR AG-CE-0378c requested a list of accomplishments achieved by the Quality Lean Office. As stated on page 25 of my rebuttal testimony, the purpose of the Lean Office is to accelerate value delivery by building lean capabilities in the organization. The Lean Office mobilizes resources to support other departments in the application of the CE Way to support performance improvement. The examples provided in my rebuttal testimony were achieved by other departments with the support of the Quality Lean Office.
- b. The Lean Office has supported the owners of EICP metrics through the responsibilities listed on page 12, lines 12-23 and page 13, lines 1-17 in my direct testimony, and page 25, lines 12-17 in my rebuttal testimony. However, a specific example of the Lean Office supporting the EICP Employee Safe metrics includes, but is not limited to: (1) facilitation of problem solving on recordable injuries, (2) implementation of the CAPA process to ensure countermeasures are tracked to completion and are effective in preventing recurrence, and (3) facilitation of Failure Modes and Effects Analysis (FMEA) to reduce incident occurrences, reduce severity, and increase detection capabilities to effectively reduce risk.
- c. On page 46, lines 4-38 of my direct testimony, I provided the actions the Company has taken to reduce the cost per mile for EIRP projects. These actions were identified by leveraging the CE Way toolkit – specifically value stream mapping, problem solving, and waste elimination capabilities – to reduce engineering design lead times, streamline work planning processes, optimize resource allocation, implement quality checks to reduce defects, etc. Many of these activities were facilitated by the Lean Office and led by leaders in the gas organization – demonstrating their high level of proficiency in the CE Way. The Lean Office has been instrumental building lean capabilities through coaching, facilitating, and administering training. The Lean Office has trained 777 individuals in the gas organization. Specifically, 261 of these individuals are leaders in the gas organization progressing through the CE Way certification program designed to build proficiency through coursework, validate their ability to successfully apply their knowledge through project work, and demonstrate their facilitation capabilities to ultimately achieve their certification as a lean practitioner.

Witness: Kristine A. Pascarello

Date: May 25, 2025

Question:

491. Refer to lines 19-23 on page 6 of Mr. Sherwani's rebuttal testimony on the Company's sales and transportation volume forecasting model. Please:

- a. Identify where and when the MPSC approved a standard model or methodology to forecast gas sales and transportation volumes.
- b. Explain why a simple approach that uses a customer group most recent gas usage with recent usage trends cannot also provide an accurate forecast of volumes for the projected test year.

Response:

- a) Please refer to my direct testimony page 5 lines 14 and 15.
- b) Please refer to page 8 of my rebuttal testimony lines 19 through 22 and the related chart on page 9 showing the fluctuations in 3-year commercial transport avg use CAGR. This methodology could cause rate fluctuations and there is no evidence showing the simplistic model's accuracy.

Witness: Mustafa A. Sherwani

Date: May 27, 2025

Question:

492. Refer to lines 3-13 on page 7 of Mr. Sherwani's rebuttal testimony on Mr. Coppola's forecasting methodology for commercial transportation. Please explain why using the 2024 actual weather-normalized volumes and the three-year decreasing trend in usage is not appropriate to accurately forecast commercial transportation volume for the project test year, given that this most recent information reflects declines in usage unencumbered by unusual gas usage patterns during the 2020-2021 Covid-19 pandemic.

Response:

As stated in my rebuttal testimony on page 7, lines 5 through 7, this approach assumes customers' future behavior will be identical to the behavior during the last 3 years. This approach is simplistic and has not been proven to be accurate. The 3yr Commercial Transport Sales avg use CAGR chart on page 9 of my rebuttal testimony shows exactly the fluctuations in avg. use CAGR from 2019 to 2024.

Witness: Mustafa A. Sherwani

Date: May 27, 2025

Question:

494. Refer to lines 1-6 on page 8 of Mr. Sherwani's rebuttal testimony on the Company's sales and transportation volume forecasting model. Please confirm that the 11 years of customer usage data used by the Company includes usage data from previous customers that may no longer be customers of the Company and also includes significant variances in usage during the 2020-2021 impact of Covid-19. If not confirming, explain why not.

Response:

It is challenging to determine whether a customer who was in the Company's territory 11 years ago is still with the Company. Instead, it is more effective to view the situation in terms of service connections. When a connection is established for gas usage in the Company's territory, customers may come and go, but the usage point remains active. A new customer would typically take over the service if the previous one leaves. This ongoing transition is precisely why the Company uses regression modeling—to analyze historical data and improve the accuracy of the Company's gas delivery forecasts over time as it continuously learns.

Consumers Energy did not observe significant long-term impact from Covid-19 on gas usage. The pandemic impacted Commercial and Industrial usage during the mandated shut down but returned to normal quickly after the mandate was removed.

Witness: Mustafa A. Sherwani

Date: May 27, 2025

Question:

495. Refer to lines 7-22 on page 8 of Mr. Sherwani's rebuttal testimony on the Company's sales and transportation volume forecasting model. Please:

- a. Confirm that the forecasting models used by the Company and other utilities are as accurate as the data inputs included in the model, are not infallible, and that significant forecasting errors can occur for specific classes of customers. If not confirming, explain why not.
- b. Provide any adjustments that the Company made outside the forecasting model by customer class for the projected test year or other future years after running this forecasting model and prior models within the past five years.
- c. Confirm that any EWR volumes achieved each year are reflected in the usage decline rate calculated by Mr. Coppola for the three years and also reflected in the 2024 usage per customer for the commercial transportation class. If not confirming, explain why not.
- d. Confirm that the statement that Mr. Coppola's methodology would cause forecasts to fluctuate substantially from year to year is purely speculation given that the chart on page 9 visually exaggerates the three-year average percentage, which is generally between 0.50% to 1.50%, while the Company's model over an eight-year period has a variance of 0.60%. If not confirming, provided evidence otherwise.

Response:

- a) Please refer to my direct testimony page 5, lines 13 to 24 on how Consumers Energy uses the regression model approach to forecast sales and how each model is evaluated for reasonableness. Every model is limited by the quality of data used to develop the model (including Mr. Coppola's approach in this case, which uses lower quality data than the Company's). The Company's models are based on deliveries on customer bills, historic weather, the number of customers billed and econometric data. These factors are solid data points and are not based on conjecture.
- b) Please note that Consumers Energy evaluates each model for reasonableness and if it fits theoretically and logically. If required, the Company adjusts as necessary based on professional judgment and experience.
Per Itron, it is normal and expected that analysts will review the model results and adjust the forecast based on expert experience and judgment. Itron is the vendor of Metrix ND and serves over 150 utilities. Please see attachment U21806-AG-CE-1001_Sherwani_Attachment_1 for model adjustment for the current and prior rate case.
- c) I cannot say if Mr. Coppola's calculated usage decline rate includes EWR target volume, historic volumes are driven by many factors and the AG's simplistic approach doesn't address individual components. However, in the Company's forecast, Consumers Energy removes historic Energy Waste Reduction ("EWR") from the data and builds a regression excluding EWR. EWR savings are then added back to the regression model results historically and in the forecast period to get deliveries including EWR savings.

- d) This is not speculation, as the chart clearly illustrates, the fluctuations in the 3-year average use CAGR for Commercial Transport Sales range from -0.58% to 1.6%. The chart also demonstrates that the 3-year average CAGR approach is ineffective for predicting year-to-year changes and has no history of producing accurate forecasts.

Witness: Mustafa A. Sherwani

Date: May 27, 2025

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Year	Month	ResSlsCyc (MMcf)	ComSlsCyc (MMcf)	ComTrnCyc (MMcf)	IndTrnCyc (MMcf)
2024	10		0	0	
2024	11		0	0	
2024	12		0	0	
2025	1		2,000	-100	
2025	2		1,000	200	
2025	3		500	400	
2025	4		500	400	
2025	5		0	350	
2025	6		0	-50	
2025	7		0	0	
2025	8		0	0	
2025	9		0	0	
	total	0	4,002	1,200	0

U21806

Year	Month	ResSlsCyc (MMcf)	ComSlsCyc (MMcf)	ComTrnCyc (MMcf)	IndTrnCyc (MMcf)
2025	11	201			200
2025	12	201			200
2026	1	201			200
2026	2	201			150
2026	3	101			100
2026	4	50			100
2026	5	50			100
2026	6	50			100
2026	7	50			100
2026	8	50			100
2026	9	100			100
2026	10	150			150
	total	1,405	0	0	1,600

Question:

496. Refer to lines 1-13 on page 9 and page 10 of Mr. Sherwani's rebuttal testimony on the Company's transportation volume forecasting model results. Please:

a. Confirm that the Company has not been able to explain why commercial transportation average usage per customer decreases by 5.5% in 2025 from 2024 and an additional 0.6% in 2026. If not confirming, provide evidence otherwise.

b. Does the Company agree that it has the burden to support its forecasted sales and transportation volumes, and it is not the responsibility of intervenors in a rate case to determine how the Company's forecasting model works and why it is producing the low volume result? If not agreeing, explain why the Company does not have the burden of proof.

c. Assuming Mr. Sherwani misunderstood the previous questions in DR AG-CE-0313 and 0746 requesting an explanation for the decline in transportation volumes, please provide a clear, detailed, and complete explanation supported by data and calculations in Excel showing what caused the decline or increase in each components of transportation volumes and usage per customer, and particularly for commercial transportation, from 2024 actual weather normalized volumes to 2025 forecasted volumes and from 2025 to 2026 forecasted volumes.

Objection by Counsel: Consumers Energy objects to part b. of this discovery request on the grounds that it does not state a question of fact, but instead improperly calls for a legal conclusion. The Company also objects to part c. of this discovery request on the grounds that it assumes information which has not been established in this case. Mr. Sherwani did not misunderstand any of the Attorney General's previous discovery requests. Furthermore, both questions are argumentative and appear interposed to harass rather than to seek discoverable facts. Subject to the Company's objection, and without waiving its objection, Consumers Energy responds as follows:

Response:

- a) Not confirmed. As noted in discovery responses AG-CE-0313 and AG-CE-0746 the primary drivers for the load reduction for Transportation forecast are economic indicators and usage patterns in recent history.
- b) Consumers Energy has the burden to place in evidence facts relied upon to support the Company's application to increase its rates, including the Company's gas sales forecast. The Company has no obligation to anticipate every potential criticism that another party might attempt to make with respect to its gas sales forecast and to refute such arguments in advance, especially when they are not valid or sound criticisms. In my opinion, the Company has adequately supported its gas sales forecast in my testimony, exhibits, and audit and discovery responses. No other party except the Attorney General has offered any testimony claiming that the Company's gas sales forecast is deficient.

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- c) Please refer to U21806-AG-CE-1002_Sherwani_Attachment_1, this is the same attachment that is already provided in Part III attachment 028. I have added a column to the right showing the annual change in service production for the last five years, as you can see the service production growth is projected to be decreased in the forecast periods starting 2025 when compared to actuals. The regression translates the slower growth into reduced deliveries in the forecasted period.

Witness: Mustafa A. Sherwani

Date: May 27, 2025

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY
PART III - Standard Filing Requirements

Provide the employment and industrial production forecasts that were used as inputs in the forecasting model.

Year	Month	Empl. Weighted Production	Service Production	Real GCP	HSTART	Annual change in Srcv Prod
2020	1	89.51	99.93	101.50	19.35	
2020	2	89.41	99.95	101.69	19.49	
2020	3	89.54	100.13	102.03	19.68	
2020	4	89.88	100.46	102.51	19.91	
2020	5	90.40	100.91	103.09	20.17	
2020	6	91.07	101.45	103.75	20.44	
2020	7	91.85	102.06	104.47	20.73	
2020	8	92.72	102.72	105.22	21.01	
2020	9	93.63	103.40	105.98	21.28	
2020	10	94.56	104.09	106.71	21.52	
2020	11	95.48	104.75	107.40	21.73	
2020	12	96.34	105.36	108.02	21.90	5.43
2021	1	97.13	105.90	108.54	22.01	
2021	2	97.81	106.35	108.95	22.06	
2021	3	98.39	106.73	109.26	22.04	
2021	4	98.88	107.04	109.50	21.98	
2021	5	99.27	107.31	109.68	21.87	
2021	6	99.58	107.55	109.85	21.73	
2021	7	99.82	107.78	110.00	21.55	
2021	8	100.00	108.02	110.18	21.34	
2021	9	100.11	108.28	110.41	21.12	
2021	10	100.18	108.58	110.70	20.89	
2021	11	100.20	108.94	111.09	20.65	
2021	12	100.19	109.37	111.59	20.41	3.47
2022	1	100.15	109.89	112.23	20.18	
2022	2	100.10	110.51	113.03	19.97	
2022	3	100.02	111.21	113.97	19.78	
2022	4	99.94	111.99	115.02	19.60	
2022	5	99.84	112.83	116.16	19.44	
2022	6	99.73	113.69	117.35	19.31	
2022	7	99.62	114.58	118.57	19.21	
2022	8	99.50	115.46	119.80	19.13	
2022	9	99.39	116.33	121.01	19.08	
2022	10	99.27	117.16	122.17	19.07	
2022	11	99.16	117.93	123.26	19.09	
2022	12	99.06	118.64	124.25	19.14	8.75
2023	1	98.97	119.25	125.11	19.24	
2023	2	98.90	119.76	125.82	19.37	

2023	3	98.83	120.18	126.39	19.54	
2023	4	98.78	120.51	126.84	19.73	
2023	5	98.73	120.76	127.19	19.93	
2023	6	98.70	120.95	127.44	20.15	
2023	7	98.67	121.09	127.61	20.37	
2023	8	98.65	121.18	127.72	20.59	
2023	9	98.63	121.24	127.79	20.79	
2023	10	98.62	121.27	127.82	20.97	
2023	11	98.61	121.30	127.83	21.12	
2023	12	98.60	121.32	127.85	21.24	2.07
2024	1	98.60	121.36	127.88	21.31	
2024	2	98.59	121.41	127.94	21.33	
2024	3	98.59	121.49	128.02	21.31	
2024	4	98.58	121.57	128.12	21.24	
2024	5	98.58	121.67	128.25	21.15	
2024	6	98.57	121.79	128.39	21.03	
2024	7	98.56	121.91	128.54	20.88	
2024	8	98.55	122.03	128.70	20.73	
2024	9	98.54	122.16	128.87	20.57	
2024	10	98.52	122.29	129.04	20.40	
2024	11	98.51	122.42	129.21	20.25	
2024	12	98.49	122.55	129.37	20.10	1.19
2025	1	98.47	122.67	129.53	19.97	
2025	2	98.44	122.77	129.67	19.87	
2025	3	98.42	122.88	129.81	19.78	
2025	4	98.39	122.97	129.94	19.72	
2025	5	98.37	123.06	130.05	19.68	
2025	6	98.34	123.14	130.17	19.65	
2025	7	98.31	123.22	130.27	19.63	
2025	8	98.29	123.29	130.38	19.62	
2025	9	98.27	123.37	130.48	19.62	
2025	10	98.26	123.44	130.58	19.62	
2025	11	98.24	123.51	130.68	19.63	
2025	12	98.24	123.58	130.78	19.63	0.91
2026	1	98.24	123.65	130.88	19.64	
2026	2	98.24	123.73	130.98	19.63	
2026	3	98.25	123.80	131.09	19.63	
2026	4	98.27	123.88	131.21	19.62	
2026	5	98.29	123.96	131.32	19.61	
2026	6	98.31	124.04	131.44	19.59	
2026	7	98.33	124.12	131.56	19.58	
2026	8	98.36	124.21	131.68	19.56	
2026	9	98.38	124.29	131.80	19.55	
2026	10	98.40	124.37	131.92	19.53	
2026	11	98.42	124.46	132.04	19.52	
2026	12	98.44	124.54	132.16	19.50	0.89
2027	1	98.45	124.63	132.28	19.49	

2027	2	98.45	124.71	132.39	19.48	
2027	3	98.45	124.79	132.51	19.48	
2027	4	98.44	124.87	132.63	19.48	
2027	5	98.43	124.96	132.74	19.48	
2027	6	98.42	125.03	132.85	19.48	
2027	7	98.41	125.11	132.96	19.48	
2027	8	98.39	125.19	133.07	19.49	
2027	9	98.37	125.26	133.18	19.49	
2027	10	98.36	125.33	133.28	19.50	
2027	11	98.34	125.40	133.38	19.50	
2027	12	98.33	125.47	133.48	19.50	0.84
2028	1	98.31	125.53	133.58	19.50	
2028	2	98.30	125.60	133.67	19.50	
2028	3	98.30	125.66	133.76	19.50	
2028	4	98.29	125.71	133.85	19.50	
2028	5	98.30	125.77	133.94	19.49	
2028	6	98.30	125.83	134.03	19.48	
2028	7	98.31	125.88	134.12	19.47	
2028	8	98.32	125.94	134.21	19.45	
2028	9	98.34	126.00	134.31	19.43	
2028	10	98.36	126.06	134.41	19.40	
2028	11	98.39	126.13	134.51	19.37	
2028	12	98.42	126.20	134.62	19.34	0.67
2029	1	98.46	126.27	134.73	19.30	
2029	2	98.50	126.35	134.85	19.25	
2029	3	98.55	126.43	134.98	19.21	
2029	4	98.60	126.51	135.11	19.15	
2029	5	98.65	126.60	135.25	19.10	
2029	6	98.71	126.69	135.38	19.04	
2029	7	98.77	126.78	135.52	18.98	
2029	8	98.82	126.88	135.67	18.91	
2029	9	98.88	126.97	135.81	18.85	
2029	10	98.93	127.06	135.95	18.79	
2029	11	98.99	127.16	136.09	18.73	
2029	12	99.03	127.25	136.23	18.67	0.98

Question:

498. Refer to line 18 on page 21 through line 19 on page 22 of Mr. Warriner's rebuttal testimony on the Company's possession of TVC records under the PHMSA rule. Please explain why the Company failed to keep those basic records on the listed segments of the 11 pipelines.

Response:

Expectations regarding traceable, verifiable, and complete (TVC) record requirements were defined by code amendments enacted in 2020. The 11 pipeline segments listed on page 22 of my rebuttal testimony were originally constructed between 1969 and 2006. The Company performed a thorough document review of its available records for these segments and determined that the historical documentation found did not meet the current TVC requirements. Any attempt to explain the reasons why records complying with current TVC requirements were not maintained several years prior to the adoption of the current requirements would be speculative and highly uncertain.

Witness: Lincoln D. Warriner

Date: May 23, 2025

Question:

499. Refer to page 23 and 24 of Mr. Warriner's rebuttal testimony on the Company's possession of TVC records under the PHMSA rule. Does the Company believe it should not maintain basic records that are traceable, verifiable, and complete on its pipelines unless it is compelled to do so under federal and state rules and requirements?

Response:

The Company believes it should have traceable, verifiable, and complete pipeline records. The concept of traceable, verifiable, and complete pipeline records is a recent evolution in industry safety standards that is specifically defined by PHMSA's new requirements. Many of the historical pipeline records maintained by the Company align with the traceable, verifiable, and complete standards adopted by PHMSA. Given that the pipeline segments identified in my rebuttal testimony were constructed prior to the development of the definition of TVC recordkeeping requirements, the PHMSA rule required the review of historical records. The Company's plan to perform MAOP reconfirmation to update the existing historical records associated with those pipeline segments to the TVC standard is evidence that the Company is committed to complying with both industry safety standards and federal/state rules and regulations.

Witness: Lincoln D. Warriner

Date: May 23, 2025

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Question:

506. Refer to Figure 3 on pages 10 of Ms. Bulkley's rebuttal testimony on short-term market interest rates. Please:

- Explain why Ms. Bulkley did not show the 30-year U.S. Treasury rates in this table.
- Provide the actual 30-year U.S. Treasury rate on the date the Company filed each rate case and the 30-year Treasury rate forecasted in each rate case for the calculation of the cost of equity.

Response:

- Ms. Bulkley did provide the 30-year Treasury bond yields in Figure 3 at the referenced page. As noted, she relied on the 30-day average of the yield on the 30-year Treasury bond. The use of an average eliminates concern for outlier trading day data.
- Note Figure 3 on page 10 of Ms. Bulkley's rebuttal testimony provides the 30-day average 30-year treasury bond yield as of the decision for the company's previous rate case (U-21490) on July 23, 2024. The previous rate case (U-21490) was filed on December 15, 2023, and Ms. Bulkley was not a witness as part of this proceeding. See the table below for the 30-day average 30-year treasury bond yield, spot 30-year treasury bond yield, and the treasury bond yield used by the Company witness in the previous rate case and for the direct and rebuttal testimonies of the current rate case.

Rate Proceeding	Date	30-day average 30-year Treasury Bond Yield	Spot 30-year Treasury Bond Yield	30-year Treasury Bond Yield used in the rate case	
U-21490 Direct Filing	12/15/2023	4.49%	4.00%	4.73% ¹	
U-21490 Decision	7/23/2024	4.44%	4.48%	N/A	
U-21806 Direct Filing	12/16/2024	4.50%	4.60%	30-day average	4.07% ²
				Near-term projection	4.02%
				Long-term projection	4.30%
U-21806 Rebuttal Filing	4/30/2025	4.70%	4.66%	30-day average	4.68% ³
				Near-term projection	4.44%
				Long-term projection	4.30%

Witness: Ann E. Bulkley

Date: May 23, 2025

¹ Note this is the risk-free rate utilized by witness Todd A. Wehner in his CAPM analysis and is an estimate from Bloomberg's Forward Curve.

² Note the 30-day average of the 30-year treasury bond yield used in the direct testimony for the current rate case was as of September 30, 2024.

³ Note that 30-day average of the 30-year treasury bond yield used in the rebuttal testimony for the current rate case was as of April 25, 2024.

Question:

507. Refer to page 33 of Ms. Bulkley's rebuttal testimony on the inclusion of Chesapeake and BKH in Mr. Coppola's peer group for the calculation of the cost of capital. Please:

- a. Confirm that natural gas transmission is a regulated business for Chesapeake and an integral part of the Company that feeds the distribution pipeline system. If not confirming, provide evidence otherwise.
- b. Confirm that with 50% of the operating income coming from natural gas and the remainder primarily or entirely from the electric business BKH is a combination gas and electric utility similar to Consumers Energy, except it has a large percentage of operating income coming from the gas business than Consumers Energy. If not confirming, provide evidence otherwise.

Response:

- a. As discussed in Ms. Bulkley's rebuttal testimony at lines 2-16 on page 33, Mr. Coppola applied his regulated operating income screen inconsistently. In the case of Chesapeake, Mr. Coppola considered natural gas transmission assets as regulated operations for the purpose of this screen, whereas for Atmos Energy, Mr. Coppola excluded natural gas pipeline (transmission) assets from the calculation of operating income for its "utility business". Therefore, to be consistent with how Mr. Coppola considered the risk of the transmission pipeline operations for Atmos, it is necessarily the case that the Chesapeake natural gas transmission assets would also be excluded from the "utility business".
- b. Confirmed, however please see Ms. Bulkley's rebuttal testimony at lines 17-22 on page 33 and lines 1-3 on page 34 for the reasons that BKH should be excluded from the proxy group in this circumstance.

Witness: Ann E. Bulkley

Date: May 23, 2025

Question:

508. Refer to lines 7-23 on pages 24 of Mr. Bleckman's rebuttal testimony on the Company's equity ratio recommendation. Explain what has changed in the Company's risk profile since Case Nos. U-21585 and U-21389 to warrant a higher equity ratio.

Response:

Refer to page 14, line 6 through page 15 line 9 of my rebuttal testimony.

Witness: MARC R. BLECKMAN

Date: May 23, 2025

Question:

511. Refer to lines 7-19 on pages 26 of Mr. Bleckman's rebuttal testimony on the Company's higher net income in 2024 and his claim that the net income is skewed by non-cash transactions. Please confirm that the largest non-cash expense is depreciation expense which depresses net income and increases cash flow. If not confirming, provide evidence otherwise.

Response:

Confirmed; however, there are also several non-cash income items which are subtracted from net income to calculate cash flows such as postretirement benefits credits and allowance for equity used during construction. Regardless, as explained on page 26 of my rebuttal testimony, rating agencies do not look to net income in evaluating the Company's credit quality but instead assess the Company's cash flow metrics, including its FFO-to-Debt ratio. Rating agencies also look at the strength of the Company's balance sheet, including its equity ratio. Based on the rating agencies' criteria, the weighted rate of return authorized in this case, and not net income, will be a significant factor in determining the Company's credit quality.

Witness: MARC R. BLECKMAN

Date: May 23, 2025

Question:

512. Refer to pages 28 of Mr. Bleckman's rebuttal testimony on the pro-forma 2023 FFO-to-Debt coverage ratio calculated by Mr. Coppola and Mr. Bleckman's claims that it implies the Company actually earned an authorized ROE of 9.75% in 2023, lacks logical sense, and provides an inflated coverage ratio. Please answer:

a. Is Mr. Bleckman not familiar with pro-forma presentations of financial information that simulates what the impact would be on the FFO-to-Debt coverage ratio if the Commission approved at least a 9.75% ROE and a 50% equity ratio? If familiar, explain why Mr. Bleckman is confused by a simple pro-forma presentation that shows a positive 20.1% coverage ratio.

b. Confirm that if Mr. Coppola had used the current authorized ROE rate of 9.90% instead of 9.75% in the pro-forma calculation, the cash flow would have increased, and the coverage ratio would have been higher than 20.1%. If not confirming, provide evidence otherwise.

Response:

a. I am very familiar with pro-forma presentations of financial information. This familiarity gives me the ability to identify such presentations that are misleading and lack sound reasoning. Also, as shown on page 28 of my rebuttal testimony, there is no confusion on my part as to Mr. Coppola's distorted calculations. Instead of only calculating the pro-forma FFO-to-Debt ratio in 2023 assuming an authorized ROE of 9.75% and an equity ratio of 50%, Mr. Coppola also assumes that the Company actually earned that authorized ROE in 2023, significantly overstating the pro forma results. If Mr. Coppola was truly attempting to isolate the impact of an authorized 9.75% ROE and a 50% equity ratio on 2023 results, he would not have made this additional assumption. Mr. Coppola's results are evidence of this fallacy - Mr. Coppola is suggesting that if the Company's authorized ROE in 2023 was 15 basis points lower than it was (9.75% versus 9.90%), the Company's FFO would have been \$155 million higher. This lacks logical sense and results in a pro-forma FFO-to-Debt ratio that is significantly overstated.

b. The Company cannot confirm or validate the results of utilizing different assumptions in Mr. Coppola's pro forma analysis since, as explained in part a. of this response, Mr. Coppola's methodology lacks sound reasoning. The Company can confirm that a higher authorized ROE should result in higher FFO and credit metric results, and a lower authorized ROE should result in lower FFO and credit metric results.

Witness: MARC R. BLECKMAN

Date: May 23, 2025

Question:

513. Refer to lines 4-17 on pages 31 of Mr. Bleckman's rebuttal testimony on his expectation of new tax legislation. It is not clear if Mr. Bleckman is concerned with the U.S. Congress will pass new tax legislation to lower the corporate tax rate or what other concerns he has. Does Mr. Bleckman or the Company have information on an upcoming corporate tax rate reduction that has not been made public? If yes, please provide the source of that information and what the new tax rate will be.

Response:

As explained in my testimony, there is the potential for new tax legislation which, if enacted, could have a negative impact on the Company's cash flows and financial credit metrics. Although a reduction in the corporate income tax rate would have negative financial and credit metric impacts (similar to the Tax Cuts and Jobs Act of 2017), there now appears to be a low likelihood of such legislation passing in the near future. However, the U.S. House of Representatives recently passed a comprehensive tax reform bill which includes a phase out or repeal of portions of the Inflation Reduction Act of 2022 ("IRA"). Since aspects of the IRA allow the Company to recognize cash proceeds from tax credit sales, this could be detrimental to the Company's credit metrics. With this potential credit-harmful legislation looming during the test year of this case, it is especially important for the Commission to authorize an ROE and equity layer that will be supportive of the Company's credit quality.

Witness: MARC R. BLECKMAN

Date: May 23, 2025

Question:

514. Refer to line 18 on pages 31 and through page 32 of Mr. Bleckman's rebuttal testimony denying that CMS Energy injects debt capital in Consumers Energy as equity capital. Please identify which amounts in the two tables on page 21 of Mr. Coppola's testimony the Company disagrees with as inaccurate and provide the accurate amounts.

Response:

The Company does not validate the 2 tables on page 121 of Mr. Coppola's direct testimony. As stated in my testimony, the Company objects to Mr. Coppola's assertion that debt issued by the CMS Energy parent company is directly tied to specific equity infusions made into Consumers Energy. As explained on page 32 of my rebuttal testimony, the timing and amounts of long-term debt and equity issued by CMS Energy have no bearing on the timing and amount of equity infusions made into Consumers Energy. Equity infusions are determined after considering the capital spending and financing needs of Consumers Energy.

Witness: MARC R. BLECKMAN

Date: May 23, 2025

Question:

515. Refer to lines 7-8 on pages 15 of Mr. Bleckman's rebuttal testimony on the Company's adherence to an established selection criteria for utility equity ratios. Please confirm that by "established selection criteria" you mean a selection criteria you have decided on. If not confirming, explain otherwise.

Response:

Confirmed, as to the selection criteria outlined on Exhibit A-32 (MRB-10), which is the established selection criteria that is responsive to previous Commission orders and has been consistently applied by the Company in its peer company authorized equity ratio analyses.

Witness: MARC R. BLECKMAN

Date: May 23, 2025

Question:

516. Refer to lines 3-11 on pages 39 of Mr. Bleckman's rebuttal testimony on the forecasted amount of cash balance included in working capital. Please:

a. Confirm that using the Company's forecasted revenue would imply that the Company will receive 100% of the request rate increase, which is unlikely given recent past rate case decisions, and to base the cash balance on such an inflated forecasted revenue amount would also inflate the cash balance. If not confirming, provide evidence otherwise.

b. Confirm that the forecasted \$28.4 million cash balance requested by the Company has no basis on any actual or forecasted revenue in this rate case because the forecasted revenues are \$2.53 billion, which would result in a cash balance of \$25.3 million. If not confirming, provide evidence otherwise.

Response:

a. Confirmed that the Company's projection of the working capital cash balance is based on 1% of the test year revenues as filed by the Company in this case. Not confirming that the Company's test year revenues are "inflated." Refer to the various Company witnesses' testimony and exhibits filed in this case.

b. Not confirmed. The Company does not recognize the \$2.53 billion of forecasted revenues stated in this question. The Company's projection of the working capital cash balance is based on 1% of the test year revenues as filed by the Company in this case. Refer to Exhibit A-13 (HLR-39) which shows test year total operating revenues of \$2.313 billion. As explained on page 23 of my rebuttal testimony, the Company accepts Staff witness Hecht's cash balance of \$23,130,000. This equates to approximately 1% of test year gas revenues and, as I have shown in my rebuttal testimony, results in a level that is needed, reasonable, and adequately minimizes the Company's financial risk.

Witness: MARC R. BLECKMAN

Date: May 23, 2025

Question:

517. Refer to lines 1-5 on pages 41 of Mr. Bleckman's rebuttal testimony on the forecasted amount of cash balance included in working capital based on 1% of revenue.

- a. Does Mr. Bleckman deny the fact that under GAAP publicly-traded companies report short-term cash investments under Cash?
- b. Is it possible that prudent management would invest most of its cash in short-term investments and therefore most of the 1.9% ratio of cash to revenue reflects those short-term investments?

Response:

a. Cash investments are typically included in the "Cash" line item of the GAAP balance sheets; however, with regards to the cash analysis that the Company performed in Case No. U-17990, it was not determined whether or not the peer companies had actually had these cash investments. Even so, the peer average from that analysis was 1.9% of revenues which is 90 basis points higher than projected for the Company in the current case.

b. While it is possible for a company to invest most of its cash in short-term investments, different companies have different cash and liquidity management practices which could be considered "prudent." For example, if the Company has excess cash, it may be temporarily placed in cash investments, but it would not be invested in this manner on a long-term basis, as the Company believes excess cash should be utilized in its business (i.e. operating, capital, and financing activities). As noted in part a. of this response, it was not determined whether or not the peer companies had cash investments included in their cash balances.

Witness: MARC R. BLECKMAN

Date: May 23, 2025

Question:

518. Refer to lines 6-8 on pages 41 of Mr. Bleckman's rebuttal testimony confusing the inclusion of short-term cash investments with other cash under GAAP, which the Commission has ruled is not allowed to be included in working capital, to the use of the capital structure of publicly traded utilities used in the calculation of the cost of equity capital. Does Mr. Bleckman understand that the capital structure of each of those utilities in the peer group reflects the financial risk of those companies assessed by investors and that the financial risk and capital structure need to be synchronized with the cost of equity to determine an appropriate ROE rate and capital structure for the Company?

Response:

No, the capital structure of an ROE proxy group company at the parent holding company level should not have any bearing on the appropriate equity ratio for Consumers Energy, a regulated subsidiary. This has been made clear in the Company's testimony in rate case filings dating back several years, most recently on page 33 of my rebuttal testimony in the current case.

Witness: MARC R. BLECKMAN

Date: May 23, 2025

Question:

520. Refer to lines 3-16 on pages 44 of Mr. Bleckman's rebuttal testimony on the issuance of bonds and having a lower cash balance. Please confirm that when the Company issues bonds, even prematurely, it receives cash and therefore actual cash balances should be higher not lower. If not confirming, provide evidence otherwise.

Response:

The Company confirms that when bonds are issued, cash increases. The Company's cash balance will fluctuate month-to-month with debt issuances and retirements and also as a result of the seasonal nature of utility cash inflows and outflows. However, the Company is not projecting the cash balance for a point in time, but rather an average cash balance for the entire test year in this case.

On page 44 of my rebuttal testimony, I highlighted some of the benefits of maintaining an adequate level of cash on hand, including providing the Company with flexibility with the timing of its long-term debt issuance, while continuing to be supportive of the Company's operating and capital investment activities.

Witness: MARC R. BLECKMAN

Date: May 23, 2025